UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

August 14, 2009

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 INTEGRATED INSPECTION REPORT 05000456/2009003 AND 05000457/2009003

Dear Mr. Pardee:

On June 30, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Braidwood Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on July 15, 2009, with Mr. B. Hanson 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, six findings of very low safety significance (Green) were identified. Five of these findings involved violations of NRC requirements. Because of the very low safety significances and because the issues were entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations (NCV), consistent with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest any Non-Cited Violation or Severity Level IV Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies 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 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 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, its enclosure and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-erm/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 05000456/2009003; 05000457/2009003
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Braidwood Station
Plant Manager - Braidwood Station
Manager Regulatory Assurance - Braidwood Station
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
Manager Licensing - Braidwood, Byron and LaSalle
Associate General Counsel
Document Control Desk - Licensing
Assistant Attorney General
J. Klinger, State Liaison Officer,
Illinois Emergency Management Agency
Chairman, Illinois Commerce Commission

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Document Control Desk - Licensing
Assistant Attorney General
J. Klinger, State Liaison Officer,
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Letter to C. Pardee from R. Skokowski dated August 14, 2009.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2 INTEGRATED INSPECTION REPORT 05000456/2009003 AND 05000457/2009003

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REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2009003 and 05000457/2009003
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	April 1, 2009, through June 30, 2009
Inspectors:	B. Dickson, Senior Resident Inspector A. Garmoe, Resident Inspector T. Hartman, Reactor Engineer M. Holmberg, Reactor Inspector R. Jones, Reactor Engineer M. Mitchell, Health Physicist R. Ng, Project Engineer M. Thorpe-Kavanaugh, Reactor Engineer M. Perry, Resident Inspector, Illinois Department of Emergency Management
Approved by:	R. Skokowski, Chief Reactor Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000456/2009003, 05000457/2009003; 04/01/2009-06/30/2009; Braidwood Station, Units 1 & 2; Fire Protection, Identification and Resolution of Problems.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Five Green findings were identified by the inspectors or self-revealed. Four of the findings were considered Non-Cited Violations of Nuclear Regulatory Commission requirements. The inspectors also identified one Severity Level IV Non-Cited Violation. 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 inspector identified a Green finding associated with the failure to control or remove material adjacent to the Unit 1 main power transformers, station auxiliary transformers and unit auxiliary transformers. Plant personnel failed to identify these discrepant conditions during the performance of a plant surveillance procedure with the purpose of identifying and removing potential missile hazards from areas where they could damage important plant electrical equipment during adverse weather conditions. The licensee entered this issue into their correction action program. Proposed corrective actions included relocating storage to an appropriate less vulnerable location and reemphasizing good practices related to housekeeping.

  The finding is greater than minor because the finding could be reasonably viewed as a precursor to a significant event, such as a loss of Technical Specification (TS) required power supplies or a loss of off-site power caused by missile damage to the auxiliary power system. The inspectors determined that because the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator; the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available; and the finding did not increase the likelihood of a fire or internal or external flooding, it was of very low safety significance. The cause of the finding is related to the work practices attribute of the cross-cutting element of Human Performance (H.4(c)). (Section 1R01)

Cornerstone: Mitigating Systems

- Green: A Non-Cited Violation of License Condition 2.E, “Fire Protection Program,” was self-revealed when the automatic carbon dioxide (CO_2) fire suppression system was isolated from the Unit 1 and Unit 2 Lower Cable Spreading Rooms (LCSRs) from July 23, 2007, through August 11, 2008. Specifically, the licensee identified that a modification to the Upper Cable Spreading Room (UCSR) CO_2 system, on July 23, 2007, had inadvertently isolated the CO_2 system to the LCSRs. The licensee entered the deficiency with the automatic carbon dioxide fire suppression system into their corrective action program and installed a modification to return the LCSR CO_2 system to service.

The finding was determined to be more than minor because the design control attribute of the mitigating systems cornerstone was impacted. The inspectors determined this finding to be of very low safety significance based on the Phase 2 SDP evaluation in accordance with IMC 0609, Appendix F, "Fire Protection SDP." This finding is related to the cross-cutting area of Human Performance associated with the attribute of resources (H.2(c)). (Section 1R05)

- SL IV: The inspectors identified a Severity Level IV NCV of 10 CFR 50.59 following a review of changes made to TS required surveillance test procedures. These procedures allowed testing of Reactor Protection System (RPS) analog channels in the bypassed conditions by use of jumpers during surveillance test. This technique had been deemed unacceptable in NRC safety evaluation report for Westinghouse Topical Report WCAP 10271.

  This issue involves traditional enforcement because it involves a violation of 10 CFR 50.59 and is more than minor because there was a reasonable likelihood that the change would require NRC review and approval prior to its implementation. This issue did not represent an actual loss of safety function for greater than the TS allowed outage time; therefore it was of very low safety significance. Consequently, the finding is categorized as a Severity Level IV NCV in accordance with the NRC Enforcement Policy. There were no cross-cutting aspects identified by the inspectors. This finding was documented in the license's corrective action program. Corrective actions included changing the method of reactor trip system testing. (Section 1R22)

- Green: A NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for failure to install a modified Emergency Core Cooling System (ECCS) throttle valve design commensurate with the design control measures applicable to the original design. This resulted in the failure to select a material suitable to the application. Specifically, the licensee selected a design that included gas nitrided surfaces, contrary to the Westinghouse design specification for the original emergency core cooling system throttle valves that prohibited the use of nitrided surfaces in reactor coolant applications. Corrective actions included replacing the ECCS throttling valve that showed worst flow degradation. Additionally the licensee re-performed the surveillance test and adjusted the throttle valves such that any future degradation of the flow area (caused by corrosion or brazing material loss) will not result in pump run-out.

  The finding was determined to be more than minor because it was similar to Example 5.a of IMC 0612, Appendix E, "Examples of Minor Issues," in that a modification that did not meet design requirements was returned to service prior to discovery. The inspectors determined the issue did not result in the actual loss of a safety function and the issue screened out as having very low safety significance. This finding has a cross-cutting aspect in the area of Problem Identification and Resolution associated with the corrective action program attribute, because the licensee did not thoroughly evaluate all aspects of the modification to the ECCS throttle valves. (P.1(c)) (Section 4OA2)

- Green: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action Program,” associated with the licensee's failure to promptly identify that the 2A Essential Service Water (SX) subsystem was inoperable and hence, entry into Braidwood Improved Technical Specification (TS) 3.7.8, “Essential Service Water (SX) System, Condition A was appropriate. Following the failure of the Unit 1A SX pump due to indications of discharge strainer fouling from Bryozoan infestation in the lake screenhouse the operators failed to properly evaluate possible common mode failures associated with the 2A SX subsystem. This resulted in an approximately 45 hour delay in recognizing that the 2A SX subsystem was inoperable and therefore delayed actions to recover the subsystem. The licensee entered this performance deficiency into their corrective action program.

  The finding is greater than minor because the lack of prompt identification of the common failure affected the Mitigating Systems Cornerstone objective of ensuring the availability, capability and reliability of the Unit 1 and Unit 2 SX trains to respond to initiating events to prevent undesirable consequences. The finding is of very low safety significance because based on the results of an analysis performed by the licensee, which concluded that, even under severely degraded flow conditions, the affected trains of SX would have provided sufficient cooling to components served by the SX system following a reactor trip, a loss of coolant accident, or a loss of offsite power. The primary cause of the finding was related to the cross-cutting element of Human Performance and the associated attribute of decision making (H.1(b)). (Section 4OA3)

- Green: The inspectors identified a NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action Program,” having very low safety significance, associated with the licensee's failure to identify a significant condition adverse to quality and to develop corrective actions to prevent recurrence. Specifically, the licensee failed to identify the October 2005 bryozoa infestation as a significant condition adverse to quality and did not establish corrective actions to preclude recurrence. This was evidenced by the September 2008 accumulation of bryozoan colonies in the SX and Circulating Water System forebays that resulted in the SX system strainer plugging and hence represented a challenge to the reliability and operability of the SX system. The licensee entered this performance deficiency into their corrective action program.

  The finding is greater than minor because the failure to identify the significant condition adverse to quality and to develop corrective actions to prevent recurrence affected the Mitigating Systems Cornerstone objective of ensuring the availability, capability and reliability of the Unit 1 and Unit 2 SX trains to respond to initiating events to prevent undesirable consequences. The finding is of very low safety significance because based on the results of an analysis performed by the licensee, which concluded that, even under severely degraded flow conditions, the affected trains of SX would have provided sufficient cooling to components served by the SX system following a reactor trip, a loss of coolant accident, or a loss of offsite power. The primary cause of the finding was related to the cross-cutting element of Human Performance and the associated attribute of decision making (H.1(b)). (Section 4OA3)

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 began the inspection period in a scheduled refueling outage. The unit was made critical and the generator was placed online on April 19, 2009. Full power operation was achieved on April 24, 2009. Unit 1 operated at or near full power for the remainder of the inspection period.

Unit 2 operated at or near full power until April 24, 2009 when a reactor trip occurred. The unit tripped 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. Unit startup and synchronization to the grid occurred on April 25, 2009, with full power operations being reached on April 27, 2009. Unit 2 operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- coordination between the TSO and the plant during off-normal or emergency events;
- explanations for the events;
- estimates of when the offsite power system would be returned to a normal state; and
- notifications from the TSO to the plant when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- the actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- the compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- a re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- the communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

This inspection constitutes one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings of significance were identified.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee’s preparations for summer weather for selected systems, including conditions that could lead to an extended drought as a result of high temperatures.

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. Specific documents reviewed during this inspection are listed in the Attachment. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment. The inspectors’ reviews focused specifically on the following plant systems:

- cooling water lake (ultimate heat sink);
- transformer yard; and
- switchyard.

This inspection constitutes one seasonal adverse weather sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings of significance were identified.

.3 Readiness For Impending Adverse Weather Condition – Severe Thunderstorm Watch

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility on June 1, 2009, with the 1A emergency diesel generator (DG) out of service for maintenance, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. The inspectors evaluated the licensee's preparations against the site's procedures and determined that the actions were adequate. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a severe thunderstorm or a tornado. The inspectors' evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of the corrective action program (CAP) to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01-05.

b. Findings

Failure to Control and Secure Material Adjacent to Unit 1 Transformer Yard Which Could Become Potential Missiles

Introduction: A finding of very low safety significance was identified by the inspectors associated with the failure to control or remove material adjacent to the Unit 1 main power transformers, station auxiliary transformers and unit auxiliary transformers. Plant personnel failed to identify these discrepant conditions during the performance of a plant surveillance procedure with the purpose of identifying and removing potential missile hazards from areas where they could damage important plant electrical equipment during adverse weather conditions. No violations of NRC requirements were identified.

Description: On June 1, 2009, inspectors noted that the National Weather Service issued a severe thunderstorm watch for Northern Illinois (Thunderstorm Watch 318). The report predicted hail and thunderstorms with gusts to 70 miles per hours for the affected area. During this time, the 1A DG was out-of-service for planned maintenance and the online risk status was "Yellow." The online risk status would change to "Orange" if severe weather occurred based on plant conditions at the time.

Due to the weather forecast and online risk status, the inspectors performed Inspection Procedure (IP) 71111.01 Section 02.03. The inspectors identified that a licensee approved material storage area near the Unit 1 transformer yard contained loose or unrestrained materials that could become missile hazards during adverse weather conditions, such as tornados or severe thunderstorms. This material included several pieces of wood planks, 4 feet by 8 feet plywood board, scaffold poles and construction material. In many cases, the inspectors identified the loose material lying on top of restrained material and on top of storage cages. The inspectors were not only concerned about the potential for physical damage to the transformers but also to the electrical lines that connect the transformers to the Unit 1 switchyard.

In response to this issue, the inspectors reviewed licensee Procedure MA-AA-716-026, “Station Housekeeping/Material Condition Program.” During this review, the inspectors noted that the material storage area was outside the areas designated as transformer material exclusion areas and the secured equipment area as depicted in the procedure. However, because the material was in the line-of-sight to the transformers and closer than much of the secured equipment area, the inspectors concluded that the loose material stored in that area posed a wind generated missile threat to the Unit 1 offsite power supplies.

The licensee has included this issue in their corrective action program. Proposed corrective actions included relocating storage to an appropriate less vulnerable location and reemphasizing good practices related to housekeeping. The intent of the corrective action would be to ensure that appropriate precautions are established that would minimize the risk of equipment damage or transients as a result of inclement weather.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to adequately protect the Unit 1 transformer yard was a performance deficiency that warranted a significance evaluation. The inspectors determined that the issue was more than minor in accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, “Issue Screening,” because the issue could be reasonably viewed as a precursor to a significant event, such as a loss of Technical Specification (TS) required power supplies or a loss of off-site power caused by missile damage to the auxiliary power system.

The inspectors completed a significance determination review of this finding using IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At Power Situations.” In the Phase 2 screening, the inspectors determined that the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator; the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available; and the finding did not increase the likelihood of a fire or internal or external flooding. Therefore, the finding screened as one of very low safety significance.

This finding is related to the Work Practices attribute of the Human Performance cross-cutting area (H.4(c)). Specifically, the licensee did not ensure supervisory and management oversight of work activities, including contractors, such that nuclear safety is supported.

<u>Enforcement</u>: Since the procedure in question was not controlled by 10 CFR 50 Appendix B, no violation of NRC requirements occurred. **(FIN 05000456/2009003-01)**

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:

- 2A Safety Injection (SI) pump following fire drill in room;
- 1B SX system during 1A SX system work window; and
- 1A SX system during 1B SX system work window.

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, TS requirements, outstanding work orders, 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 three partial system walkdown samples as defined in IP 71111.04-05.

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:

- Unit 1 Containment Pipe Penetration Area, Elevation 364;
- Unit 2 Containment Pipe Penetration Area, Elevation 364;
- Auxiliary Building 383 Elevation General Area;
- Technical Support Center Ventilation Area;

- Auxiliary Building Laundry Area; and
- Unit 1 LCSR.

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 had 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. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings of significance were identified.

.2 (Closed) Unresolved Item (URI) 05000456/2008004-03; 05000457/2008004-03: Inadvertent Isolation of Lower Cable Spreading Room Carbon Dioxide Fire Suppression

Introduction: A finding of very low safety significance (Green) and associated NCV of License Condition 2.E, "Fire Protection Program," was self-revealed when the automatic CO_2 fire suppression system was isolated from the Unit 1 and Unit 2 LCSRs from July 23, 2007, through August 11, 2008. Specifically, the licensee identified that a modification to the UCSR CO_2 system on July 23, 2007, had inadvertently isolated the CO_2 system to the LCSR.

Description: On August 8, 2008, the licensee performed Procedure MA-BR-EM-5-F002, "Lower Cable Spreading Room Low Pressure CO_2 System Air Actuation Test," in the Unit 2 LCSR. The automatic CO_2 system was the only fire suppression system in the LCSRs, with manual water hose stations and fire extinguishers as a backup. During the surveillance the test air did not successfully migrate through the flowpath from the test source near the main CO_2 storage tank to the Unit 2 LCSR discharge nozzles. Troubleshooting activities identified that the sensing lines for the LCSR discharge valves were not pressurized. Further investigation identified that, on July 23, 2007, a blank flange had been installed on the CO_2 system as part of a permanent modification to abandon the CO_2 system in the Unit 1 and Unit 2 UCSRs. Installation of the blank flange isolated CO_2 to the UCSRs but also isolated the pressure sensing lines that open the CO_2 discharge valves in the Unit 1 and Unit 2 LCSRs.

When it was revealed that the LCSR CO_2 system was not functional, the licensee initiated a prompt investigation, entered the issue into their CAP as IR 805480, and installed a modification to route the LCSR discharge valve pressure sensing lines around the blank flange. The modification to the sensing lines was completed on August 11, 2008, and the system was returned to service. The licensee's Apparent Cause Evaluation determined the drawings used to develop the work package and pre-job walkdown for installation of the blank flange did not accurately represent where the LCSR discharge valve sensing lines connected to the CO_2 system. As a result, the pre-job walkdown for the blank flange installation did not include the area where the sensing lines actually connected to the CO_2 system.

<u>Analysis</u>: The inspectors determined that the isolation of the automatic fire suppression in the Unit 1 and Unit 2 LCSRs was a performance deficiency. Specifically, the licensee installed a modification to the Unit 1 and Unit 2 UCSR CO_2 system that resulted in isolation of the Unit 1 and Unit 2 LCSR CO_2 system. The issue was determined to be more than minor because the design control aspect of the mitigating systems cornerstone was impacted.

The finding was evaluated using IMC 0609 Appendix F, "Fire Protection Significance Determination Process." The finding category assigned was Fixed Fire Protection Systems because the LCSR CO_2 fire suppression system was impacted. The degradation rating was determined to be "High" since the suppression system was isolated and would not have functioned to suppress a fire in the room. The modification of the system affected Unit 1 and Unit 2 differently. For Unit 1, both automatic and manual actuation of the system was disabled; however, for Unit 2, only the automatic actuation was affected. The duration of the degraded condition was greater than 30 days. The finding did not screen as very low safety significance (Green) in the Phase 1 analysis and a Phase 2 SDP analysis was required.

The inspectors and the Region III Senior Reactor Analyst (SRA) performed a SDP Phase 2 evaluation. The LCSR contains a room called the "non-segregated bus duct area" which contains segmented bus ducts. These segmented bus ducts would normally be counted as fixed ignition sources; however, the licensee determined that either the bus ducts were not energized during the exposure period or that there were no targets within the zone of influence based on a review of bus duct transition points. Therefore, the Phase 2 analysis considered only transient and hot work fires as potential contributors to the fire ignition frequency. The potential for hot work to ignite a fire in the area was considered and ultimately discounted based on information provided by the licensee. If hot work was planned in the fire area, the automatic suppression system would already be disabled for personnel protection concerns, and would not be available for automatic fire suppression. The likelihood rating for transient combustible fires was assumed to be medium. Although personnel access was not restricted to the LCSR, it was not normally occupied and plant personnel did not routinely pass through the area. The safe shutdown path for a fire in the LCSR involves manual operator actions and was not affected by the finding or the postulated fire scenario.

The SRA determined that the fire scenario of interest for this finding was fire damage state (FDS) 2, which is widespread fire damage in the fire area. The fire suppression system would not normally prevent fire damage to cables or components near the ignition source (FDS 1) but would be expected to limit the fire damage in the room and protect against widespread fire damage (FDS 2). Since none of the fire area barriers were impacted by the finding, fire damage across barriers (FDS 3 scenarios) was not evaluated.

The fire ignition frequency was estimated to be 1.7E-4/yr, assuming a medium likelihood rating for transient combustible fires. For a FDS 2 scenario, both divisions of equipment could be affected and safe shutdown could require operator manual actions in the plant. The inspectors determined that a hot gas layer would not develop given a transient combustible ignition source. As a result, only fire spread horizontally and vertically across cable trays could result in the fire damage state of interest. No specific fire scenarios were developed given the many targets and possible fire scenarios in the area. The SRA credited the conditional core damage probability for the safe shutdown path to be 1.0E-2.

The licensee determined that a fire in only a certain limited areas area of the lower cable spreading room had the potential for fire spread to affect cables from both divisions of equipment. Therefore, the SRA used a location weighting factor of 0.1.

Given an ignition frequency of 1.7E-4/yr, a location weighting factor of 0.1, and a conditional core damage probability of 1.0E-2, the result of the Phase 2 SDP was a change in core damage frequency of 1.7E-7/yr, which represented a finding of very low safety significance.

This finding is related to the cross-cutting area of Human Performance, specifically the attribute of resources (H.2(c)), because the LCSR discharge valve sensing lines were not included on the design drawings used to develop the UCSR modification and the scope of field walkdowns was determined based on the same documentation.

Enforcement: Braidwood Unit 1 and Unit 2 License Condition 2.E requires, in part, that the licensee implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR, as supplemented and amended. Section 2.3.3 of the Braidwood Fire Protection Report contains the fire area analysis for the LCSRs, and describes an automatic CO_2 suppression system as the primary fire suppression system. Contrary to the above, the licensee did not maintain the LCSRs in accordance with their fire protection program by inadvertently isolating the primary fire suppression (CO_2) from July 23, 2007, through August 11, 2008. Because this non-willful violation was non-repetitive, and was captured in the licensee's corrective action program as IR 805480, it is considered an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000456/2009003-02; 05000457/2009003-02)**

Based on the above discussion, URI 05000456/2008004-03; 05000457/2008004-03 is closed.

.3 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On May 5, 2009, the inspectors observed a fire brigade activation for a drill simulating a fire in the 2A SI pump 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. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the corrective action program to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Unit 2 Residual Heat Removal Pump Room Flood Barriers.

Documents reviewed are listed in the Attachment. This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08P)

From April 5 through April 14, 2009, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the Unit 1 reactor coolant system, steam generator (SG) tubes, emergency feedwater systems, risk significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, R08.3, 1R08.4, and 1R08.5 below count as one inspection sample as defined by IP 71111.08–05. Documents reviewed are listed in the Attachment.

.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 were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Ultrasonic Examination of the B Main Steam Line Lug Weld (1MS-05-PG-4);
- Magnetic Particle Examination of the B Main Steam line lug welds (1MS-05-PG-6-8); and
- Bare Metal Visual Examination of the B Reactor Coolant Hot Leg Dissimilar Metal Weld (1RV-01–29).

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 Vessel Weld (1RV-01-003), and
- Indication Assessment of Reactor Vessel Weld (1RV-01-006).

The inspectors reviewed the following pressure boundary welds completed for risk significant systems during the Unit 1 refueling outage to determine if the licensee applied the preservice non-destructive examinations and acceptance criteria required by the construction code, and a NRC approved Code Case N-416. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedures were qualified in accordance with the requirements of construction code and the ASME Code Section IX.

- Auxiliary Feedwater System Welds (FW-1.1, 22 and 2A-1) Fabricated during Replacement of a Section of 4-inch Diameter Pipe on Line 1AF02EB-4.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 1 vessel head, no examination was required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D). However, the licensee had previously committed to perform a bare metal visual examination of vessel head Penetration 74 pursuant to an exemption request to NRC Order EA-03-009 (reference NRC approval letter dated September 26, 2007, ADAMS Accession No. ML0724304520). Therefore, the inspectors reviewed records of the visual examination conducted on penetration 74 to determine if the activities were performed in accordance with the licensee's commitments to NRC Order EA–03–009, and if any indications were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement. The inspectors also 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

On March 29 and 30, 2009, the inspectors observed the licensee staff performing visual examinations of the Unit 1 Reactor Coolant System (RCS) and ECCS 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 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 reactor coolant system components to determine if they met the ASME Section XI Code.

- RCS Loop 1A to Residual Heat Removal Pump 1A Suction Isolation Valve;
- RCS Loop 1C Pressure Transmitter; and
- Pressurizer Level Transmitter 1LT-0461.

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 50, Appendix B, Criterion XVI.

- IR 899611, 1RC8042 (Significant Active Boric Acid Leakage);
- IR 689187, Leakage of Pressurizer Differential Pressure Cell; and
- IR 689186, Leakage on 1PT-RC011 Fitting.

b. .Findings

No findings of significance were identified.

.4 SG Tube Inspection Activities

a. Inspection Scope

From April 5 through 14, 2009, the inspectors performed an on-site review of the Unit 1 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 Electric Power Research Institute (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;
- in situ pressure test records demonstrated pressure and hold times consistent with EPRI TR 107620;
- in situ pressure test results were properly applied to SG tube integrity performance criteria identified in EPRI TR 107621;
- 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 which 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 May 20, 2009 and June 3, 2009, the inspectors observed a crew of licensed operators (Crew 1 and Crew 3, respectively) in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems 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;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and emergency plan actions and notifications.

Each crews' performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Braidwood Licensed Operator Scenario #0931 "SGWLC Transient/Large Break RCS LOCA/Cold Leg Recirculation UFSAR Timing/Loss of All AC UFSAR Timing Scenario" was observed for both crews. Other documents reviewed are listed in the Attachment to this report.

This inspection constituted two quarterly licensed operator requalification program samples 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:

- Service Air System, and
- Auxiliary Steam.

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 (SSCs)/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)

.1 Maintenance Risk Assessments and Emergent Work Control

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:

- Elevated Unit 1 RCS Unidentified Leakrate;
- Auxiliary Feedwater Surveillance and Slave Relay Surveillance;
- 1A SX Work Window;
- 1A DG Work Window with Severe Weather in the Area; and
- 1A Reactor Coolant Pump Seal Temps, 2B Main Steam Isolation Valve Loss of Indication, 2B DG Failed to Start, 1SI8811B Failed to Stroke Open.

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 five samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 1 ECCS Flow;
- Elevated Unit 1 SI Discharge Pressure;

- Loss of Control Power to Unit 1 Train A Single Valve Actuation Group Valves;
- Unit 2 ECCS Throttle Valves;
- 2B Charging Pump Unusual Oil Indication; and
- Valve 1SI8811B Failed to Stroke.

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

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- 1A Auxiliary Feedwater Pump Oil Leak Repair.

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 system. 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 are listed in the Attachment.

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

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

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 DG Following Voltage Regulator Replacement;
- 1A Heater Drain Pump Following Replacement;
- Unit 0A Control Room Ventilation System Chiller;
- 1A SX Strainer Panel Modification;
- 2A Main Bus Duct Cooling Fan Following Maintenance;
- 1A DG Following Work Window; and
- 1A Auxiliary Feedwater Pump Following Unit 1 Outage Work.

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 seven post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

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 1 refueling outage (RFO), conducted March 30 through April 19, 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, cooldown, and startup processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment to this report.

- 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 primary containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- 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)

.1 Surveillance Testing

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:

- ECCS Full Flow Balance Surveillance (Routine);
- 1A DG Full Load Reject and ECCS Sequencer Test (Routine);
- 2A Charging Pump ASME (Inservice Testing);
- 2B Auxiliary Feedwater ASME (Inservice Testing);
- Unit 1 N-41 Channel Axial Flux Distribution with Solid State Protection System Card Pulled (Routine); and
- Valve 1SI8811B Failed to Stroke (Isolation Valve).

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
- 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, two inservice testing samples, and one containment isolation valve sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

(1) Failure to Perform a 50.59 for Reactor Protection System Testing

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR 50.59 following a review of changes made to TS required surveillance test procedures. These procedures allowed testing of the RPS's analog channels in the bypassed conditions by installing jumpers during surveillance test. This technique had been deemed unacceptable in NRC Safety Evaluation Report for WCAP 10271.

Description: As discussed in Licensee Event Report (LER) 05000457/2009-001-00, on April 24, 2009, Braidwood Unit 2 tripped from full power while instrument maintenance personnel were performing a planned 18-month calibration of the 2B pressurizer pressure instrument loop, 2P-0456. The calibration placed the 2B channel of the Overtemperature Delta Temperature (OTdT) trip function in tripped condition for the duration of the calibration. The sequence of events recorder indicated that a reactor trip was generated from the actuation of the 2D OTdT reactor protection system trip function while performing the planned surveillance test. The actuation of the 2D OTdT function was not expected for the plant conditions at the time. The setpoint on the 2D OTdT channel was exceeded due to a spike on the 2D RCS cold leg temperature instrument loop (2T-0441B). With the 2B channel of the OTdT already in the tripped condition, the second coincidence of the two-out-of-four reactor trip logic was satisfied. The reactor protection system performed as expected to trip the reactor.

Following the reactor trip, the licensee completed troubleshooting and replaced three suspected circuit cards in the 2D channel logic strings. The 2D channel had a history of spiking and one of the cards that the licensee suspected most likely caused the spikes had been replaced twice within the last 3 years (in early 2006 and once in August 2008). Following the replacement of the three suspected cards, the licensee performed additional troubleshooting and post maintenance testing before restarted Unit 2. However, the licensee's testing has been unable to replicate a failure for any of the replaced cards. All three cards were tested for functional operation and each performed as expected.

On May 15, 2009, the licensee informed the inspectors that the surveillance testing methodology for the Unit 2 RPS would be temporarily changed until the fall 2009 Unit 2 refueling outage. These changes were being implemented due to vulnerabilities identified during an ongoing root cause investigation associated with the failure of the 2D OTdT channel while 2B OTdT was in test. The new testing methodology would involve installing temporary jumpers in the RPS analog system logic that would bypass the trip signal during TS required surveillance testing for the channel being tested. To support this testing methodology, the licensee generated IR 921598, “Proposed Bypass Testing and UFSAR Statements.” The IR documented that:

> “As a result of the recent Reactor Trip of Unit 2 (IR 911389), Senior Management requested that bypass testing be performed on coincident logic loops with respect to loop 2D Delta Temperature/Temperature Average until outage A2R14 (when repairs to loop 2D DT/TA can be made).”

IR 921598 also referenced Engineering Change (EC) 375421 “Evaluation of Performing Limited Bypass Testing for Unit 2.” In this EC, the licensee states the following:

> “Braidwood Senior Management has requested Design Engineering to provide the electrical means of bypassing trip functions within the Solid Sated Protection System for 7300 loops coincident with 2T-0441/0442 (2D Delta Temperature/Temperature Average, DT/TA). This request is based on the recent Unit 2 Reactor trip in which the 2D Tcold signal spiked low while IMD was performing a scheduled surveillance on loop 2P-0456 (Reference 1). The direction being taken from now until outage A2R14 is to bypass the trip functions of the loop that is having maintenance or surveillance performed which is coincident with loop 2T-0441/0442.”

Based on this information the inspectors concluded that these actions were interim compensatory action. The procedure changes were developed by the licensee due to concerns/vulnerabilities associated with the 2D OTdT RPS instrument channel. According to Section 4.4 of NEI 96-07, “Guidelines for 10 CFR 50.59 Evaluations,” Revision 1, 10 CFR 50.59, should be applied to the temporary change if an interim compensatory action is taken to address a condition and involves a temporary procedure or facility change. This guideline provides a NRC staff endorsed method for complying with the provisions of 10 CFR 50.59.

Following the discussion with the licensee regarding the new testing methodology, the inspectors reviewed the NRC approved Westinghouse Topical Report WCAP-10271, Supplement 1-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System." This WCAP was submitted In February 1983 by the Westinghouse Owners Group to the NRC for review and approval. This report proposed TS changes governing operability and surveillance testing of the RPS based on equipment unavailability and risk analyses. This WCAP was referenced as the bases documented for a license amendment, which was granted on December 16, 1993, to both Braidwood and Byron to increase allowed outage times (Licensee Amendment 44 for Braidwood Station).

The inspector noted that this issue was specifically addressed in the NRC safety evaluation report for WCAP-10271, under “Testing in the Bypassed Mode.” In this section, the NRC concluded:

> “The WCAP proposes that operational testing of the analog channels be performed with the channel being tested in a bypassed condition instead of a tripped condition. The analyses conducted by Westinghouse and by the NRC staff and its contractors included this proposal in the calculational models. Therefore, the staff concludes that the proposal is acceptable. However, the

staff is aware that the design of reactor trip system circuitry at many plants does not include provisions to perform testing in a bypassed condition without operator action such as lifting leads or installing temporary jumpers. Testing of RTS analog channels in the bypassed conditions by use of jumpers or by lifting leads is not acceptable. Therefore, licensees choosing the option to perform routine channel testing in the bypass mode should ensure that the plant design allows testing in bypass without lifting leads or installing temporary jumpers. The staffs' acceptance of this option is contingent on confirmation of this capability."

The inspectors concluded that any procedure changes that allowed the use of jumpers to bypass the RTS analog trip system was not in accordance with restrictions contained in the licensing bases and hence, departed from accepted NRC surveillance testing methodology. Additionally, the inspectors concluded that based on the facts that a number of TS required surveillance test procedure were being revised to incorporate this methodology and would be performed multiple times, this practice was considered routine.

The inspectors consulted with NRC staff from the Office of Nuclear Reactor Regulation, Instrument and Control Branch (EICB) regarding this testing. The EICB staff members agreed with inspectors that the change proposed by the licensee required NRC approval prior to proceeding. The staff's position regarding this issue was communicated to the licensee via a phone call on June 16, 2008.

Prior to the phone call, the licensee completed surveillance test procedures BwISR 3.3.1.10-M239, "Operational Test and Channel Verification Calibration for LOOP 0.457 Pressurizer Pressure Protection Channel III Cabinet 3," Revision 10, and BwISR 3.3.1.10-M237, "Operational Test and Channel Verification Calibration for LOOP 0.455 Pressurizer Pressure Protection Channel I5 Cabinet 1," Revision 8. Step F.2.7.A in each of the procedures, instructed maintenance personnel to "INSTALL jumper to defeat OTdT Rx Trip Function from TB 106-10 to TB 111-9 at PA09J input bay 1." This procedural step provided an electrical means of bypassing trip functions within Solid State Protection System for analog input loops coincident with the 2D 2T-0441/0442 (2D Delta Temperature/Temperature Average, DT/TA).

<u>Analysis</u>: The inspectors determined that the failure to perform the appropriate 10 CFR 50.59 review as specified in NEI 96-07 was a performance deficiency that warranted a significance evaluation. The issue was addressed by traditional enforcement since it had the potential for impacting the NRC's ability to perform its regulatory function. The issue was more than minor because there was a reasonable likelihood that the change would require NRC review and approval prior to its implementation. The inspectors completed a Significance Determination Review using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At Power Situations." Using the Phase I Screening worksheet, the finding was determined to be of very low safety significance (Green) since the finding did not represent an actual loss of safety function for greater than the TS allowed outage time. Therefore, this is a Severity Level IV violation as described in the NRC Enforcement Policy Supplements, Item D.5, "Violations of 10 CFR 50.59 that result in conditions evaluated as having very low safety significance (i.e., green) by the SDP."

The inspectors determined that there was no cross-cutting aspect associated with this finding.

Enforcement: 10 CFR 50.59, "Changes, Tests and Experiments," contains requirements for the process by which licensees may make changes to their facilities and procedures as described in the safety analysis report without prior NRC approval, under certain conditions. 10 CFR 50.59 (c)(1)(i) states, in part, that a licensee may make changes in the facility as described in the final safety analysis report without obtaining a license amendment pursuant to 10 CFR 50.90 only if a change to the TS incorporated in the license is not required. Contrary to the above, on June 15, 2009, the licensee approved and implemented changes to Procedures BwISR 3.3.1.10-M239 and BwISR 3.3.1.10-M237. These changes resulted in testing of the RTS analog channel in bypass condition instead of a tripped condition by use of jumpers during surveillance testing. This methodology was previously determined to be unacceptable by the NRC in a safety evaluation report for WCAP 10271. This WCAP was part of the Braidwood licensing bases in Licensee Amendment 44. Therefore, bypassing the RTS analog channel with jumper would have required additional review by the NRC. This violation was of very low safety significance and did not represent a condition where the licensee failed to restore compliance within a reasonable time; was not repetitive and did not appear to have any willful aspects. This issue was entered into the licensee's CAP (IR 942574). Corrective action included changing the way the RPS surveillance test was performed. This violation is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy. **(NCV 05000457/2008003-03)**

(2) Failure of Containment Sump Suction Valve 1SI8811B to Stroke Open

On June 24, 2009, the licensee began a planned work window on the 1B Residual Heat Removal train. Part of the planned work included an 18-month surveillance to stroke open the 1B Containment ECCS Sump Suction Valve, 1SI8811B. The 1SI8811B valve is a normally closed motor operated valve that provides a containment isolation function. The valve is required to open to provide a suction source from the ECCS sump to the 1B Residual Heat Removal train for the recirculation phase of emergency core cooling. During performance of the surveillance the valve stopped moving at approximately 35 percent open and failed to stroke. The licensee entered TS 3.6.3, Condition A, due to the inoperable containment isolation function and was already in TS 3.5.2 Condition A for the 1B Residual Heat Removal train work. Initial troubleshooting activities identified a corroded torque switch as the cause of the stroke failure. The licensee replaced the torque switch and the limit switch, and performed several other planned preventive maintenance tasks prior to returning the valve to service on June 26, 2009. To address extent of condition, the licensee completed a successful stroke of the 1SI8811A valve on June 30, 2009, as previously scheduled.

At the conclusion of the inspection period, the licensee was performing a past operability evaluation of the 1SI8811B valve. This evaluation will include an analysis of the flow characteristics of the valve at approximately 35 percent open. An URI was opened pending further review of this issue. **(URI 05000456/2009003-04)**

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on June 3, 2009, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator and Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff 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. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

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 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys for the following radiologically significant work within radiation areas, high radiation areas, and airborne radioactivity areas in the plant to determine if radiological controls including surveys, postings, and barricades were acceptable:

- valve team outage activities in containment;
- reactor head disassembly/reassembly;
- lead shielding install/maintain/remove; and
- SG eddy current testing and all tube repairs.

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

The inspectors reviewed the radiation work permits (RWPs) and work packages used to access these areas and other high radiation work areas. The inspectors assessed the work control instructions and control barriers specified by the licensee. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors interviewed workers to verify that they were aware of the actions required if their electronic dosimeters noticeably malfunctioned or alarmed.

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

The inspectors walked down and surveyed (using an NRC survey meter) these areas to verify that the prescribed RWP, procedure, and engineering controls were in place; that licensee surveys and postings were complete and accurate; and that air samplers were properly located.

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

The inspectors reviewed RWPs for airborne radioactivity areas to verify barrier integrity and engineering controls performance (e.g. high-efficiency particulate air ventilation system operation) and to determine if there was a potential for individual worker internal exposures in excess of 50 millirem committed effective dose equivalent. There were no airborne radioactivity work areas during the inspection period.

Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and had provided appropriate worker protection.

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

The inspectors assessed the adequacy of the licensee's internal dose assessment process for internal exposures in excess of 50 millirem committed effective dose equivalent. There were no internal exposures greater than 50 millirem committed effective dose equivalent.

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

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed a sample of the licensee's self-assessments, audits, Licensee Event Reports (LERs), and Special Reports related to the access control program to verify that identified problems were entered into the CAP for resolution.

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

The inspectors reviewed corrective action reports related to access controls and any high radiation area radiological incidents (issues that did not count as performance indicator (PI) occurrences identified by the licensee in high radiation areas less than 1R/hr). Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

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

The inspectors evaluated the licensee's process for problem identification, characterization, and prioritization and verified that problems were entered into the CAP and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

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

b. Findings

No findings of significance were identified.

.3 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation safety work requirements. The inspectors evaluated whether workers were aware of any significant radiological conditions in their workplace, of the RWP controls and limits in place, and of the level of radiological hazards present. The inspectors also observed worker performance to determine if workers accounted for these radiological hazards.

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

The inspectors reviewed radiological problem reports for which the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. Problems or issues with planned or completed corrective actions were discussed with the Radiation Protection Manager.

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

b. Findings

No findings of significance were identified.

.4 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation safety work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

This inspection constitutes one sample as defined in Inspection Procedure 71121.01-5.

The inspectors reviewed radiological problem reports for which the cause of the event was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

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

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstone: Mitigating System

.1 Mitigating System Performance Indexes Performance Indicators

a. Inspection Scope

The inspectors sampled the licensee's Mitigating System Performance Indexes (MSPIs) and PI submittals for the periods listed below. The inspectors used MSPI and PI definitions and guidance contained in Nuclear Energy Institute Document 99-02; "Regulatory Assessment Performance Indicator Guideline," Revision 5, to verify the accuracy of the data. The following were reviewed for a total of four samples:

Unit 1

- Safety System Functional Features (MS05),
- Emergency AC Power System (MS06).

Unit 2

- Safety System Functional Failures (MS05),
- Emergency AC Power System (MS06).

The inspectors reviewed licensee IRs, electronic logs, and other records for the period from July 1, 2008, through September 30, 2008, for each area specified above. The inspectors independently re-performed calculations where applicable. The inspectors compared the information acquired for each MSPI and PI to the data reported by the licensee. The inspectors verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

.1 Routine Review of items Entered Into the Corrective Action Program

a. 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 attached List of Documents Reviewed.

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. 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 Selected Issue Follow-Up Inspection: Modified ECCS Throttle Valve Design

a. Scope

The inspectors reviewed the licensee's modification to the ECCS throttle valves, installed in October 2007 and April 2008. The licensee experienced unexpected flow changes during comprehensive flow testing of the high head and intermediate head safety injection systems during the Unit 1 refueling outage. The inspectors reviewed the licensee's CAP documents, root cause evaluation, calculations, and engineering analyses associated with the design change.

b. Findings

Failure to Properly Evaluate Installation of ECCS Throttle Valves

Introduction: A finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to install a modified ECCS throttle valve design commensurate with the design control measures applied to the original design, which resulted in the failure to select a material suitable to the application. Specifically, the licensee selected a design that included gas nitrided surfaces, which was contrary to the Westinghouse design specification for the original ECCS throttle valves that prohibited the use of nitrided surfaces in reactor coolant applications.

Description: On September 13, 2004, the NRC issued Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized Water Reactors." The Generic Letter required, in part, that the licensee perform an evaluation to determine the susceptibility to debris blockage of components downstream of the ECCS sump screens. The licensee performed an evaluation (Design Analysis BRW-05-0061-M) that determined three sets of valves were susceptible:

- 1SI8810A-D, Charging Pump Discharge to RCS Cold Legs;
- 1SI8816A-D, SI pumps Discharge to RCS Hot Legs; and
- 1SI8822A-D, SI pumps Discharge to RCS Cold Legs.

Upon a SI actuation, the and SI pumps inject into the RCS cold legs through the 1SI8810A-D and 1SI8822A-D, respectively. Approximately 6 hours following an accident, the SI injection path is changed from the RCS cold legs to the RCS hot legs through 1SI8816A-D. The accident analyses required certain flow rates into the RCS that are balanced between pump trains. At the time of the evaluation, proper flow rates and train balance were maintained using locked throttle valves and flow orifices.

The evaluation determined that valves 1SI8810A-D, 1SI8816A-D, and 1SI8822A-D needed to be replaced because the flow openings were smaller than the ECCS sump screen openings. The evaluation also determined that the downstream flow orifice plates would result in cavitation and should be removed. Based on the results of the evaluation, the licensee elected to replace the 1SI8810A-D, 1SI8816A-D, and 1SI8822A-D valve internals with a modified design that would eliminate the debris blockage concern and allow for removal of the flow orifice plates.

Flow testing was conducted on the modified internals with debris-laden water to evaluate for flow blockage, cavitation, and flow induced erosion. The licensee evaluated the test results in EC 364979. Flow testing identified erosion of flow path edges through the valve internals that resulted in higher flow through the valve. As a result, a gas nitriding process, used throughout many industries for surface hardening, was applied to the valve internals to reduce internal erosion and maintain a more stable flow rate over time.

The licensee elected to install the modification during the Unit 1 refueling outage in October 2007 and the Unit 2 refueling outage in April 2008. Prior to installation, the licensee evaluated the modification in accordance with 10 CFR 50.59 in EC 360141 for Unit 1 and EC 360143 for Unit 2. The evaluations were completed and approved by the Plant Operations Review Committee on October 3, 2007, for EC 360141 and April 7, 2008, for EC 360143, with the conclusion that NRC approval was not required to implement the activity.

On March 29, 2009, the licensee shut down Unit 1 for the first scheduled refueling outage since installing the new valve internals. On April 2, the licensee performed charging system comprehensive flow testing in accordance with their Inservice Testing Program. The flow through the 1A charging pump was 560.9 gpm, which exceeded the pump runout limit of 560 gpm. The flow difference between the 1A and 1B pumps was 13.2 gpm, which exceeded the 10 gpm differential limit. When the new throttle valves were installed in the previous outage the valves were locked throttled to achieve a 1A charging pump flow rate of 544 gpm.

The licensee also performed SI system comprehensive flow testing in accordance with their Inservice Testing Program. The flow through the 1A SI pump was 680.6 gpm, which exceeded the pump runout limit of 675 gpm. When the new throttle valves were installed in the previous outage the valves were locked throttled to achieve a 1A SI pump flow rate of 645 gpm. The licensee took immediate corrective actions to shut down the pumps during the respective surveillances, initiated a prompt investigation, and entered the issue into their CAP as IR 902241.

The licensee replaced Valve 1SI8822A with the only spare on hand. A detailed analysis of the removed valve was performed. This valve was selected to be replaced because it showed the largest flow change from the time of installation. Prior to startup, the other throttle valves were re-positioned and locked at the low end of the acceptable flow band, which the licensee concluded would ensure the valve flows remain in the acceptable flow band even if further degradation occurred.

The licensee's investigation revealed two independent mechanisms responsible for the flow increase. First, the manufacturing process of the modified valve internals included nesting concentric cylinders together using a brazing process to form a single piece. This process left some excess braze metal in the flowpath through the valve internals. Based on the design of the internals, some of the braze metal could not be removed during fabrication cleaning and visual inspection of the entire flowpath was not possible. The vendor knew the braze metal would be left in the valve and did not believe it was a concern, however the licensee was unaware of the braze metal in the flowpath until it was identified during the examination of 1SI8822A. When the comprehensive flow tests were performed, some amount of the braze metal was washed out by the flow and contributed to increased flow through the valves.

Second, the nitride layer was removed by flow through the valve due to corrosion and contributed to a larger flow path. Applying a nitride layer to a stainless steel surface sensitizes the surface to corrosion. This is a known phenomenon throughout many industries and the issue was previously addressed by Westinghouse. The Westinghouse design specification for the original ECCS throttle valves (Westinghouse Equipment Specification G-678844, Control Valves) includes the following statement: "Nitriding treatments on any surfaces exposed to the working fluid (Reactor Coolant water) are prohibited." This requirement is still in place for all new equipment designs. Exelon and the modified throttle valve vendor had copies of Westinghouse Equipment Specification G-678844 available during the design and testing of the ECCS throttle valve modification.

Analysis: The inspectors determined that the failure to address the change in original design specifications to the modified ECCS throttle valve design, which resulted in the selection of an inappropriate material for the application, was a performance deficiency. The issue was determined to be more than minor because it was similar to example 5.a of IMC 0612, Appendix E, "Examples of Minor Issues," in that a modification that did not meet design requirements was returned to service prior to discovery. Specifically, the Westinghouse design specification for the ECCS throttle valves explicitly prohibits the use of nitrided surfaces in the reactor coolant system. This design deficiency was not identified until after degradation of the modified valves had occurred during an operating cycle.

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 'yes' to Question 1 in the Mitigating Systems Cornerstone column of Table 4a. Specifically, the design deficiency (gas nitrided stainless steel layer) did not result in a loss of operability or functionality of the CV or SI systems. Therefore, the inspectors determined the issue did not result in the actual loss of a safety function and screened as having very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Problem Identification and Resolution, associated with the attribute of the corrective action program (P.1(c)), because the licensee did not thoroughly evaluate all aspects of the modification to the ECCS throttle valves. Specifically, a more thorough evaluation of the modified design could have identified that the Westinghouse guidance prohibited the use of gas nitriding for this application.

Enforcement: 10 CFR 50, Appendix B, Criterion III, "Design Control," states, in part, that measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components; and also that design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design.

Contrary to the above, the licensee implemented a modification to the ECCS throttle valve design using a material (gas nitrided stainless steel) that was prohibited by the design specifications without evaluation of its suitability. Specifically, replacement of valve internals with a new design in the 1SI8810A-D, 1SI8816A-D, and 1SI8822A-D valves introduced the nitride layer that corroded and contributed to flow rate changes in the 1A charging pump and 1A SI trains. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 918633, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000456/2009003-05; 05000457/2009003-05)**.

Corrective actions included replacing the ECCS throttling valve that showed worst flow degradation. Additionally the licensee re-performed the surveillance test and adjusted the throttle valves such that any future degradation of the flow area (caused by corrosion or brazing material loss) will not result in pump run-out.

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

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

.1 (Closed) Licensee Event Report 05000457/2008-001-01: 2A Essential Service Water Train Inoperable due to Strainer Fouling from Bryozoa Deposition and Growth

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action Program," associated with the licensee's failure to promptly identify that the 2A SX subsystem was inoperable and hence entry into Braidwood Improved TS 3.7.8, "Essential Service Water (SX) System," Condition A was appropriate. Following the failure of the 1A SX pump due to indications of discharge strainer fouling from Bryozoan infestation in the lake screenhouse the operators failed to properly evaluate possible common mode failures associated with the 2A SX subsystem. This resulted in an approximately 45-hour delay in recognizing that the 2A SX subsystem was inoperable and thus delayed the actions to recover the subsystem.

Description: On September 2, 2008, the 1A SX pump discharge strainer differential pressure increased significantly during a surveillance test for the pump. The operators declared the 1A SX train inoperable due to strainer fouling as a result of a bryozoa infestation. Shortly after the discovery of the condition of 1A SX system, the inspectors questioned operations personnel regarding the status of the 2A SX system since the 1A and 2A SX pumps share a common suction source. At that time, the licensee stated that the 2A SX subsystem had passed its last ASME surveillance and there were no known indications of degraded flow or system pressure on Unit 2. The licensee also stated that the 2A strainer was functioning properly to clear any debris in the 2A SX discharge strainer.

During a subsequent review of the event, as documented in LER 05000457/2008-001-01, the licensee determined that the 2A SX train should have been considered inoperable at the same time the 1A SX train was declared inoperable. This conclusion was based on the 1A and 2A SX pumps sharing a common suction source (i.e., Unit 1 CW forebays). The licensee also concluded that a lack of questioning attitude existed regarding capability of the SX strainers to address rapid fouling challenges. Previous reviews for re-affirming the SX strainer design basis did not fully consider initiating events that could cause rapid strainer fouling or how these events could negate the compensatory actions that the station could take to restore strainer functionality. According to information contained in the LER, the licensee should have entered Limiting Condition for Operation (LCO) Action Requirement 3.7.8 at 8:45 a.m. on September 2, 2008, instead of September 4, 2008, at 5:36 a.m. following failure to perform a successful manual backwash. The 2A SX system was restored to operable status on September 6, 2008 at 3:38 a.m. However, the failure to promptly identify that the 2A SX subsystem was inoperable delayed recovery by approximately 45 hours.

Analysis: The failure to recognize that the 2A SX subsystem was inoperable and enter into the TS Action Statement promptly during a bryozoa infestation event, which already caused the 1A SX subsystem to be inoperable, was a performance deficiency. The inspectors determined that the issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Disposition Screening," because it affected the Mitigating Systems Cornerstone objective of ensuring the availability, capability and reliability of the Unit 1 and Unit 2 SX train to respond to initiating events to prevent undesirable consequences. The inspectors completed a significance determination of this issue using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At Power Situations," and answered "No" to Question 1 under the Mitigation System Cornerstone column on Table 4a "Characterization Worksheet for Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones." The inspectors then answered "Yes" to Question 2 in that same column. The "Yes" answer was based on the results of an analysis performed by the licensee, which concluded that, even under severely degraded flow conditions, the affected train of SX would have provided sufficient cooling to components served by the SX system following a reactor trip, a loss of coolant accident, or loss of offsite power. Therefore, the inspectors concluded that this issue was of very low safety significance.

This finding has a cross-cutting aspect in the Decision Making component of the Human Performance cross-cutting area (H.1(b)). In particular, the licensee did not demonstrate conservative assumptions in decision-making in regards to the Bryozoa colonies effect on systems that shared common suction piping. Additionally, the licensee relied on unverified assumptions associated with the ability to manually backwash the SX strainers under loaded conditions.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment and nonconformance are promptly identified and corrected.

Contrary to the above, on September 2, 2009, licensed operators failed to promptly identify that the bryozoa infestation event, which caused the 1A SX subsystem to be inoperable, also caused the 2A SX to be inoperable due to a common mode failure.

This resulted in an approximately 45-hour delay in recognizing the 2A SX subsystem inoperability and implementing actions to recover the subsystem. Because this violation was of very low safety significance and it was entered into the licensee's CAP as IR 813142, this violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. Corrective actions included the establishment of a challenge process for use during situations where key decisions are made related to the performance of the safety related system. **(NCV 05000457/2009003-06)**.

This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

.2 (Closed) Unresolved Item 05000456/2008004-04; 05000457/2008004-04: Bryozoan Infestation At The Lake Screenhouse Circulating Water Forebays

Introduction: The inspectors identified a NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action Program," having very low safety significance, associated with the licensee's failure to identify a significant condition adverse to quality and to develop corrective actions to prevent recurrence. Specifically, the licensee failed to identify the October 2005 bryozoa infestation as a significant condition adverse to quality and therefore did not establish corrective actions to preclude recurrence. This was evidenced by the September 2008 accumulation of bryozoan colonies in the SX and Circulating Water System forebays that resulted in the SX system strainer plugging and hence represented a challenge to the reliability and operability of the SX system.

Description: On September 2, 2008, during the performance of 1BwVSR 5.5.8.SX-1, "ASME Surveillance Requirements for 1A Essential Service Water Pump," the 1A SX pump discharge strainer experienced high differential pressure. Shortly after the high differential pressure alarm annunciated, the licensee noted differential pressure across the discharge strainer exceeded twenty psid (normally less than six psid). Additionally, the SX system discharge header pressure dropped by 40 psig (normally 100 -105 psig) and system flow had decreased more than 3000 gpm over a relatively short period of time. The licensee suspended the surveillance and entered TS LCO 3.7.8 Action Statement, A.1 for an inoperable SX train.

As discussed in Inspection Report 05000456/2008004; 05000457/2008004, Section 1R22.4, the licensee had experienced previous Bryozoa related issues. The most significant previous occurrence was in October 2005. At that time, the licensee discovered abnormal growth of an unnamed species of Bryozoa in the circulating water intake forebay. Shortly after the 1A circulating water pump was secured on October 2, 2005, the 2A and 2B SX pump discharge header pressure and the 2A SX strainer differential pressure high alarms annunciated in the control room.

Following the 2005 event, the licensee performed an equipment apparent cause evaluation (EACE) to address this issue. The EACE concluded that the apparent cause for the abnormal growth of bryozoans in the circulating water forebays was indeterminate. The EACE concluded that the impact of bryozoa to the station raw water systems (circulating water, non-safety-related service water, fire protection and SX) had been minimal. This conclusion was reached because the monitored SX strainer backwashes operated normally, experienced normal differential pressures and performed SX strainer backwash cycles as required and as designed. The licensee risk assessment also concluded that, based on the Unit 1 and Unit 2 SX system performance as monitored via the Adverse Condition Monitoring Plan, the consequences of bryozoan growth in the forebays were of low risk to plant operation. The risk assessment also concluded that there was not a regulatory impact caused by the abnormal growth of bryozoans in the circulating water forebays.

During an ongoing bryozoa infestation event on September 4, 2008, with power removed from the strainer, the licensee attempted to manually backwash the Unit 2A SX discharge strainer at six psid using Procedure BwMP 3300, "SX Strainer Manual backwash Operation on Loss of Offsite Power." During this attempt, the licensee discovered that the strainer could not be manually backwashed and that differential pressure continued to rise. The 2A SX pump was immediately secured and the 2B SX pump was started. The lowest 2A SX pump discharge observed during the transient was 89 psig.

The power for the SX strainers was not supplied from a safety-related source; therefore, following a loss of off-site power (LOOP) event the SX strainers would not cycle to clear debris from the strainer. The ability to manually cycle the strainers in response to a loss of power event was credited by the licensee in response to earlier NRC concerns expressed in URI 05000456/2005007-06; 05000457/2005007-06; however performing the procedure for manually cycling the strainers under the conditions went untested until September 4, 2008. Therefore, the inspectors concluded that the licensee failed to adequately evaluate the effects of a loss of offsite power event to strainer performance.

Exelon Procedure LS-AA-125, "CAP Procedure," states that significant conditions adverse to quality are conditions that, if left uncorrected, could have a serious effect on safety or reliability. The inspectors concluded that based on fact that the SX backwash strainers would not be available during a design basis event such as a LOOP/Loss of Coolant Accident, the potential impact of the abnormal bryozoan colonies on the safety-related SX system, as demonstrated during the system's surveillance test could result in a condition where system design to response to design basis event would not be adequately supported.

Analysis: The inspectors determined that the licensee's failure to identify and implement corrective action to prevent the adverse effects of Bryozoan colonies in the intake structure was a performance deficiency that warranted a significance evaluation. The inspectors determined that the finding was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," because the failure to identify and implement corrective actions affected the Mitigating Systems Cornerstone objective of ensuring the availability and reliability of the Unit 1 and Unit 2 SX train to respond to initiating events to prevent undesirable consequences.

The inspectors completed a significance determination of this issue using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At Power Situations," Phase 2 screening and answered "No" to Question 1 under the Mitigation System Cornerstone column on Table 4a, "Characterization Worksheet for Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones." The inspectors then answered "Yes" to Question 2 in that same column. The "Yes" answer was based on the results of an analysis performed by the licensee, which concluded that even under severely degraded flow conditions, the affected train of SX would have provided sufficient cooling to components served by the SX system following a reactor trip, a loss of coolant accident, or a loss of offsite power. Therefore, the inspectors concluded that this issue was of very low safety significance.

This finding has a cross-cutting aspect in the Decision Making component of the Human Performance cross-cutting area (H.1(b)). In particular, the licensee did not demonstrate conservative assumptions in the response to URI 05000456/2005007-06; URI 05000455/2005007-06. As documented in 0500456/2007004; 05000457/2007004 as part of the licensee's response to the URI, the licensee presented procedures that showed that the SX strainer backwash system would be able to be operated manually operated to recover the loss of the SX automatic backwash capability. However, this statement had not been validated or qualified under the conditions.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment and nonconformance are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Exelon Procedure LS-AA-125, "CAP Procedure," states that significant conditions adverse to quality are conditions that, if left uncorrected, could have a serious effect on safety or reliability.

In October 2005 following a bryozoa infestation event, the licensee took corrective actions to address the abnormal bryozoan growth on the Braidwood intake structures, which were not effective in preventing reoccurrence of negative impact on the SX system.

Contrary to this requirement, on or before September 2, 2008, the licensee failed to identify that the October 2005 bryozoa infestation was a significant condition adverse, in that if the condition was left uncorrected could have serious effect on safety or reliability of the SX system, and corrective actions were not taken to preclude repetition as evidenced by the September 2, 2008 bryozoa infestation event.

Following the 2008 bryozoa infestation event, the licensee completed a root cause report for this issue that developed two corrective actions to prevent reoccurrence. One of these corrective actions included developing and implementing a lake macro-biological program. The other corrective action included establishing a challenge process for use during situations where key decisions are made related to the performance of the safety related system. Because this violation was of very low safety significance and it was entered into the licensee's CAP as IR 813142, this violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 5000456/2009003-07; 05000457/2009003-07)

This URI is closed.

.3 (Closed) Licensee Event Report 05000456/2009-001-00: Steam Generator Tube Exceeding Plugging Criteria Remained In Service During Previous Cycle

On April 4, 2009, with Unit 1 in Mode 6 for a refueling outage, the licensee performed eddy current testing on the 1B steam generator. A distortion was identified that required additional testing. On April 8, 2009, the licensee identified a 73 percent through-wall wear indication. Technical Specification 5.5.9.c.1 require plugging of tubes with flaws exceeding 40 percent of nominal wall thickness. The identified tube was plugged prior to startup. The licensee's investigation revealed that this indication was previously identified by a computer screening tool during eddy current testing in spring 2006 and fall 2007. The indication was less than the required 40 percent through-wall thickness in 2006 but was exceeded 40 percent nominal through-wall thickness in fall 2007. In both cases, the data was not maintained during a manual review and the indicated was not previously reported. Specifically, a review of the historical eddy current testing data revealed that the computer screening system had identified the indication during the fall 2007 refueling outage, but a manual data review did not identify the flaw and, thus, it was not reported and the tube was not plugged. The flaw was identified again by the computer screening system during the spring 2009 refueling outage, and during this outage the manual data review did catch the flaw, it was reported, and the tube was plugged. This licensee-identified finding involved a violation of TS 5.5.9. The enforcement aspects of this violation are discussed in Section 4OA7. Documents reviewed as a part of this inspection are listed in the Attachment. This LER is closed.

This inspection constituted one sample as defined in IP 71153. Documents reviewed as part of this inspection are listed in the Attachment.

.4 (Closed) Licensee Event Report 05000457/2009-001-00: Reactor Trip on Over Temperature Delta Temperature due to a Signal Spike on One Channel with Another Channel Placed in the Tripped Condition for Surveillance Testing

On April 24, 2009, the licensee performed a TS surveillance calibration of the 2B pressurizer pressure loop. The channel was placed in the tripped condition per the surveillance requirement. During the surveillance a spurious spike of the 2D OTdT channel occurred. Pressurizer pressure is one of the inputs into the OTdT calculation. The spurious spike of the 2D channel, combined with the 2B channel in trip due to surveillance testing, resulted in a Unit 2 reactor trip since the 2/4 reactor trip channel logic was satisfied. One NRC inspector was on-site at the time of the reactor trip and responded to the control room. The inspector verified that the expected automatic actions had taken place and that operators performed the actions required by their procedures.

The licensee's investigation did not identify the cause of the spike. Prior to startup the licensee replaced three cards in the circuit that could have initiated the spike. Following startup the licensee identified a pressure transmitter that also could have initiated the spike. Since that transmitter is unable to be replaced while the unit is online, the licensee modified several surveillance procedures that required a reactor protection system channel to be placed in trip. This procedure modification is discussed in more detail in Section 1R22 of this report. Documents reviewed as a part of this inspection are listed in the Attachment. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

4OA5 Other Activities

.1 Reactor Coolant System 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."

Temporary Instruction (TI) 2515/172, "Reactor Coolant System Dissimilar Metal Butt Welds," was issued to support NRC review and evaluation of the licensees' implementation of MRP-139. The review for Unit 1 DMBWs under Revision 0 to TI 2515/172 had been previously completed (reference Braidwood Inspection Report 05000456/2008003; 05000457/2008003). From April 5 through April 14, 2009, the inspectors performed a review for the Unit 1 DMBWs in accordance with Sections of TI 2515/172 (Draft Revision 1) as described below.

b. Observations

Braidwood Unit 1 is a Westinghouse four loop designed plant. The licensee 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. The licensee was considering mitigation of the Unit 1 DMBWs located on the reactor coolant loop hot legs using a mechanical stress improvement process in Refueling Outage No. 16.

Based on the schedule of DMBW examinations under MRP-139, no examinations were required for the current Unit 1 refueling outage (1R14) 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.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 15, 2009, the inspectors presented the inspection results to Mr. B. Hanson, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of access control to radiologically significant areas were discussed with Site Vice-President, Mr. B. Hanson, and other members of the licensee's staff on April 10, 2009.

- The results of the inservice inspection were discussed with Site Vice President, Mr. B. Hanson, on April 14, 2009.

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

4OA7 Licensee-Identified Violation

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

.1 Steam Generator Tube Exceeding Plugging Criteria Remained In Service During Previous Cycle

Braidwood TS 5.5.9, Condition c.1, requires that steam generator tubes identified with a flaw exceeding 40 percent of the nominal wall thickness be plugged or repaired, unless alternate repair criteria can be applied. Contrary to this requirement, in October 2007, a 1B SG tube with a 73 percent nominal wall thickness indication remained in service for one operating cycle before being plugged during the Spring 2009 refueling outage and no other alternate repair criteria was applied. The finding was determined to be of very low safety significance because the tube degradation did not violate the structural integrity performance criterion (three times the differential pressure across the tube at normal full power operation).

The details of this issue are discussed in Section 4OA3.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

B. Hanson, Site Vice President
L. Coyle, Plant Manager
K. Aleshire, Emergency Preparedness Manager
G. Bal, Engineering Program Manager
G. Dudek, Site Training Manager
R. Gadbois, Maintenance Manager
D. Gullott, Regulatory Assurance Manager
J. Knight, Nuclear Oversight Manager
T. McCool, Operations Manager
J. Moser, Radiation Protection Manager
T. Schuster, Chemistry Manager
M. Smith, Engineering Manager

Nuclear Regulatory Commission

R. Skokowski, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2009003-01	FIN	Failure to Control and Secure Material Adjacent to Unit 1 Transformer Yard Which Could Become Potential Missiles (Section 1R01.3)
05000456/2009003-02; 05000457/2009003-02	NCV	Isolation of Lower Cable Spreading Room Carbon Dioxide Fire Suppression (Section 1R05.2)
05000457/2009003-03	SL IV	Failure to Perform Appropriate 10 CFR 50.59 Review (Section 1R22.2)
05000456/2009003-04; 05000457/2009003-04	URI	Failure of Containment Sump Suction Valve 1SI8811B to Stroke Open (Section 1R22.3)
05000456/2009003-05; 05000457/2009003-05	NCV	Failure to Properly Evaluate Installation of ECCS Throttle Valves (Section 4OA2.3)
05000456/2009003-06; 05000457/2009003-06	NCV	Failure to Promptly Identify Bryozoa Infestation Caused 2A SX subsystem to be inoperable (Section 4OA3.2)
05000456/2009003-07; 05000457/2009003-07	NCV	Bryozoan Infestation at the lake Screenhouse Circulating Water forebays (Section 4OA3.3)
05000456/2009-001-00	LER	Steam Generator Tube Exceeding Plugging Criteria Remained In Service During Previous Cycle
05000457/2008-001-01	LER	Essential Service Water Train Inoperable due to Strainer Fouling from Bryozoa Deposition and Growth
05000457/2009-001-00	LER	Reactor Trip on Over Temperature Delta Temperature due to a Signal Spike on One Channel with Another Channel Placed in the Tripped Condition for Surveillance Testing

Closed

05000456/2009003-01	FIN	Failure to Control and Secure Material Adjacent to Unit 1 Transformer Yard Which Could Become Potential Missiles (Section 1R01.3)
05000456/2009003-02; 05000457/2009003-02	NCV	Isolation of Lower Cable Spreading Room Carbon Dioxide Fire Suppression (Section 1R05.2)
05000457/2009003-03	SL-IV	Failure to Perform Appropriate 10 CFR 50.59 Review (Section 1R22.2)
05000456/2009003-05 05000457/2009003-05	NCV	Failure to Properly Evaluate Installation of ECCS Throttle Valves (Section 4OA2.3)
05000456/2009003-06; 05000457/2009003-06	NCV	Failure to Promptly Identify Bryozoa Infestation Caused 2A SX subsystem to be inoperable (Section 4OA3.2)
05000456/2009003-07; 05000457/2009003-07	NCV	Bryozoan Infestation at the lake Screenhouse Circulating Water forebays (Section 4OA3.3)
05000456/2008004-03; 05000457/2008004-03	URI	Inadvertent Isolation of Lower Cable Spreading Room Carbon Dioxide Fire Suppression
05000456/2008004-04; 05000457/2008004-04	URI	Bryozoan Infestation At The Lake Screenhouse Circulating Water Forebays
05000457/2008-001-01	LER	Essential Service Water Train Inoperable due to Strainer Fouling from Bryozoa Deposition and Growth
05000456/2009-001-00	LER	Steam Generator Tube Exceeding Plugging Criteria Remained In Service During Previous Cycle
05000457/2009-001-00	LER	Reactor Trip on Over Temperature Delta Temperature due to a Signal Spike on One Channel with Another Channel Placed in the Tripped Condition for Surveillance Testing

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

- 0BwOA ELEC-1; Abnormal Grid Conditions; Revision 7
- 0BwOA ENV-1; Adverse Weather Conditions Unit 0; Revision 105
- 0BwOA ENV-1; Adverse Weather Conditions Unit 0; Revision 106
- 0BwOA ENV-4; Earthquake Unit 0; Revision 106
- BwAP 340-1; Use of Procedures for Operating Department; Revision 23
- HU-AA-104-101; Procedure Use and Adherence; Revision 3
- OP-AA-108-107; Switchyard Control; Revision 2
- OP-AA-108-107-1001; Station Response to Grid Capacity Conditions; Revision 2
- OP-AA-108-107-1002; Interface Agreement Between Exelon Energy Delivery and Exelon Generation for Switchyard Operations; Revision 4
- 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, 1008
- IR 782043; Lake Screen House 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 ID'd 50.59 Evaluation Not Completed for 1/2BwOA ELEC-4; October 15, 2008
- IR 922156; NOS Id - Issues Not Addressed for Summer Readiness; May 20, 2009
- IR 922522; NOS Id Summer Readiness Letter Silent on Id Exceptions; May 21, 2009
- IR 924051; 2B VP Chiller Failed to Restart After Shutdown for RCFC Monthly; May 26, 2009
- Braidwood Certification Letter for Summer Readiness; May 15, 2009
- 50.59 Evaluation BRW-E-1006-196, Revision 1; EC 357102 and DRP 11-092, Revision 002,0
- Design Summary EC 357102; Sulfuric Acid System Addition at Lake Screen House; Revision 01
- Work Planning Instructions EC 357102; Sulfuric Acid System Addition at Lake Screen House; Revision 000

1R04 Equipment Alignment

- BwOP SX-E1; Electrical Lineup - Unit 1 Essential Service Water System Operating; Revision 7
- BwOP SX-M1; Operating Mechanical Lineup Unit 1; Revision 25

1R05A Fire Protection

- Braidwood Station Pre-Fire Plans; 2S-57 (Fire Zone 18.26-0); TSC Filters 0VV21/22F 451 Elevation

- Braidwood Station Pre-Fire Plan Map; Grade Floor Plan Elevation 401-Figure 2.3-12;
- Braidwood Station Pre-Fire Plan Map; Condensate Clean Up & Technical Support Center; Figure 2.3-41
- OP-AA-201-003; Fire Drill Scenario 2SI01PA, 2A SI Pump, Electrical Fire; May 5, 2009
- Fire Drill Info; AB-364-P18, S18, S19 and 2SI01PA Photographs
- Braidwood Station Pre-Fie Plans, U2 Containment Pipe Penetration Area, Elevation 364 and SI Pump
- Nuclear Accident Reporting System Form; 2A Room Fire Drill 2A SI Pump Motor Fire; May 5, 2009
- BwOP FP-27T11; 364 SI Pump 1A Room and Containment Pipe Penetration Area; Revision 1

1R05Q Fire Protection

- Braidwood Station Pre-Fire Plans 1D-11; Auxiliary building - General Area – Elevation 383'-0" (Fire Zone 11.4-0)
- Braidwood Station Pre-Fire Plans 1D-13; Radwaste and Remote Shutdown Control Room - Elevation 383'-0" (Fire Zone 11.4C-0)
- Braidwood Station Pre-Fire Plan Map; Figure 2.3-13, Plan at EL. 383'-0"
- NES-MS-04.1; Seismic Prequalified Scaffolds; Revision 5
- BWAP 1100-23; Seismic Housekeeping Requirements for the Temporary Storage of Materials in Category I Areas; Revision 3

1R06 Flood Protection Measures

- IR 928040; NRC/IEMA Identified Walkdown Concerns; June 1, 2009

1R08 Inservice Inspection Activities

- IR 677540; VT-2 Recordable Indication; September 29, 2007
- IR 681083; FME Found in the 1C SG A1R13; October 6, 2007
- IR 681140; Significant Corrosion on 1AF02EB-4; October 7, 2007
- IR 683682; FME Found in the 1A SG A1R13; October 11, 2997
- IR 687232; Minimum Wall on SX Piping; October 20, 2007
- IR 689187; Leakage of Pressurizer Differential Pressure Cell; October 25, 2007
- IR 689186; Leakage on 1PT-RC011 Fitting; October 25, 2007
- IR 706376; 0SX115F SX Suction Valve Pit Flooded; December 3, 2007
- IR 749749; 1CV06A-4 Spool Boric Acid Leakage; April 14, 2008
- IR 766459; UT Detected Line SX38AA-2 Below Nominal Wall; April 23, 2008
- IR 766927; PT Indication Discovered During Examination; April 24, 2008
- IR 770787; Repeat Leakage 2RH606 ASME Bolted Connection, May 2, 2008
- IR 899611; 1RC8042 (Significant Active Boric Acid Leakage); March 30, 2009
- IR 901376; MT Indications Identified During ISI Exam; April 1, 2009
- IR 904471; 1RC 8042C Loss of Base Metal; April 8, 2009
- IR 904935; 1RC 8042C Structural Integrity Review Question by NRC; April 8, 2009
- IR 905029; NRC identified weakness in Procedure ER=AP-335-001; April 9, 2009
- IR 905551; NRC Identified Opportunity (Rx Head Exam Visual Training); April 9, 2009
- ASME Weld Record; 1AF02EB-4 Replacement (WO 01170562) FW 1-1; March 26, 2009 through April 4, 2009
- ASME Weld Record; 1AF02EB-4 Replacement (WO 01170562) FW 22; March 26, 2009 through April 4, 2009

- ASME Weld Record; 1AF02EB-4 Replacement (WO 01170562) FW 2A-1; March 25, 2009 through April 4, 2009
- ASME Weld Map, 1AF02EB-4 Replacement (WO 01170562); Revision 4
- ASME Section XI Repair/Replacement Plan, 1AF02EB-4 Replacement (WO 01170562); Revision 5
- Attachment 1; ER-AP-331-1001; Visual Examination NDE Report; 1RV-03-74-BMV; April 3, 2009
- Attachment 1; ER-AP-331-1001; Visual Examination NDE Report; VT-2 Examination of 1B RH Train; October 3, 2008
- Attachment 3; ER-AP-331-1002; Boric Acid Evaluation Reactor Coolant Loop 1A to RH pump 1A Suction Isolation Valve; December 18, 2007
- Attachment 3; ER-AP-331-1002; Boric Acid Evaluation Reactor Coolant Loop 1C Pressure Transmitter; December 18, 2007
- Attachment 3; ER-AP-331-1002; Boric Acid Evaluation 1LT-0461 Pressurizer Level Transmitter RC loop; December 18, 2007
- Indication Sketch Sheet; 1MS-05-PG-4; April 10, 2009
- Liquid Penetrant Examination Report 900640-001, Safety Nozzle A; April 23, 2008
- Liquid Penetrant Examination Report 900640-035, Safety Nozzle A; May 3, 2008
- Liquid Penetrant Examination Report 900640-037, Safety Nozzle A; May 4, 2008
- Magnetic Particle Examination Report 1MS-07-SW08; April 3, 2009
- Magnetic Particle Examination Report 1MS-05-SW14 through SW17; April 10, 2009
- Magnetic Particle Examination Report 1MS-05-SW7 through SW10; April 7, 2009
- Magnetic Particle Examination Report 1MS-05-PG-01 through PG-03; April 7, 2009
- Magnetic Particle Examination Report 1MS-05-PG-05 through PG-08; April 10, 2009
- Magnetic Particle Examination Report 1MS-05-PG-13 through PG-16; April 10, 2009
- Memorandum, Braidwood U1 SG Inspection Degradation Assessment and Condition Monitoring Input Checklist for A1R14; January 22, 2009
- Procedure ER-AP-331, Boric Acid Corrosion Control Program; Revision 4
- Procedure ER-AP-331-1001, Boric Acid Inspection Locations, Implementation of Inspection Guidelines; Revision 4
- Procedure ER-AP-331-1002, Boric Acid Corrosion Program Identification, Screening and Evaluation; Revision 5
- Procedure ER-AA-335-01, Bare Metal Visual Examination for Alloy 600/82/182 Materials; Revision 0
- Procedure ER-AA-335-04, Manual Ultrasonic Requirements for Non-PDI Examinations; Revision 1
- Procedure MRS 2.4.2 Gen-45, Standard In Situ Pressure Test Using the Computer Data Acquisition System; January 25, 2008
- Procedure Qualification Record, A-001; October 19, 1998
- Procedure Qualification Record, A-002; March 9, 1999
- Procedure Qualification Record, 1-50C; January 3, 1984
- Radiographic Examination Interpretation Report (and Film), FW 1-1, FW-22 and FW-2A-1; April 1, 2009
- Weld Rod Ticket, ER 7052, Heat No. 2726532; March 24, 2009
- Welder Qualification, ID No BW40; March 13, 2009
- WPS 1-1-GTSM-PWHT; Revision 1
- Wesdyne Indication Assessment Weld 1RV-01-003; October 10, 2007
- Wesdyne Indication Assessment Weld 1RV-01-006; October 11, 2007
- Westinghouse Letter, In Situ Pressure Testing at Braidwood Unit 1 (A1R14); April 14, 2009
- Westinghouse Letter, Use of Appendix H Qualified Techniques at Braidwood A1R14; February 19, 2009

1R11 Licensed Operator Requalification Program

- OP-AA-1; conduct of Operations; Revision 0
- OP-AA-100; Description of the Exelon Nuclear conduct of Operations Manual; Revision 0
- OP-AA-101-111-1001; Operations Philosophy Handbook; Revision 5
- OP-AA-101-112; Roles and Responsibilities of Of-shift Personnel; Revision 5
- OP-AA-101-113-1006; 4.0 Crew Critique Guidelines; Revision 0
- SGWLC Transient/Large Break RCS LOCA/ Cold Leg Recirculation UFSAR Timing/Loss of All AC UFSAR Timing Scenario #0931; Revision 0; February 27, 2009
- 1BwEP-0; Reactor Trip or Safety Injection
- 1BwEP-1; Loss of Reactor or Secondary Coolant
- 1BwEP ES-1.3; Transfer to Cold Leg Circulation
- 1BwCA-0.0; Loss of All AC Power

1R12 Maintenance Effectiveness

- OU-AA-103; Shutdown Safety Management Program
- ER-AA-600; Risk management
- ER-AA-600-1044; Maintenance Rule Support
- ER-AA-2001; Plant Health Committee
- LS-AA-115; Operating Experience Procedure
- ER-AA-1100; Establishing and Managing Engineering Programs
- ER-AA-2030; conduct of Plant engineering
- ER-AA-310-1001; Maintenance Rule - Scoping
- ER-AA-310-1002; Maintenance Rule - SSC Risk Significance Determination
- ER-AA-310-1003; Maintenance Rule -Performance Criteria Selection
- ER-AA-310-1004; Maintenance Rule -Performance Monitoring
- ER-AA-310-1005; Maintenance Rule -Dispositioning Between (a)(1) and (a)(2)
- ER-AA-310-1006; Maintenance Rule -Expert Panel Roles and Responsibilities
- ER-AA-310-1007; Maintenance Rule -Periodic (a)(3) Assessment
- ER-AA-310-1008; Maintenance Rule -Exelon Maintenance Rule Process Map
- NRC Regulatory Guide (RD) 1.160, Monitoring the Effectiveness of Maintenance of Nuclear Power Plants
- NRC RG 1.182; Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
- NUMARC 93-01; Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants
- WC-AA-101; On-Line Work Control Process
- WC-AA-104; Review and Screening for Production Risk
- ER-AA-310; Implementation of the Maintenance Rule; Revision 7
- IR 903757; 1IA663 Ball Valve Stem Broken at Handle
- IR 912149; Update UFSAR Table 6.2.58
- IR 916116; Emergent Dose Required for BwOP SA-10
- IR 922629; Review Seismic Report EC-2698, Rev 0 for 2 in Check Valve
- IR 923583; U2 Station Air Receiver Bottom Needs to be Painted
- IR 933226; NOS Id - Inadequate Job Prep for SAC 0SA01C Work
- IR 933304; 0SA02CA - Compressor Needs to be Replaced
- IR 935919; Acceptance Criteria per BwVX 800-2 Not Met on 1A Sampling
- IR 936138; U0 SAC Tripped on Hi Vibes During PMT run - 0SA01C
- IR 936532; 75% MR Unavailability Has Been Exceeded on U0 SAC
- IR 938321; Troubleshooting Results for 0 SAC Failure

- IR 938708; One of Three Temporary Air Compressors Not Working Properly
- IR 941369; 1SA033 Failed As-Found LLRT - Seat Leakage
- IR 941445; 100 percent MR Unavailability has been Exceeded on Unit 0 SAC

1R13 Maintenance Risk Assessments and Emergent Work Control

- IR 862065; 1CV8382A Has a 0.4 GPM Leakby When Isolated; January 2, 2009
- IR 909048; SI Pumps Discharge Pressures Indicating 1200 PSIB; April 18, 2009
- IR 910512; 1CV8396B Needs Retorque, Leaking When Operated; April 22, 2009
- IR 910523; Small Loss of Metal on Leading Edge of One Impeller Vane; April 22, 2009
- IR 910646; 1FT-0531 High Side Test Tap Leaking; April 23, 2009
- IR 912495; U1 PRT Pressure Rise Rate Went Up; April 28, 2009
- IR 912948; U1 RCS Unidentified Leakrate Exceeds Action Level 3; April 28, 2009
- Complex Troubleshooting (Failure Mode Tree); High Levels of Unidentified RCS Leakage: Unit 1
- Drawing CV-1, CVCS; June 20, 2008; Revision 10
- Drawing M-64, Sheet 38; Diagram of Chemical Volume & Boron Thermal Regeneration; June 4, 1985
- WC-AA-101; On-Line Work Control Process
- WC-AA-104; Review and Screening for Production Risk
- ER-AA-600; Risk Management

1R15 Operability Evaluations

- IR 902241; CV Full flow Testing Acceptance Criteria Issues (1CV01PA); April 3, 2009
- IR 902597; A1R14 - Anomaly Noted During SI System Full flow Testing; April 3, 2009
- IR 902815; SI Hot Leg ECCS Flow Trend; April 4, 2009
- IR 902725; Perform Valve 1SI8822A Inspection to Support Troubleshooting; April 3, 2009
- IR 910029; Long Term Fix to ECCS Throttle Valves Degradation; April 21, 2009
- IR 909048; SI Pumps Discharge Pressures Indicating 1200 psig; April 22, 2009
- IR 909535; NOS ID: NIRB Results for ECCS Flow Issue; April 20, 2009 [NRC Identified]
- IR 909601; 1SI8853B - 1B SI Pump Discharge Relief Valve Actuation; April 18, 2009
- IR 909639; Need Engineering disposition to Vendor Exception; April 20, 2009
- IR 910653; Possible SI System Siphoning to RWST; April 23, 2009 [NRC Identified]
- IR 909942; NRC Identified Discrepancy with 1A AF Pump Mission Time; April 21, 2009
- IR 910882; Question on Temp Leak Repair Permit Requirements; April 23, 2009
- Complex Troubleshooting Data Sheet, SI/CV Cold Leg Injection Lines Flow Inbalance
- NFM0100126; Input to EDG Loading and Fuel Consumption Calculcation, Seq. 0
- EC Request 389963; Provide Bolt Torque Values on Aux Feedpump Bearing Housing and End Cover; April 17, 2009
- EC 375171; Evaluate the Acceptability of the OIl Leak at the 1A AF Pump Outboard Bearing Cover; Revision 0
- Byron Station Design Information Transmittal; BYR-04-029, Safety Analysis AF System Mission Time and AF Pump Flow Profile; Revision 2
- WO 1164186-10; MM-Repair Oil Leak at Outboard Bearing Cover; April 17, 2009
- Operability Evaluation 09-003, SI Pumps Discharge Pressure Indicating 1200 PSIG; Revision 0
- Drawing M-61; Diagram of Safety Injection Unit 1; June 4, 1985
- MA-AA-716-004; RCS Inleakage from SI Cold Leg Discharge Check Valves; Revision 7
- BwOP SI-1; Safety Injection System Startup; Revision 19
- BwOP SI-2; Safety Injection System Shutdown; Revision 12

- BwVSR SI-1; ECCS Injection Line Depressurization with Optional Leakage Test of SI8948A/B/C/D and SI1895A/B/C/D; Revision 1

1R18 Temporary Plant Modifications

- Procedure CC-AA-404; Maintenance Specification: Application Selection, Evaluation and Control of Temporary Leak Repairs; Revision 8
- WO 1228394-01; MM-Temp Repair - Oil Leak at Outboard Bearing Cover; April 19, 2009
- IR 908495; 1A AF PMP Seal Leak at Outboard End Plus Oil Leak at Housing; April 17, 2009
- IR 910882; Question on Temp Leak Repair Permit Requirements; April 23, 2009 [NRC Identified]

1R19 Post Maintenance Testing

- BwOP HD-1; Heater Drain System Startup; Revision 23
- MEV Listing: UBRWWQ(3); CV Valve Fragnet Schedule with Weekend Work; April 30 - May 3, 2009
- WO 1071057-03, Attachment A; Adjustment of DG Basler Voltage Regulator

1R20 Outage Activities

- BwVS 500-6; Low Power Physics Test Program; Revision 22
- Furmanite America, Inc. Certificate of Calibration #101926; Digital Ring Gauge; February 25, 2009
- Trevitest Test Sheet; Valve 1MS017C; March 27, 2009
- Trevitest Test Sheet; Valve 1MS013B; March 27, 2009
- Trevitest Test Sheet; Valve 1MS015B; March 27, 2009
- Trevitest Test Sheet; Valve 1MS017B; March 27, 2009
- Trevitest Test Sheet; Valve 1MS013C; March 27, 2009
- Trevitest Test Sheet; Valve 1MS014C; March 27, 2009
- Trevitest Test Sheet; Valve 1MS015C; March 27, 2009
- IR 899574; Material Identified on PZR Heater Lower Weld; March 30, 2009
- IR 899611; 1RC8042 (Significant Active Boric Acid Leakage); March 30, 2009
- IR 909402; 1RC01R Head Area (Additional Boric Acid Cleaning Required A1R15); April 18, 2009
- TIMQ102; Execute to PE Request Maintenance
- TIMQ110; (BRW) Pressurizer Relief Tank Rupture Disc
- TIMQ111; (BRW) Pressurizer Relief Tank Rupture Disc
- TIMQ112; (BRW) Pressurizer Relief Tank Rupture Disc
- TIMQ120; Disc, Rupture, 18 Inches, Type BV, Disc and Vacuum Support Material 31
- TIMQ121; Disc, Rupture, 18 inches, Type BV, Disc and Vacuum Support Material 31
- OU-AA-103; Shutdown Safety management Program

1R22 Surveillance Testing

- 1BwOSR 3.8.1.10-1; 1A Diesel Generator Full Load Rejection and Simulated SI in Conjunction with UV During Load Test; Revision 7
- 1BwOSR 3.8.1.19-1; 1A Diesel Generator ECCS Sequencer Surveillance; Revision 8
- OP-AA-108-111; Adverse Condition Monitoring and Contingency Plan; 1A DG Lube Oil Temperature Monitoring; Revision 5

- IR 89124; 1A DG Unexpected Ventilation Indications; March 11, 2009
- WO 1073973; Comprehensive Inservice Testing (IST) Requirements for Unit 1 Charging Pumps and Safety Injection System Check Valve Stroke Test; April 2, 2009
- WO 1075542; Comprehensive Inservice Testing (IST) Requirements for Unit 1 Safety Injection Pumps and Safety Injection System Check Valve Stroke Test; April 2, 2009

<u>2OS1 Access Control to Radiologically Significant Areas</u>

- IR 837415-02; A1R14 Outage ALARA Planning and Controls; March 6, 2009
- IR 837394-02; Access Control to Radiologically Significant Areas and ALARA Controls; February 8, 2009
- IR 874206; Dose Rates Increasing in Radwaste; January 30, 2009
- IR 877085; Lead Shielded Source Carrier Broken; February 5, 2009
- IR 888340; Radioactive Material Shipper Not Informed of Incoming Radioactive Shipment; March 3, 2009
- IR 883920; Radioactive Shipment Was Not Recognized as Radioactive Material; February 23. 2009
- IR 898357; Personnel Contamination Events; March 26, 2009
- IR 898876; Whole Body Counter Upgrades; February 25, 2009
- IR 902224; Nasal Count of Four Thousand Unit-1 Containment 426 Cavity During Fuel Moves; April 3, 2009
- IR 904570; Training: Thermoluminescent Dosimeter Issued Based on Bad Data; March 31, 2009
- IR 905721; Radwaste Outer Door Locks Behind Individual, Needs Repair; April 10, 2009
- RP-AA-203-1001; Personnel Exposure Investigation; Revision 6
- RP-AA-402; Braidwood Station 2009- 2013 Exposure Reduction Plan; Revision 0
- RP-BR-1020; Radiological Controls For Steam Generator Work; Revision 0
- RWP 10009754; A1R14: Lead Shielding Install/Maintain/Remove (Auxiliary and Containment Buildings); Revision 1
- RWP 10009768; A1R14: Valve Team Outage Activities In Containment; Revision 2
- RWP 10009777; A1R14: Reactor Head Disassembly/Reassembly; Revision 2
- RWP 10009821; A1R14: Manway and Diaphragm Removal, Installation and Bolt; Revision 3
- RWP 10009815; A1R14: Steam Generator Eddy Current Testing and All Tube Repairs; Revision 2

<u>4OA1 Performance Indicator</u>

- LER 05000456/2007-001-00; Unit 1 Reactor Trip Following a 345 Kv Transmission Line Lightning Strike; June 27, 2007
- LER 05000456/2007-002-00; Unit 1 Power Range N43 Positive Rate Trip Inoperable due to Miscalibration of time Constant; September 22, 2007
- LER 05000456/2007-003-00; Improper Installation of Insulation on the Unit 1 Main Steam Safety Valve; October 24, 2007
- LER 05000456/2008-001-00; TS Non-Compliance Due to Inadequate Design of Auxiliary Feedwater Tunnel Access Covers Causing Auxiliary Feedwater Valves Within the Tunnel to be Inoperable; December 16, 2008
- LER 05000456/2008-002-00; Unit 1 Containment Isolation Valve 1PS229B De-energized Open Instead of Closed per TS 3.6.3; December 17, 2008
- LER 05000457/2007-001-00; Unit 2 Manual Reactor Trip Due to High Condenser Backpressure Resulting from Circulating Water Pump Trips; August 8, 2007

- LER 050004572008-001-01; 2A Essential Service Water Train Inoperable due to Strainer Fouling from Bryozoa Deposition and Growth; September 2, 2008
- LER 05000457/2008-002-00; Reactor Trip on Unit Auxiliary Transformer 241-1 Sudden Pressure Relay Actuation Due to 2C Heater Drain Pump Motor Electrical Fault; December 27, 2008
- WO 1229701 01; OP ASME Surveillance Requirements for 2CV01PA Pump, 2A Centrifugal Charging Assembly; May 6, 2009
- BwOSR 5.5.8.CV-4A; Group A 1st Requirements for 2A Centrifugal Charging Pump (2CV01PA) and Check Valve 2CV8480A Stroke Test; Revision 3

4OA2 Identification and Resolution of Problems

- IR 902241; CV Full flow Testing Acceptance Criteria Issues (1CV01PA); April 3, 2009
- IR 918633; NRC ID - Potentially Inadequate 50.59 for ECCS Throttle Valves; May 12, 2009
- IR 925110; NOS ID concerns with U2 ECCS Throttle Valve Op Evaluation; April 15, 2009
- EC 364979; Evaluation of Wyle Test Report WLTR53637
- Generic Letter 2004-02; Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors; September 13, 2004
- Apparent Cause Report 906108; ECCS Throttle Valves Require Re-Adjustment and Flow Testing, Resulting in Significant Outage Impact; April 10, 2009
- Root Cause Investigation Report 902241-21; Braidwood U1 ECCS Flows Exceed Flow Balance Surveillance Criteria Due to Unanticipated Material Degradation of ECCS Throttle Valves; May 29, 2009
- Assignment Report #02; Conduct Complex Troubleshooter for U1 ECCS Full flow Test Failure; April 22, 2009
- 50.59 Review; Braidwood Unit 1 EC 360141 UFSAR Change Package #DRP 12-017; Modifications to the SI Throttle Valves 1SI8810A-D, 1SI8816A-D, 1SI822A-D
- 50.59 Review; Braidwood Unit 2 EC 360143 UFSAR Change Package #DRP 12-038; Modifications to the SI Throttle Valves 2SI8810A-D, 2SI8816A-D, 2SI822A-D
- Assignment Report #03; OTDM Associated with Complex Troubleshooter Approve OTDM Associated with U1 ECCS Full Flow Issues; April 17, 2009
- Assignment Report #04; Failure Analysis on Broken Piston Ring; June 17, 2009
- Assignment Report #05; Review Throttle Valve Cage Failure Analysis Report; June 24, 2009
- Assignment Report #10; Document Metallurgists Used in Decision Making Process PORC Follow-up Item from OTDM 90224
- Assignment Report #11; Perform FME Evaluation per Attachment 10 of MA-AA-716-008 for Degraded Throttle Valve Condition; April 22, 2009
- Assignment Report #12; Revise Operating Procedures Unit 1; April 22, 2009
- Assignment Report #13; Incorporate Comments from PORC into EC 375081; April 24, 2009
- Assignment Report #19; Complete root Cause Charter; May 1, 2009
- SDP Phase 1 Screening Worksheet; 50.59 Came to Wrong Conclusion Re: ECCS Throttle Valve Internals in A1R13

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
DG	Diesel Generator
DMBW	Dissimilar Metal Butt Weld
DRP	Division of Reactor Projects
EACE	Equipment Apparent Cause Evaluation
EC	Engineering Change
ECCS	Emergency Core Cooling System
EPRI	Electric Power Research Institute
ET	Eddy Current
FDS	Fire Damage State
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISI	Inservice Inspection
LCO	Limiting Condition for Operation
LCSR	Lower Cable Spreading Room
LER	Licensee Event Report
LOOP	Loss of Off-site Power
MSPI	Mitigating System Performance Index
NCV	Non-Cited Violation
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety
OTdT	Over Temperature Delta Temperature
PARS	Publicly Available Records
PI	Performance Indicator
RCS	Reactor Coolant System
RFO	Refueling Outage
RWP	Radiation Work Permit
SDP	Significance Determination Process
SI	Safety Injection
SRA	Senior Reactor Analyst
SX	Essential Service Water
TI	Temporary Instruction
TS	Technical Specifications
TSO	Transmission System Operator
UCSR	Upper Cable Spreading Room
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item