July 20, 2004

Mr. Mark Peifer
Site Vice-President
Duane Arnold Energy Center
Nuclear Management Company, LLC
3277 DAEC Road
Palo, IA 52324

SUBJECT: DUANE ARNOLD ENERGY CENTER
NRC INTEGRATED INSPECTION REPORT 5000331/2004003

Dear Mr. Peifer:

On June 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Duane Arnold Energy Center. The enclosed integrated inspection report documents the inspection findings which were discussed on July 1, 2004, with Mr. J. Bjorseth and other members of your staff.

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

Based on the results of this inspection, there was one NRC-identified and two self-revealed findings of very low safety significance, all of which involved violations of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into the licensee's corrective action program, the NRC is treating these findings and issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, licensees identified violations are listed in Section 4OA7 of this report.

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 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 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Duane Arnold Energy Center.

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Sincerely,

/RA/

Bruce L. Burgess, Chief
Branch 2
Division of Reactor Projects

Docket Nos. 50-331
License Nos. DPR-49

Enclosure: Inspection Report 5000331/2004003
w/Attachment: Supplemental Information

cc w/encl: E. Protsch, Executive Vice President -
Energy Delivery, Alliant;
President, IES Utilities, Inc.
C. Anderson, Senior Vice President, Group Operations
J. Cowan, Executive Vice President and Chief Nuclear Officer
J. Bjorseth, Plant Manager
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B. Lacy, Nuclear Asset Manager
Chairman, Linn County Board of Supervisors
Chairperson, Iowa Utilities Board
The Honorable Charles W. Larson, Jr.
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REGION III

Docket No:	50-331
License No:	DPR-49
Report No:	05000331/2004003
Licensee:	Alliant, IES Utilities Inc.
Facility:	Duane Arnold Energy Center
Location:	3277 DAEC Road Palo, Iowa 52324-9785
Dates:	April 1, 2004 through June 30, 2004
Inspectors:	G. Wilson, Senior Resident Inspector S. Caudill, Resident Inspector
Observer:	M. Franke, Reactor Engineer
Approved by:	B. Burgess, Chief Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000331/2004003; 04/01/04 - 06/30/04; Duane Arnold Energy Center; Operability Evaluations, Operator Workarounds, and Post-Maintenance Testing.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections. The inspections were conducted by a Region III reactor inspector and the resident inspectors. These inspections identified three Green findings, all of which involved Non-Cited Violations (NCV). 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: Initiating Events

- Green. A finding of very low safety significance was identified by the resident inspectors when control room operators failed to implement portions of an annunciator response procedure (ARP) 1C04B for high vibrations on the 'B' recirculation pump, after the alarm was validated locally by the vibration engineer. Once identified, the licensee conducted operator training on procedural compliance and performed a root cause evaluation to evaluate the issue of procedural noncompliance.

  The finding was more than minor since the failure to perform actions contained in approved procedures has the potential to adversely impact plant safety. The finding was determined to be of very low safety significance since no adverse transients or consequences occurred. An NCV of Technical Specification (TS) 5.4.1.a for procedural non adherence was identified. (Section 1R16)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was identified through a self-revealing event when Reactor Engineering personnel did not verify that the calculations used to determine depletion limits for the D230 Control Rods were consistent with control rod design limits. As a result, two control rods exceeded segment depletion limits. A contributing cause of this design control violation was related to the cross-cutting area of Human Performance. Once identified, the licensee performed independent calculations and verified that the rods did not exceed nodal depletion limits, thereby maintaining reactivity control. In addition, the licensee is performing a root cause evaluation for the issue.

  The finding was more than minor since, if left uncorrected, eight control rods would have potentially exceeded their design depletion limits. Rod programming sequences were changed to prevent exceeding depletion limts. The finding was determined to be of very low safety significance since the control rods design limits were not exceeded. An NCV of 10 CFR 50, Appendix B, Criterion III, was identified for the failure to ensure that design control was maintained. (Section 1R15)

- Green. A finding of very low safety significance was identified through a self-revealing event when the licensee failed to take prompt corrective actions for potential degraded underground cable after the April 2003 switchyard cable failure. Prior to the licensee performing corrective actions, an additional underground cable failure of the ‘A’ river water system (RWS) pump occurred. Once identified, the licensee replaced the cable to the ‘A’ RWS pump. In addition, the licensee is developing a degraded/aging cable program.

  The finding was more than minor since the availability and reliability of the ‘A’ RWS pump was affected. The finding was determined to be of very low safety significance since three redundant RWS pumps were still available. An NCV of 10 CFR 50, Appendix B, Criterion XVI, was identified for the failure to take prompt corrective actions. (Section 1R19)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Duane Arnold Energy Center operated at full power for the entire assessment period except for brief down-power maneuvers to accomplish rod pattern adjustments and to conduct planned surveillance testing activities with the following exceptions:

- On April 18, 2004, the reactor was shut down for a maintenance outage to replace a leaking safety relief valve. The reactor was restarted and the generator was connected to the grid on April 22. Full power was achieved on April 24.

- On April 26, there was an unplanned power reduction to 48.4 percent due to feedwater control valve oscillations resulting from a faulty valve control circuit. The circuit was repaired and full power was achieved on April 27.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather (71111.01)

.1 Situational Preparation

a. Inspection Scope

During the week ending April 10, 2004, the inspectors performed a detailed review of the licensee's procedures and a walkdown of areas to observe preparations for adverse weather, in particular, high winds and/or tornadoes for a total of one sample. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. During the inspection, the inspectors focused on plant specific system design features and implementation of procedures for responding to or mitigating the effects of adverse weather. Inspection activities included, but were not limited to, a review of the licensee's adverse weather procedures, and a review of analysis and requirements identified in the Updated Final Safety Analysis Report (UFSAR). The inspectors also verified that operator actions specified by plant specific procedures were appropriate.

b. Findings

No findings of significance were identified.

.2 Summer Preparations

a. Inspection Scope

The inspectors performed a detailed review of the licensee's procedures and a walkdown of three systems to observe the licensee's preparations for summer conditions for a total of one sample. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. During the inspection, the inspectors focused on plant specific system design features and implementation of procedures for responding to or mitigating the effects of adverse weather. Inspection activities included, but were not limited to, a review of the licensee's adverse weather procedures, preparations for the summer season, and a review of analysis and requirements identified in the UFSAR.

The inspectors evaluated summer readiness of the following three systems for a total of one sample:

- River Water Supply System de-icing secured during the week ending June 12, 2004;
- Intake Structure heating, ventilation and air-conditioning (HVAC) during the week ending June 12, 2004; and
- Pumphouse HVAC during the week ending June 12, 2004.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors performed four partial walkdowns of accessible portions of trains of risk-significant mitigating systems equipment. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Equipment alignment was reviewed to identify any discrepancies that could impact the function of the system and potentially increase risk. Redundant or backup systems were selected by the inspectors during times when the trains were of increased importance due to the redundant trains of other related equipment being unavailable. Inspection activities included, but were not limited to, a review of the licensee's procedures, verification of equipment alignment, and an observation of material condition, including operating parameters of in-service equipment. Identified equipment alignment problems were verified by the inspectors to be properly resolved.

The inspectors selected the following equipment trains to verify operability and proper equipment line-up for a total of four samples:

- ‘A’ train of the Residual Heat Removal Service Water (RHRSW) system with the ‘B’ train of RHRSW out-of-service (OOS) for maintenance during the week ending May 1, 2004;
- ‘A’ train of the Emergency Service Water (ESW) system with the ‘B’ train of ESW OOS for maintenance during the week ending May 1, 2004;
- ‘A’ train of the River Water Supply (RWS) system with the ‘B’ train of RWS OOS for maintenance during the week ending May 1, 2004; and
- Diesel Fire Pump (DFP) with the Electric Fire Pump OOS for maintenance during the week ending May 8, 2004.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Zone Walkdowns (71111.05Q)

a. Inspection Scope

The inspectors walked down nine risk-significant fire areas to assess fire protection requirements. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Various fire areas were reviewed to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and had implemented adequate compensatory measures for OOS, degraded or inoperable fire protection equipment, systems or features. Fire areas were selected based on their overall contribution to internal fire risk as documented in the plant’s Individual Plant Examination of External Events, their potential to adversely impact equipment which is used to mitigate a plant transient, or their impact on the plant’s ability to respond to a security event. Inspection activities included, but were not limited to, the control of transient combustibles and ignition sources, fire detection equipment, manual suppression capabilities, passive suppression capabilities, automatic suppression capabilities, compensatory measures, and barriers to fire propagation.

The inspectors selected the following areas for review for a total of nine samples:

During the week ending April 24, 2004:

- Area Fire Plan (AFP) 5, Drywell;
- AFP 17, Heater Bays; and
- AFP 21, North Turbine Operating Floor.

During the week ending May 1, 2004:

- AFP 25, Cable Spreading Room;
- AFP 31, Intake Structure Pump Rooms; and
- AFP 32, Intake Structure Traveling Screen Areas.

During the week ending May 8, 2004:

- AFP 7, Laydown Area 786';
- AFP 8, Standby Gas Treatment (SBGT) System; and
- AFP 9, Reactor Building Closed Loop Cooling Water (RBCCW) Heat Exchanger.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

During the week ending April 10, 2004, the inspectors performed an annual review of flood protection barriers and procedures for coping with external flooding for a total of one sample. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Inspection activities focused on verifying that flood mitigation plans and equipment were consistent with design requirements and risk analysis assumptions. Inspection activities included, but were not limited to, a review and/or walkdown to assess design measures, seals, drain systems, contingency equipment condition and availability of temporary equipment and barriers, performance and surveillance tests, procedural adequacy, and compensatory measures.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

During the week ending April 24, 2004, the inspectors observed a training crew performance on Simulator Exercise Guide (SEG) 2004C2-01 for a total of one sample. The scenario included a loss of the ‘A’ drywell cooling loop and a small break Loss of Coolant Accident (LOCA). The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. The inspection activities assessed the licensee’s effectiveness in evaluating the requalification program, ensuring that licensed individuals operated the facility safely and within the conditions of their license, and evaluated licensed operators’ mastery of high-risk operator actions. Inspection activities included, but were not limited to, a review of high risk activities, emergency plan performance, incorporation of lessons learned, clarity and formality of communications, task prioritization, timeliness of actions, alarm response actions, control board operations, procedural adequacy and implementation, supervisory oversight, group dynamics, interpretations of technical specifications, simulator fidelity, and the licensee critique of performance.

The crew performance was compared to licensee management expectations and guidelines as presented in the following documents:

- Administrative Control Procedure (ACP) 110.1, “Conduct of Operations,” Revision 1;
- ACP 101.01, “Procedure Use and Adherence,” Revision 25; and
- ACP 101.2, “Verification Process and SELF/PEER Checking Practices,” Revision 5.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed three systems to assess maintenance effectiveness. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Maintenance activities were reviewed to assess maintenance effectiveness, including maintenance rule activities, work practices, and common cause issues. Inspection activities included, but were not limited to, the licensee's categorization of specific issues including evaluation of maintenance performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed implementation of the Maintenance Rule (10 CFR 50.65) requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with reviewed condition reports, and current equipment performance status.

The inspectors performed the following maintenance effectiveness reviews for a total of three samples:

- A function-oriented review of the Standby Diesel Generator (SBDG) System was performed because it was designated as risk-significant under the Maintenance Rule, during the week ending May 22, 2004;

- A function-oriented review of the Off-site Power System was performed because it was designated as risk-significant under the Maintenance Rule, during the week ending May 29, 2004; and

- An issue/problem-oriented review of the RWS System was performed because it was designated as risk-significant under the Maintenance Rule and the system experienced problems with degraded pump breaker trip-coil control cables during the week ending June 19, 2004.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, and configuration control for a total of ten samples. An evaluation of the performance of maintenance associated with planned and emergent work activities was completed by the inspectors to determine if they were adequately managed. In particular, the inspectors reviewed the program for conducting maintenance risk safety assessments and to ensure that the planning, assessment and management of on-line risk was adequate. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Licensee actions taken in response to increased on-line risk were reviewed including the establishment of compensatory actions, minimizing activity duration, obtaining appropriate management approval, and informing appropriate plant staff. These activities were accomplished when on-line risk was increased due to maintenance on risk-significant structures, systems, and components (SSCs).

The following activities were reviewed for a total of ten samples:

- The inspectors reviewed the maintenance risk assessment for work planned during the weeks of April 10, April 17, May 1, May 8, May 15, May 22, May 29, June 12, June 19, and June 26, 2004.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions and Events (71111.14)

a. Inspection Scope

During the week ending April 24, 2004, the inspectors observed portions of the licensee's power ascension and post maintenance testing activities associated with the replacement of pressure set valve (PSV) 4401 for a total of one sample. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Operator performance in the control room was observed including evolutions to place steam seals in service, establish initial condenser vacuum, start steam jet air ejectors, heat up and pressurize the reactor, withdraw control rods to increase power, initiate reactor feed pump operation, roll the turbine, and synchronize the generator to the grid.

In addition, the inspectors observed that the licensee effectively prepared for and conducted a drywell entry to visually confirm that there was no leakage from PSV-4401. For this evolution, the inspectors verified that the licensee took the necessary radiation protection and personnel safety measures to minimize personnel exposure and preclude injuries.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed seven of the licensee's operability evaluations of degraded or non-conforming systems. The documents listed in the Attachment were used by the inspectors to accomplish the objectives of the inspection procedure. Operability evaluations were reviewed that affected mitigating systems or barrier integrity cornerstones to ensure adequate justification for declaration of operability and that the component or system remained available. Inspection activities included, but were not limited to, a review of the technical adequacy of the evaluation against the Technical Specifications (TSs), UFSAR, and other design information; validation that appropriate compensatory measures, if needed, were taken; and comparison of each operability evaluation for consistency with the requirements of ACP-114.5, "Action Request System" and ACP-110.3, "Operability Determination."

The inspectors reviewed the following operability evaluations for a total of seven samples:

- Operability (OPR) 000258, Electrical Conduit for Motor Operator (MO) 2202, during the week ending April 10, 2004;
- OPR 000257, Control Relay (CR) 4841 needs replacement, during the week ending April 17, 2004;
- OPR 000260, Bearing clearance for High Pressure Core Injection (HPCI), during the week ending April 17, 2004;
- Corrective Work Order (CWO) A671908, Bracket Loose for SCRAM Outlet Valve for Control Rod 26-15, during the week ending April 17, 2004;
- OPR 000261, Fuel Pool Exhaust Duct Radiation Monitor, during the week ending May 15, 2004;
- Corrective Action Plan (CAP) 002213, Source Range Monitor (SRM)/Intermediate Range Monitor (IRM) Overlaps, during the week ending May 15, 2004; and
- OPR 00265, Control Rods, during the week ending June 19, 2004.

b. Findings

Introduction: A finding of very low significance (Green) and an associated Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to the failure to ensure that the D230 control rods would be able to perform their design function was identified through a self-revealing event.

Description: In January 2004, an individual from Reactor Engineering evaluated the new segment depletion limits as specified in General Electric (GE) Service Information Letter (SIL) 637 for D230 control rods. Depletion limits are used to ensure that the control rods contain sufficient negative reactivity to shut down the reactor and maintain it shut down under all conditions. The evaluation concluded that all control rods would remain below the segment depletion limits for the current cycle and that no compensatory measures were necessary.

During a non-routine process to verify the potential for control rod blade damage based on unusual lithium values contained in a chemistry sample, a reactor engineer identified that two D230 control rods had exceeded their depletion limits as specified by GE. Upon further review, the Reactor Engineering group discovered that the projected control rod exposures entered in the January 2004 evaluation were wrong, causing the software produced results to be incorrect. In addition, they also identified that no peer checking or alternate projection method was used to evaluate whether or not errors had been inadvertently used during control rod design verification calculations. The failure to properly verify design calculations used to determine control rod segment depletion limits resulted in the exceeding of design segmental depletion limits for two control rods. An ancillary concern was the fact that the data entered into the calculation by the reactor engineer was not verified for accuracy and was considered to be a human performance deficiency.

Upon finding that the segment depletion rates were exceeded for two rods, the Reactor Engineering group had additional discussions with GE and were informed that the actual limiting depletion rate was a nodal limit and not a segment limit. Independent calculations were then performed, which verified that none of the control rods had exceeded the nodal depletion limits. Further evaluation showed that eight high exposure control rods would have potentially exceeded the nodal depletion limits if the planned rod sequences were not modified. Therefore, compensatory measures were required to ensure that the control rod design limits were maintained. The failure to ensure that the design control calculations were properly verified to ensure that the depletion limits of specific control rods were maintained within design parameters was an example of inadequate design control. Recalculation of depletion limits required that rod sequence exchanges be altered to ensure that adequate core reactivity control was maintained.

Analysis: The inspectors determined that the design control measure used to calculate that the D230 control rods would meet their design function was not adequate and was a performance deficiency. Since a performance deficiency existed, the inspectors reviewed this issue against the guidance contained in Appendix B, "Issue Dispositioning Screening," of Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports." In particular, the inspectors compared this finding to the findings identified in Appendix E, “Examples of Minor Issues,” of IMC 0612 to determine whether the finding was minor. Following that review, the inspectors concluded that the guidance in Appendix E was not applicable for the specific finding. As a result, the inspectors compared this performance deficiency to the minor questions contained in Appendix B of IMC 0612. The inspectors determined that the finding was more than minor because if the condition was left uncorrected, it would have become a more significant safety concern. The more significant safety concern was based on the fact that eight rods were identified that could have potentially exceeded design depletion limits without compensatory actions.

To assess the safety concern, the inspectors reviewed this issue in accordance with IMC 0609, “Significance Determination process (SDP).” The inspectors determined that the finding affected the Mitigating Systems Cornerstone; however, since the incorrect calculation did not result in GE nodal limits being exceeded, did not represent the actual loss of a safety function, did not exceed a TS Allowed Outage Time (AOT), did not represent an actual loss of safety function for a non-Tech Spec train, and was not risk significant due to seismic, fire, flooding or severe weather, that the finding was of very low safety significance and screened as Green.

Enforcement: 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires, in part, that design control measures shall provide for verifying or checking the adequacy of designs, such as by performance of design reviews or by use of alternate or simplified calculational methods. Following a rod sequence exchange in June 2004, the Reactor Engineering group identified that the original calculations performed in January 2004 for GE SIL 637 did not have adequate measures to verify or check that the calculation results were within design parameters. A subsequent calculation identified that compensatory measures would have to be put into place to ensure control rod design limits were not exceeded. The failure to ensure that the calculations performed in January for D230 control rods, which are part of a 10 CFR 50, Appendix B system, provided sufficient measures to check or verify that design parameters were met was an example of a violation of 10 CFR 50, Appendix B, Criterion III. However, because of its low safety significance and because it was entered into the corrective action program, the NRC is treating this issue as a Non-Cited Violation (NCV 5000331/2004003-01), in accordance with Section VI.A.1 of the NRC’s Enforcement Policy. This issue was entered into the licensee’s corrective action program as CAP 031891.

Corrective actions taken included adjusting rod sequence exchanges to ensure depletion limits are not exceeded. In addition, a root cause analysis is being performed on the issue to evaluate the overall event.

1R16 Operator Workarounds (71111.16)

.1 Individual Workaround

a. Inspection Scope

The inspectors reviewed one operator workaround (OWA). Inspectors used the documents listed in the Attachment to accomplish the objectives of the inspection procedure. Inspectors verified that the selected OWA did not impact the functionality of a mitigating system. Inspection activities included, but were not limited to, a review of the selected OWAs to determine if the functional capability of the system or human reliability in responding to an initiating event was affected, including a review of the impact of the OWAs on the operator's ability to execute Emergency Operating Procedures (EOPs).

The inspectors reviewed the following OWA for a total of one sample:

- CAP 031427, "Departure from established procedure," during the week ending June 19, 2004.

b. Findings

Introduction: A finding of very low safety significance (Green) and an associated NCV of TS Specification 5.4.1, related to the failure to follow the annunciator response procedure (ARP) for high vibrations in the 'B' recirculation pump in accordance with Regulatory Guide 1.33 was identified by the resident inspectors.

Description: On April 27, 2004, the Operators received annunciator 1C04B, "'B' Recirc Pump Motor Hi Vibration." During the performance of the ARP 1C04B, the Operators did not perform Step 3.4, which requires that the speed of both recirculation pumps be reduced as necessary to clear the high vibration condition. The step was not performed, even though the alarm was validated locally by the vibration engineer.

Instead ACP 101.01, "Procedure Use and Adherence" was used by the operators to depart from the ARP 1C04B based on various inputs from Engineering and Plant Management. After reviewing the sequence of events, the resident inspectors challenged Plant Management on the decision to not perform the ARP as written.

Plant Management reevaluated the event and determined that ACP 101.01 had been inappropriately used to depart from ARP 1C04B. Step 4.2.3 of ACP 101.01 only allows the departure from the procedure when the safety of persons, the reactor, or other equipment is in immediate jeopardy, which was not the case in this situation. Therefore, Plant Management agreed that procedural adherence was not maintained during the performance of ARP 1C04B.

Analysis: The inspectors determined that the plant operator's failure to follow the ARP was an example of not complying with a procedural requirement that could have reasonably been foreseen or corrected by the licensee and was a performance deficiency.

Since a performance deficiency existed, the inspectors reviewed this issue against the guidance contained in Appendix B, “Issue Dispositioning Screening,” of IMC 0612, “Power Reactor Inspection Reports.” In particular, the inspectors compared this finding to the findings identified in Appendix E, “Examples of Minor Issues,” of IMC 0612 to determine whether the finding was minor. Following that review, the inspectors concluded that the guidance in Appendix E was not applicable for the specific finding. As a result, the inspectors compared this performance deficiency to the minor questions contained in Appendix B of IMC 0612. The inspectors determined that the finding was more than minor, since if it was left uncorrected, it would become a more significant safety concern. This was based on the fact that the failure to perform actions and procedures based on valid plant indications and parameters has the potential to adversely impact plant safety.

As a result, the inspectors reviewed this issue in accordance with IMC 0609, “SDP.” The inspectors determined that the finding affected the Initiating Event Cornerstone; however, since the failure to follow the annunciator procedure did not contribute to the likelihood of a Primary Or Secondary System LOCA, did not contribute to the likelihood of a reactor trip or affect mitigating plant equipment, or increase the likelihood of a fire or flooding, that the finding was of very low safety significance and screened as Green.

Enforcement: TS 5.4.1.a and Regulatory Guide 1.33, Revision 2, Appendix A, Section 5 requires ARPs to be properly performed in accordance with written procedures or documented instructions appropriate to the circumstances. Contrary to this requirement, operations personnel failed to perform a specific portion of ARP 1C04B for the high vibration on the ‘B’ recirculation pump on April 27, 2004. Step 3.4, which requires that the speed of both recirculation pumps be reduced as necessary to clear the high vibration condition, was not performed. The failure to follow a portion of the ARP as it was written was an example where the requirements of TS 5.4.1.a, were not met and was a violation. However, because of its low safety significance and because it was entered into the corrective action program, the NRC is treating this issue as a Non-Cited Violation (NCV 5000331/2004003-02), in accordance with Section VI.A.1 of the NRC’s Enforcement Policy. This issue was entered into the licensee’s corrective action program as CAP 031427.

Corrective actions taken included training on procedural adherence for the Operations Department and the revision of ACP 101.01. In addition, an independent assessment was performed on procedural compliance.

.2 Semiannual Workaround Review

a. Inspection Scope

During the week ending April 17, 2004, the inspectors performed a semiannual review of the cumulative effects of OWAs for a total of one sample. The documents listed in the Attachment were reviewed to accomplish the objectives of the inspection procedure. OWAs were reviewed to identify any potential effect on the functionality of mitigating systems. Inspection activities included, but were not limited to, a review of the cumulative effects of the operator workarounds on the availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents. Additionally, reviews were conducted to determine if the workarounds could increase the possibility of an initiating event, if the workaround was contrary to training, required a change from long standing operational practices, created the potential for inappropriate compensatory actions, impaired access to equipment, or required equipment uses for which the equipment was not designed.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed ten post-maintenance testing (PMT) activities. The documents listed in the Attachment were used to accomplish the objectives of the inspection procedure. PMT procedures and activities were verified to be adequate to ensure system operability and functional capability. Inspection activities were selected based upon the SSC's ability to impact risk. Inspection activities included, but were not limited to, witnessing or reviewing the integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use and compliance, control of temporary modifications or jumpers required for test performance, documentation of test data, system restoration, and evaluation of test data. Also, the inspectors verified that maintenance and PMT activities adequately ensured that the equipment met the licensing basis, TS, and UFSAR design requirements.

The inspectors selected the following PMT activities for review for a total of ten samples:

- Preventative Work Order (PWO) 1128061, Pilot Valve for Main Steam Line 'A' Low-Low-Set (LLS) Relief Valve (PSV-4401) during the week ending May 1;
- PWO 1128062, Relief Valve Body for Main Steam Line 'A' LLS Relief Valve (PSV-4401) during the week ending May 1;
- CWO A67068, Main Steam Drain Valve to Condenser (CV-1064), during the week ending May 1;
- CWO A67100, 'A' Feed Reg Valve, during the week ending May 1, 2004;
- CWO A59650, Electric Fire Pump Replacement, during the week ending May 8, 2004;
- CWO A57287, 'A' Reactor Protection System (RPS) Motor Generator (MG) Set, during the week ending May 8, 2004;
- PWO 1123230, Remove Residual Heal Removal (RHR) Heat Exchanger (HX) 1E-201B Discharge Header Pressure Relief Valve, during the week ending May 15, 2004;
- CWO A61158, Replace 'B' RHR Pump Seal Water Cooler with New Cooler, during the week ending May 15, 2004;

- PWO 1125797, Mechanical Maintenance Inspection of ‘B’ SBDG, during the week ending May 21, 2004; and
- CWO A65013, Received 125 volts direct current (Vdc) System 1 Trouble Alarm, June 14, 2004.

b. Findings

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, were identified for the failure to take timely corrective actions to address potential degraded underground cable through a self-revealing event.

Description: During June 2004, Electrical Maintenance had to replace the safety-related 125Vdc underground cables for the ‘A’ RWS pump due to degradation. The degraded cable was identified by a lit ground annunciator in the main control room.

A similar degraded 125Vdc underground cable replacement was performed in the switchyard in April 2003. Following that failure, the resident inspectors questioned Plant Management and Engineering on the extent of condition of the potential underground cable degradation, with particular emphasis being placed on the safety-related cables for the batteries and for the RWS at the intake structure.

An action plan was put into place by the licensee to develop and establish a program to evaluate potential degraded underground cables. The program was never fully developed or any other actions taken to evaluate the potential degraded underground cables prior to this additional failure occurring on the safety-related cables of the “A” RWS pump at the intake structure. After reviewing the actions that were performed for evaluating potential degraded underground cable, Plant Management agreed that timely corrective actions were not taken.

Analysis: The inspectors determined that the degradation of cables that rendered a RWS pump inoperable was a condition that could have been reasonably foreseen and therefore was a performance deficiency. Since a performance deficiency existed, the inspectors reviewed this issue against the guidance contained in Appendix B, “Issue Dispositioning Screening,” of IMC 0612, “Power Reactor Inspection Reports.” In particular, the inspectors compared this finding to the findings identified in Appendix E, “Examples of Minor Issues,” of IMC 0612 to determine whether the finding was minor. Following that review, the inspectors concluded that the guidance in Appendix E was not applicable or useful for the specific finding. As a result, the inspectors compared this performance deficiency to the minor questions contained in Appendix B of IMC 0612. The inspectors concluded that the issue was more than minor since the finding affected the cornerstone attribute of mitigating systems and the availability and reliability of the ‘A’ RWS pump.

The inspectors reviewed this issue in accordance with Manual Chapter 0609, “SDP," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." The inspectors determined that the finding affected the Mitigating Systems Cornerstone; however, because the failure to perform timely corrective actions did not constitute a design deficiency that resulted in a loss of function per GL 91-18, did not represent the actual loss of a safety function, did not exceed the TS AOT, did not represent an actual loss of safety function for a non-Tech Spec train, and were not risk significant due to seismic, fire, flooding or severe weather, that the finding was of very low safety significance and screened as Green.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures be established to assure that conditions adverse to quality, such as defective material and equipment, deficiencies, and nonconformances are promptly identified and corrected. In April 2003, the electrical maintenance shop replaced a degraded underground 125Vdc cable in the switchyard. The issue was entered into the corrective action program but actions were not taken to evaluate the remaining underground cables. In June 2004, an additional failure occurred, that resulted in the 'A' RWS pump 125Vdc underground cables being replaced due to degradation. The degraded cable affected the availability and reliability of the 'A' RWS pump, which is an Appendix B system. The failure to perform prompt corrective actions to evaluate potential degraded underground cable was considered an example of where the requirements of 10 CFR 50, Appendix B, Criterion XVI were not met and was a violation. However, because of its low safety significance and because it was entered into the corrective action program, the NRC is treating this issue as a Non-Cited Violation (NCV 5000331/2004003-03), in accordance with Section VI.A.1 of the NRC's Enforcement Policy. This issue was entered into the licensee's corrective action program as
CAP 031811.

Corrective actions taken include the replacement of the 125Vdc cable to the 'A' RWS pump and the plan to develop a degraded cable monitoring program.

1R20 Outage Activities (71111.20)

.1 Forced Outage for PSV 4401 Replacement

a. Inspection Scope

The inspectors observed shutdown activities for the forced outage to replace PSV- 4401, which began on April 18, 2004, for a total of one sample. Activities monitored by the inspectors included the licensee's cooldown process and that TSs were followed during the transition into Modes three and four. Outage configuration management was also monitored on a daily basis by verifying that the licensee maintained appropriate defense in depth to address all shutdown safety functions and satisfy TS requirements.

Proper operation of the decay heat removal system was reviewed during multiple reactor building and control room tours and observations. The licensee restarted the reactor on April 22, 2004. The documents listed in the Attachment were used to accomplish the objectives of the inspection procedure.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed five surveillance test activities. Inspection procedure objectives were accomplished as indicated by the documents listed in the Attachment to this inspection report. Surveillance testing activities were reviewed to assess operational readiness and ensure that risk-significant SSCs were capable of performing their intended safety function. Surveillance activities were selected based upon risk significance and the potential risk impact from an unidentified deficiency or performance degradation that a SSC could impose on the unit if the condition were left unresolved. Inspection activities included, but were not limited to, a review for preconditioning, integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use, control of temporary modifications or jumpers required for test performance, documentation of test data, TS applicability, impact of testing relative to Performance Indicator (PI) reporting, and evaluation of test data.

The inspectors selected the following surveillance testing activities for review for a total of five samples:

- Surveillance Test Procedure (STP) 3.3.6.3-04, LLS Pressure Setpoint Channels Calibration, during the week ending April 17, 2004;
- STP 3.10.4-01, Single Control Rod Withdrawal (Cold Shutdown), during the week ending April 24, 2004;
- STP 3.5.1-02, Low Pressure Coolant Injection (LPCI) System Operability Test, during the week ending May 1, 2004;
- STP 3.3.6.1-34, Room Temperature Monitoring Channel Calibration, during the week ending May 1, 2004; and
- STP 3.8.7-01, LPCI Swing Bus Alternating Current (AC) and Direct Current (DC) Undervoltage Transfer Test, during the week ending May 8, 2004.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed two temporary modifications. The documents listed in the Attachment were used to accomplish the objectives of the inspection procedure. Temporary modifications were reviewed to assess the modification’s impact on the safety function of the associated systems. Inspection activities included, but were not limited to, a review of design documents, safety screening documents, UFSAR, and applicable TSs to determine that the temporary modification was consistent with modification documents, drawings and procedures. Inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified.

The inspectors selected the following temporary modifications for review for a total of two samples:

- Temporary Modification 04-019, “Change Power Supply Feed to Several Area Radiation Monitors Associated with E/S9150C,” during the week ending May 1, 2004; and
- Temporary Modification 04-016, “Temporary Feedwater Vent Restraints,” during the week ending June 26, 2004.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

On June 23, 2004, the inspectors observed an Emergency Preparedness (EP) drill for a total of one sample. The drill simulated a failure of a radioactive waste high integrity container during a transfer of resin from the reactor water cleanup (RWCU) system, followed later by a main steam line double-ended rupture.

Inspectors evaluated the licensee’s drill conduct and the adequacy of the post-drill performance critique to identify weaknesses and deficiencies. The documents listed in the Attachment were used to accomplish the objectives of the inspection procedure. Exercises that the licensee had previously scheduled were selected to provide input to the Drill/Exercise PI. Inspection activities included, but were not limited to, the classification of events, notifications to off-site agencies, protective action recommendation development, and drill critiques. Observations were compared with the licensee’s observations and corrective action program entries. Inspectors verified that there were no discrepancies between observed performance and reported PI statistics.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Barrier Integrity

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors reviewed the licensee PI submittals for a total of two PIs. Performance Indicator guidance and definitions contained in Nuclear Energy Institute (NEI) Document 99-02, Revision 2, “Regulatory Assessment Performance Indicator Guideline,” were used to verify the accuracy of the PI data. The documents listed in the Attachment were used to accomplish the objectives of the inspection procedure. The inspectors’ review included, but was not limited to, conditions and data from logs, LERs, condition reports, and calculations for each PI specified.

The following PIs were reviewed for a total of two samples during the week ending May 8, 2004:

- Reactor Coolant System (RCS) Specific Activity, for the period of March 2003 through March 2004; and
- RCS Leakage, for the period of March 2003 through March 2004.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

For inspections performed and documented 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 corrective action program 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 corrective action program as a result of the inspectors’ observations are included in the attached list of documents reviewed.

b. Findings

A specific issue related to the failure to perform prompt corrective actions on potential degraded underground cable was discussed in Section 1R19.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

b. Findings

Two specific issues which involved Licensee-Identified Violations were identified during this daily review as discussed in Section 4OA7.

.3 Semi-Annual Trend Review

a. Inspection Scope

Inspectors performed a review of the licensee's CAPs and associated documents to identify trends that could indicate the existence of a more significant safety issue. This review focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in section 4OA2.2 above, licensee trending efforts, and licensee human performance results. Nominally, the review considered the six-month period of January 2004 through June 2004, although some examples expanded beyond those dates when the scope of the trend warranted.

The inspectors' semi-annual trend review also included issues documented in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The results of this trend review was compared and contrasted with the results contained in the licensee's CAP and Nuclear Oversight Department reports. Corrective actions associated with a sample of the trends identified by the licensee were reviewed for adequacy.

Inspectors also evaluated the licensee's trending CAPs against the requirements of the licensee's Corrective Action Program as specified in ACP 114.8, "Action Request Trending," Revision 5. Additional documents reviewed are listed in the attachment.

b. Findings and Issues

No findings or issues of significance were identified.

.4 Instructions, Procedures and Drawings

Introduction: During routine reviews of the licensee's CAPs issued during 2004, the inspectors noted that inadequate instructions, procedures, and drawings have caused several problems. These problems have included delays in completing TS STPs, potential unplanned breaches of secondary containment, and potential cases of procedural noncompliance.

The inspectors selected the following CAPs for review:

- CAP 30395, BECH M133 Prints Need Drains Labeled to Show If They Penetrate Containment, January 15, 2004;
- CAP 30846, Possible Secondary Containment Concern When Filling RW Demineralizers with Resin, February 26, 2004;
- CAP 31068, Revision to STP 3.5.1-01 (Core Spray Operability Test) Introduced Errors, March 22, 2004;
- CAP 31445, Error in Calculation of Tritium Values in STP, April 28, 2004;
- CAP 31555, Unable to Perform STP NS100102, RWS, Due to Procedure Error, May 9, 2004;
- CAP 31577, Completion on RCIC Quarterly STP Delayed Due to Not Meeting Suction Pressure Step, May 10, 2004;
- CAP 31861, Direction in STP-NS530001 Unclear to Hold Time for SBLC Pumps, June 3, 2004; and
- CAP 32008, Procedure Changes not Following Directions of ACP 106.1, June 17, 2004.

a. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the multiple related CAPs to determine if they addressed generic implications and that corrective actions were appropriately focused to correct the problem.

(2) Issues

The licensee began an overall effort to address problems associated with inadequate instructions, procedures, and drawings in late 2003. As such, the licensee began measures to improve procedure quality and validation through enhanced staff training and benchmarking. A program was started to review and validate all the "Notes and Cautions" statements in safety-related procedures to correct hidden error traps. Another effort was underway to consolidate and enhance the existing site-wide procedure writing guidance into a single document. In addition, the licensee also instituted a more rigorous on-line method to help ensure adequate procedure validation, including validating new Abnormal Operating Procedures (AOPs) in the control room simulator.

In spite of these efforts, the inspectors observed that problems continue to exist with the validation of procedures and drawings. The inspectors concluded that, while overall programmatic improvements are underway, more generic and fundamental weaknesses will need resolution to ensure that adequate procedures and drawings are provided to plant staff. In particular, the inspectors noted several cases in which accurate technical information such as set points, throttled valve positions, drawing and instrumentation labels, and lubricating oil levels were not effectively incorporated into procedures or drawings during either the development, review or validation process.

The inspectors will continue to evaluate the licensee's efforts to improve procedures and drawings by reviewing the cumulative effect of their corrective actions.

.5 Work Scheduling, Planning, and Equipment Tag-Out Deficiencies

Introduction: During routine reviews of the licensee's CAPs issued since May 2004, the inspectors noted numerous examples of delays in beginning or completing maintenance on both non-safety and safety-related SSCs due to inadequate work scheduling/planning, inadequate communication between departments, and incorrect equipment tag-outs. Some of these resulted in unplanned entries into or extensions of TS Limiting Condition for Operations (LCOs), or unnecessary equipment unavailability. On two separate occasions, the failure to properly communicate issues in the work scheduling/control process challenged the Operations Department's ability to manage the plant risk profile.

The inspectors selected the following CAPs for review:

- CAP 31600, Conflicting Items Scheduled Together, May 12, 2004;
- CAP 31726, Scheduling Didn't Identify Unavailability Risk Item Until The Day of Performance, May 21, 2004;
- CAP 31784, Work Removed From the Schedule Was Not Adequately Communicated and Reviewed, May 27, 2004;
- CAP 31859, Three Fuel Pool Cooling Work Orders (WOs) Postponed Due to Scheduling Conflicts, June 3, 2004;
- CAP 31880, Planning for Work Order A62795 Was Found to Be Incomplete, June 6, 2004;
- CAP 31916, Scheduled Valve Work Removed From Schedule Unexpectedly, June 9, 2004; and
- CAP 32084, Annual Pre-Planned Task for Temperature Control Valve TCV-6935B Was Not Scheduled Causing Unplanned Chiller LCO, June 24, 2004.

a. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the multiple related CAPs to determine if they addressed generic implications and that corrective actions were appropriately focused to correct the problem.

(2) Issues

Several corrective measures have been put into place, since problems with the work scheduling/planning process were previously identified in August 2003. Beginning in May 2004, the work control program was revised to incorporate new staff positions for Work Week Coordinators. The Work Week Coordinators will work with the previously established Cycle Scheduler position for overall schedule analysis and control. In addition, the licensee moved from a 10-week to a 13-week scheduling process to be current with industry standards. Discussions with licensee staff indicated that the new process will take some time to effectively mature.

The inspectors focused their observations on CAPs generated since the new work scheduling/control process was implemented in May 2004. By the number of issues seen thus far, the implementation of the new process has not yet solved all the problems associated with work control management. In addition, the inspectors concluded that generic and basic fundamental weaknesses, such as interdepartmental communications and errors in the equipment tagging process, contributed to several of the work control problems. Until these generic and basic fundamental weaknesses are resolved, problems will continue to exist.

Evaluation of the licensee's efforts to improve overall work scheduling and control by reviewing the cumulative effect of their corrective actions will continue.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R15 of this report had, as its primary cause, a human performance deficiency, in that, the Reactor Engineering group failed to properly perform and verify calculations to ensure that the D230 control rods would meet and maintain design depletion limits throughout the current fuel cycle.

4OA5 Other Activities

.1 TI 2515/156, Offsite Power System Operational Readiness

Cornerstone: Initiating Events, Mitigating Systems

a. Inspection Scope

The inspectors reviewed licensee maintenance records, event reports, corrective action documents and procedures, and interviewed the station engineering, maintenance, and operations staff to collect data necessary to complete the Temporary Instruction (TI) 2515/156. This review was conducted to confirm the operational readiness of the offsite power systems in accordance with NRC requirements such as Appendix A to 10 CFR Part 50, General Design Criterion (GDC) 17; Criterion XVI of Appendix B to10 CFR Part 50, Plant TS for offsite power systems; 10 CFR 50.63; 10 CFR 50.65 (a)(4), and licensee procedures. Specifically, the inspectors reviewed the licensee's procedures and processes for ensuring that the grid reliability conditions are appropriately assessed during periods of maintenance in accordance with the maintenance rule 10 CFR 50.65 (a)(4). The inspectors also assessed the reliability and grid performance through a review of historical and current data to verify compliance with the station blackout rule 10 CFR 50.63, TS, and GDC 17. Lastly, the inspectors assessed the licensee's implementation of operating experience that was applicable to the site as well as corrective action documents to ensure issues were being identified at an appropriate threshold, assessed for significance, and then appropriately dispositioned. Inspectors used the documents listed in the Attachment to accomplish the objectives of the TI.

b. Observations and Findings

No findings of significance were identified. Based on the inspection, no immediate operability issues were identified. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data in the work sheets provided with the TI to the headquarters staff for further analysis.

The inspectors have summarized below the licensee's responses to the significant issues reviewed during the TI.

(1) There is a contractual agreement in place between the Nuclear Management Company and the Nuclear Power Plant Asset Owner Titled "Nuclear Power Plant Operating Services Agreement Between Alliant Energy – IESU and Nuclear Management Company" which discusses offsite power supply in Exhibit B Section 6.0.

(2) "Mid-Continent Area Power Pool (MAPP) Members Reliability Criteria and Study Procedures Manual," dated August 6, 2003, address acceptable voltage ranges. Per this document, DAEC would use the criteria for 161 kV buses in the MAPP. Therefore, for the 161kV bus, normal range (steady state) is 153kV to 169kV; transient range (minimum) is 113kV to 193 kV; and post contingency range is 145kV to 177kV.

(3) Plant AOP 304 "Grid Instability" lists a probable Indication of potential grid instability as notification from the System Operating Center (SOC). A parallel SOC procedure "Operating Procedure in preparation for high grid loading and potential instability" states that the American Transmission Company (ATC) Transmission Operator will notify the DAEC Plant Operator:

- Whenever two or more transmission lines are open to the plant or a configuration of line outages that would directly affect flows to/from DAEC.
- Major grid disturbance which results in islanding of portions of the midwest region or the islanding of portions of the Eastern Interconnection.
- System Frequency declining, or frequency deviations.
- Loss of two or more 345/161 kV Transformers in eastern Iowa area.

- Storm Warnings, severe weather warnings with potential to seriously affect grid flows in eastern Iowa or southern Minnesota areas.

- Whenever DAEC 161KV switchyard voltage drops to 95 percent or below for either actual or potential grid conditions, within 5 minutes or as soon as possible.

(4) When an emergency diesel generator is set to 'unavailable' in the on-line risk model (ORAM-Sentinel), the startup and standby transformer are listed in its remain-in-service list. This would normally lead to restricting maintenance activities in the switchyard.

Work Procedure Guidelines (WPG) -2 Section 4.0 (2) (f) states that “Systems Engineering is responsible for: Ensuring that the Switchyard System Engineer or Design Engineer reviews the weekly transmission outage schedule and notifying the Operations Shift Manager/Control Room supervisor and the Scheduling Team Leader of potential impacts to offsite power circuits terminating at the DAEC substation.”

(5) WPG-2, Section 6.2 (6) (a) states that “Prior to entering the LCO, the Control Room Supervisor shall: (a) evaluate the current plant maintenance, surveillance and operational activities to ensure that the concurrent activities will not compromise plant safety or performance. Also, evaluate potential for adverse impact from conditions external to the facility such as extreme high or low outside air temperatures, high or low river water levels, or degraded offsite power availability. Entry into the LCO should only be done with the plant in a stable condition. “

WPG-2, Section 6.2(12) states that, “The following guidelines apply to the number of transmission lines that can be removed from service for maintenance: Work outside these guidelines may be allowable per TSs. However, these guidelines have been developed to minimize the risk of loss of offsite power. If emergency work outside of these guidelines is required, it should be given high priority.”

In addition, DAEC plant operating personnel should notify the ATC Transmission Operator to obtain current grid conditions when: the generating unit automatic voltage regulator control is NOT available; whenever unit Power System Stabilizer (PSS) is NOT available; or, other significant plant or unit equipment problems / limitations exist that could cause a unit scram or forced plant outage. The grid information is to be used as part of the decision-making process for routine testing and maintenance procedures at DAEC Plant or Substation to help ensure reliable plant and interconnected transmission operations.

(6) There have been two different Loss of Offsite Power (LOOP) events at the DAEC. During the LOOP event in 1984, both Emergency Diesel Generators (EDGs)

started to power the essential loads within 10 seconds. Offsite power was never lost, just degraded.

During the LOOP event in 1990, the ‘B’ Emergency Diesel Generator (EDG) started immediately to power the essential loads and offsite power was restored in 37 minutes.

Per the UFSAR, DAEC has a design coping time of four hours for a LOOP.

(7) The licensee initiated CAP 029018 on September 12, 2003, in response to the Institute of Nuclear Power Operation (INPO) Significant Event Notification - 242, Loss-of-Grid event, August 14, 2003. Previous evaluations of Significant Operating Event Report (SOER) 99-01 and SOER 2003-01 evaluated LOOP frequency and coping time. They are documented on action request AR 18401 and CAP 25245.

The licensee completed a review of the generic lessons learned and identified the weakness that resulted in follow up corrective action plans being developed. The Operations Department is looking into the lessons learned from other stations for procedure improvements to streamline the restoration of non safety-related electrical buses and to ensure system walkdowns are performed before mechanical systems are restored that may not be properly aligned for startup. A corrective action plan Other (OTH) 36085 has been written to evaluate this.

The Emergency Planning Group is looking into the problems associated with cordless phones, pagers, and cellular phones. Many employees only had cordless phones in their homes and when power was lost they could not be contacted for a call out of the emergency response organization. In addition, cellular phones were affected by the extended losses of electrical power and the systems were also overloaded. A corrective action plan OTH 36086 has been written to evaluate this and other problems associated with the emergency response facilities and actions. The other items being evaluated by OTH 36086 are the potential connection of a diesel to the off-site facility, cooling/ventilation problems in the Technical Support Center, communication with off-site agencies, computer unavailability, and the availability of flashlights for personnel.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. J. Bjorseth and other members of licensee management on July 1, 2004. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

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

Cornerstone: Mitigating Systems

.1 10 CFR 50.65(a)(4), requires, in part, that before performing maintenance activities (including, but not limited to, surveillance, post maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to these requirements, the licensee failed to adequately manage risk during the repairs on the control rod drive (CRD) pump room coolers. Specific instructions were written to ensure that temporary cooling was in place prior to isolating the coolers in the maintenance tagging activities. The licensee had determined that alternate room cooling was needed to maintain the CRD pumps' availability. It would be provided by propping open the CRD Pump Room's upper and lower doors, and staging a temporary fan to force air circulation. On May 7, 2004, the coolers were isolated without providing the alternate heat removal method as described in the tagging activities. Therefore, the plant risk profile was inadvertently increased from Green to Yellow. Since the room did not reach the design temperature limits during cooler isolation and the licensee identified the problem and took immediate corrective actions, this violation is of low safety significance and is being treated as an NCV. The licensee documented the issue in CAP 31539.

Cornerstone: Mitigating Systems

.2 10 CFR 50 Appendix B, Criterion XI, "Test Control," requires, in part, that a test program shall be established to assure that all testing required to demonstrate that SSCs will perform satisfactorily in-service is identified and performed in accordance with written test procedures and that adequate test instrumentation is available and used. Contrary to these requirements, Instrument and Control technicians performed STP 3.3.2.1-02, "Rod Block Monitor (RBM) Calibration" on May 6, 2004, for the 'A' channel using a digital multimeter of less accuracy than procedurally required. The STP was also being used to ensure post maintenance operability of the RBM, due to the replacement of capacitors in the system. After the calibration, the 'A' channel was declared operable and returned to service. During the subsequent performance of the 'B' channel calibration, the technicians realized that the wrong digital multimeter had been used for the 'A' RBM calibration, and the 'A' RBM was declared inoperable. The 'A' channel calibration was then satisfactorily completed with the correct test equipment. Since neither RBM was required by a limiting control rod pattern during the period of inoperability, and the licensee identified the problem and took immediate corrective actions, this violation was of low safety significance, and is being treated as an NCV. The licensee documented the issue in CAP 31552.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
M. Peifer, Site Vice President
J. Bjorseth, Site Director
D. Curtland, Plant Manager
S. Catron, Regulatory Affairs Manager
M. Davis, Acting Operations Manager
S. Haller, Acting Site Engineering Director
B. Kindred, Security Manager
C. Kress, Training Manager
W. Simmons, Maintenance Manager
D. Wheeler, Chemistry Manager
J. Windschill, Radiation Protection Manager

Nuclear Regulatory Commission
D. Beaulieu, Project Manager, NRR
B. Burgess, Chief, Reactor Projects Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

5000331/2004003-01	NCV	Failure to Ensure that Adequate Design Control was maintained for D230 Control Rods (1R15)
5000331/2004003-02	NCV	Failure to Follow the Annunciator Response Procedure for Recirculation Pumps (1R16)
5000331/2004003-03	NCV	Failure to Perform Prompt Corrective Actions for Potential Degraded Underground Cable (1R19)

Closed

5000331/2004003-01	NCV	Failure to Ensure that Adequate Design Control was maintained for D230 Control Rods (1R15)
5000331/2004003-02	NCV	Failure to Follow the Annunciator Response Procedure for Recirculation Pumps (1R16)
5000331/2004003-03	NCV	Failure to Perform Prompt Corrective Actions for Potential Degraded Underground Cable (1R19)

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

AOP 903, Tornado, Revision 13
Integrated Operating Instructions (IPOI) 6, Attachment 2, Plant Return To Normal (From Cold Weather Alignment) Checklist, Revision 29, June 4, 2004
CAP 31158, Perform a Summer Reliability Review, April 1, 2004
Summer Reliability Plan, June 1, 2004
OTH 37559, System Engineering Summer Reliability Review, June 2004
OTH 37562, Operations Summer Reliability Review, June 2004
CAP 32032, IPOI 6 for Securing from Plant Cold Weather Lineup Not Completed Per Schedule, June 18, 2004
CAP 31881, Well Water System Configuration Problems Following Summer Lineup, June 6, 2004
CAP 31424, Returning DAEC to and from Winterization Conflicting with Mechanics' Tasks, April 27, 2004
CAP 32009, Control Building Chillers Spring Setup for IPOI 6, June 17, 2004
CAP 031737, Effects on Plant Due to May 22, 2004 Storm, May 23, 2004
CAP 031985, EP Response Generated during the Tornado/Flood Event of May 21, 2004, June 16, 2004
CAP 32082, Excessive Flow to the Chillers Found After Semi-Annual Setup, June 24, 2004
CAP 31525, Maintenance Workload (The main intake coils have yet to be filled with well water as required by IPOI 6), May 5, 2004

1R04 Equipment Alignment

Operating Instruction (OI) 513A1, Fire Protection System-Electrical Lineup, Revision 2
OI 513A2, Fire Protection System-Valve Lineup, Revision 7
OI 416A6, RHRSW System Control Panel Lineup, Revision 4
OI 416A1, RHRSW System Electrical Lineup, Revision 2
OI 416A2, 'A' RHRSW System Valve Lineup, Revision 5
OI 410A2, 'A' River Water Supply System Valve Lineup, Revision 12
OI 410A1, RWS System Electrical Lineup, Revision 7
OI 454A1, ESW System Electrical Lineup, Revision 1
OI 454A2, 'A' ESW System Valve Lineup, Revision 6
OI 454A6, ESW System Control Panel Lineup, Revision 0

CAP 31470, “Abandoned Equipment in Intake Structure Needs Removal or Identification,” April 30, 2004 (NRC Identified)

1R05 Fire Protection

AFP 5, Drywell, Revision 24
AFP 7, Laydown Area 786', Revision 25
AFP 8, SBGT System, Revision 23
AFP 9, RBCCW Heat Exchanger, Revision 23
AFP 17, Heater Bays, Revision 22
AFP 21, North Turbine Operating Floor, Revision 22
AFP 25, Cable Spreading Room, Revision 24
AFP 31, Intake Structure Pump Rooms, Revision 24
AFP 32, Intake Structure Traveling Screen Areas, Revision 26
CAP 31446, “Divers’ Equipment Including Ropes and Hoses Left Without Combustible Permit,” April 28, 2004 (NRC Identified)

1R06 Flood Protection Measures

AOP 902, Flood, Revision 21
CAP 31243, “Caulking for Flooding Material not in the Warehouse,” April 9, 2004 (NRC Identified)
Nuclear Oversight Observation Report 2003-003-1-010
CAP 031738, River Water Level Predicted to Surpass AOP 902 Action Level, May 23, 2004

1R11 Licensed Operator Requalification Program

SEG 2004C2-1, Loss of ‘A’ Drywell Cooling, Small Break LOCA, Revision 0
EOP 2, Primary Containment Control, Revision 12
EOP 1, Reactor Pressure Control, Revision 11
Emergency Action Level (EAL) Table 1, Revision 2
ACP 110.1, Conduct of Operations, Revision 1
ACP 101.01, Procedure Use and Adherence, Revision 26
ACP 101.2, Verification Process and SELF/PEER Checking Practices, Revision 5

1R12 Maintenance Effectiveness

March/April 2004 Maintenance Rule Monitoring and Status Report, April 30, 2004
Maintenance Rule Performance Criteria Basis Document for SBDGs, Revision 3
Maintenance Rule Performance Criteria Basis Document for Offsite Power, Revision 3
Maintenance Rule Performance Criteria Basis Document for RWS System, Revision 2
CWO A67134, 1K010C will not start. The fuel solenoid is not picking up, May 7, 2004
CWO A65372, Excessive movement in the swivel ball joint of the lower rod end uniball bearing in the governor fuel control linkage (See Attached), June 11, 2004
CWO A65079, During STP 3.8.1-05, the diesel was loaded to 2750-2950 KW. A few unexplained load swings, June 16, 2004
CWO A70142, DS44 would not flash until diesel was loaded to approximately 500 KW. All other lights were flashing, March 17, 2004

CWO A58368,Threads damaged on four port inlet to turbocharger. Female threads on inbd. bolted connection at manifold extension flange for, October 2, 2003

CWO A62912, Compressor tripped. Had to reset @ 175 PSIG to continue filling, June 13, 2003
CWO A62586, During work under CWO A61678 it was found that SV3262B has AC Internal parts installed in a DC application, April 23, 2003
CWO A60577, Diesel generator 1G31, 125VDC ground caused by arcing in/around SS3237A, March 4, 2003
CWO A60172, Component is leaking 5 DPM of diesel on engine while diesel is running, May 17, 2004
CWO A67912, We received numerous internal pressure relief alarms. Transformer is not pressurized, March 29, 2004
PWO 1123734, Transformer inspection, March 29, 2004
PWO 1127517, Oil circuit breaker major service and inspection inspect isolation switch SW9181 and SW9182, August 31, 2004
PWO 1127293, SF6 Breaker major maintenance inspect isolation switch SW4731, SW4732 and SW7122, October 05, 2004
CWO A65700, Damaged lighting arrestor caused loss of XR1 and T4. Located in north east portion of switchyard, July 12, 2004
CWO A63140, CB2820 Phase ‘C’ C.T. still has a SF6N2 leak. This was overhauled in Spring 2002 under CWO A53632, still leaked and was attempted to fix in Fall, May 28, 2004
CWO A62085, Trace wire and cable from switchyard control house distribution panel AC#3, circuit breaker #18, January 10, 2004
CWO A61614, High combustible gas alarms reading 1.2 percent on TCB monitor. Inspect and repair transformer per ARP, April 23, 2003
CWO A62370, 125 Volt ground indication on charger. Operator noted voltage and AMP fluctuations, May 1, 2003
CWO A60923, J Breaker failed to close after 1X3 work window, February 10, 2003
CAP 30313, CB5550 (J) Breaker Failed to Close Following Maintenance on Startup Transformer, January 8, 2004
CAP 30589, Maintenance Rule 50.65(a) RED, Switchyard Breakers, Repetitive MPFF, February 2, 2004
CAP 30628, Hazelton (161kV) Line Problem, February 5, 2004
CAP 31602, Main Generator Auto Voltage Regulator Unstable, May 12, 2004
Condition Evaluation (CE) 001727, Perform a Re-work Evaluation on ‘B’ RWS Screen Wash INOP following Calibration, June 16, 2004
CAP 031811, 125Vdc grounds found out of spec without alarm, June 3, 2004
CE 001704, 125Vdc grounds found out of spec without alarm, June 3, 2004
CWO A65013, Received 125 VDC System 1 Trouble Alarm, June 14, 2004
CAP 31464, Pull Boxes on Vaults for Duct Bank on the Way Out to Intake Structure, April 30, 2004 (NRC Identified)
CAP 32074, Pre-Installation Verification Not Performed, June 23, 2004
CAP 32077, Cut Incorrect Cable While Repairing ‘A’ RWS Control Cables, June 23, 2004

1R13 Maintenance Risk Assessments and Emergent Work Control

WPG - 2, On-Line Risk Management Guideline, Revision 17

Maintenance Risk Evaluation for Week 14, Revision 0, March 23, 2004
CAP 31124, Revised Risk Review of Week 14, 2004, March 29, 2004
Maintenance Risk Evaluation for Week 14, Revision 1, March 29, 2004
DAEC Online Schedule, Week 9413/9414, March 26, 2004
Startup Transformer Work, Level A Plan, March 15, 2004
Maintenance Risk Evaluation for Week 16, April 7, 2004
Level A Plan for ‘B’ Control Building Chiller Work, Revision 5, March 22, 2004
Online “LookAhead” Work Schedule Report for Week 16, April 6, 2004
Maintenance Risk Evaluation for Week 16 April 2, 2004
DAEC Online Schedule Week 16, April 2, 2004
Maintenance Risk Evaluation for Week 17, April 9, 2004
DAEC Online Schedule Week 17, April 9, 2004
Maintenance Risk Evaluation for Week 18, April 23, 2004
DAEC Online Schedule Week 18, April 23, 2004
Maintenance Risk Evaluation for Week 19, April 30, 2004
DAEC Online Schedule Week 19, April 30, 2004
CAP 031539, Failure to Verify Conditions as specified, May 7, 2004
Maintenance Risk Evaluation for Week 20, May 7, 2004
DAEC Online Schedule Week 20, May 7, 2004
Maintenance Risk Evaluation for Week 21, May 14, 2004
DAEC Online Schedule Week 21, May 14, 2004
Maintenance Risk Evaluation for Week 22, May 21, 2004
DAEC Online Schedule Week 22, May 21, 2004
Maintenance Risk Evaluation for Week 24, June 4, 2004
DAEC Online Schedule Week 24, June 4, 2004
Maintenance Risk Evaluation for Week 25, June 11, 2004
DAEC Online Schedule Week 25, June 11, 2004
CAP 031997, Two Risk Assessments were Contradictory, June 16, 2004
Maintenance Risk Evaluation for Week 26, June 18, 2004
DAEC Online Schedule Week 26, June 18, 2004

1R14 Personnel Performance During Non-Routine Plant Evolutions and Events

IPOI 3; Power Operation; Revision 64
IPOI 2; Startup; Revision 78
PWO 1128061, Remove Pilot Valve for Main Steam Line ‘A’ Low-Low-Set Relief Valve (PSV-4401) and Replace with Spare, March 30, 2004
PWO 1128062, Remove Relief Valve Body for Main Steam Line ‘A’ Low-Low-Set Relief Valve (PSV-4401), and Replace with Spare, March 30, 2004

1R15 Operability Evaluations

ACP 110.3, Operability Determination, Revision 1
ACP 114.5, Action Request System, Revision 32
OPR 000258, Electrical Conduit for MO 2202, March 10, 2004
OPR 000257, CR 4841needs replacement, March 8, 2004
OPR 000260, Bearing clearance for HPCI, March 12, 2004

CWO A671908, Bracket Loose for SCRAM Outlet Valve for Control Rod 26-15, April 13, 2004
OPR 000261, Fuel Pool Exhaust Duct Radiation Monitor, May 4, 2004
CAP 002213, SRM/IRM Overlaps, August 13, 1998
Safety Evaluation 98-124
OPR 00265, Control Rods, June 9, 2004
CAP 031891, Control Blades 22-15 and 22-31 have exceeded segmental depletion limits, June 7, 2004

1R16 Operator Workarounds

ACP 1410.12, Operator Burden Program, Revision 0
Semiannual Assessment of Aggregate Impact of Equipment Issues on Operator Response, January 12, 2004
Long-Term Tagout Sections List, March 20, 2004
Temporary Modification Index, February 21, 2004
Degraded Indicating Instrument Log, March 20, 2004
Monthly Tagout Audit, March 20, 2004
Monthly Degraded Instrument Audit, March 20, 2004
Monthly Temporary Modification Audit, March 20, 2004
Monthly Lit Annunciator Audit, March 20, 2004
Monthly Operator Workarounds Audit, March 20, 2004
Monthly Operator Challenges Audit, March 20, 2004
CAP031427, Departure from established procedure, April 27, 2004
ARP 1C04B, “B” Recirc Pump Motor High Vibration, Revision 11
ACP 101.01, Procedure Use and Adherence, Revision 25
CAP 32029, “Poor Control Room Log Entries on Operability/Inoperability of Tech. Spec. Equipment,” June 18, 2004 (NRC Identified)

1R19 Post-Maintenance Testing

PWO 1128061, Remove Pilot Valve for Main Steam Line ‘A’ Low-Low-Set Relief Valve (PSV-4401) and Replace with Spare, March 30, 2004
PWO 1128062, Remove Relief Valve Body for Main Steam Line ‘A’ Low-Low-Set Relief Valve (PSV-4401), and Replace with Spare, March 30, 2004
STP 3.4.3-03, Manual Opening and Exercising of the ADS and LLS Relief Valves, Revision 5
CWO A67068, CV-1064 Has No open Indication When Taken to Open, April 19, 2004
STP 3.6.1.3-06, ASME In-Service Valve Testing, Revision 12
STP 3.3.3.1-06, Valve Position Indicator Verification - Shutdown, Revision 4
A67100, ‘A’ Feed Reg Valve, April 26, 2004
CWO A57287, ‘A’ RPS MG Set, May 3, 2004
CWO A59650, Electric Fire Pump Replacement, May 3, 2004
STP NS13B005, Electric Driven Fire Pump Full Flow Discharge Test for NFPA Trending, Revision 11
STP NS13B010, Electric Driven Fire Pump Monthly Operability Tests, Revision 7
CAP 31591, 1P-48 Failed to Pass STP NS13B005, May 12, 2004

CAP 31630, Peer Review of 1P-48 Vibration Data to Ensure Reliable Operation of Pump, May 14, 2004
CAP 31632, 1P-48 Vibrations Remain Elevated to Pre-Pump Replacement Activities, May 14, 2004
PWO 1123230, Remove RHR HX 1E-201B Discharge Header Pressure Relief and Replace with Spare, February 10, 2004
PWO 1125797, Mechanical Maintenance Inspection of ‘B’ SBDG, May 20, 2004
CAP 031605, Plant Page Speaker in Valve Repair Room, May 13, 2004 (NRC Identified)
CAP 031811, 125Vdc grounds found out of spec without alarm, June 3, 2004
CE 001704, 125Vdc grounds found out of spec without alarm, June 3, 2004
CWO A65013, Received 125 VDC System 1 Trouble Alarm, June 14, 2004
CAP 31464, Pull Boxes on Vaults for Duct Bank on the Way Out to Intake Structure, April 30, 2004 (NRC Identified)
CAP 32074, Pre-Installation Verification Not Performed, June 23, 2004
CAP 32077, Cut Incorrect Cable While Repairing ‘A’ RWS Control Cab les, June 23, 2004

1R20 Outage Activities

IPOI 1; Startup Checklist; Revision 92
IPOI 2; Startup; Revision 78
IPOI 3; Power Operation; Revision 64
IPOI 4; Shutdown; Revision 65
IPOI 8; Outage & Refueling Operation; Revision 33
Outage Schedule Risk Review; April 8, 2004
Outage Schedule for PSV 4401; April 18, 2004

1R22 Surveillance Testing

STP 3.3.6.3-04, Low-Low Set Pressure Setpoint Channels Calibration, Revision 7
STP 3.5.1-02, LPCI System Operability Test, Revision 12
STP 3.3.6.1-34, Room Temperature Monitoring Channel Calibration, Revision 5
STP 3.8.7-01, LPCI Swing Bus AC and DC Undervoltage Transfer Test, Revision 5
STP 3.10.4-01, Single Control Rod Withdrawal (Cold Shutdown), Revision 3

1R23 Temporary Modifications

ACP 1410.6, Temporary Modification Process, Revision 38
Temporary Modification 04-019, Change Power Supply Feed to Several Area Radiation Monitors Associated with E/S9150C, March 5, 2004
Temporary Modification 04-016, Temporary Feedwater Vent Restraints, February 27, 2004
CAP 30852, Temporary Restraining Device Installed Prior to Completion of Temp. Mod. Paperwork, February 26, 2004
CAP 030777, RFP 1P-1A Discharge Vent Pipe Vibration, February 19, 2004
CAP 32090, Clarify 50.59 Expectations In Temp Mod Procedure ACP 1410.6,

June 24, 2004

1EP6 Drill Evaluation

2004 Full Scale Emergency Response Drill Scenario, June 23, 2004
Emergency Plan Implementing Procedure (EPIP) 1.1, Emergency Plan Implementing Procedure, Revision 19
EPIP 2.5, Control Room Emergency Response Operation, Revision 14
EAL, Determination of Emergency Action Levels, Revision 2
EOP 1, RPV Control, Revision 9
EOP 2, Primary Containment Control, Revision 9
EOP 3, Secondary Containment Control, Revision 10
CAP 32109, Missed 2 NRC PI Notification Opportunities During EP Drill, June 25, 2004
CAP 32110, Full Scale Emergency Response Drill Issues & Enhancements, June 25, 2004

4OA1 Performance Indicator Verification

NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 2
ACP 1402.4, NRC Performance Indicators Collection and Reporting, Revision 3
Memorandum, DAEC 4th Quarter 2003 PI Summary, January 21, 2004
Memorandum, DAEC 3rd Quarter 2003 PI Summary, October 21, 2003
Memorandum, DAEC 2nd Quarter 2003 PI Summary, July 20, 2003
Memorandum, DAEC 1st Quarter 2003 PI Summary, April 21, 2003
Plant Chemistry Procedure (PCP) 1.2, DAEC Chemistry Quality Assurance Program, Revision 18
PCP 2.13, Reactor Water Sampling, Revision 11
PCP 6.10, Reactor Coolant Iodine and Crud Activity, Revision 3
Form 218, Reactor Water Isotopic, Revision 1, Data from May 7, 2004
Form 321, Reactor Water - Counting, Revision 7, Data from May 7, 2004
VMS Quality Assurance Report V1.3, Ge-Li Detector No. 3, May 7, 2004
DAEC Chemistry Report for Detector No. 3, 2 Liter MAR BKG, May 7, 2004

4OA2 Identification and Resolution of Problems

ACP 114.4, Corrective Action Program, Revision 16
ACP 114.5, Action Request System, Revision 40
ACP 114.8, Action Request Trending, Revision 5
ACP 106.1, Procedure Preparation, Revision, Review, and Approval, Revision 37
CAP 30746, ECP 1679 Was Worked and Closed Without Procedures Being Ready or Issued, February 17, 2004
CAP 30860, Nuclear Oversight Assessment: ACP 101.13, ‘Medical Response’ Not Consistent With EPIP 4.2, ‘First Aid, Decontamination, and Medical Support,’ February 27, 2004
CAP 31597, Change Made on ACP 1411.26, Att. 7, Revision 3, Doesn’t Match Tag and Wrong Revision Being Used, May 12, 2004
CAP 031760, Discrepancy Between UFSAR and AOP-902 ‘Flood’, May 25, 2004

CAP 031855, Changes Needed to Flood Protection Procedure, June 3, 2004
ACP 1206.13, Equipment Database Control Program, Revision 7
CAP 031779, Return to Service of FPC ‘A’ F/D Delayed Due to Lack of Procedural Guidance, May 26, 2004
CAP 031764, Determine if Infrequent Sections of OIs Require a Biennial Review per ACP106.1, May 26, 2004
CAP 031569, Unreasonable Procedural Actions Based on Plant Operation, May 10, 2004
CAP 031664, Mispositioned HS2001B (2/3 Core Covered/LPCI Init Interlock Override), May 18, 2004
CAP 031422, Request Engineering Evaluation on IPOI-3, April 27, 2004
CAP 030965, RCIC Turbine (1S203) Oil Level Above High Mark, March 10, 2004

4OA5 Other Activities

Calculation-E95-006, 4.16kv Essential Bus Degraded Voltage, Revision 3
Calculation-E02-006, Analysis of 1A3 Essential Electrical Power, Revision 1
Mid-Continent Area Power Pool Reliability Criteria and Study Procedures Manual, August 6, 2003
ATC Operating Procedure Memorandum, Revision 1
AOP 304, Grid Instability, Revision 7
Nuclear Power Plant Operating Services Agreement between Alliant Energy and Nuclear Management Company, 1999
WPG-2, On-Line Risk Management Guideline, Revision 17
OTH 001437, Evaluate risk evaluation criteria for offsite power in WPG-2, May 27, 2004
Performance Criteria Basis Document, Offsite Power, Revision 3
Licensee Event Report (LER) 50-331/90-007
LER 50-331/84-028
CAP 029018, INPO Significant Event Notification -242, Loss-of-Grid event, August 14, 2003
OTH 036085, INPO Significant Event Notification -242, Loss-of-Grid event, November 7, 2003
OTH 036086, INPO Significant Event Notification -242, Loss-of-Grid event, November 7, 2003
Action Request 18401, SOER 99-01 “Loss of Grid”, January 13, 2000
CAP 25245, SOER 2003-1, Emergency power Reliability, January 20, 2003
CAP 031874, Load Dispatcher Unable to see our Net Generation, June 6, 2004

4OA7 Licensee-Identified Violations

CAP 031539, Failure to Verify Conditions as specified, May 7, 2004
CAP 031552, STP 3.3.2.1-02 performed with wrong test equipment, May 8, 2004

LIST OF ACRONYMS USED

AC	Alternating Current
ACP	Administrative Control Procedure
ADS	Automatic Depressurization System
AFP	Area Fire Plan
AR	Action Request
ARP	Annunciator Response Procedure
AOP	Abnormal Operating Procedure
AOT	Allowed Outage Time
ATC	American Transmission Company
CAP	Corrective Action Plan
CE	Condition Evaluation
CFR	Code of Federal Regulations
CR	Control Relay
CRD	Control Rod Drive
CWO	Corrective Work Order
DC	Direct Current
DFP	Diesel Fire Pump
DRP	Division of Reactor Projects
EAL	Emergency Action Level
ECP	Engineering Change Package
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
ESW	Emergency Service Water
FPC	Fire Protection Control
GDC	General Design Criteria
GE	General Electric
GL	Generic Letter
HPCI	High Pressure Core Injection
HVAC	Heating, Ventilation, Air-Conditioning
HX	Heat Exchanger
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operation
IPOI	Integrated Plant Operating Instructions
IR	Inspection Report
IRM	Intermediate Range Monitor
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLS	Low-Low Sett
LOCA	Loss of Coolant Accident
LOOP	Loss Of Offsite Power
LPCI	Low Pressure Coolant Injection
MAPP	Mid-Continent Area Power Pool

LIST OF ACRONYMS USED

MG	Motor Generator
MO	Motor Operator
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NCV	Non-Cited Violation
OI	Operating Instruction
OOS	Out-Of-Service
OPR	Operability
OTH	Other
OWA	Operator Workaround
PARS	Publicly Available Records
PCP	Plant Chemistry Procedure
PI	Performance Indicator
PMT	Post-Maintenance Testing
PSS	Power System Stabilizer
PSV	Pressure Set Valve
PWO	Preventative Work Order
RBCCW	Reactor Building Closed Loop Cooling Water
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup
RWS	River Water Supply
SBDG	Standby Diesel Generator
SBGT	Standby Gas Treatment
SDP	Significance Determination Process
SEG	Simulator Exercise Guide
SIL	Service Information Letter
SOC	System Operating Center
SOER	Significant Operating Event Report
SRM	Source Range Monitor
SSC	Structures, Systems, Components
STP	Surveillance Test Procedure
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
Vdc	Volts Direct Current
WPG	Work Procedure Guidelines
WO	Work Order