UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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LISLE, IL 60532-4352

February 3, 2010

Mr. Charles G. Pardee
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO), Exelon Nuclear
4300 Winfield Road
Warrenville IL 60555

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000456/2009005; 05000457/2009005

Dear Mr. Pardee:

On December 31, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Braidwood Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on January 7, 2010, with Mr. A. Shahkarami 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, three NRC-identified findings and one self-revealed finding of very low safety significance (Green) were identified. These findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy*.* Additionally, licensee 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 disagreement, 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 Braidwood Station. In addition, if you disagree with the characterization the cross-cutting aspect of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Braidwood Station. The information that you provide will be considered in accordance with Inspection Manual Chapter 0305.

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

Sincerely,

/RA/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-456; 50-457
License Nos. NPF-72; NPF-77

Enclosure: Inspection Report 05000456/2009005; 05000457/2009005
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2009005 and 05000457/2009005
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	October 1 through December 31, 2009
Inspectors:	B. Dickson, Senior Resident Inspector A. Garmoe, Resident Inspector M. Holmberg, Reactor Inspector R. Jickling, Senior Emergency Preparedness Inspector M. Mitchell, Health Physicist R. Ng, Project Engineer B. Palagi, Senior Operations Engineer M. Perry, Resident Inspector Illinois Department of Emergency Management B. Metrow, Illinois Department of Emergency Management
Observers:	J. Gall, Nuclear Safety Professional Development Program Participant
Approved by:	R. Skokowski, Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000456/2009005, 05000457/2009005; 10/01/2009 - 12/31/2009; Braidwood Station, Units 1 & 2; Inservice Inspection Activities; Operability Evaluations; Post Maintenance Testing; Followup of Events and Notices of Enforcement Discretion

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. The inspectors identified three Green findings and one self-revealed Green finding. The findings were considered Non-Cited Violations of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Cross-cutting aspects were determined using IMC 0305, “Operating Reactor Assessment Program.” 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 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a Green finding and an associated Non-Cited Violation of Technical Specification 5.4.1 for the failure to fully implement an abnormal procedure following a seismic event. Specifically, on April 18, 2008, following a seismic event, the licensee chose to perform field walkdowns to verify that sulfuric acid and sodium hypochlorite tanks were intact rather than to isolate control room ventilation as required by Procedure 0BwOA ENV-4, “Earthquake.” As a corrective action, the licensee performed training activities to clarify when procedural deviations are allowed.

  The finding was determined to be more than minor because it impacted the procedure quality attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors evaluated the finding in accordance with IMC 0612, Appendix B, “Issue Screening.” The inspectors performed a significance evaluation in accordance with IMC 0609, Attachment 4, “Determining the Significance of Reactor Inspection Findings for At-Power Situations.” The inspectors answered ‘No’ to the external event initiators question in the Initiating Events Cornerstone column of Table 4a and the issue screened as one of very low safety significance. This finding is associated with the cross-cutting attribute of decision making in the Human Performance cross-cutting component (H.1(b)). Specifically, the licensee did not use conservative assumptions in the decision to send an operator to locally verify rather than perform a procedural step from the control room as written. In the event the sulfuric acid and sodium hypochlorite tanks were damaged, the control room operators could have been impacted with chlorine gas prior to receiving verification from the locally dispatched operator since the licensee elected not to isolate control room ventilation. (Section 4OA3)

Cornerstone: Mitigating Systems

- Green. On October 20, 2009, the inspectors identified a Green finding and an associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, for the licensee's failure to follow work order instructions and establish a 2-to-1 weld profile on the auxiliary feedwater system cross-tie pipe drain line socket welds. Licensee corrective actions included rejecting the nonconforming welds, establishing interim guidance for the range of acceptable socket weld profiles, and initiating revisions to weld procedures to clarify applicable instructions.

  The inspectors determined that this finding was more than minor because, if left uncorrected, the failure to properly control maintenance activities could become a more significant safety concern. Specifically, the failure to implement a 2-to-1 socket weld profile could result in a vibration induced pipe fatigue failure affecting the operability of Unit 2 Auxiliary Feedwater System Train "A." This finding was of very low safety significance because it was a design or qualification deficiency, confirmed to not result in loss of operability or functionality. This finding has a cross-cutting aspect in the area of Human Performance, Resources because the licensee did not provide adequate procedural resources (H.2(c)). Specifically, the licensee failed to ensure that the work instruction for the welding contained adequate guidance to implement the required 2-to-1 weld profile. (Section 1R08.1.b)

- Green. The inspectors identified a Green finding and an associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," related to post maintenance testing. Specifically, the licensee failed to follow maintenance procedures and work instructions by performing the post maintenance testing prior to completing work on the 2B Auxiliary Feedwater Pump Essential Service Water cooling water supply. As part of the corrective actions for this issue, the licensee retested the valve and revised the affected surveillance test procedure.

  The inspectors concluded that the finding was more than minor because the licensee returned equipment to an operable status following maintenance without performing required testing. Licensee Procedure MA-AA-716-012, "Post Maintenance Testing," Revision 11, requires that "post maintenance testing shall be performed following any corrective and some preventive maintenance activities on plant equipment that may have impacted the equipment's ability to perform its intended function." The performance of a flow scan may impact the stroke time of a valve, therefore post maintenance testing was required following completion of the flow scan testing.

  Using the Significance Determination Process Phase 1 worksheet of IMC 0609.04, the inspectors determined the finding affected the Core Decay Heat Removal attribute of the Mitigation Systems Cornerstone. Because subsequent testing confirmed that no loss of operability or functionality existed the finding was determined to be of very low safety significance. The finding has a cross-cutting aspect in the area of Human Performance, Work Control, because the licensee performed work packages out of sequence, thereby allowing a safety system to be returned to service without the required post maintenance testing after completion of all work (H.3.(b)). (Section 1R19.b(1))

- Green. A Green finding and an associated Non-Cited Violation of Technical Specification 5.4.1 was self-revealed for the failure to follow procedures during the restoration of the essential service water supply valve to the engine driven cooling water pump for the 2B auxiliary feedwater pump (2SX173) following scheduled maintenance. This issue resulted in a water hammer occurring in the essential service water system. The licensee walked down the system to ensure that the essential service water system was not damaged. Additionally, the licensee developed training actions to emphasize procedural adherence.

  The inspectors determined the finding was more than minor because it impacted the Human Error attribute of the Mitigating System Cornerstone to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors performed a significance evaluation in accordance with IMC 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklist for both PWRs and BWRs" Checklist 4, and determined that the finding did not increase the likelihood of a loss of RCS inventory, degrade the licensee's ability to terminate a leak path or add inventory, or degrade the licensee's ability to recover decay heat removal) DHR once it is lost, therefore the issue screened as one of very low safety significance (Green). This finding has a cross-cutting aspect in the area of Human Performance, because the work supervisor did not make safety-significant or risk-significant decisions using a systematic process, especially when faced with uncertain or unexpected plant conditions, to ensure safety is maintained (H.1(a)). The supervisor did not seek further guidance surrounding the observed conditions upon arrival at the work site.
  (Section 1R15.b)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power for the duration of the inspection period.

Unit 2 operated at or near full power until October 11 when the Unit was shut down to commence a scheduled refueling outage. On October 31, the Unit 2 reactor became critical, was started up, and the generator was placed online. The Unit achieved full power operation on November 4. Unit 2 operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter weather conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues.

- Refueling Water Storage Tank Heaters;
- Main Steam Isolation Valves;
- Control Room Ventilation; and
- Various Outdoor Tanks.

This inspection constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- 1A Chemical and Volume Control (CV) train during 1B CV train work window; and
- 1A Essential Service Water (SX) system.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted two partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On December 21, 2009, the inspectors performed a complete system alignment inspection of the 2A Safety Injection (SI) sub-system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the corrective action program database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

These activities constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings of significance were identified.

.3 System Walkdown Associated with Temporary Instruction 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems"

a. Inspection Scope

On October 23 and 24, 2009, the inspectors conducted refueling outage (RFO) walkdowns of portions of the SI system (including multiple trains and locations inside containment) in sufficient detail to reasonably assure the acceptability of the licensee's walkdowns (Temporary Instruction (TI) 2515/177, Section 04.02.d).

In addition, the inspectors verified that the licensee had isometric drawings that described the SI system's configuration and had acceptably confirmed the accuracy of the drawings (TI 2515/177, Section 04.02.a). The inspectors verified the following related to the isometric drawings:

- High point vents were identified;
- High points that do not have vents were acceptably recognizable;
- Other areas where gas can accumulate and potentially impact subject system operability, such as at orifices in horizontal pipes, isolated branch lines, heat exchangers, improperly sloped piping, and under closed valves, were acceptably described in the drawings or in referenced documentation;
- Horizontal pipe centerline elevation deviations and pipe slopes in nominally horizontal lines that exceed specified criteria were identified;
- All pipes and fittings were clearly shown; and
- The drawings were up-to-date with respect to recent hardware changes and that any discrepancies between as-built configurations and the drawings were documented and entered into the corrective action program for resolution.

The inspectors verified that Piping and Instrumentation Diagrams accurately described the subject systems, that they were up to date with respect to recent hardware changes, and that any discrepancies between as-built configurations, the isometric drawings, and the Piping and Instrumentation Diagrams were documented and entered into the corrective action program for resolution (TI 2515/177, Section 04.02.b).

Documents reviewed are listed in the Attachment to this report.

This inspection effort counted towards the completion of TI 2515/177, which will be closed in a later inspection report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Auxiliary Building General Area 383' Elevation;
- 1A CV Pump Room;
- Unit 1 Miscellaneous Electrical Equipment Room; and
- Unit 2 SI Pump Room.

The inspectors reviewed areas 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 implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On November 17, 2009, the inspectors observed an unannounced fire brigade drill in the Unit 2 Containment Chiller room. Based on this observation, the inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were: (1) proper wearing of turnout gear and self-contained breathing apparatus; (2) proper use and layout of fire hoses; (3) employment of appropriate fire fighting techniques; (4) sufficient firefighting equipment brought to the scene; (5) effectiveness of fire brigade leader communications, command, and control; (6) search for victims and propagation of the fire into other plant areas; (7) smoke removal operations; (8) utilization of pre planned strategies; (9) adherence to the pre planned drill scenario; and (10) drill objectives.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

.1 Underground Cable Vaults

a. Inspection Scope

The inspectors selected underground bunkers/manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors reviewed whether the cables were submerged, the condition of splices, and whether appropriate cable support structures were in place. Since the cable vaults did not contain dewatering devices, the inspectors reviewed whether drainage of the area was available or if the cables were qualified for submergence conditions. The inspectors also reviewed the licensee’s corrective action documents with respect to past submerged cable issues identified in the corrective action program to verify the adequacy of the corrective actions. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one underground cable vault sample as defined in IP 71111.06-05.

b. Findings

Introduction: The inspectors have identified an Unresolved Item (URI) related to underground cable vaults. Specifically, the inspectors reviewed an Issue Report (IR) generated by the licensee that documented the deteriorating condition of numerous underground cable vaults. The IR stated that water was found in all of the vaults that were opened and many cables were partially or fully submerged in water.

Description: During a review of the condition of cable vaults at Braidwood, the inspectors reviewed IR 968522, which documented the condition of cable vaults that were accessed as part of the installation of unrelated plant modifications. The inspectors also reviewed photographs of each cable vault that was accessed during the modification installation. None of the cables contained in the vaults were safety-related but many were associated with Maintenance Rule systems, such as Circulating Water, Non-Essential Service Water, and Auxiliary Power systems.

The cable vaults that were accessed were 1E, 1Z, 2D, 2E, 2F, 2G, 2H, 2J, and X. The licensee reported that water was found in each cable vault and at least some cables were submerged in water in each cable vault. In addition to submerged cables, personnel also observed cracking of the concrete vault walls, rusting cable trays and supports, taped cable splices that were submerged in water, and sludge build-up on many cables and structures. All cable vaults on-site have not been inspected; however, the licensee believes the conditions observed in the vaults that were accessed exist in the remaining vaults as well. The licensee has developed a modification to add the capability to remove water from the vaults but it has not yet been implemented.

At the conclusion of the inspection period, the inspectors have notified NRC personnel from the Office of Nuclear Reactor Regulation, per IP 71111.06, and are awaiting further instruction. Pending additional information, this issue will remain open. **(URI 05000456/2009005-01; 05000457/2009005-01)**

1R08 Inservice Inspection Activities (71111.08G)

For Unit 2, from October 13, 2009, through October 22, 2009, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the Reactor Coolant system (RCS), Steam Generator (SG) tubes, Emergency Feedwater Systems, risk significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, 1R08.3, IR08.4, and 1R08.5 below, count as one inspection sample as defined by IP 71111.08-05.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed the following nondestructive examinations required by the American Society of Mechanical Engineers, (ASME) Section XI Code, and/or 10 CFR 50.55a to evaluate compliance with the ASME Code, Section XI, applicable ASME Code Case and Section V requirements, and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or a NRC approved alternative requirement.

- Ultrasonic examination (UT) of two RCS 4-inch diameter pipe-to-elbow welds (2RC-17-09 and 2RC-17-10);
- UT of the B Reactor Coolant elbow-to-sweepolet weld (2RC-07-16);
- UT of the A Residual Heat Exchanger flange-to-vessel weld (2RHX-01-2RHEC-01);

- Magnetic particle examination the A Main Steam line lug welds (1MS-04-SW-18);
- UT of the Pressurizer support skirt attachment weld (2PRZ-01-07);
- UT of the Pressurizer shell-to-lower head weld (2PRZ-01-08A);
- UT of the Pressurizer lower shell longitudinal weld (2PRZ-01-09A);
- UT of the Main Steam Outboard Isolation valve-to-pipe weld (2MS-06-14); and
- Dye penetrant examination of Pressurizer support skirt attachment weld (2PRZ-01-07).

The inspectors reviewed the following examinations completed during the previous outage with relevant/recordable conditions/indications accepted for continued service to determine if acceptance was in accordance with the ASME Code Section XI or an NRC approved alternative.

- Indication Assessment of Reactor Nozzle-to-Vessel Welds (2RV-01-011); and
- Indication Assessment of Reactor Vessel Shell-to-Flange Weld (2RV-01-005).

The inspectors observed the following pressure boundary welds completed for risk significant systems to determine if the licensee followed an ASME Code Section XI qualified welding procedure, maintained control of foreign material, and to confirm that the welder used qualified weld rod filler material and base material. The inspectors also reviewed the work order for this welding to determine if appropriate post weld nondestructive examinations was specified.

- Auxiliary Feedwater System (AF) butt welds (FW-5, 7A and 8) fabricated during installation of a new cross-tie pipe line (2AF25A-6) between Unit 1 and 2.

b. Findings

Failure to Establish a 2-to-1 Weld Profile on Auxiliary Feedwater System Cross-Tie Drain Line Socket Welds

Introduction: The inspectors identified a finding of very low safety-significance and an associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, for the licensee's failure to follow work order instructions and establish a 2-to-1 (2x1) weld profile on the AF cross-tie pipe drain line socket welds.

Description: On September 29 and September 30, 2009, under WO 1171778-06 the licensee completed fabrication of three socket fillet welds (FW-10, -11 and -12) on the ¾ inch diameter drain line (2AF28A-3/4), attached to the Unit 2 side of the AF cross-tie line (2AF25A-6). Welds FW-10 and FW-11 were safety-related Code Class 3 welds not isolable from the Unit 2 AF Train "A." Weld FW-12 was a non-safety-related weld between the drain isolation valve and pipe run terminal end cap. The work order required each of these welds to have a 2x1 weld profile to provide enhanced resistance to fatigue type failure. The Electric Power Research Institute (EPRI) has determined that vibration fatigue is the leading cause of piping failures in U.S. Nuclear Power Plants and has conducted extensive testing of socket welds to determine what weld fabrication elements contribute to early fatigue failures. Based on tests documented in

EPRI TR-113890, “Vibration Fatigue Test of Socket Welds,” and EPRI TR-107455, “Vibration Fatigue of Small Bore Socket-Welded Pipe Joints,” a 2x1 weld profile results in significant high cycle fatigue improvement over the standard Code socket weld profile of 1x1.

On October 20, 2009, the inspectors measured the fillet weld leg dimensions for FW-10, FW-11, and FW-12 and identified that these welds did not meet the 2x1 weld profile specified in WO 1171778-06. These completed welds had been accepted by the licensee’s Quality Verification (QV) inspectors. The NRC inspectors’ observations prompted licensee QV staff to measure the weld leg dimensions and document the weld leg dimensions in IR 981831. Based on these measurements, FW-10 and FW-12 weld profiles were 1.3x1 and the FW-11 weld profile was 1.1x1. In IR 981831, the licensee documented that numerous QV inspectors were questioned at Braidwood and other Exelon stations, and each QV inspector questioned would have accepted these welds based on their training. Additionally, Exelon Nuclear Welding Manager had stated that larger weld profiles which approach twice the required leg on both the pipe and fitting were not detrimental, but are more expensive to make (reference IR 079134 dated October 2001). This information had been previously shared with QV staff at the Braidwood Station.

On October 20, 2009, the Braidwood QV Manager contacted the Exelon corporate welding staff (reference IR 981981) and was instructed that these welds should have a 2x1 weld profile. Because site welding and weld acceptance instructions were not correctly understood by site welders and QV staff, the welds were accepted without a 2x1 weld profile. Absent NRC intervention, these welds would have been returned to service and may have been subject to vibration induced fatigue failures prior to the end of their service life. To resolve this issue, the licensee implemented the following corrective actions.

- The licensee QV staff rejected FW-10, FW-11, and FW-12 as documented in the revised weld data sheets and in IR 981981.

- The licensee’s corporate Asset Management Senior Manager issued interim guidance for site QV and welding staff to accept socket weld profiles that ranged from 2x1 to 3x1.

- Site QV staff requested a revision to welding Procedures CC-AA-501-1025, “Exelon Nuclear Welding Program Weld End Preparation and Joint Details” and CC-AA-501-1003, “Exelon Nuclear Welding Program Visual Weld Acceptance Criteria,” to clarify applicable instructions.

- The licensee subsequently issued corporate level Nuclear Event Report NC-09-044 to evaluate the extent of condition across the licensee’s fleet of nuclear plants.

Analysis: The inspectors determined that the failure to follow the work order instructions to fabricate a 2x1 weld profile for FW-10, FW-11, and FW-12 was a performance deficiency that impacted the Mitigating Systems Cornerstone.

The inspectors determined that this finding was more than minor because if left uncorrected, the failure to properly control maintenance activities could become a more significant safety concern. Specifically, the failure to implement a 2x1 socket weld profile could result in vibration induced pipe fatigue failure affecting the operability of the Unit 2 AF Train “A.”

The inspectors completed a significance determination, in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of findings,” Table 4a for the Mitigating Systems Cornerstone. Based on this screening, the finding was determined to be of very low safety-significance because it was a design or qualification deficiency, confirmed to not result in loss of operability or functionality. This finding has a cross-cutting aspect in the area of Human Performance, Resources because the licensee did not provide adequate procedural resources. Specifically, the licensee failed to ensure that the work instruction for the welding contained adequate guidance to implement the required 2x1 weld profile (H.2(c)).

Enforcement: 10 CFR 50, Appendix B, Criterion V, requires, in part, that activities affecting quality be performed in accordance with instructions, procedures, and drawings appropriate to the circumstance. Instructions, procedures or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Work Order 01171778-06, Attachment 1, Exhibit A- ASME Weld Data Record, page 17 of 36, stated in part, “Fillet – Min. Size ¼ X ½ inch(es) EPRI 2X1 WELD PROFILE APPLIES.” Contrary to this requirement, on September 29, 2009, and September 30, 2009, following fabrication and acceptance of safety-related socket welds FW-10, and FW-11 in accordance with WO 1171778-06, on AF line (2AF28A-3/4), the licensee failed to establish a 2x1 weld profile. Based on measurements recorded in IR 981831, the weld profiles were 1.1x1 and 1.3x1 respectively. Failure to follow the work order instruction and establish a 2x1 weld profile is a violation of 10 CFR Part 50, Appendix B, Criterion V. Since socket weld FW-12 is non-safety-related, the licensee’s failure to follow work order instruction was only a performance deficiency with no violation of regulatory requirement. Because this violation was of very low safety-significance and it was entered into the corrective action program (IR 981831 and IR 981981), this violation is being treated as a Non-Cited Violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000457/2009005-02)**.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 2 vessel head, a bare metal head visual examination was not required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D). Therefore, the inspectors reviewed the vessel head visual examination procedure to determine if the procedure incorporated the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D).

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors observed the licensee staff performing visual examinations of the Unit 2 Reactor Coolant and Emergency Core Cooling Systems within containment to determine if these visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of RCS connected components with boric acid deposits to determine if degraded components were documented in the corrective action system. The inspectors also evaluated corrective actions for any degraded RCS components to determine if they met the ASME Section XI Code.

- Evaluation of Manual Vent Valve 2CV217; and
- Evaluation of Manual Vent Valve 2CV224.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- IR 771304 2RH01CA (repeat boric acid leakage);
- IR 873170 2RH029B pipe cap boric acid leak; and
- IR 801836 2CS01AB-16 suction spool boric acid leak.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

The inspectors performed an on-site review of the Unit 2 SG tube examination activities conducted pursuant to TS and the ASME Code, Section XI requirements. The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documentation related to the SG ISI program to determine if:

- in situ SG tube pressure testing screening criteria used were consistent with those identified in the EPRI TR-107620, “Steam Generator In Situ Pressure Test Guidelines” and that these criteria were properly applied to screen degraded SG tubes for in situ pressure testing;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee’s previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to meet the TSs, and the EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines”;

- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- the licensee implemented repair methods that were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of EPRI 1003138;
- the licensee performed secondary side SG inspections for location and removal of foreign materials;
- the licensee implemented repairs for SG tubes damaged by foreign material; and
- inaccessible foreign objects were left within the secondary side of the SGs, and if so, that the licensee implemented evaluations, which included the effects of foreign object migration and/or tube fretting damage.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the licensee's corrective action program and conducted interviews with licensee staff to determine if;

- the licensee had established an appropriate threshold for identifying ISI/SG related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On December 3, 2009, the inspectors observed a crew of licensed operators during classroom training activities and in the plant’s simulator during licensed operator requalification training to ensure that operator performance was adequate and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew’s clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations; and
- oversight and direction from supervisors.

The crew’s performance in these areas was compared to pre-established operator action expectations.

The inspectors also reviewed training records for other licensed operating crews to ensure that during annual examination the crew’s performance was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment.

This inspection constituted one quarterly licensed operator requalification program sample as defined in IP 71111.11.

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results and Biennial Written Examination Results (71111.11B)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the individual Job Performance Measure operating tests, the simulator operating tests, and the biennial written examination (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee in 2009 as part of the licensee’s operator licensing requalification cycle. These results were compared to the thresholds established in Inspection Manual Chapter 0609, Appendix I, “Licensed Operator Requalification Significance Determination Process (SDP)." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG 1021, “Operator Licensing Examination Standards for Power Reactors,” and Inspection Procedure 71111.11, “Licensed Operator Requalification Program.” The documents reviewed during this inspection are listed in the attachment.

This inspection constituted one inspection sample as defined in IP 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- Unit 0 Auxiliary Building Ventilation; and
- Unit 1 Excore Nuclear Monitoring.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

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 and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- 1B CV Pump Unplanned Motor Replacement;
- 1B CV Pump Work Window;
- 1A Reactor Coolant Pump Seal Leakoff Flow at Low Limit; and
- 1SI8811B Valve Emergent Maintenance.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Documents reviewed are listed in the Attachment.

These maintenance risk assessments and emergent work control activities constituted four samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 2 Pressurizer Heatup Rate Exceeded;
- SX System Water Hammer due to Opening of 2XS173;
- 2A CV Pump Elevated Vibrations on New Rotating Element;
- 2CV8321 Packing Leakoff Line Weld Leak;
- 2B SX Pump Discharge Check Valve Slow to Seat; and
- 2B Diesel Generator Ventilation Exhaust Fan and Recirculation Hydromotor Issues.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment.

This operability inspection constituted six samples as defined in IP 71111.15-05.

b. Findings

Introduction: A Green finding and an associated Non-Cited Violation of TS 5.4.1 were self-revealed for the licensee's failure to follow procedure during the restoration of the SX Supply Valve (2SX173) to the engine driven cooling water pump for the 2B AF pump following schedule maintenance. This issue resulted in a water hammer occurring in the SX system.

Description: On October 18, 2009, while Unit 2 was shut down, a water hammer event occurred after air-operated valve 2SX173 was opened in an uncontrolled fashion. The 2SX173 valve is a fail-open valve (spring force open) and requires air applied through the actuator to close. In accordance with Task 9 of WO 1136768, the licensee installed a blocking device on the valve to maintain the valve in a closed position to support the scheduled maintenance on the 2B Auxiliary Feed Pump.

On the day of the event, maintenance workers were assigned Task 13 of WO 1136768, which instructed the workers to remove the blocking device. Task 13 also included specific instructions to remove the block then open the valve in a controlled manner to assure the valve was opened slowly to minimize the possibility of a water hammer. Specifically, Steps 5.4.1 – 5.4.6 required that the air supply line to the valve operator be disconnected and a temporary air supply, with an air regulator and valve, be connected. Then regulated air pressure was to be admitted to the operator (80 psig max) prior to removing the valve block. Once the blocking device was removed, the work package stated to "very slowly release air pressure from the air operator to open the valve."

During the execution of Task 13, the maintenance crew noted that the pressure gauge attached to the actuator was reading 80-psig and assumed there was sufficient pressure to the actuator to hold the valve closed. The supervisor then decided not to attach the temporary air supply and directed the workers to remove the blocking device. When the mechanical valve block was removed, the 2SX173 valve unexpectedly opened. This caused the drained piping to rapidly pressure up to the next closed valve, 2SX175. After the blocking device was removed, operators in the main control room reported hearing the water hammer event. Unit 1 received a SX discharge pressure low and suction pressure low alarm and Unit 2 received a SX discharge pressure low alarm. All alarms cleared shortly thereafter and SX system parameters returned to normal.

Subsequent investigation by the licensee revealed that, when the supervisor initially arrived at the 2SX173 valve, the pressure gauge attached to the valve actuator read 80 psig. This gauge was installed plant equipment, not the temporary gauge/valve/regulator arrangement specified on the work package. The gauge only measured air pressure to the solenoids, not the actuator. The work package instructions, Step 5.4.3, stated to admit regulated air pressure to the actuator, 80 psig maximum. The supervisor incorrectly assumed the required air pressure existed to the actuator and proceeded to have the blocking device removed.

Following the SX water hammer event the licensee performed a walkdown of portions of the SX system to look for evidence of equipment damage in accordance with licensee Procedures CC-AA-5001 and NES-MS-01.3. According to the licensee, the walkdown revealed no physical damage to the system, no evidence of piping displacement, no piping hanger movement/shift, no hanger bed plate damage and no contacting of adjacent components. The inspectors also performed a walkdown of the SX piping and noted no issues related to the water hammer.

<u>Analysis</u>: The inspectors determined that the failure to follow maintenance work instructions was a performance deficiency. The finding was determined to be more than minor because it impacted the Human Error attribute of the Mitigating Systems Cornerstone to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage).

The inspectors performed a significance evaluation in accordance with IMC 0609, Appendix G, Attachment 1, “Shutdown Operations Significance Determination Process Phase 1 Operational Checklist for both PWRs and BWRs” Checklist 4, and determined that the finding did not increase the likelihood of a loss of RCS inventory, degrade the licensee’s ability to terminate a leak path or add inventory, or degrade the licensee’s ability to recover decay heat removal (DHR) once it is lost, therefore the issue screened as one of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance, because the work supervisor did not make safety significant or risk significant decisions using a systematic process, especially when faced with uncertain or unexpected plant conditions, to ensure safety is maintained. The supervisor did not seek further guidance surrounding the observed conditions upon arrival at the work site. (H.1(a))

<u>Enforcement</u>: Technical Specification 5.4.1.a requires that written procedures shall be established, implemented, and maintained for the activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Regulatory Guide 1.33 states, in part, that maintenance affecting safety related equipment performance should be performed in accordance with written procedures or documented instructions appropriate to the circumstances.

Contrary to the above, on October 10, 2009, the licensee failed to follow work instructions contained in WO 123456, Task 13 related to removal of a mechanical blocking device for valve 2SX173. Specifically, Steps 5.4.1 to 5.4.6 provided instructions for attaching and supplying air to the valve actuator to facilitate slowly opening the

2SX173 valve. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 981024, this violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000457/2009005-03)**.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modifications:

- Temporary Removal of 1B Diesel Generator Temperature Element; and
- 2B Reactor Vessel Level Indication Probe Sensors.

The inspectors compared the temporary configuration changes and associated 10 CFR 50.59 screening and evaluation information against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors also compared the licensee's information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee's decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operations, engineering, and training personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment.

This inspection constituted two temporary modification samples as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The following engineering design packages were reviewed and selected aspects were discussed with engineering personnel:

- Engineering Change 369292, "AF Cross-Tie U1 Discharges" and Engineering Change 369972 "AF Cross-Tie U2 Discharges."

This document and related documentation were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. The purpose of this permanent modification was to install piping, manual isolation valves, supports and other piping components to the discharge piping to both the Unit 1 and Unit 2 Motor Driven AF Pumps discharge line to enable the two systems to be cross-tied between units. Documents reviewed in the course of this inspection are listed in the Attachment.

This inspection constituted one permanent plant modification sample as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following post-maintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- 1B CV Pump following Motor Replacement;
- 2A SX Pump following Motor Replacement;
- 2A CV Pump following Rotating Element Replacement;
- 1SI8811B Stroke following Actuator Replacement;
- Resistance Temperature Detector (RTD) Cross-Calibration after 2D T-ave RTD Replacement;
- Stroke Test of SX Cooling Water Supply Valve (2SX178) following Maintenance;
- 2B SX Pump following Replacement of Discharge Check Valve; and
- Stroke Test of 2B Containment Spray Suction Valve (2CS001B) following Planned Maintenance.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TS, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

This inspection constituted eight post-maintenance testing sample as defined in IP 71111.19-05.

b. Findings

(1) Failure to Follow Maintenance Procedures and Work Instructions

Introduction: The inspectors identified a Green finding and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," related to Post Maintenance Testing (PMT). Specifically, the licensee failed to follow maintenance procedures and work instructions thus work that could have affected the operability of safety-related SX Return Isolation Valve from the Auxiliary Feed Water Diesel Heat Exchanger was completed and the system returned to operable status without completing the necessary PMT.

Description: On November 12, 2009, following the completion of the Unit 2 RFO, the licensee performed a scheduled stroke time test for Valve 2SX178 (SX Return Isolation Valve from the Auxiliary Feed Water Diesel Heat Exchanger). The stroke time exceeded the alert limit and was nearly double the expected time. Since the valve had been satisfactorily stroke time tested on October 27, 2009, the inspectors questioned why the stroke time had increased in such a short period of time.

The October 27, while the unit was shut down, stroke time of the valve was scheduled to be completed in accordance with Work Order 1133366-01. The work order included two tasks. Task 1 was to perform a flowscan of the valve and Task 2 was to complete a PMT stroke time test following the flowscan. Since the process of performing a flowscan can affect the time it takes for a valve to stroke, it is necessary to verify stroke times after completion of the flowscan. Specifically, Procedure MA-AA-716-012, "Post Maintenance Testing," Revision 11, requires that a "PMT shall be performed following any corrective and some preventive maintenance activities on plant equipment that may have impacted the equipment's ability to perform its intended function."

During the review of this matter, the inspectors noted the following three issues:

1. Task 1 of Work Order 1133366-01, the flowscan, was completed on October 28 and Task 2 of the Work Order, the stroke time test, was completed on October 27. Therefore, the PMT was not performed following completion of an work activity as required by Procedure MA-AA-716-012.

2. The stroke time test procedure had previously been modified due to a temporary modification that changed the valve opening logic. Maintenance performed during the RFO, prior to completion of WO 1133366-01, eliminated the need for the temporary modification. The temporary modification was removed on October 14, 2009, but the procedure for stroke time testing the 2SX178 valve was not revised. Therefore, the test procedure used on October 27 and initially on November 12 was not appropriate for the plant configuration after the temporary modification was removed. Furthermore, this was the reason for the test results of a stroke time in excess of the alert limit, as was found on November 12.

3. The test procedure in place on October 27 was not appropriate for the plant configuration after the temporary modification was removed. If followed properly, it should have resulted in a stroke time in excess of the alert limit, as was found on November 12. Therefore, the licensee apparently did not follow the stroke time test procedure during the RFO.

Once discovered, the licensee revised the stroke time test procedure and re-performed the test satisfactorily. At the completion of the inspection period, the licensee was performing an Apparent Cause Evaluation to determine why the procedure was not revised and how operators used the procedure to time the valve stroke on October 27. Pending on the review of the licensee's evaluation, the issue related to not following the stroke time test procedure is considered an URI. (URI 05000457/2009005-04)

Analysis: The inspectors determined that the failure to adequately complete the stroke time test of Unit 2 SX Return Isolation Valve from the Auxiliary Feed Water Diesel Heat Exchanger following the flowscan on October 28, 2009, was a performance deficiency warranting a significance evaluation. Specifically, Procedure MA-AA-716-012, "Post Maintenance Testing," Revision 11, requires that a "PMT shall be performed following any corrective and some preventive maintenance activities on plant equipment that may have impacted the equipment's ability to perform its intended function." The performance of a flowscan, which may impact the stroke time of a valve, therefore a PMT was required following completion of the flow scan testing. The inspectors concluded that the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," because the licensee returned equipment to an operable status following maintenance without performing required testing.

The finding affected the Core Decay Heat Removal attribute of the Mitigating Systems Cornerstone. Using the SDP phase 1 worksheet of IMC 0609.04, the inspectors determined the finding screened as Green because the finding does not represent a loss of system or train function, is not a design deficiency and is not risk significant in external events.

The finding was related to the Work Control attribute of the cross-cutting area of Human Performance. The licensee performed work packages out of sequence thereby allowing a safety related system to be returned to service without the required PMT being completed after completion of all work. (H.3(b))

The failure to revise the test procedure following the removal of the temporary modification had no safety significance since the subsequent test results were acceptable; therefore, it was considered a minor procedure violation.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality be prescribed by documented procedures and shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Specifically, Procedure MA-AA-716-012, "Post Maintenance Testing," Revision 11, requires that a "PMT shall be performed following any corrective and some preventive maintenance activities on plant equipment that may have impacted the equipment's ability to perform its intended function." Contrary to the above, Task 1 of Work Order 1133366-01, the flowscan, was completed on October 28 and Task 2 of the

Work Order, the stroke time test (post maintenance testing), was completed on October 27. Once identified, the licensee entered the finding into their corrective action program as IR 995118. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program, this violation is being treated as an NCV. (**NCV 05000457/2009005-05**)

(2) RCS Resistance Temperature Detector Cross-Calibration

Introduction: The inspectors identified a URI during their review of post maintenance testing for RCS RTD replacement that occurred during the Unit 2 RFO in October 2009.

Description: From October 28 to October 31, 2009, following the Unit 2 refuelling outage, the licensee performed RCS RTD cross-calibration. The cross-calibration was credited as a post maintenance test for several RCS RTDs that were replaced during the refuelling outage. Cross-calibration is a method where, rather than performing a standard calibration on each RTD, each RTD in a system is compared against the RTD group average. Outliers from the average may be replaced or have their scaling equation adjusted. At Braidwood, the outlier criteria is 0.5ºF for narrow range RTDs and 4.0ºF for wide range RTDs.

On February 21, 1995, the licensee submitted a license amendment request to the NRC regarding elimination of the RTD bypass manifold and installation of thermowell-mounted dual element fast response RTDs to replace the bypass manifold. The amendment request indicated that cross-calibration would be used to calibrate the RTDs and to verify per TS requirements that there has not been unacceptable drift. The NRC approved the amendment request in a Safety Evaluation dated September 5, 1995, and referenced NUREG/CR-5560 in the discussion of instrument uncertainty and drift.

Cross-calibration of RTDs is discussed in Section 23 of NUREG/CR-5560. The method for cross-calibration introduces inherent uncertainties that must be accounted for. These uncertainties are accuracy of measurement equipment, stability of plant conditions, and uniformity of the system temperature. The value of these uncertainties is provided in NUREG/CR-5560 with the total uncertainty as high as 0.1ºC to 0.32ºC.

The licensee performs RTD cross-calibration in accordance with Procedure 2BwISR 3.3.1.10-1, "Unit 2 RCS RTD Cross Calibration." During the review of this procedure and the data generated during the cross-calibration conducted in October 2009, it was not immediately clear that the uncertainties were included in the cross-calibration results.

At the conclusion of the inspection period, the inspectors continue to review cross-calibration data and intend to continue discussions of the issue with NRC Instrument & Controls personnel. This issue is also applicable to Unit 1. Pending additional information, this issue will remain open. **(URI 05000456/2009005-06; 0500457/2009005-06)**

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 2 RFO, conducted October 12 to October 29, 2009, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out of service.
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.
- Controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of secondary containment as required by TS.
- Refueling activities, including fuel handling and sipping to detect fuel assembly leakage.
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to RFO activities.

This inspection constituted one RFO sample as defined in IP 71111.20-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- Unit 2 AF Full Flow Testing (Routine);
- Unit 2 Main Steam Safety Valve Testing (Inservice Testing);
- 1B AF Pump Monthly (Routine); and
- 2B Diesel Generator Operability Surveillance Test (Routine).

The inspectors observed in plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, (ASME code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment.

This inspection constituted three routine surveillance testing samples and one inservice testing sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Evaluation (71114.02)

a. Inspection Scope

The inspectors reviewed documents and conducted discussions with Emergency Preparedness staff and management regarding the operation, maintenance, and periodic testing of the Alert and Notification System in the Braidwood Station's plume pathway Emergency Planning Zone. The inspectors reviewed monthly trend reports and the daily and monthly operability records from February 2007 through September 2009. Information gathered during document reviews and interviews was used to determine whether the Alert and Notification System equipment was maintained and tested in accordance with Emergency Plan commitments and procedures. Documents reviewed are listed in the Attachment.

This alert and notification system inspection constituted one sample as defined in IP 71114.02-05.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed with plant Emergency Preparedness management and staff the emergency plan commitments and procedures that addressed the primary and alternate methods of initiating an Emergency Response Organization activation to augment the on shift Emergency Response Organization as well as the provisions for maintaining the station's Emergency Response Organization qualification and team lists. The inspectors reviewed reports and a sample of corrective action program records of unannounced off-hour augmentation tests and pager test, which were conducted between March 2007 and September 2009, to determine the adequacy of the drill critiques and associated corrective actions. The inspectors also reviewed a sample of the emergency preparedness training records of approximately 23 Emergency Response Organization personnel, who were assigned to key and support positions, to determine the status of their training as it related to their assigned Emergency Response Organization positions. Documents reviewed are listed in the Attachment.

This emergency response organization augmentation testing inspection constituted one sample as defined in IP 71114.03-05.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

Since the last NRC inspection of this program area, Emergency Plan Annex, Revisions 21 and 22 were implemented based on your determination, in accordance with 10 CFR 50.54(q), that the changes resulted in no decrease in effectiveness of the Plan, and that the revised Plan as changed continues to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the Emergency Action Level (EAL) changes to evaluate for potential decreases in effectiveness of the Plan. However, this review does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety.

This EAL and emergency plan changes inspection constituted one sample as defined in IP 71114.04-05.

b. Findings

Changes to Emergency Action Level HU6 Potentially Decrease the Effectiveness of the Plans without Prior NRC Approval

Introduction: The inspectors reviewed changes implemented to the Braidwood Station Emergency Plan Annex EALs and EAL Basis. In Revision 21, the licensee changed the basis of EAL HU6, "Fire not extinguished within15 minutes of detection within the protected area boundary," by adding two statements. The two changes added to the EAL basis stated that if the alarm could not be verified by redundant control room or nearby fire panel indications, notification from the field that a fire exists starts the 15-minute classification and fire extinguishment clocks. The second change stated the 15-minute period to extinguish the fire does not start until either the fire alarm is verified to be valid by additional control room or nearby fire panel instrumentation, or upon notification of a fire from the field. These statements conflict with the previous Braidwood Station Annex, Revision 20, basis statements and potentially decrease the effectiveness of the Plans.

Description: Braidwood Station Radiological Emergency Plan Annex, Revision 20, EAL HU6 initiating condition stated, "Fire not extinguished within 15 minutes of detection, or explosion, within the protected area boundary." The threshold values for HU6 were, in part: 1) Fire in any Table H2 area not extinguished within 15 minutes of Control Room notification or verification of a Control Room alarm, or 2) Fire outside any Table H2 area with the potential to damage safety systems in any Table H2 area not extinguished within 15 minutes of Control Room notification or verification of a Control Room alarm. Table H2, Vital Areas, were identified as containment, auxiliary building, fuel handling building, main steam tunnels, radioactive waste storage tanks, condensate storage tanks, and lake screen house. The basis defined fire as "combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is not required if large quantities of smoke and heat are observed."

The basis for Revision 20, EAL HU6 thresholds 1 and 2 stated, in part, the purpose of this threshold is to address the magnitude and extent of fires that may be potentially significant precursors to damage to safety systems. As used here, notification is visual observation and report by plant personnel or sensor alarm indication. The 15-minute period begins with a credible notification that a fire is occurring or indication of a valid fire detection system alarm. A verified alarm is assumed to be an indication of a fire unless personnel dispatched to the scene disprove the alarm within the 15-minute period. The report, however, shall not be required to verify the alarm. The intent of the 15-minute period is to size the fire and discriminate against small fires that are readily extinguished (e.g., smoldering waste paper basket, etc.).

Revision 21 of the Braidwood Station Radiological Emergency Plan Annex, changed the threshold basis for EAL HU6 by adding the following two statements: 1) "If the alarm cannot be verified by redundant control room or nearby fire panel indications, notification from the field that a fire exists starts the 15-minute classification and fire extinguishment clocks," and 2) "The 15-minute period to extinguish the fire does not start until either the fire alarm is verified to be valid by utilization of additional control room or nearby fire panel instrumentation, or upon notification of a fire from the field."

The two statements added to the basis in Revision 21 conflict with the Revision 20 threshold basis and initiating condition. The changed threshold basis in Revision 21 could add an indeterminate amount of time to declaring an actual emergency until a person responded to the area of the fire and made a notification to the control room of a fire in the event that redundant control room or nearby fire panel indications were not available.

Pending further review and verification by the NRC to determine if the changes to EAL HU6 threshold basis potentially decreased the effectiveness of the Plans, this issue was considered an Unresolved Item. **(URI 05000456/2009005-07; 05000457/2009005-07)**

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed a sample of Nuclear Oversight staff's 2007, 2008, and 2009 audits of the Braidwood Station's emergency preparedness program to determine that the independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with the 2008 biennial exercise, as well as various emergency preparedness drills conducted in 2007, 2008, and 2009, in order to determine whether the licensee fulfilled drill commitments and to evaluate the licensee's efforts to identify and resolve identified issues. The inspectors reviewed a sample of emergency preparedness items and corrective actions related to the facility's emergency preparedness program and activities to determine whether corrective actions were completed in accordance with the site's corrective action program. The inspectors conducted tours of the emergency response facilities to evaluate the material condition and readiness of the facilities and equipment. Documents reviewed are listed in the Attachment.

This correction of emergency preparedness weaknesses and deficiencies inspection constituted one sample as defined in IP 71114.05-05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on June 10 to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors reviewed emergency response documentation to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also reviewed documentation associated with the licensee drill critique in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

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

a. Inspection Scope

The inspectors reviewed the licensee’s Occupational Exposure Control Cornerstone performance indicator to determine whether the conditions resulting in any performance indicator occurrences had been evaluated and whether identified problems had been entered into the licensee’s CAP for resolution.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors also reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within the spent fuel pool or other storage pools. Documents reviewed are listed in the Attachment.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed licensee documentation packages for all performance indicator events occurring since the last inspection to determine if any of these performance indicator events involved dose rates in excess of 25 R/hr at 30 centimeters or in excess of 500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. Unintended exposures exceeding 100 millirem total effective dose equivalent (or 5 rem shallow dose equivalent or 1.5 rem lens dose equivalent) were evaluated to determine if there were any regulatory overexposures or if there was a substantial potential for an overexposure.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following three jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- SG Eddy Current Testing;
- Containment Lead Shielding; and
- Containment Valve Work.

The inspectors reviewed radiological job requirements for these activities, including Radiological Work Permit requirements, work procedure requirements and attended as-low-as-is-reasonably available job briefings.

This inspection constituted one sample as defined in IP 71121.01-5.

Job performance was observed with respect to the radiological control requirements to assess whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors evaluated the adequacy of radiological controls, including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage, including any applicable audio and visual surveillance for remote job coverage; and contamination controls.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors reviewed radiological work in high radiation work areas having significant dose rate gradients to evaluate whether the licensee adequately monitored exposure to personnel and to assess the adequacy of licensee controls. These work areas involved areas where the dose rate gradients were severe, thereby increasing the necessity of providing multiple dosimeters or enhanced job controls.

This inspection constituted one sample as defined in IP 71121.01-5.

Documents reviewed are listed in the Attachment.

b. <u>Findings</u>

No findings of significance were identified.

.5 <u>High Risk Significant, High Dose Rate, High Radiation Area, and Very High Radiation Area Controls</u>

a. <u>Inspection Scope</u>

The inspectors held discussions with the Radiation Protection Manager concerning high dose rate, high radiation area and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to assess whether any procedure modifications substantially reduced the effectiveness and level of worker protection. Documents reviewed are listed in the Attachment.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors discussed with radiation protection supervisors the controls that were in place for special areas of the plant that had the potential to become very high radiation areas during certain plant operations. The inspectors assessed if plant operations required communication beforehand with the radiation protection group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors conducted plant walkdowns to assess the posting and locking of entrances to high dose rate high radiation areas and very high radiation areas.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Residual Heat Removal System performance indicator. The inspectors sampled licensee submittals for the MSPI - Heat Removal System performance indicators for Units 1 and 2 for the period from the third quarter 2008 through the third quarter 2009. To determine the accuracy of the Performance Indicator (PI) data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of October 1, 2008, through October 31, 2009, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI - Residual Heat Removal System samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems performance indicator. The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems performance indicators for Units 1 and 2 for the period from the third quarter 2008 through the third quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of October 1, 2008, through September 31, 2009, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance.

The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI - Cooling Water Systems samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.3 Drill/Exercise Performance

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill/Exercise Performance PI for the period from the fourth quarter 2008 through second quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the Drill/Exercise Performance indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; assessments of PI opportunities during predesignated control room simulator training sessions, performance during the 2008 biennial exercise, and performance during other drills. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Drill/Exercise Performance sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.4 Emergency Response Organization Drill Participation

a. Inspection Scope

The inspectors sampled licensee submittals for the Emergency Response Organization Drill Participation PI for the period from the fourth quarter 2008 through second quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; performance during the 2008 biennial exercise and other drills; and revisions of the roster of personnel assigned to key emergency response organization positions. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Emergency Response Organization Drill Participation sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.5 Alert and Notification System

a. Inspection Scope

The inspectors sampled licensee submittals for the Alert and Notification System PI for the period from the fourth quarter 2008 through second quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, were used. The inspectors reviewed the licensee’s records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI and results of periodic Alert and Notification System operability tests. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Alert and Notification System sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee’s CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.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.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was 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. The inspectors' review nominally considered the 6 month period of July 2009 through December 2009, although some examples expanded beyond those dates where the scope of the trend warranted.

The inspectors followed-up on an elevated trend in the Unit 1 RCS unidentified leakrate values. The unidentified leakrate values had increased from a baseline of 0.058 gpm to approximately 0.18 gpm. The inspectors reviewed the licensee's program for calculating RCS leakrate values, monitoring containment tritium values, interviewed staff from the Operating, Radiation Protection, and Engineering departments, and monitored troubleshooting activities. At the end of the inspection period, licensee troubleshooting activities had identified the most likely source of the elevated unidentified leakrate values was from Valve 1CV121, and the licensee was developing actions to address the issue.

The review also included issues documented outside the normal CAP 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 inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

Documents reviewed are listed in the Attachment.

This review constituted one semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the Operator Workarounds (OWAs) on system 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.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one operator workaround annual inspection sample as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

.5 Selected Issue Follow-Up Inspection: Review of Corrective Actions to Address Spurious Spikes on the 2C RCS Cold Leg Temperature Instrument Loop (2T-0441B)

a. Inspection Scope

On April 24, 2009, Unit 2 experienced a reactor trip. The unit trip was cause by a spurious actuation of the 'D' channel of Over Temperature Delta Temperature (OTdT) reactor trip system's trip function while the 'B' channel of the OTdT trip function was in a tripped condition. The 'B' channel was in the tripped condition due to planned surveillance testing. During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting the corrective action taken to the cause of temperature spiking Unit 2 'D' RCS cold leg loop. The inspectors reviewed of the licensee's inspection efforts and evaluations of the cause of the temperature spiking.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Observations and Findings

Following the reactor trip on April 24, 2009, the inspectors discussed the results of the licensee's troubleshooting effort with the engineering staff. Following the reactor trip the licensee replaced three suspected circuit cards in the 2C channel logic strings. A review of the 2D channel indicated that the channel had a history of spiking and one of the cards that the licensee suspected as the most likely cause of the spiking had been replaced multiple times in the recent past. No issues were noted during the troubleshooting of the system following the reactor trip and the plant was restarted.

During the Unit 2 RFO in October 2009, the licensee completed a number of troubleshooting, inspection and replacement activities to address the issue. The following is a list of activities completed by the licensee and the result of those activities:

- Inspected front side circuit card connector in 2PA04J cabinet. The licensee determined that that the front side circuit connectors were normal.

- Inspected and bench tested installed Delta-T, T-ave summer cards, and computer isolator cards; Each card's input resistors common to 2D cold leg channel were bench tested to verify to ensure resistance was within expected values. Specific cards affected were 2TY-0441R Delta-T summer, 2TY-0441 T-ave summer and 2TY-0441E cold leg computer point isolator cards. No issues were identified.

- Measured resistance across the associated card edge pins for each card discussed above. Verified that resistance results were within expected valves.

After bench tests, each card was replaced with new cards to support loop reliability. The wire wrap connector in the back of card frame 1 was inspected and replaced. The licensee also performed an as-found resistance measurement for 2D Loop Cold Leg RTD (2TE-0441B/2TE-0440B). No issues were identified.

Following replacement of the above three cards, full calibration of the loop was performed. Additionally, the cold leg NRC card was rescaled to utilize a new replacement RTD. RCS RTD cross calibration was performed during plant heat up to normal operating temperature and normal operating pressure under WO 1135844. Additionally, response time testing of replaced RTDs was performed at normal operating temperature and normal operating pressure under WO 1236560-03. No issues were identified from these tests.

Additionally, during Delta-T and T-ave summer card and computer isolator card inspections, the licensee identified multiple occurrences of an unknown fibrous material on these cards. Multiple strands were identified on each summer card and one potential strand on the isolator card. The inspectors reviewed PowerLabs Report BRW-13626, which contained failure analysis and card inspection results and noted the report found no faults and testing was not able to recreate a spiking condition.

No findings of significance were identified.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

Failure to Fully Implement Abnormal Operating Procedures Following a Seismic Event

Introduction: The inspectors identified a Green finding and an associated NCV of TS 5.4.1 for the failure to fully implement an abnormal operating procedure following a seismic event. Specifically, on April 18, 2008, following a seismic event, the licensee chose to perform field walk downs to verify sulfuric acid and sodium hypochlorite tanks were intact rather than isolate control room ventilation as required in Procedure 0BwOA ENV-4, "Earthquake."

Description: In December 2006, the licensee installed a bulk sulfuric acid system near the lake screenhouse to control pH in the cooling lake. The system consisted of two 15,000 gallon tanks of sulfuric acid that shared a common drain path with a nearby sodium hypochlorite tank. These tanks were located near the lake screenhouse, which the inspectors estimated was approximately 0.5 miles from the main control room air intake. The licensee identified in Safety Evaluation BRW-E-2006-196 that if the sulfuric acid and sodium hypochlorite tanks were damaged and the chemicals mixed, a hazardous chlorine gas cloud would form. The safety evaluation concluded that the modification can be implemented provided that operators take actions to isolate main control room ventilation in the event of possible damage of the tanks. Because the tanks were not designed to withstand the wind loads or postulated missiles described in UFSAR Table 3.5-3 "Tornado Generated Missiles and Their Properties," the tanks could become damaged in the event of a tornado or earthquake.

The licensee had previously abandoned the automatic chlorine gas detection system and associated TS surveillances based upon the capability to manually realign the control room ventilation system and isolate the control room envelope from potential off-site spills of chlorine gas (no on-site source of chlorine gas existed at the time). To address the new potential for on-site generation of chlorine gas, the licensee modified Abnormal Operating Procedures 0BwOA ENV-1, "Adverse Weather," and 0BwOA ENV 4, "Earthquake," to include steps to isolate main control room ventilation and modified Procedure BwOP CF-45, "Sulfuric Acid Addition to the Braidwood Station Lake," to drain the acid tanks as low as possible during March through June. Additional information is available in NRC Inspection Report 05000456/2007002; 05000457/2007002.

On April 18, 2008, station logs indicate an earthquake event was confirmed by the United States Geological Survey at 4:44 a.m. and the licensee entered Procedure 0BwOA ENV-4. Step 6 of 0BwOA ENV-4 directs the licensee to dispatch an operator to isolate main control room ventilation. A control room log entry inserted on April 24, 2008, but time stamped 7:00 a.m. on April 18, 2008, stated:

> "During the performance of 0BwOA ENV-4, it was identified Step 6 would isolate the control room ventilation system and place both units in TS 3.0.3. Based on the fact there was no operational basis earthquake or safe shutdown earthquake detected and all main control room indications were normal for plant operations, the decision was made to perform in-field walkdowns and obtain more information before placing both units in TS 3.0.3 unnecessarily. Subsequent walkdowns did not identify any issues that would require the VC system to be isolated. Issue Report 767223 was written to capture a procedure enhancement for step 6 to give the SM better guidance."

The licensee also identified, in IR 791323, dated June 27, 2008, that the sulfuric acid tanks had not been drained from March through June, as required by Procedure BwOP CF-45. The tanks were subsequently drained on June 28. At the time of the April 18 earthquake, the sulfuric acid tanks were not drained and the licensee did not isolate main control room ventilation as required by 0BwOA ENV-4. Procedure BwAP 340-1, "Use of Procedures for Operating Department," states that procedures shall be followed as written, except when following emergency operating procedures where actions outside of procedures can be taken in accordance with 10 CFR 50.54(x) to place the plant in a safe condition. The circumstances surrounding the April 18, 2008, earthquake were guided by Abnormal Procedures, which are required to be followed as written.

<u>Analysis</u>: The inspectors determined that the failure to drain the sulfuric acid tanks per Procedure BwOP CF-45 and to complete the step to isolate main control room ventilation while in Procedure 0BwOA ENV-4 were performance deficiencies. Since the failure to drain the sulfuric acid tanks has no safety consequence, it was considered a minor procedure violation. The failure to follow Abnormal Operating Procedure 0BwOA ENV-4 was determined to be more than minor because it impacted the procedure quality attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. It was also determined that the senior on-shift licensed staff incorrectly believed it had the authority to deviate from the directions provided in the abnormal operating procedures.

The inspectors evaluated the finding in accordance with IMC 0612, Appendix B, "Issue Screening." The inspectors performed a significance evaluation in accordance with IMC 0609, Attachment 4, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The inspectors answered 'No' to the external event initiators question in the Initiating Events Cornerstone column of Table 4a and the issue screened as one of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance, because the licensee did not use conservative assumptions in the decision to send an operator to locally verify rather than perform a procedural step from the control room as written. In the event the sulfuric acid and sodium hypochlorite tanks were damaged, the control room operators could have been impacted with chlorine gas prior to receiving verification from the locally dispatched operator since the licensee elected not to isolate control room ventilation. (H.1(b))

Enforcement: Technical Specification 5.4.1.a requires that written procedures shall be established, implemented, and maintained for the activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Regulatory Guide 1.33 states, in part, that response to abnormal conditions should be covered by written procedures.

Contrary to the above, following an earthquake on April 18, 2008, the licensee did not isolate control room ventilation as required by Abnormal Operating Procedure 0BwOA ENV-4. Specifically, Step 6.a, of 0BwOA ENV-4, required operators to isolate control room ventilation following an earthquake to prevent chlorine gas from potentially damaged on-site storage tanks from entering the control room. Corrective actions included procedure enhancements to the guidance for seismic events. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 767223, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000456/2009005-08; 05000457/2009005-08)**

4OA5 Other Activities

.1 RCS Dissimilar Metal Butt Welds (Temporary Instruction 2515/172, Draft Revision 1)

a. Inspection Scope

The inspectors conducted a review of the licensee's activities regarding licensee dissimilar metal butt weld (DMBW) mitigation and inspection implemented in accordance with the industry self-imposed mandatory requirements of Materials Reliability Program (MRP)-139, "Primary System Piping Butt Weld Inspection and Evaluation Guidelines." TI 2515/172, "RCS Dissimilar Metal Butt Welds (DMBWs)" was issued to support NRC review and evaluation of the licensees' implementation of MRP-139.

From October 13, 2009, through October 22, 2009, the inspectors performed a review for the Unit 2 DMBWs in accordance with Sections of TI 2515-172 (Draft Revision 1) as described below. The review for Unit 2 DMBWs under Revision 0 to TI 2515-172 had been previously completed and documented in Inspection Report 05000456/2008003; 05000457/2008003.

b. Observations

Summary: Braidwood Station Unit 2 is a Westinghouse four loop designed plant. The licensee had identified a population of DMBWs susceptible to primary water stress corrosion cracking in accordance with MRP-139 guidelines. The licensee had previously completed mitigation by weld overlay repair to the pressurizer DMBWs.

Based on the schedule of DMBW examinations under MRP-139, no examinations were required for the current Unit 2 RFO (A2R14) and hence, none were performed.

Additionally, the licensee had not made any changes to the MRP-139 inspection program since the NRC had previously reviewed this program. Therefore, the specific questions identified in TI 2515/172 were not applicable.

.2 (Closed) NRC Temporary Instruction 2515/175 "Emergency Response Organization, Drill/Exercise Performance Indicator, Program Review"

The inspectors performed TI 2515/175, ensured the completeness of the TI's Attachment 1 and then forwarded the data to NRC, Headquarters. Therefore, this TI is closed.

.3 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 7, 2010, the inspectors presented the inspection results to Mr. A. Shahkarami and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of the Emergency Preparedness Program Inspection with Mr. A. Shahkarami conducted at the site on October 9, 2009.
- The results of the Inservice Inspection with Mr. A. Shahkarami, and other members of the licensee staff on October 22, 2009.
- The results of the Radiological Access Control Training Program Inspection with Mr. A. Shahkarami on October 23, 2009.
- The Licensed Operator Requalification Training Program Annual Inspection results with Operations Training Requalification Lead, Mr. G. Pickar, on December 16, 2009, via telephone.

- The Annual Review of EAL and Emergency Plan Changes with the licensee's Emergency Preparedness Manager, Mr. S. Butler, via telephone on December 21, 2009.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

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

- 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be accomplished in accordance with documented instructions, procedures or drawings. Contrary to the above, on October 12, 2009, the Unit 2 pressurizer temperature limit, as described in the Braidwood Technical Requirements Manual, Section 3.4.c, was exceeded. Specifically, the heatup limit of less than or equal to 200ºF in any one hour was exceeded during filling of the Unit 2 pressurizer. This was documented in the licensee's CAP as IR 977969. This finding is of very low safety significance because the licensee demonstrated through analysis that the transient was bounded by existing analyses for pressurizer structural integrity limits and there were no unacceptable flaws in the pressurize lower head and surge nozzle.

- 10 CFR 50.65 requires, in part, that the licensee shall assess and manage the increase in risk from the proposed maintenance activities before performing maintenance. Contrary to this, on November 16, 2009, the licensee failed to manage the increase in risk during the 2B AF pump suction pressure calibration. Specifically, for nearly 4 hours, dedicated personnel were not present to restore the instrumentation if it were needed, which renders the 2B AF pump unavailable. This resulted in an unplanned change from Green to Yellow risk. Upon discovery, the licensee immediately assigned continuous dedicated personnel for the remainder of the surveillance. The finding is of very low safety significance because the Incremental Core Damage Probability is not greater than 1E-6. The licensee entered this issue into their CAP as IR 994317 and was also written as a Prompt Investigation Report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

A. Shahkarami, Site Vice President
L. Coyle, Plant Manager
K. Aleshire, Emergency Preparedness Manager
L. Antos, Security Operations Manager
K. Appel, Corporate Emergency Preparedness Manager
G. Bal, Engineering Program Manager
S. Butler, Emergency Preparedness Manager
G. Dudek, Site Training Manager
R. Gadbois, Maintenance Manager
G. Galloway, Work Control Manager
D. Gullott, Regulatory Assurance Manager
J. Knight, Nuclear Oversight Manager
T. McCool, Operations Manager
J. Moser, Radiation Protection Manager
J. Odeen, Project Management Manager
T. Schuster, Chemistry Manager
J. Smith, Exelon Asset Manager
M. Smith, Engineering Manager

Nuclear Regulatory Commission

R. Skokowski, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED AND CLOSED

Opened

05000456/2009005-01 05000457/2009005-01	URI	Water Found in Underground Cable Vaults (Section 1R06.b)
05000457/2009005-02	NCV	Failure to Establish 2-to-1 Weld Profile on AF Cross-Tie Drain Line Socket Welds (Section 1R08.1.b)
05000457/2009005-03	NCV	Failure to Follow Work Instructions During Restoration of 2SX173 (Section 1R15.b)
05000457/2009005-04	URI	Possible Failure To Follow Stroke Time Test Procedure (Section 1R19.b(1))
05000457/2009005-05	NCV	Failure to Follow Maintenance Procedures and Work Instructions (Section 1R19.b(1))
05000456/2009005-06 05000457/2009005-06	URI	RCS RTD Cross Calibration (Section 1R19.b(2))
05000456/2009005-07 05000457/2009005-07	URI	Changes to EAL HU6 Potentially Decreased the Effectiveness of the Plans Without Prior NRC Approval (Section 1EP4.b)

05000456/2009005-08; 05000457/2009005-08	NCV	Failure to Fully Implement Abnormal Operating Procedures Following a Seismic Event (Section 4OA3)

Closed

05000457/2009005-02	NCV	Failure to Establish 2-to-1 Weld Profile on AF Cross-Tie Drain Line Socket Welds (Section 1R08.1.b)
05000457/2009005-03	NCV	Failure to Follow Work Instructions During Restoration of 2SX173 (Section 1R15.b)
05000457/2009005-05	NCV	Failure to Follow Maintenance Procedures and Work Instructions (Section 1R19.b(1))
05000456/2009005-08 05000457/2009005-08	NCV	Failure to Fully Implement Abnormal Operating Procedures Following a Seismic Event (Section 4OA3)

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 Protection

- BwAP 340-1; Abnormal and Emergency Operating Procedure Writers Guide; Revision 23
- 0BwOA ENV-4; Earthquake Unit 0; Revisions 104 and 106
- 0BwOA ENV-1; Adverse Weather Conditions; Revisions 105 and 106
- HU-AA-104-101; Procedure Use and Adherence; Revision 3
- 50.59 Evaluation Form BRW-E-2006-196 Revision 1; EC 357102 and DRP 11-092 Revision 002,0
- IR 583639; NRC Mod/50.59 Inspection Identified an Inadequate 50.59 Evaluation; January 24, 2007
- IR 601635; NRC Issued Green Severity Level IV NCV for Inadequate Mod 50.59; January 26, 2007
- IR 767223; Procedure Enhancements for 0BwOA ENV-4; April 24, 2008
- IR 782043; LSH Acid Unloading Station is Degraded; June 2, 2008
- IR 791323; Sulfuric Acid Tanks Not Emptied Per BwOP CF-45; June 27, 2008
- IR 831223; NRC PI&R Identified 50.59 Evaluation Not Completed for 1/2BwOA ELEC-4; October 15, 2008
- Design Summary EC 357102; Sulfuric Acid System Addition at LSH; Revision 000

1R04 Equipment Alignment

- M-42, Sheet 1A - 6; Diagram of Essential Service Water (Critical Control Room Drawing)
- M-136, Sheet 1 - Sheet 6; Diagram of Safety Injection Pump Unit 2 (Critical Control Room Drawing)
- M-64, Sheet 1 - Sheet 8; Diagram of Chemical Volume and Boron Thermal (Critical Control room Drawing)
- BwOP CV-M1; Chemical Volume Operating Mechanical Lineup Unit 1; Revision 20
- 2C-SI-35 Safety Injection Containment Building,
- EC 375868 Unit 2 ECCS Ventilation Installation
- 2C-SI-34 Safety Injection Containment Building,
- M-539 Reactor Bldg. El. 377’-0” & 401’-0” Safety Injection System, Rev J.
- M-136 Diagraph of Safety Injection System Sheet 4
- 50.59 Evaluation for DRP 13-022 “ECCS-SI8818 Vent Installation (Generic Letter 08-01)
- BwOP SI-E2, Rev 6; Electrical Lineup – Unit 2 Operating
- BwOP SI-M2; Operation Mechanical Lineup Unit 2, Revision 20

1R06 Flood Protection

- IR 968522; Deteriorating condition of Cable Vaults; September 22, 2009
- Photos of Underground Cable Vault Conditions at Braidwood; Manhole 1E, 1Z, and 2D

1R08 Inservice Inspection Activities

- IR 770884; Foreign Material Event A2R13; April 30, 2008 IR 00771304; 2RH01CA (Repeat Boric Acid Leakage); May 3, 2008
- IR 774562; Foreign Material Identified in Secondary Side of SG; May 9, 2008
- IR 766758; IWL 3510-1 Table Used for Acceptance; April 17, 2008
- IR 801836; Suction Spool Piece 2CS01AB-16 Boric Acid Leakage; July 30, 2008
- IR 079134; Dresden Clarify 2X1 Weld Size; October 16, 2001
- IR 903945; Rejectable PT Indications 1CVB8368A Final Weld; April 7, 2009
- IR 904986; SG 1B Foreign Object Wear; January 8, 2009
- IR 975004; 2CV8149C (Boric Acid Leakage); August 14, 2009
- IR 978883; NRC Identification of Requirement for Reactor Head Doors; October 14, 2009
- IR 981831; NRC Question on 2X1 Weld Criteria; October 20, 2009
- IR 981981; NRC Concern with 2X1 Weld Condition; October 20, 2009
- IR 991935; Typo in WPS 1-1-GTSM-PWHT; October 20, 2009
- Braidwood Unit 2 A2R13 Condition Monitoring and Operational Assessment Report; August 11, 2008
- EPRI TR-113890; Vibration Fatigue Test of Socket Welds (PWRMRP-07); December 1999
- EPRI TR-107455; "Vibration Fatigue of Small Bore Socket-Welded Pipe Joints; June 1997
- ER-AP-331-1002; Attachment 2 Boric Acid Evaluation, Manual Vent 2CV216; January 15, 2009
- ER-AP-331-1002; Attachment 2 Boric Acid Evaluation, Manual Vent 2CV217; January 26, 2009
- ER-AP-331-1002; Attachment 2 Boric Acid Evaluation, Manual Vent 2CV224, February 2, 2009
- ER-AP-331-1002, Attachment 2 Boric Acid Evaluation, Manual Vent 2CV225; January 26, 2009
- ETTS CDE-0001-1009; 0610 Bobbin 40 IPS; October 13, 2009
- ETTS CDE-0002-1009; 0590 Bobbin 24 IPS; October 09, 2009
- ETTS CDE-0003-1009; 3 Coil +Pt, October 13, 2009
- ETTS CDE-0004-1009; 3 Coil +Pt Dent, October 13, 2009
- ETTS CDE-0006-1009; Low Row UB +Pt; October 13, 2009
- ETTS CDE-0007-1009; High Row UB +Pt, October 13, 2009
- ETTS CDE-0008-1009; 3 Coil +Pt (590); October 13, 2009
- Procedure ER-AP-331; Boric Acid Corrosion Control Program, Revision 4
- Procedure ER-AP-331-1002; Identification and Screening of Boric Acid Leakage; Revision 5
- Procedure ER-MW-335-1009; Site Specific Performance Demonstration Program; Revision 4
- Procedure EXE-ISI-70; Magnetic Particle Examination; Revision 3
- Procedure EXE-ISI-11; Liquid Penetrant Examination; Revision 2
- Procedure EXE-PDI-UT-2; Ultrasonic Examination of Austenitic Piping Welds in Accordance with PDI-UT-2; Revision 5
- Procedure ER-MW-335-1003; SG Eddy Current Data Analysis Guidelines for Braidwood and Byron Station Unit 2; Revision 4
- Procedure ER-AP-335-04; Evaluation of Eddy Current Data for SG Tubing; Revision 4
- Procedure Qualification Record; A-001; October 19, 1998
- Procedure Qualification Record; A-002; March 9, 1999
- Procedure Qualification Record; 1-50C; January 3, 1984
- Welder W2677; ANI Certification of Qualification; October 19, 2009
- Welder F5519; ANI Certification of Qualification; October 19, 2009
- Weld Procedure Specification 1-1-GTSM-PWHT; Revision 1
- Wesdyne Indication Assessment; Shell-to-Flange Weld 2RV-01-005; May 5, 2008

- Wesdyne Indication Assessment; Shell-to-Flange Weld 2RV-01-011; May 3, 2008
- Work Order 01171778; Install the Cross-Tie per EC 369972; March 24, 2009

1R11 Licensed Operator Requalification Program

- Requalification Examination Results/Calendar Year 2009
- LORT Lesson Plan I1-SP-09-32
- 1BWep E.S 0.2, 0.3, 0.4
- Cycle 4, Scenario #0941, Failed fuel (High RCS Activity) SGTR and Faulted/Rupture, Crew 1 performance Information.
- Procedure TQ-AA-224_F100; Remediation Training.

1R12 Maintenance Effectiveness

- IR 844665; VA Missed Surv-Results of VA Non-Access. PL. DP Measurements
- IR 847260; CCP VA Prints Differ from SX Prints for AF Cubicle Cooling
- IR 848499; OVA25J FU-1 Fuse was Missing During RTS
- IR 860472; Clogged Funnel for 1A CV Pump Cubicle Cooler Drain Line
- IR 861809; 2VA01CC Not Running While 2A SX Pump Running
- IR 866485; Snow found in VA Plenums
- IR 868031; Unable to Restore Normal VA Lineup Due to VA Prefilter DP
- IR 868239; High DP Across Filters 0VA01FD (DUP)
- IR 869223; Replace VA Supply Plenum Pre-Filters-HI D/P - Snow Intrusion
- IR 869224; Replace VA Supply Plenum Pre-Filters-HI D/P - Snow Intrusion
- IR 869226; Replace VA Supply Plenum Pre Filters-HI D/P - Snow Intrusion
- IR 869229; Replace VA Supply Plenum Pre Filters-HI D/P - Snow Intrusion
- IR 869230; Replace VA Supply Plenum Pre Filters-HI D/P - Snow Intrusion
- IR 869231; Replace VA Supply Plenum Pre Filters-HI D/P - Snow Intrusion
- IR 876318; The Door in VA Exhaust Plenum Cannot Be Securely closed
- IR 876323; VA C-NAC Charcoal run Time
- IR 881115; Long Range Planning for 1VA06CA Motor Refurb
- IR 881124; Long Range Planning for 1VA06CD Motor Refurb
- IR 886818; Unexpected 0-31-E6 Annunciator
- IR 887413; 0VA088YB Needs Tag

1R13 Maintenance Risk and Emergent Work

- MA-AA-716-004; IR 974691 1A RCO 1RC01OAl Seal Injection Flows Have Been Elevated; October 5, 2009
- OP-AA-108-11; 1A RCP Low Seal Leak Off; October 5, 2009
- 1B CV Pump Work Window; Protected Equipment Initial Assessment After Emergent Trip; October 3, 2009

1R15 Operability Evaluations

- EC 392597; Evaluation of the Pressurizer Heatup/Cooldown Transient During A2R14 Shutdown; October 27, 2009
- IR 983896; A2R14 LL 2ACV Pump Rotating Element Increased Vibration; October 24, 2009
- IR 985118; 2B DG Ventilation Hydramotor Power Lost and Restored; October 27, 2009
- IR 987448; 2B DG Ventilation Lost Control Power; November 2, 2009
- IR 999797; 2B DG Ventilation Operability Clarification; December 1, 2009

- IR 994133; 2VC03CB Thermals Found Tripped; November 16, 2009
- IR 983851; 2A CV ASME Data; October 24, 2009
- IR 977969; A2R14LL - Unplanned TRM Energy 3.4.c, U2 Pressurizer; October 12, 2009
- IR 981024; 2SX173 Opening Causes Water Hammer; October 18, 2009
- IR 983851; 2A CV ASME Date; October 24, 2009
- IR 984049; 2A DV Pump Curve Per 2BwOSR 5.5.8.CV-8 is Invalid; October 24, 2009
- 2BwGP 100-5; Plant Shutdown and Cooldown; Revision 36
- Prompt Investigation Report; Water Hammer Event
- Assignment Report; Water Hammer Event Results from Failure to Follow Work Package; November 4, 2009
- EC 369644 Evaluation of DG Fuel Line Leak.
- Cooper-Bessemer drawing KSV-31-3 Engine Driven fuel Oil Transfer Pump.

1R18 Temporary Plant Modifications

- EC 376885; Temporary Removal of Temperature Element 1TE-DG052B and Sealing of the Opening; September 4, 2009E
- EC 377675; Internal-External Wiring diagram Reactor Vessel Level CH B HJTC Cabinet; November 10, 2009
- 2BwEP EX-0.3; Natural Circulation Cooldown with Steam Void in Vessel (With RVLIS) Unit 2; Revision 201
- UFSAR E.31; Instrumentation for Detection of Inadequate Core cooling (II.F.2)
- UFSAR Figure E.31-5; Probe Holder Assembly and Sensor Locations

1R18 Permanent Plant Modifications

- IR 986425; 2B RVLIS Probe Appears Not Functioning Due to Sensor 1; October 30, 2009
- EC 377675; Restore Function to Sensors 3, 5 & 7 to Restore Minimum Number of Sensors to 2B RVLIS Probe
- 2BwEP ES-0.3; Natural Circulation Cooldown with Steam Void in Vessel (with RVLIS) Unit 2, Revision 201
- EC 376885; Temporary Removal of Temperature Element 1TE-DG052B and Sealing of the Opening

1R19 Post Maintenance Testing

- EC 375521 Revision 000; NRA Scaling (2TY-0441B) for Replacement of RTD 2TE-0441B/2T#-0440 (Loop 2D RCS Cold Leg Temperature
- IR 983851; 2A CV ASME Date; October 24, 2009
- IR 984049; 2A DV Pump Curve Per 2BwOSR 5.5.8.CV-8 is Invalid; October 24, 2009
- IR 992258; 2SX178 Stroke Time Exceeds Alert Limit, Needs Evaluation; November 12, 2009
- IR 995118; Issues Identified for Valve 2SX178 During A2R14; November 18, 2009
- 1BwOSR 5.5.8.CV-4B; Group A IST Requirements for 1B Centrifugal Charging Pump (1CV01PB) and Check Valve 1CV8480B Stroke Test; Revision 0
- 1BwOSR 5.5.8.SI-7B; Safety Injection System Containment Sump 1SI8811B Valve Stroke Surveillance; Revisions 4 and 5
- 2BwISR 3.3.1.10-1; Unit 2 RCS RTD Cross-Calibration; Revision 1 NUREG-0800; Branch Technical Position 7-13; Guidance on Cross-Calibration of Protection System RTDs
- 2BwOSR 5.5.8SX-1B; Essential Service Water Train B Valve Stroke Surveillance; Revision 11
- 2BwOSR 5.5.8SX-1B; Essential Service Water Train B Valve Stroke Surveillance; Revision 12
- WO 0789584 03; 2FSV-SX178 Replace solenoid Every 3rd Refueling Outage

- WO 0993431 02; Clean or Replace the Air Muffler on Actuator
- WO 1136768 03; Perform 18 Month Inspection in Supp or 1BwVX 7.1.2.3.C-1
- WO 1084024 01; 1SI8811B Lubricate Valve Stem; June 25, 2009
- WO 1133366 01; 2SX178 Flow Scan Valve; October 28, 2009
- WO 1245941 01; 1SI8811B Failed to Stroke Full Open During Surveillance; June 26, 2009
- WO 1258632 01; ASME Surveillance Requirements for 2A Essential Service Water Pump; October 22, 2009
- OP-AA-106-101-1006; IR 911389-23, 984642-02; System 2T-0441 2D, Delta T/T Ave Protection Loop
- MA-AA-716-012; Post Maintenance Test Selection Considerations; Revision 11
- MA-AA-716-030; AOV Troubleshooting Guide/Matrix; Revision 0
- MA-AA-743-310; Diagnostic Testing and Evaluation of Air Operated Valves; Revision 5
- 00078685; Containment Sump 1B Isolation Valve Assembly, 1SI8811B Drain and Valve Stroke
- Letter from D. Saccomando Commonwealth Edison to NRC Document Control Desk; Application for Amendment to Facility Operating Licenses; February 21, 1995
- Letter from R. Assa, NRR to D. Farrar Commonwealth Edison; Issuance of Amendment #66 Braidwood Technical Specifications; September 5, 1995
- Letter from S. Richards, NRR to G. Vine Electric Power Research Institute; EPRI Topical Report (TR) 104965, "On-Line Monitoring of Instrument channel Performance," Final Report, November 1998; July 24, 2000
- ANSI/IEEE Std 338-1987; IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems; 1988
- Reg Guide 1.118; Periodic Testing of Electric Power and Protection systems; Revision 3

1R22 Surveillance Testing

- BwMSR 3.7.1.1; Main Steam Safety Valves Operability Test (Setpoint Verification Using the Furmanite Trevitest System; Revision 0
- IR 976821; Results of MSSV Trevi Testing Pre A2R14; October 8, 2009
- IR 976930; Test Equipment Damaged During Removal; October 8, 2009
- WO 1268166 01; Diesel Driven AF Pump Monthly; October 19, 2009

1EP2 Alert and Notification (ANS) Evaluation

- EP-AA-1001, Section 4.3.1; Exelon Nuclear Radiological Emergency Plan for Braidwood Station; Revision 22
- Braidwood Station Off-Site Emergency Plan Alert and Notification Addendum; April 15, 1994
- Braidwood Off-Site Siren Test Plan; December 28, 2007
- Exelon Semi-Annual Siren Report; January 1, 2009 - June 30, 2009
- Braidwood Warning System Maintenance and Operational Report; September 24, 2008 - November 18, 2008
- Braidwood Monthly Siren Availability Reports; February 2007 - September 2009
- Braidwood Daily Siren Operability Reports; January 2007 - June 2009
- IR 00664068; EP Loss of Greater than 25 Percent Emergency Sirens; August 24, 2007

1EP3 Emergency Response Organization Augmentation Testing

- Section 5; Prairie Island Nuclear Generating Plant Emergency Plan; Organizational Control of Emergencies; Revision 40
- SP 1744; Semi-Annual Emergency Organization Augmentation Response Test; Revision 32

- Emergency Response Organization Off-hours, Unannounced, Augmentation Response Test Records; April 2007 - April 2009
- IR01189478; ERO Augmentation Test Methods in Question; July 15, 2009

1EP4 Emergency Action Level and Emergency Plan Changes

- Exelon Nuclear Standardized Radiological Emergency Plan; Sections B and N; Revision 19
- EP-AA-122-1001; Drill and Exercise Scheduling, Development, and Conduct; Revision 11
- TQ-AA-113; ERO Training and Qualification; Revision 13
- Braidwood ERO Augmentation Call-In Drill Reports; March 2007 - September 2009
- ERO Call-In Augmentation Drill Results for EOF and JIC; August - September 2009
- IR 00961914; September 2, 2009, ERO Call-In Drill Results; September 4, 2009
- IR 00961905; Operations Training Individual Yellow on ERO Bingo Chart (Team D); September 4, 2009
- IR 00961895; Team A RP Individual is Red on the ERO Bingo Chart; September 4, 2009
- IR 00951809; RP Needs to Provide EP with a Replacement for the Radiation Control Coordinator; August 11, 2009
- IR 00894179; ERO Duty Members Failed to Respond to Call-In Drill; March 17, 2009
- IR 00882545; Issues with RPT Call-In Drills for ERO Augmentation; February 19, 2009
- IR 00866503; Call-In Drill for RPT Did Not Work Correctly; January 14, 2009
- Braidwood Station Radiological Emergency Plan annex; Revisions 20, 21, and 22

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

- FASA Self-Assessment Report Assignment Number 842800; Braidwood Emergency Preparedness NRC Baseline Inspection Readiness; August 5, 2009
- Event Summary Report for Unusual Event, July 30, 2009; August 2, 2009
- Braidwood Station July 30, 2009, Unusual Event Report; August 18, 2009
- NOSA-BRW-09-04; Braidwood Station Emergency Preparedness Audit; May 5, 2009
- NOSA-NCS-09-04; Corporate Emergency Preparedness Audit; April 8, 2009
- NOSA-BRW-08-03; Braidwood Station Emergency Preparedness Audit; April 16, 2008
- NOSA-NCS-08-03; Cantera and Kennett Square Emergency Preparedness Audit; April 9, 2008
- NOSA-BRW-07-04; Braidwood Station Emergency Preparedness Audit; April 25, 2007
- NOSA-NCS-07-04; Cantera and Kennett Square Emergency Preparedness Audit; May 23, 2007
- IR 00948495; Call-In Response for Unusual Event Less than Desired; August 1, 2009
- IR 00898759; Results of First Quarter EP Inventories Conducted by RP; March 27, 2009
- IR 00880557; OSC Performance Issues from February 4, 2009 Performance Indicator Drill; February 13, 2009
- IR 00880438; Technical Managers Did Not Show For CDAM/DAPAR Training; February 13, 2009
- IR 00849507; Incorrect CDAM Output Obtained and Used During Graded Exercise; November 25, 2009
- IR 00804450; Attention to Detail Items from July LORT DEP Opportunities; August 6, 2008
- IR 00755900; Braidwood Emergency Preparedness Improvement Plan; March 28, 2008

1EP6 EP Drill Evaluation
- EP-MW-114-1000-F-01; Nuclear Accident Reporting System Form, Revision D
- EP-AA-111-F-02; Braidwood Plant Based PAR Flowchart, Revision C

- EP-AA-125-1002; R.EP.01 and EPPI.01a-c PI Summary, Revision 4
- Braidwood EP Team D June Mini-Drill Findings and Observation Report

2OS1 Access Control to Radiologically Significant Areas

- LS-AA-2140; Monthly Data Elements for NRC Occupational Exposure Control Effectiveness; Revision 4
- RP-AA-376; Radiological Postings; Labeling and Markings; Revision 4
- RP-AA-401; Work-In-Progress Review; RWP 10010320, A2R14: Reactor Head disassembly and Reassembly; Revision 9
- RP-AA-460; Controls for High and Locked High Radiation Areas; Revision 19
- RP-AA-460-001; Controls for Very High Radiation Areas; Revision 2
- RP-AA-460-002; Additional High Radiation Exposure Control; Revision 0
- RP-AA-460; Attachment 8; Approval for High Radiation Area/Locked High Radiation Area Deviations; Revision 19
- RP-AA-461; Radiological Controls For Contaminated Water Diving Operations; Revision 2
- RP-AA-500-1001; Requirements for Radioactive Materials Stored Outdoors; Revision 2
- RP-BR-376-3002; Radiological Controls for Handling Items and Hanging Active parts in the Spent Fuel Pool; Revision 0
- NF-AA-390; Spent Fuel Pool Material Log; Revision 0
- RWP 10010279; A2R14: Radiation Protection Outage Support Activities; Revision 1
- RWP 10010297; A2R14: Lead Shielding Installation and Removal; Revision 0
- RWP 10010311; A2R14: Valve Team: Outage Activities in Containment; Revision 1
- RWP 10010320; A2R14: Reactor Head Disassembly and Reassembly; Revision 9
- RWP 10010344; A2R14: Dive Activities in Contaminated Water; Revision 0
- RWP 10010362; A2R14: SG Eddy Current Testing and All Tube Repairs; Revision 0
- Updated Final Safety Analysis Report Section 11.4.2.7 Storage Areas; Revision 12

4OA1 Performance Indicator Verification

- 2009 Braidwood ERO Duty and Drill Schedule; Revision 0
- LS-AA-2110; Monthly Data Elements for NRC Emergency Response Organization (ERO) Drill Participation; December 2008 - June 2009
- Key ERO Participation and Stability Monthly Data Reporting Elements; December 2008 – June 2009
- LS-AA-2120; Monthly Data Elements for NRC Drill and Exercise Performance; October 2008 - June 2009
- LS-AA-2130; Monthly Data Elements for NRC Alert and Notification System (ANS) Reliability; October 2008 - June 2009
- Braidwood Monthly Siren Availability Reports; October 2008 - June 2009
- IR 00832012; Operations Individual Failure to Classify an EAL in the Simulator; October 16, 2008
- IR 00953142; Failed DEP Due to Inaccurate NARS Form; August 13, 2009
- IR 00942768; Minor Errors in PAR Notification Times in Seven Documents; July 16, 2009
- IR 00927522; DEP Failure on Simulator during June Performance Indicator Drill; June 3, 2009

4OA2 Identification and Resolution of Problems

- IR 869905; Radiation Mon Alarms While Venting U-2 VCT-Corrective Action Required; January 22, 2009
- IR 908527; Evaluation for Operator Workaround Required; April 15, 2009

- IR 909228; MCB Flow Indication Not Present for 1B FW Pump; April 19, 2009
- IR 976328; OB Waste Gas compressor Will Not Run; October 7, 2009
- IR 1005862; NRC Concern About Operator Work Around Evaluation; December 15, 2009
- OP-AA-102-103; Operator Work-Around Program; Revision 3
- 3rd Quarter 2009 OWA Aggregate Review; IR 927465 on DG Vent Fan Partially Sheared Key from 1VD01CA; September 28, 2009

4OA7 Licensee Identified Violations

- IR 987199; Loss of Unit 2 Condenser Vacuum - Challenge; November 1, 2009
- OP-AA-101-113-1004; Prompt Investigation Report for IR 987199; Revision 15
- IR 987342; Water in Actuator Limit Switch Compartment Valve 1DI8811B November 1, 2009
- Prompt Investigation Report for IR 987342
- IR 994317; Loop 2P-AF055 Unattended Contrary to the PRA; November 16, 2009
- OP-AA-101-113-1004; Prompt Investigation Reports for IR 994317; Revision 15
- IR 1007068; Missed Tech Spec Valve Stroke on 2MS018B; November 16, 2009
- Prompt Investigation Report for IR 1007068

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CV	Chemical and Volume Control
DMBW	Dissimilar Metal Butt Weld
EAL	Emergency Action Level
EPRI	Electric Power Research Institute
ET	Eddy Current
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report / Inspection Report
ISI	Inservice Inspection
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
OTdT	Over Temperature Delta Temperature
OWA	Operator Workaround
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post-Maintenance Testing
PORV	Power Operated Relief Valve
QV	Quality Verification
RCS	Reactor Coolant System
RFO	Refueling Outage
RTD	Resistance Temperature Detector
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SX	Essential Service Water
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ulatrasonic Examination
WO	Work Order

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Sincerely,

/RA/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-456; 50-457
License Nos. NPF-72; NPF-77

Enclosure: Inspection Report 05000456/2009005; 05000457/2009005
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Letter to C. Pardee from R. Skokowski dated February 3, 2010.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, INTEGRATED INSPECTION REPORT 05000456/20009005; 05000457/2009005

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