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

November 9, 2011

EA-11-166

Mr. Michael J. Pacilio
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, NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000456/2011004; 05000457/2011004

Dear Mr. Pacilio:

On September 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Braidwood Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on October 5, 2011, with Mr. D. Enright 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, four NRC-identified findings of very low safety significance (Green) that involved violations of NRC requirements were identified. The NRC identified an additional Green finding that was associated with a Severity Level IV violation of NRC requirements evaluated through the traditional enforcement process. However, because of their very low safety significance, and because these issues were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and to the Senior Resident Inspector at Braidwood Station. In addition, if you disagree with the cross-cutting aspect assigned to 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 to the Senior Resident Inspector at Braidwood Station. The information that you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, 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 System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000456/2011004; 05000457/2011004
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2011004; 05000457/2011004
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	July 1, 2011, through September 30, 2011
Inspectors:	J. Benjamin, Senior Resident Inspector A. Garmoe, Resident Inspector R. Ng, Project Engineer G. O'Dwyer, Reactor Inspector B. Palagi, Senior Operations Engineer D. Reeser, Operations Engineer M. Perry, Resident Inspector, Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS 1

REPORT DETAILS 6

Summary of Plant Status 6

1. REACTOR SAFETY 6
1R01 Adverse Weather Protection (71111.01) 6
1R04 Equipment Alignment (71111.04) 9
1R05 Fire Protection (71111.05) 10
1R06 Flooding (71111.06) 11
1R07 Annual Heat Sink Performance (71111.07) 13
1R11 Licensed Operator Requalification Program (71111.11) 14
1R12 Maintenance Effectiveness (71111.12) 16
1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13) 17
1R15 Operability Determinations and Functional Assessments (71111.15) 18
1R18 Plant Modifications (71111.18) 29
1R19 Post-Maintenance Testing (71111.19) 32
1R22 Surveillance Testing (71111.22) 33
1EP6 Drill Evaluation (71114.06) 37

4. OTHER ACTIVITIES 38
4OA1 Performance Indicator Verification (71151) 38
4OA2 Identification and Resolution of Problems (71152) 40
4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153) 44
4OA6 Management Meetings 46

SUPPLEMENTAL INFORMATION 1

Key Points of Contact 1

List of Items Opened, Closed and Discussed 1

List of Documents Reviewed 3

List of Acronyms Used 13

SUMMARY OF FINDINGS

Inspection Report 05000456/2011004, 05000457/2011004; 07/01/2011 – 09/30/2011; Braidwood Station, Units 1 & 2; Adverse Weather Protection; Operability Evaluations; Plant Modifications; Surveillance Testing; and 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 and one Green finding was self-revealed. Five of the findings were considered Non-Cited Violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Assigned cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance when licensee personnel failed to adhere to station housekeeping procedures to ensure materials that could become missile hazards during high winds or tornado conditions were not stored in the vicinity of the station's offsite power transformers. Specifically, the licensee failed to remove or secure three boards and a tarp within the secured material zone that were intended for work scheduled the next day. No violation of regulatory requirements was identified. The licensee entered this issue into their corrective action program as Issue Report (IR) 1243186 and IR 1246870. Corrective actions included plans to brief licensee staff and supervisors on the procedural requirements to ensure materials that could become missile hazards during high winds or tornado conditions were not stored in the vicinity of the station's offsite power transformers, a daily walkdown of outdoor areas to identify inappropriately stored material, reduction in the size of the secured material zone to credit buildings as a barrier, and painting to identify the boundaries of the secured material zone.

  The performance deficiency was determined to be more than minor because it was associated with the Human Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, controls prescribed by station procedures to limit the likelihood of losing offsite power during adverse weather conditions were not adhered to by station personnel. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a, for the Initiating Events Cornerstone. Specifically, the inspectors answered 'No' to all of the Transient Initiator questions in IMC 0609.04, Table 4a, and therefore the finding screened as having very low safety significance (Green). This finding had a cross-cutting aspect in the Work Practices component of the Human Performance cross-cutting area [H.4(c)] since the licensee failed to provide supervisory and

management oversight of work activities to ensure that nuclear safety was supported. (Section 1R01.1.b)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to ensure that Unit 1 and Unit 2 boundary doors credited as shut in design basis High Energy Line Break (HELB) room heat-up calculations were effectively controlled in station procedures. Specifically, doors separating divisions for the Unit 1 and Unit 2 Engineered Safety Feature (ESF) Switchgear Rooms and Miscellaneous Electrical Equipment Rooms (MEERs) were not considered HELB boundaries in the station's Plant Barrier Impairment (PBI) procedure as required. Therefore, these doors could have been impaired for various reasons (e.g., maintenance) without the licensee ensuring that regulatory requirements were maintained, including those contained in the Technical Specifications (TSs) and 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The licensee entered this issue into their corrective action program as IR 1242942. Corrective actions included a revision to the station's PBI procedure to ensure that these barrier doors were considered HELB boundaries.

  The performance deficiency was determined to be more than minor because it was associated with the Protection Against External Events attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, if these doors had been impaired during a design basis turbine building HELB event with an active single failure of a HELB isolation damper, both electrical divisions in the ESF Switchgear Rooms or MEERs could have been adversely affected by the harsh steam environment. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase - 1 Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. Specifically, the inspectors answered 'No' to all of the Mitigating Systems Cornerstone questions in Table 4a of IMC 0609.04 and, as a result, the finding screened as having very low safety significance (Green). Due to the age of this issue, it was not reflective of current licensee performance and therefore the inspectors did not assign a cross-cutting aspect to this finding. (Section 1R15.1.b)

- Green. A finding of very low safety significance and an associated NCV of TS 3.7.5, "Auxiliary Feedwater (AF) System," was self-revealed when, on various occasions between March and July 2011, asiatic clam shells were identified in the 2A AF essential service water (SX) suction piping. Specifically, the asiatic clam shells in the 2A AF pump SX suction piping were of sufficient size to interfere with flow through the downstream steam generator flow control valves, which rendered the 2A AF pump inoperable for greater than the 72-hour Allowed Outage Time (AOT) prescribed in TS 3.7.5. This condition was determined to likely have existed since the late 1990's. The licensee entered this issue into their corrective action program as IR 1213669. Corrective actions included the removal of the clam shells from the 2A AF pump SX suction piping and completion of both an apparent cause and root cause evaluation.

The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. The inspectors answered 'Yes' to the screening question, "Does the finding represent [an] actual loss of safety function of a single Train for > [greater than] its TS Allowed Outage Time?" since the inoperability of the 2A AF pump due to clam shells in the SX suction piping could have been present for at least one year. Therefore, a Phase 2 SDP evaluation was required using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." Since the dominant risk was associated with external events, a Phase 3 analysis was required in order to estimate the risk significance of the issue. Therefore, a Region III Senior Reactor Analyst (SRA) performed a Phase 3 SDP evaluation of the finding. Based on the Phase 3 analysis, the finding was determined to be of very low safety significance (Green). This finding had a cross-cutting aspect in the Corrective Action Program component of the Problem Identification and Resolution cross-cutting area [P.1(c)] since the licensee failed to thoroughly evaluate the identification of asiatic clam shells in the 2A AF SX suction piping in March 2011 and May 2011 and, as a result, implemented corrective actions that were inadequate. (Section 1R15.1.b)

- Severity Level IV. The inspectors identified a finding of very low safety significance and an associated Severity Level IV NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," when licensee personnel failed to obtain a license amendment prior to implementing a proposed change to the plant that resulted in a more than minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the Updated Final Safety Analysis Report (UFSAR). Specifically, the licensee performed a modification to the facility that permitted the Unit 1 and Unit 2 "A" AF trains to be shared between units and the 10 CFR 50.59 evaluation that was performed reached the erroneous conclusion that prior NRC approval was not required. The licensee entered this issue into the corrective action program as IR 1258017 and planned to submit a License Amendment Request (LAR) to the NRC for this design change.

  The violation was determined to be more than minor because the inspectors determined that the change required prior NRC approval. Violations of 10 CFR 50.59 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. However, if possible, the underlying technical issue is evaluated through the SDP to determine the severity of the violation. In this case, the inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. Specifically, the inspectors answered "Yes" to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that this was a change confirmed not to result in the loss of operability. Based upon this Phase 1 screening, the inspectors concluded that the issue was of very low safety significance (Green). In accordance with Section 6.1.d.2 of the NRC Enforcement Policy, this violation is

categorized as Severity Level IV because the resulting changes were evaluated by the SDP as having very low safety significance. This finding had a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution (PI&R) cross-cutting area [P.2.(b)] because the licensee failed to make adequate use of known industry operating experience in the screening of a modification prior to installation. (Section 1R18.1.b)

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when licensee personnel failed to adhere to licensee procedure ER-AA-310, "Implementation of the Maintenance Rule." Specifically, the licensee failed to adhere to the requirements of procedure ER-AA-310 when crediting availability of the Unit 1 and Unit 2 'B' train AF pumps by not having documented restoration actions (i.e. Risk Management Actions (RMAs)) during quarterly in-service testing surveillances that involved the manual cycling of cooling water valves. The licensee entered the issue into the corrective action program as IR 1251652 and took immediate corrective actions to revise the applicable portion of the Excel spreadsheet that documented restoration actions. The licensee was also considering a more robust process for the documentation of restoration actions to credit equipment availability.

  The performance deficiency was determined to be more than minor because it was associated with the Procedure Quality attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of system that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, procedural requirements to credit the availability of the 'B' train AF pumps were not met. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase - 1 Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. The inspectors answered 'No' to all of the Mitigating Systems Cornerstone questions in Table 4a of IMC 0609.04 and, as a result, the finding screened as having very low safety significance (Green). This finding had a cross-cutting aspect in the Work Control component of the Human Performance cross-cutting area [H.2(c)] since during performance of the 1B and 2B AF pump surveillances that involved the manual cycling of cooling water valves, the licensee did not have complete and accurate documentation related to the implementation of RMAs for these surveillances. (Section 1R22.1.b)

- Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to properly analyze the configuration of the SX connections to the AF pumps. Specifically, a section of the piping was intentionally maintained empty (voided), but was not previously analyzed. This condition existed since initial plant construction. The issue was entered into the licensee's corrective action program as IR 1173517. Additionally, the licensee filled the voided sections of pipe, restoring compliance with the licensed design basis.

  The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the unverified configuration might have rendered each of the AF

pumps inoperable. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase - 1 Initial Screening and Characterization of Findings,” Table 4a, for the Mitigating Systems Cornerstone. Specifically, the inspectors answered ‘Yes’ to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that this finding was confirmed not to result in a loss of operability. This conclusion was reached after reviewing tests performed by the licensee. The tests demonstrated there was reasonable assurance that the AF system would perform its safety function in the installed configuration. Based on this Phase 1 screening, the inspectors concluded that the issue was of very low safety significance (Green). Due to the age of this issue, the inspectors did not identify a cross-cutting aspect associated with this finding because it was not indicative of current licensee performance. (Section 4OA2.3.b)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power for the duration of the inspection period with the following exceptions. On July 13, reactor power was reduced to about 20 percent to allow isolation of a reactor coolant leak from the packing of a pressurizer spray bypass valve from inside containment. Unit 1 returned to full power on July 15. On September 2, reactor power was rapidly reduced to about 72 percent in response to the unexpected full closure of the #2 turbine throttle valve. Following repairs, Unit 1 returned to full power on September 4.

Unit 2 operated at or near full power for the duration of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition – High Wind Conditions

a. Inspection Scope

Since thunderstorms with potential high winds were forecast in the vicinity of the facility on August 2, 2011, the inspectors reviewed the licensee's overall preparations and protection for the expected weather conditions. On August 2, the inspectors walked down the outdoor transformer secured material and exclusion zones, because their functions could be affected as a result of high wind generated missiles, which could result in the loss of offsite power. The inspectors determined whether licensee staff preparations conformed with site procedures. 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 evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. 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. The inspectors also reviewed a sample of corrective action program (CAP) items 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. Documents reviewed are listed in the Attachment.

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

b. Findings

Failure to Adhere to Standards of Outdoor Secured Material Zones

Introduction: The inspectors identified a finding of very low safety significance (Green) when licensee personnel failed to adhere to station housekeeping procedures to ensure materials that could become missile hazards during high winds or tornado conditions were not stored in the vicinity of the station's offsite power transformers. Specifically, the licensee failed to remove or secure three boards and a tarp within the secured material zone that were intended for work scheduled the next day.

Description: On August 2, 2011, due to a forecast of thunderstorms and high winds, the inspectors performed outside plant walkdowns and identified a tarp and three pieces of wood in an area marked as a "Secured Material Zone," within the line-of-sight of the station's offsite power lines. The secured material zone area was specified in licensee procedure MA-AA-716-026, Revision 9, "Station Housekeeping/Material Condition Program." The inspectors immediately notified the licensee of the material storage issue and the licensee entered the issue into the CAP as Issue Report (IR) 1246870. Later that night, at 10:07 p.m., the National Weather Service issued a Severe Thunderstorm Warning in the vicinity of the plant. The plant's meteorological tower instruments subsequently measured wind gusts of up to 70 miles per hour (mph) as the storm passed over the station.

The inspectors identified that the licensee had not adhered to housekeeping standards. Specifically, procedure MA-AA-716-026, Attachment 1, Note 5, "Storage Practices," stated, "The areas around the Unit 1 and Unit 2 Unit Auxiliary Transformers, Station Auxiliary Transformers, and Main Power Transformers as determined by the vehicle barrier blocks and the walls of the auxiliary building, turbine building, and containments are the Transformer Material Exclusion Areas. In addition, a secured material zone has been established. Reference Attachment 5 for specifications of the two zones." Section c of Note 5 further stated, "Material shall be secured in the secured area zone to prevent damage in the excluded area in the event of adverse weather conditions." Attachment 5 of procedure MA-AA-716-026 identified the boundaries of the secured material zone and exclusion zones. The area in which the inspectors identified the material was part of the secured material zone. The inspectors noted that these standards were based upon corrective actions from a 1998 Braidwood Unit 1 loss of offsite power event. The cause of the event was related to high winds blowing material (i.e., a braided cable) onto an energized station auxiliary transformer.

Corrective actions included plans to brief licensee staff and supervisors on the procedural requirements to ensure materials that could become missile hazards during high winds or tornado conditions were not stored in the vicinity of the station's offsite power transformers, a daily walkdown of outdoor areas to identify inappropriately stored material, reduction in the size of the secured material zone to credit buildings as a barrier, and painting to identify the boundaries of the secured material zone.

Analysis: The inspectors determined that the licensee's failure to adequately control unsecured material that could have affected offsite power availability during severe weather conditions, as required by licensee procedure MA-AA-716-026, was a performance deficiency.

The performance deficiency was determined to be more than minor in accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, “Issue Screening,” because it was associated with the Human Performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, controls prescribed by station procedures to limit the likelihood of losing offsite power during adverse weather conditions were not adhered to by station personnel. Additionally, adverse weather (i.e. high winds reaching approximately 70 mph) occurred shortly after the issue was identified by the inspectors.

The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 4a, for the Initiating Events Cornerstone. Specifically, the inspectors answered ‘No’ to all of the Transient Initiator questions in IMC 0609.04, Table 4a, and therefore the finding screened as having very low safety significance (Green).

This finding had a cross-cutting aspect in the Work Practices component of the Human Performance cross-cutting area since the licensee failed to provide supervisory and management oversight of work activities to ensure that nuclear safety was supported [H.4(c)].

Enforcement: No violation of regulatory requirements was identified. Because this finding did not involve a violation and was of very low safety significance, it was identified as a finding. The licensee entered this issue into their CAP as IR 1243186 and IR 1246870. Corrective actions included plans to brief licensee staff and supervisors on the procedural requirements to ensure materials that could become missile hazards during high winds or tornado conditions were not stored in the vicinity of the station’s offsite power transformers, a daily walkdown of outdoor areas to identify inappropriately stored material, reduction in the size of the secured material zone to credit buildings as a barrier, and painting to identify the boundaries of the secured material zone. **(FIN 05000456/2011004-01; 05000457/2011004-01, Failure to Adhere to Standards of Outdoor Secured Material Zones)**

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a detailed review of the licensee’s procedures and preparations for operating the facility during an extended period of time when ambient outside temperature was high and the ultimate heat sink was experiencing elevated temperatures. The inspectors focused on plant-specific design features and implementation of the procedures for responding to or mitigating the effects of these conditions on the operation of the facility’s essential service water (SX), component cooling water (CC), alternating current power, and direct current power systems. Inspection activities included a review of the licensee’s adverse weather procedures, daily monitoring of the off-normal environmental conditions, and a verification that operator actions specified in plant-specific procedures were appropriate to ensure operability of the facility’s normal and emergency cooling systems.

This inspection constituted one seasonal extreme weather sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Motor Driven Fire Pump with Diesel Driven Fire Pump Not Available;
- Unit 1 Train 'B' Emergency Diesel Generator (EDG) with Unit 1 Train 'A' Emergency Diesel Generator (EDG) Out-of-Service; and
- 125 Volts Alternating Current Division 111 and 211 with Division 212 Out-of-Service.

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

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

b. Findings

No findings were identified.

.2 Semiannual Complete System Walkdown

a. Inspection Scope

On July 18, 2011, the inspectors performed a complete system alignment inspection of the Unit 1 EDGs to verify the functional capability of the system. This system was

selected because it was considered both safety-significant and risk-significant in the licensee's probabilistic risk assessment (PRA) model. The inspectors walked down the system to review mechanical and electrical equipment line ups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected system functionality. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings 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 (Fire Zone 11.3-1);
- Unit 2 Containment Pipe Penetration Area (Fire Zone 11.3-2);
- Auxiliary Building 383' Elevation General Area (Fire Zone 11.4-0);
- Technical Support Center (Fire Zone 18.26-0); and
- Auxiliary Building 451' Elevation General Area (Fire Zone 11.7-0).

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

during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings 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. 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 CAP 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:

- Auxiliary Building Ventilation Plenums (451' Elevation).

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

b. Findings

Use of Mesh Strainer Bags in Auxiliary Building Floor Drains

Introduction: The inspectors identified an Unresolved Item (URI) related to the use of fine mesh strainer baskets in auxiliary floor drains. Specifically, the strainer baskets in auxiliary building ventilation inlet plenums had repeatedly clogged, causing flooding inside the plenum that overflowed into various electrical penetration areas. At the end of the inspection period, the inspectors had not completed an evaluation to determine whether the issue adversely affected the ability to achieve safe shutdown due to a moderate energy line break in the auxiliary building ventilation plenum area.

Description: During routine daily reviews of the licensee's CAP documents, the inspectors noted several IRs documenting clogged floor drains in auxiliary building ventilation inlet plenums that resulted in water pooling on the floor and dripping into various electrical penetration areas. The specific IRs reviewed included the following:

- IR 1230829; Water in Auxiliary Building Ventilation Inlet Plenum Following Storm; June 20, 2011;
- IR 1249503; Operations – Auxiliary Building Floor Drain Overflowing; August 9, 2011;
- IR 1259300; Area Evaluation Required After Water Exposure; September 4, 2011; and
- IR 1260053; Clogged Floor Drain Basket in 0VA01CC/CD Supply Plenum; September 7, 2011.

On August 9, 2011, as documented in IR 1249503, the licensee noted that the floor drain in the Unit 2 auxiliary building ventilation supply plenum overflowed. This resulted in about 4 inches of standing water in the plenum and 10-20 gallons of water that seeped into the electrical penetration area below. The water pooled around the pressurizer heater substations, but did not penetrate the cabinet. No actions were assigned in the IR and it was closed on August 14.

On September 4, the licensee generated IR 1259300, which requested an area equipment evaluation for the auxiliary building electrical penetration area (Elevation 426') due to water flowing into the area from above. The water originated from the Unit 2 auxiliary building ventilation supply plenum due to a clogged floor drain. Operators replaced the mesh basket and the water then drained out of the plenum properly. The licensee noted that no safety-related equipment was wetted from the dripping water. The IR referenced existing WO 1045973 and WO 970365 scheduled for December 2011 to remove corrosion that was clogging the floor drains. Action Item 2 was assigned to review a recommendation from Engineering to include a note in the operator rounds to inspect the floor drain baskets and replace them as necessary to ensure no flooding occurred. This action was initially due on October 7, but had been extended to December 7 at the end of the inspection period. The licensee documented the September 4 overflow event in IR 1260053 and initiated a monthly recurring action to inspect the floor drain baskets.

The inspectors recalled a prior violation (NCV 05000456/2010007-04; 05000457/2010007-04, Adverse Impact of Flood Drain Strainer Design Modification on Flooding Analysis) that was issued to Braidwood in 2010 regarding auxiliary building floor drain basket strainers. In that violation the inspectors concluded that the licensee failed to adequately ensure that bag-type strainers installed in the auxiliary building floor drains, for the purpose of preventing debris from blocking the floor drain piping, would not adversely impact the analysis of record for internal flooding. As a corrective action to the NCV, the licensee developed Engineering Change (EC) 379355 to analyze the impact of clogged floor drains on the auxiliary building flooding calculation. The analysis focused on "critical" floor drains," which were defined in procedure BwMS 3350-009, "Auxiliary Building Floor Drain Strainer Basket Surveillance," Revision 9, as drains that are credited to remove water in the auxiliary building flood calculation.

The licensee concluded in EC 379355 that there was no detrimental impact to auxiliary building flooding evaluations. However, the inspectors questioned whether the auxiliary building ventilation plenum floor drains should have been analyzed in EC 379355. The inspectors discussed the issue with licensee personnel and IR 1264201, "Incorrect Floor Drains Classification in BwMS 3350-009A2," was generated. The Unit 2 auxiliary building ventilation plenum floor drains on the 451' elevation appeared to have been mischaracterized as non-critical floor drains in procedure BwMS 3350-009,

Attachment 2, and thus were not included in the analysis performed in EC 379355. The licensee concluded in IR 1264201 that there would be no impact on safe shutdown capability with a clogged auxiliary building ventilation plenum floor drain and a medium energy line break.

At the end of the inspection, the inspectors had not yet validated that there would be no impact on the ability to achieve safe shutdown due to a moderate energy line break in the auxiliary building ventilation plenum area. Due to clogged drains, there were known leakage paths from the auxiliary building ventilation plenum area into the electrical penetration areas, which contained safe shutdown equipment through penetrations that were not classified as flood seals. The inspectors had not validated that the design interactions between the auxiliary building floor drains, the auxiliary building ventilation plenums, non-flood penetrations, and safe shutdown equipment in the electrical penetration rooms was adequate. **(URI 05000456/2011004-02; 05000457/2011004-02, Use of Mesh Strainer Bags in Auxiliary Building Floor Drains)**

.2 Underground Vaults

a. Inspection Scope

The inspectors selected underground manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors observed the installation of dewatering devices (sump pumps) as part of the licensee's plan to address submerged cables. The inspectors also reviewed the licensee's corrective action documents with respect to submerged cable issues identified in the corrective action program to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following manholes subject to flooding:

- Manhole 1D; and
- Manhole 2D.

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

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's inspection of the Unit 1 CC heat exchanger to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors compared the licensee's inspection results with inspection acceptance criteria, determined whether the frequency of testing and testing schedule was adequate to detect heat exchanger degradation prior to the loss of heat removal capabilities below the design basis values,

and assessed the impact of instrument inaccuracies on test results. The inspectors also determined whether testing acceptance criteria and results appropriately considered the differences between test conditions and design conditions. Documents reviewed are listed in the Attachment.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On August 9, 2011, the inspectors observed the licensed operators of Crew 1 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.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.2 Biennial Review (71111.11B)

a. Inspection Scope

The following inspection activities were conducted during the weeks of August 22, 2011, and August 29, 2011, to assess: 1) the effectiveness and adequacy of the facility licensee's implementation and maintenance of its Systems Approach To Training (SAT)

based Licensed Operator Requalification Training (LORT) program, put into effect to satisfy the requirements of 10 CFR 55.59; 2) conformance with the requirements of 10 CFR 55.46 for use of a plant referenced simulator to conduct operator licensing examinations and for satisfying experience requirements; and 3) conformance with the operator license conditions specified in 10 CFR 55.53. Documents reviewed are listed in the Attachment.

- Facility Operating History and Licensee Training Feedback System (10 CFR 55.59(c); SAT Element 5 as Defined in 10 CFR 55.4): The inspectors evaluated the licensee's ability to assess the effectiveness of its LORT program and their ability to implement appropriate corrective actions to maintain its LORT Program up to date. The inspectors reviewed documents related to the plant's operating history and associated responses (e.g., Plant Issues Matrix and performance review reports; recent examination and inspection reports; Licensee Event Reports (LERs)). The inspectors reviewed the use of feedback from operators, instructors, and supervisors as well as the use of feedback from plant events and industry operating experience information. The inspectors reviewed the licensee's quality assurance oversight activities, including licensee Training department self-assessment reports.

- Licensee Requalification Examinations (10 CFR 55.59(c); SAT Element 4 as Defined in 10 CFR 55.4): The inspectors reviewed the licensee's program for development and administration of the LORT biennial written examination and annual operating tests to assess the licensee's ability to develop and administer examinations that are acceptable for meeting the requirements of 10 CFR 55.59(a).

  - The inspectors reviewed the methodology used to construct the examination including content, level of difficulty, and general quality of the examination and test materials. The inspectors also assessed the level of examination material duplication from week to week for both the operating tests conducted during the current year, as well as the written examinations administered in 2010. The inspectors reviewed a sample of the written examinations and associated answer keys to check for consistency and accuracy;

  - The inspectors observed the administration of the annual operating test to assess the licensee's effectiveness in conducting the examinations, including the conduct of pre-examination briefings, evaluations of individual operator and crew performance, and post-examination analysis. The inspectors evaluated the performance of one crew in parallel with the facility evaluators during two dynamic simulator scenarios, and evaluated various licensed crew members concurrently with facility evaluators during the administration of several Job Performance Measures (JPMs);

  - The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the last requalification examinations and the training planned for the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans.

- Conformance with Examination Security Requirements (10 CFR 55.49): The inspectors observed and reviewed the licensee's overall licensed operator requalification examination security program related to examination physical security (e.g., access restrictions and simulator considerations) and integrity (e.g., predictability and bias) to verify compliance with 10 CFR 55.49, "Integrity of Examinations and Tests." The inspectors also reviewed the facility licensee's examination security procedure and the implementation of security and integrity measures (e.g., security agreements, sampling criteria, bank use, and test item repetition) throughout the examination process.

- Conformance with Simulator Requirements Specified in 10 CFR 55.46: The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements. The inspectors reviewed a sample of simulator performance test records (e.g., transient tests, malfunction tests, scenario-based tests, post-event tests, steady state tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy corrective action process to ensure that simulator fidelity was being maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions as well as on nuclear and thermal hydraulic operating characteristics.

- Conformance with Operator License Conditions (10 CFR 55.53): The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators, and which control room positions were granted watch-standing credit for maintaining active operator licenses. Additionally, medical records for 12 licensed operators were reviewed for compliance with 10 CFR 55.53(l).

This inspection constitutes one biennial licensed operator requalification inspection sample as defined in IP 71111.11B.

b. Findings

No findings 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:

- Station Service Air; and
- Unit 1 Bus 156 Undervoltage Relay Troubleshooting.

The inspectors reviewed events, including those in which ineffective equipment maintenance 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 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:

- Emergent EDG Ventilation Damper Work Due to High Energy Line Break (HELB) Concerns, Planned Yellow;
- Auxiliary Feedwater (AF) Availability with Alternate SX Suction Valves De-energized Closed, Planned Yellow; and
- Risk Management of Unit 1 Train ‘A’ EDG Work Window, Planned Yellow.

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 three samples as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Non-Conservatisms in HELB Analysis;
- Asiatic Clam Shells Identified in Unit 2 Train 'A' AF Suction Line;
- Unit 1 Pressurizer Spray (1RY455B) and Bypass (1RY8050) Valves Isolated;
- Safety-Related Switchgear Room Temperature Limits;
- Air Void Identified in Unit 1 Train 'B' Emergency Core Cooling System Sump Suction Line; and
- High Energy Line Break Single Active Failure Assumptions.

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 TSs 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 reviewed a sample 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

(1) Failure to Control High Energy Line Break Barrier Doors

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III,

"Design Control," when licensee personnel failed to ensure that multiple Unit 1 and Unit 2 boundary doors credited as shut in design basis HELB room heat-up calculations were effectively controlled in station procedures. Specifically, doors separating divisions for the Unit 1 and Unit 2 Engineered Safety Feature (ESF) Switchgear Rooms and Miscellaneous Electrical Equipment Rooms (MEERs) were not considered HELB boundaries in the station's PBI procedure, as required.

Description: During a review of the licensee's actions in response to IR 1185016, "Non-Conservatisms in the Turbine Building HELB Analyses," the inspectors noted that the licensee was required by the station's licensing basis to assume a specific scope of HELBs within the turbine building. In addition, the licensing basis assumed an active single failure in systems used to mitigate the consequences of a postulated piping failure. Specifically, NRC Standard Review Plan Section 3.6.1, Branch Technical Position ASB 3-1, Section B.1.a, states that "A single active component failure should be assumed in the systems used to mitigate the consequences of the postulated piping failure and to shutdown the reactor, except as noted in item B.3.b(3) below. The single active component failure is assumed to occur in addition to the postulated piping failure and any direct consequences of the piping failure, such as a unit trip and the loss of offsite power." The subject note in item B.3.b(3) discussed an exception for dual purpose moderate-energy essential systems, which was not applicable to this issue.

At Braidwood station, the turbine building HELB protective barriers consist of dampers and roll-up doors held open by thermal links (TLs). In the absence of these TLs, the dampers are designed to close by spring force. The TLs are designed to melt through direct contact with the hot steam following a HELB, which permits the dampers to close by spring force to isolate the rooms from the source of the HELB. Additionally, certain dampers use electrical thermal links (ETLs) that utilize electrical current to melt the ETL when a temperature sensor in an area reaches a specified temperature setpoint, and permits the damper to close by spring force.

Because a single active failure of the TLs and ETLs for these HELB barriers must be considered, the inspectors reviewed the equipment that could be adversely affected by the failure of these HELB barriers to close as a result of an active failure of the TL or ETL. Much of the safety-related electrical distribution equipment, including redundant train equipment, is located in rooms with doors and penetrations along the "L-wall", which separates the turbine building from the auxiliary building. Many of the rooms are interconnected behind the L-wall with standard access doors. The inspectors reviewed the barrier evaluations of these doors in the licensee's Plant Barrier Impairment (PBI) program, which governed compensatory actions for doors or barriers that were impaired due to maintenance or malfunction. The inspectors noted that the interconnecting room doors were not pre-evaluated as HELB barriers in the PBI procedure, although they would be exposed to a HELB environment upon a single active failure of an L-wall HELB barrier such as a damper or roll-up door. The PBI program permitted barriers to be blocked open for up to 90 days based on the barrier-specific pre-evaluation provided in the PBI program procedure. Therefore, when the interconnecting room doors were blocked open, the PBI program would not consider the potential of a HELB environment reaching the equipment behind the doors. Should a HELB occur while one or more of the interconnecting room doors were blocked open under an activity utilizing the PBI procedure, a single active failure of the L-wall HELB barrier could result in unanalyzed equipment damage or a loss of safety function. The following interconnecting room doors were determined to be potentially affected:

- Door D-463 Separating the Unit 1 Division 11 and Division 12 MEERs;
- Door D-370 Separating the Unit 1 Division 11 and Division 12 4kV ESF Switchgear Rooms;
- Door D-542 Separating the Unit 2 Division 21 and Division 22 MEERs;
- Door D-474 Separating the Unit 2 Division 21 and Division 22 4kV ESF Switchgear Rooms.

The licensee entered this issue into their CAP as IR 1242942. Corrective actions included a revision to the station's PBI procedure to ensure that these barrier doors were considered a HELB boundary. On July 22, 2011, compensatory measures that prescribed a review of the impact on HELB when impairing these doors were also implemented.

Analysis: The failure to ensure that design basis assumptions for plant barrier doors were correctly translated into station procedures was a performance deficiency.

The performance deficiency was determined to be more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," because it was associated with the Protection Against External Events attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to imitating event to prevent undesirable consequences (i.e., core damage). Specifically, if these doors had been impaired during a design basis turbine building HELB event with an active single failure of a HELB isolation damper, both electrical divisions in the ESF Switchgear Rooms or MEERs could have been adversely affected by the harsh steam environment.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase - 1 Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. Specifically, the inspectors answered 'No' to all of the Mitigating Systems Cornerstone questions in Table 4a of IMC 0609.04 and, as a result, the finding screened as having very low safety significance (Green).

Due to the age of this issue, it was not reflective of current licensee performance and therefore the inspectors did not assign a cross-cutting aspect to this finding.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, and as specified in the licensee application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, as of July 22, 2011, the station had not translated design basis requirements for HELB boundaries, which were components included in Appendix B, into procedures and instructions. Specifically, the station lacked procedures and instructions to ensure that safety-related doors were evaluated as a HELB boundary during a planned or unplanned impairment accompanied by a single active failure of a ventilation damper to shut as required by the licensee's HELB licensing basis.

Corrective actions for this issue included a revision to the station's PBI procedure to ensure that these barrier doors were considered HELB boundaries. Compensatory measures that prescribed a review of the impact on HELB when impairing these doors

were also implemented. Because the associated finding was of very low safety significance and because the issue has been entered into the licensee's CAP as IR 1242942, this violation is being treated as a NCV in accordance with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2011004-03; 05000457/2011004-03, Failure to Control HELB Barrier Doors)**

(2) Operability Evaluation Not Performed in Accordance with Station Standards

Introduction: The inspectors identified an URI related to multiple quality and process issues pertaining to Operability Evaluation, "IR 1185016, Non-Conservatisms in the Turbine Building HELB Analyses." At the conclusion of this inspection, the licensee had not completed their review of the issue.

Description: During a review of Operability Evaluation, "IR 1185016, Non-Conservatisms in the Turbine Building HELB Analyses," the inspectors identified a number of issues, questions, and aspects that required additional inspection effort.

The inspectors identified several aspects of the operability evaluation that did not adhere to the station's operability determination process as described in procedure OP-AA-108-115, "Operability Determination." The following specific issues were identified:

- The evaluation did not evaluate the non-conforming condition against the plant's licensing basis single failure criterion;
- The evaluation did not adequately consider a pipe leak in accordance with licensing basis standards;
- The station did not perform an adequate extent of condition review. In particular, the inspectors identified a similar L-wall damper penetration from the turbine building into the safety-related lower cable spreading room that could be affected by a turbine building HELB.
- For MEER 12 and MEER 22, the licensee did not evaluate the consequences of a turbine building HELB and isolation damper failure. These rooms contained both trains of Unit 1 and Unit 2 reactor trip breakers, respectively.
- The evaluation was not stand alone as described in Section 4.4.2, which required that, "The Operability Evaluation should contain sufficient detail for a knowledgeable individual to independently reach the same conclusions as the Preparer (i.e., the OpEval must be able to stand alone)."

This URI will remain open pending the licensee's completion of the operability evaluation review efforts regarding the non-conforming conditions, the inspector's review of those efforts, an independent extent of condition review conducted by the inspectors, and a review of the licensee's corrective actions to restore compliance with the licensing basis. **(URI 05000456/2011004-04; 05000457/2011004-04, Operability Evaluation Not Performed in Accordance with Station Standards)**

(3) (Closed) Unresolved Item 05000456/2011003-06; 05000457/2011003-06, Asiatic Clams Identified in the Essential Service Water System Supply to the Auxiliary Feedwater System

Introduction: A finding of very low safety significance (Green) and an associated NCV of TS 3.7.5, "Auxiliary Feedwater System," was self-revealed when, on various occasions between March and July 2011, asiatic clam shells were identified in the 2A AF pump SX suction piping. Specifically, the asiatic clam shells in the SX suction piping were of sufficient size to interfere with flow through the downstream steam generator flow control valves, which rendered the 2A AF pump inoperable for greater than the 72-hour Allowed Outage Time (AOT) prescribed by TS 3.7.5. This condition was determined to likely have existed since the late 1990's.

Description: On March 30, 2011, the licensee commenced a work activity to install a vent line in the SX suction piping to the 2A AF pump between valves 2AF007A and 2AF016A through WO 1411306. The vent line was being installed to enable the licensee to fill and vent a voided portion of the suction piping to address NRC concerns that the void could adversely affect the 2A AF pump. The licensee performed a borescope inspection following vent valve installation to ensure that no metal shavings remained in the pipe. However, approximately 8 square inches of asiatic clam shells were unexpectedly identified (see IR 1194353). The licensee did not inspect the entire 13-foot piping segment between 2AF007A and 2AF016A because the borescope was only 3 feet long and the licensee did not attempt to obtain a longer borescope. However, a flush of the line was subsequently performed using a 3/4-inch hose and filter basket to collect any additional shells. The flush failed to remove any additional shells, the licensee concluded that all of the shells in the line must have been removed, and the system was declared operable. A formal operability evaluation completed on May 3, 2011, through EC 384321 concluded that based on the 8 square inches of shells removed, the system was never inoperable.

On May 9, 2011, the licensee performed a routine surveillance that cycled open and closed the 2AF006A and 2AF017A valves. A drain path was opened during the surveillance and the water passed through a filter basket before entering the floor drain system. During the surveillance, approximately 41 square inches of asiatic clam shells were identified in the 2A AF suction piping. The licensee initiated IR 1213669 and declared the system inoperable. The piping segment was re-flushed with no additional shells removed. The licensee again concluded that since all shells were apparently removed, the system was operable. On May 20, 2011, the licensee formally concluded that the past operability of the 2A AF train could not be supported with the larger amount of shells identified. The licensee determined that the shells could plug the steam generator AF flow control valves and subsequently submitted Event Notification 46868 to the NRC to report an unanalyzed condition as required by 10 CFR 50.72(b)(3)(ii)(B). This unanalyzed condition was also reported in LER 05000457/2011-001-00, which was submitted on July 19, 2011 in accordance with 10 CFR 50.73(a)(2)(i)(B), 10 CFR 50.73(a)(2)(ii)(B), and 10 CFR 50.73(a)(2)(v)(B).

The licensee initiated corrective actions to flush all AF trains on both units to identify any additional asiatic clam shells. A root cause evaluation associated with the identification of asiatic clam shells in March and May was completed on June 30, 2011. The inspectors opened URI 05000456/2011003-06; 05000457/2011003-06 to review the

licensee's root cause evaluation. The root cause evaluation concluded that the shells were removed and did not represent a current operability concern.

On July 7, 2011, a small amount (one square inch) of shells was identified during a flush of the 2A AF train. As a result, Engineering personnel requested additional flushing activities be performed. Additional flushing activities were performed on July 14 and more than 41 square inches of shells were removed. Based on this result, the licensee concluded that additional borescoping was necessary and would include all potentially affected piping. This more comprehensive borescope inspection found additional shells in several locations. The licensee used hydrolazing to remove the remaining clam shells and performed a final borescope inspection. Two pieces of shells were unable to be removed, but the licensee concluded they would not impact the downstream steam generator flow control valves. The system was declared operable on July 16, 2011. The licensee reported the additional inoperability of the 2A AF train in LER 05000457/2011-002-00, which was submitted on September 12, 2011, in accordance with 10 CFR 50.73(a)(2)(i)(B) and 10 CFR 50.73(a)(2)(v)(B).

The NRC issued Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety Related Equipment," on July 18, 1989 to address biofouling of service water systems. The GL required licensees to, among other things, implement and maintain a program to significantly reduce the incidence of flow blockage problems as a result of biofouling of open-cycle service water systems. Item III of the licensee's GL 89-13 program required, in part, that the licensee, "Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water." This Item was accomplished through implementation of licensee procedure BwVP 850-15, "Essential Service Water System Performance Monitoring," Revision 6. Step E.1.3.9 of that procedure stated that the SX/AF crosstie lines were monitored through the erosion/corrosion program.

The inspectors also reviewed the licensee's root cause and apparent cause evaluations, which noted that GL 89-13 modifications were installed to permit flushing of the SX system low flow areas, but did not include flushing of the area between the AF006 and AF017 valves. Based on the 2A train AF/SX crosstie piping conditions identified in March 2011, in May 2011, and in July 2011, the inspectors determined that the licensee's GL 89-13 program had not prevented biofouling, which resulted in flow blockage.

The licensee entered this issue into their CAP as IR 1213669. Corrective actions included the removal of the asiatic clam shells from the 2A AF pump SX suction piping and completion of both an apparent cause and root cause evaluation.

Analysis: The inspectors determined that the failure to maintain the 2A AF pump SX suction piping free of asiatic clam shells that could adversely affect the downstream flow control valves was a performance deficiency.

The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, if the safety-related

suction source (i.e., SX) of the 2A AF train was required to be used, clam shells would have been transported through the 2A AF pump and could have adversely affected the steam generator flow control valves.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. The inspectors answered 'Yes' to the screening question, "Does the finding represent [an] actual loss of safety function of a single Train for > [greater than] its TS Allowed Outage Time?" since the inoperability of the 2A AF pump due to clam shells in the SX suction piping could have been present for at least 1 year. Therefore, a Phase 2 SDP evaluation was required using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The internal events risk contribution was determined to not be risk significant because the normal level of the condensate storage tank (CST) was such that the SX supply to the AF pumps would not be needed for the first 24 hours following an initiating event.

However, IMC 0609, Appendix A, Step 2.2.5, stated that the plant-specific SDP Phase 2 Worksheets did not include initiating events related to fire, flooding, severe weather, seismic, or other initiating events that were considered by the licensee's Institute of Electrical and Electronics Engineers analysis. Since the dominant risk was associated with external events, a Phase 3 analysis was required in order to estimate the risk significance of the issue. Therefore, a Region III Senior Reactor Analyst (SRA) performed a Phase 3 SDP evaluation of the finding. The SRA used the Braidwood Standardized Plant Analysis Risk (SPAR) model version 8.17, and SAPHIRE model Version 8.0.7.17, to perform the analysis.

The contributions and risk estimates from external events were evaluated as discussed below.

Evaluation of Seismic Risk

Seismic risk contributions were evaluated using guidance from the Risk Assessment of Operational Events (RASP) Handbook, Volume 2 – External Events, and using information regarding the seismic fragility of the CST. The generic seismic fragility referenced in the RASP Handbook for large flat bottom storage tanks (i.e., Table 4B-1 in Volume 2 of the Handbook) was not used, since the Braidwood CST was constructed of aluminum and thus has a lower fragility than the generic values provided in the RASP Handbook. The following seismic fragility information for the CST was utilized:

- Median of the CST Fragility (Median Capacity) = 0.5375;
- B_r = Logarithmic Standard Deviation Representing Random Uncertainty = 0.23
- B_u = Logarithmic Standard Deviation Representing Systematic Uncertainty = 0.24

Using the methodology in Volume 2, Section 4.0 of the RASP Handbook, three seismic event categories (i.e., seismic bins) were created. A bin acceleration for each of the three seismic bins was calculated using the geometric average of the two bin range limits. A mean bin frequency for each of the three seismic bins for Braidwood was determined using Table 4A-1, "Seismic Hazard Vectors of the 72 SPAR Plants," from the RASP Handbook, and calculating the difference of the frequencies of the two bin range limits from this table.

Using the seismic fragility information for the CST, a failure probability for the CST was then calculated for each of the three seismic bins. In a similar manner, a loss of offsite power probability was calculated for each of the three seismic bins based on generic fragility information provided in Table 4B-1, "Generic SSC Seismic Fragilities," of the RASP Handbook.

The results are provided in the Table below.

Bin #	Seismic g Range	Seismic Bin Acceleration	Seismic Bin Frequency	Prob [CST Failure]	Prob [LOOP]
1	0.05-0.3g	0.122	4.1E-4	4.1E-6	4.8E-2
2	0.3-0.5g	0.387	1.1E-5	1.6E-1	6.8E-1
3	>0.5g	0.707	4.1E-6	8.0E-1	9.4E-1

Other information that was used in the Phase 3 analysis is listed below:

- EDG Failure Probability = Prob [EDG Failure] = 4.60E-2 (calculated by solving the fault tree in the SPAR model for an EDG);

- SX Motor-Operated Valve (MOV) Failure Probability = Prob [SX Individual MOV Failure] = 1.6E-3 (obtained from NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," Page A-123);

- Diesel-Driven AF Pump (DDAFWP) Failure Probability = Prob [DDAFWP Failure] = 2.27E-2 (calculated by solving the fault tree in the SPAR model for the DDAFWP);

- "Feed and Bleed" as a method of core cooling was not credited [i.e., feed with high head safety injection and bleed through the Pressurizer Power Operated Relief Valves] per Table 4-3 of the RASP Handbook;

- The "A" Train of AF is failed any time that SX is the suction source for the 2A AFW Pump;

- The exposure time of the finding was taken to be 1 year;

- Using the information provided above, the following was calculated:

    - Prob [AFs Failure] = Prob [DDAFWP Failure] + Prob [SX Supply Failure];

    - Prob [SX Supply Failure] = Prob [SX MOV Failure] + Prob [No Power to SX MOVs];

    - Prob [SX MOV Failure] = Prob [Individual SX MOV Failure] x [2 MOVs in-series]
      = [1.6E-3]x[2]
      = 3.2E-3.

- The delta core damage frequency (ΔCDF) was calculated as:

  - ΔCDF = {(Seismic Bin Frequency) x Prob [CST Failure] x Prob [AFW Failure]}$_{Bin\ 1}$ +
    {(Seismic Bin Frequency) x Prob [CST Failure] x Prob [AF Failure]}$_{Bin\ 2}$ +
    {(Seismic Bin Frequency) x Prob [CST Failure] x Prob [AF Failure]}$_{Bin\ 3}$

The results are provided in the Table below:

Bin #	Seismic g Range	Seismic Bin Frequency	Prob [CST Failure]	Prob [AF Failure]	Frequency of CST Failure with Failure of AF (ΔCDF)
1	0.05-0.3g	4.1E-4	4.1E-6	2.8E-2	4.7E-11
2	0.3-0.5g	1.1E-5	1.6E-1	5.7E-2	1.0E-7
3	>0.5g	4.1E-6	8.0E-1	6.9E-2	2.3E-7
				ΔCDF (1/yr) =	**3.3E-7**

The result was a seismic ΔCDF risk contribution of 3.3E-7/yr.

Evaluation of Tornado Risk

To obtain the risk contribution due to tornado events, NUREG/CR-4461, Revision 2, "Tornado Climatology of the Contiguous United States," was used as a resource. Although the licensee provided an analysis concerning the ability of the CST to withstand tornado winds up to 151 mph, a bounding assumption was made that the CST would always fail if impacted by a tornado of intensity F2 or above (i.e., wind speed of 113 mph or greater).

From Appendix C of NUREG/CR-4461, Revision 2, the frequency of tornado events of wind speeds of 65 mph or greater was provided based on the latitude and longitude coordinate locations. The table below provides correction factors to account for tornados of intensity F2 or greater (i.e., wind speed of 113 mph or greater). As described in Appendix C, the total frequency of tornado events that would impact an object (e.g., the CST) was the sum of the point source contribution and the line source contribution (due to the width of the object). The width of the object assumed in Appendix C of NUREG/CR-4461, Revision 2, was 200 feet. Since the diameter of the CST at Braidwood was only 45 feet, the line source contribution of the frequency of a tornado impacting the CST was reduced by the ratio of 0.225 (i.e., 45 feet/200 feet = 0.225) from that provided in the table of Appendix C. Using the above information, a value of 3.6E-5/yr was calculated for the frequency of an F2 tornado or greater of impacting the CST and rendering the CST unavailable (see Table below).

Braidwood			
	Frequency of Tornado Events of Wind Speed 65 mph or greater (>)	**Probability of Tornado of Intensity F2 or greater (>)**	**Frequency of Tornado Events of F2 or greater (>)**
Point Contribution	**3.022E-4/year**	**0.1 (Note a)**	**3.0E-5/yr [F2 or >]**
Line Contribution	**1.271E-4/year if CST was 200 feet wide**		
	2.86E-5/year for actual width of CST of 45 feet	**0.2 (Note b)**	**5.7E-6/yr [F2 or >]**
Total			**3.6E-5/yr [F2 or >]**

Notes:

a. The value of 0.1 was obtained from Figure 5.2 of NUREG/CR-4461, Revision 2

b. The value of 0.2 was obtained from Figure 5.3 of NUREG/CR-4461, Revision 2

It was assumed that a tornado of intensity F2 or above that impacted the CST would also result in a loss of offsite power.

Other information that was used in the Phase 3 analysis is listed below:

- EDG Failure Probability = Prob [EDG Failure] = 4.60E-2 (calculated by solving the fault tree in the SPAR model for an EDG);

- (SX Motor-MOV Failure Probability =
  Prob [SX Individual MOV Failure] = 1.6E-3 (obtained from NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," page A-123);

- Diesel-Driven AF Pump (DDAFP) Failure Probability =
  Prob [DDAFP Failure] = 2.27E-2
  (calculated by solving the fault tree in the SPAR model for the DDAFP);

- The "A" Train of AF is failed any time that SX is the suction source for the 2A AF Pump;

- The exposure time of the finding was taken to be one year;

- Using the information provided above, the following was calculated:

  - Prob [AF Failure] = Prob [DDAFP Failure] + Prob [SX Supply Failure];

  - where Prob [SX Supply Failure] = Prob [SX MOV Failure] + Prob [EDG Failure];

- Prob [SX MOV Failure] = Prob [Individual SX MOV Failure] x [2 MOVs in-series]

  = [1.6E-3] x [2]
  = 3.2E-3

- Therefore: Prob [AF Failure] = [2.27E-2] + [3.2E-3] + [4.60E-2]
  = 7.2E-2.

The SPAR model was used to obtain an estimate of the Conditional Core Damage Probability for an initiating event of a Loss of Offsite Power - Weather-Related (IE-LOOP WR), with an assumed loss of all AF pumps, and with an assumed failure to recover offsite power. The result was a Conditional Core Damage Probability of 2.86E-2.

Using the estimated frequency of a tornado impacting the CST [3.6E-5/yr], multiplied by the probability of AF failure [7.2E-2], and then multiplied by the Conditional Core Damage Probability value described above [2.86E-2], a value of 7.4E-8/yr for the tornado delta CDF risk contribution was obtained.

Evaluation of Fire Risk

Inspection Manual Chapter 0609, Appendix A, Attachment 3 was used to evaluate screening of other external event contributions. The risk contribution due to a fire did not screen out because the SX valves for the AF pumps (i.e., 2AF006A, 2AF006B, 2AF017A, and 2AF017B) were included in the licensee's Appendix R Fire Safe Shutdown Analysis.

However, the fire risk contribution was evaluated to not be risk significant. The fire risk contribution was not risk significant because the normal level of the CST was such that the SX supply to the AF pumps was not needed for the first 24 hours following an initiating event due to a fire.

Evaluation of Flooding Risk

Internal flood risk contributions were screened using IMC 0609 Appendix A, Table 3.1, "Plant Specific Flood Scenarios." The guidance listed structures, systems, and components (SSCs) important to internal flooding and it did not contain any SSC at Braidwood.

Thus, the total delta CDF was the sum of the seismic contribution [3.3E-7/yr] and the contribution due to a tornado [7.4E-8/yr] or 4.0E-7/yr.

The potential risk contribution for this finding from large early release frequency (LERF) was screened using the guidance in IMC 0609 Appendix H, "Containment Integrity Significance Determination Process." Braidwood is a pressurized water reactor with a large dry containment. Sequences important to LERF include steam generator tube rupture events and inter-system loss of coolant accident events. These were not the dominant core damage sequences for this finding.

Therefore, based on the Phase 3 analysis, the finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the CAP component of the Problem Identification and Resolution cross-cutting area [P.1(c)] since the licensee failed to thoroughly evaluate the identification of asiatic clam shells in the 2A AF SX suction piping in March 2011 and May 2011 and, as a result, implemented corrective actions that were inadequate.

Enforcement: Braidwood Unit 2 TS 3.7.5 required that two AF trains shall be operable. If one train of AF is inoperable, Condition A of TS 3.7.5 required that the inoperable train be restored to an operable status within 72 hours and Condition B required that, if Condition A was not completed, the Unit shall be in Mode 3 within 6 hours and Mode 4 within 12 hours. Additionally, Condition C of TS 3.7.5 required that if two trains of AF are inoperable, action must be initiated immediately to restore one AF train. Contrary to the above, from approximate 2000 to May 20, 2011, asiatic clam shells in the 2A AF suction piping from the SX system rendered the 2A AF train inoperable and Condition A, B and C of TS 3.7.5 were not followed. Specifically, the licensee did not restore the inoperable train or place the unit in Mode 3 or 4 within the TS required time period when the 2A AF train was inoperable. In addition, due to maintenance activities on the 2B AF train during that time period, there were instances where two AF trains were inoperable without immediate actions taken to restore one of them.

Corrective actions for this issue included the removal of the clam shells from the 2A AF pump SX suction piping and completion of both an apparent cause and root cause evaluation. Because the associated finding was of very low safety significance and because the issue was entered into the licensee's CAP as IR 1213669, this violation is being treated as a NCV in accordance with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000457/2011004-05, Asiatic Clams Identified in the SX System Supply to the AF System)**

Unresolved Item 05000456/2011003-06; 05000457/2011003-06 is closed.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modifications:

- EDG Backdraft Dampers (Temporary Configuration Change);
- MEER Ventilation, Switchgear Heat Removal, and EDG Room Ventilation Differential Pressure Trips Bypassed or Delayed (Temporary Configuration Change);
- AF Train 'A' Unit 1 and 2 Cross-Tie (Permanent Modification); and
- Bus 156 B-C 120V Transformer Failure (Temporary Configuration Change).

The inspectors compared the configuration changes and associated 10 CFR 50.59 safety evaluation screening with the design basis, the UFSAR, and the TSs, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-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. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the plant modification could impact overall plant performance. Documents reviewed are listed in the Attachment.

This inspection constituted four temporary and permanent plant modification samples as defined in IP 71111.18-05.

b. Findings

Modification of the Auxiliary Feedwater System Without NRC Approval

Introduction: A finding of very low safety significance (Green) and an associated Severity Level IV NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," was identified by the inspectors when licensee personnel failed to obtain a license amendment prior to implementing a proposed change to the plant that resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the UFSAR. Specifically, the licensee performed a modification to the facility that permitted the Unit 1 and Unit 2 'A' AF trains to be shared between units and the 10 CFR 50.59 evaluation that was performed reached the erroneous conclusion that prior NRC approval was not required.

Description: Engineering Change 362168, Revision 0, dated August 7, 2008, approved the installation of a modification to add a crosstie line between the Unit 1 and Unit 2 'A' AF trains to permit the sharing of the Unit 1 and Unit 'A' AF trains between the Units. The inspectors selected an IR for a more detailed review that questioned whether this plant modification required NRC review and approval prior to implementation. Issue Report 1232153 referenced operating experience (OpEx) from another licensee facility which discussed an NRC-identified violation on the sharing of a service water system between Units (reference NRC Integrated Inspection Report 05000369/370-2011002, issued May 6, 2011). The IR stated, in part, that "The concerns raised by the NRC [in the referenced NRC inspection report] which resulted in the NCV appear to be consistent with the Byron/Braidwood modifications and subsequent incorporation into station procedures, A-Train AF crosstie line modifications." On June 28, 2011, the licensee's conclusion in the IR stated that "…the McGuire finding does not apply to the AF crosstie modification at B/B [Byron and Braidwood]."

After the licensee concluded the OpEx did not apply to the AF crosstie modification, the inspectors began reviewing background material related to the AF crosstie modification. The inspectors determined that the licensee's AF crosstie modification created a shared system that had not previously existed and was not described in the UFSAR or other licensing basis documents. In addition, the inspectors determined that the processes and procedures for placing the opposite unit's 'A' train of AF in service for the accident unit resulted in the non-accident unit losing the redundancy and diversity of the AF system that would otherwise have been available if the Unit 1 and Unit 2 'A' AF trains were not crosstied. The crosstie piping was isolated with the use of two manual closed and locked isolation valves and was controlled by the licensee's Emergency Operating

Procedures (EOPs). With the use of two manually closed isolation valves separating the Unit 1 and Unit 2 'A' train AF pumps from each other, the crosstie would only be open during the implementation of certain portions of Braidwood EOP 1/2BFR H.1, "Loss of Secondary Heat Sink."

In the 10 CFR 50.59 evaluation, approved on October 6, 2008, for the AF crosstie modification and associated EOP 1/2BFR H.1, the licensee determined that the modification and the procedure change did not result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system and component important to safety previously evaluated in the UFSAR. However, based on the loss of redundancy and diversity when the crosstie was implemented, the inspectors determined that the modification and procedure change did, in fact, result in more than a minimal increase in the likelihood of occurrence of a malfunction of the AF system of the donor (non-accident) unit. Therefore, prior NRC approval was required for the licensee to utilize the crosstie, but had not been requested.

The inspectors determined that this issue did not affect the operability of the AF system because the licensee required that prior to use of the crosstie, both of the non-accident unit AF trains be operable. This would have ensured that at least one train of the AF system was available for use on the non-accident unit. The AF crosstie modification had not been used by the licensee as it would have required a beyond design basis event (loss of both trains of AF on one unit) with entry into EOP 1/2BFR H.1, and no such event had occurred.

In addition to initiating IR 1258017, as part of their corrective actions the licensee issued a Standing Order, which had the effect of modifying EOP 1/2BFR H.1. The licensee planned to submit a License Amendment Request (LAR) to the NRC for this design change by mid-December 2011.

Analysis: The inspectors determined that the failure to perform an adequate 10 CFR 50.59 evaluation and obtain a license amendment prior to implementing the portion of EOP 1/2BFR H.1 that utilized the crosstie between the Unit 1 and Unit 2 'A' AF pumps was a performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors evaluated the issue using the traditional enforcement process and assessed the significance of the underlying issue using the SDP.

Violations of 10 CFR 50.59 are dispositioned using the traditional enforcement process instead of the SDP because they are considered to be violations that potentially impede or impact the regulatory process. However, if possible, the underlying technical issue is evaluated under the SDP to determine the severity of the violation. In this case, the inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Tables 4a, for the Mitigating Systems Cornerstone. The inspectors answered 'Yes' to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that this was a change confirmed not to result in the loss of operability. Based upon this Phase 1 screening, the inspectors concluded that the finding was of very low safety significance (Green).

Therefore, in accordance with Section 6.1.d.2 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the resulting changes were evaluated by the SDP as having very low safety significance (Green).

This finding had a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution cross-cutting area [P.2.(b)] because the licensee failed to make adequate use of known industry operating experience in the screening of a modification prior to installation.

Enforcement: 10 CFR 50.59, "Changes, Tests, and Experiments," Section (c)(2)(ii), requires, in part, that the licensee obtain a license amendment prior to implementing a proposed change to the plant that would result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the UFSAR. Engineering Change 369972 approved a modification to add a crosstie line between the Unit 1 and Unit 2 "A" AF trains to permit the sharing of the Unit 1 and Unit 2 'A' AF trains between the Units and the modification was subsequently installed. The crosstie piping was isolated with the use of two manual closed and locked isolation valves and was controlled by EOP 1/2BFR H.1, "Loss of Secondary Heat Sink."

Contrary to the above, on October 6, 2008, the licensee mistakenly concluded in the 10 CFR 50.59 evaluation that the AF modification and the implementation of a crosstie line between the Unit 1 and Unit 2 "A" AF trains to permit the sharing of the Unit 1 and Unit 2 'A' AF trains did not require a licensee amendment and subsequently implemented Engineering Change 369972 and the associated EOP 1/2BFR H.1 change. Specifically, this modification and procedure change resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the UFSAR based on the loss of redundancy and diversity when the crosstie was implemented and thus required a licensee amendment prior to its implementation.

In accordance with the Enforcement Policy, the violation was classified as a Severity Level IV violation because the underlying technical issue was of very low safety significance. The licensee planned to submit a LAR to the NRC to address this issue. Because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as 1258017, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000456/2011004-06; 05000457/2011004-06, Modification of the AF System Without Prior NRC Approval)

As stated above, the underlying technical issue was evaluated separately from the traditional enforcement violation and, therefore, the finding is being assigned a separate tracking number. **(FIN 05000456/2011004-07; 05000457/2011004-07; Modification of the AF System Without Prior NRC Approval)**

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

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

- 2PT-507 Pressure Transmitter Replacement;
- Unit 2 Train ‘A’ EDG #1 Air Compressor Repair;
- Unit 0 Train ‘A‘ Fire Protection Jockey Pump Repair;
- Lake Screen House Traveling Water Screens Control Power Failure;
- Unit 1 Train ‘D‘ Steam Generator Level Controller Repair;
- Unit 1 Steam Dump Controller Repair;
- Unit 1 Train ‘A’ EDG Following Work Window; and
- Unit 2 Station Auxiliary Transformer Following 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 TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings 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:

- Unit 2 Train ‘A’ AF Alternate Suction Piping Flush (Routine);
- Reactor Containment Fan Coolers Surveillance Methodology and Frequency Change (Routine);
- Unit 1 Train ‘A’ EDG ESF Relay Start (Routine);
- Unit 2 Train ‘A’ EDG ESF Relay Start (Routine);
- Unit 1 Train ‘B’ AF Pump ASME (Inservice Testing); and
- Unit 2 Train ‘B’ AF Pump ASME (Inservice Testing).

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 was 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, American Society of Mechanical Engineers (ASME) code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment.

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

b. Findings

Failure to Adhere to Maintenance Rule Procedure

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” when licensee personnel failed to adhere to licensee

procedure ER-AA-310, “Implementation of the Maintenance Rule.” Specifically, the licensee failed to adhere to the requirements of procedure ER-AA-310 when crediting availability of the Unit 1 and Unit 2 ‘B’ train AF pumps by not having documented restoration actions (i.e. Risk Management Actions (RMAs)) during quarterly in-service testing surveillances that involved the manual cycling of cooling water valves.

Description: On August 15, 2011, the inspectors observed routine surveillance testing of the 2B AF pump in accordance with licensee procedure 2BwOSR 5.5.8.AF-3B, “Group A Inservice Testing (IST) Requirements for Unit Two Diesel Driven Auxiliary Feedwater Pump,” Revision 9. The surveillance activity included the manual cycling of the following four valves associated with SX cooling to AF pump components:

- 2SX2103B: 2B AF Pump Oil Cooler Essential Service Water Inlet Isolation Valve;
- 2SX2186: 2B AF Pump Oil Cooler Essential Service Water Outlet Valve;
- 2SX2190: 2B AF Pump Right Angle Gear Lube Oil Cooler Inlet Valve; and
- 2SX2192: 2B AF Pump Right Angle Gear Lube Oil Cooler Outlet Valve.

During the surveillance, the 2B AF pump was considered inoperable, but available and TS Limiting Condition for Operation (LCO) 3.7.5 was entered. However, cycling the four SX cooling valves closed rendered the 2B AF pump unavailable to perform its safety function for the duration of its mission time. The inspectors reviewed licensee procedure ER-AA-310, “Implementation of the Maintenance Rule,” which defined unavailability in cases of maintenance or testing. Specifically, ER-AA-310 stated, “SSCs out-of-service for testing are considered unavailable, unless the test configuration is automatically overridden by a valid start signal, or the function can be restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair.”

At Braidwood, credited restoration actions were contained in an Excel spreadsheet controlled by licensee probabilistic risk analysts and accessed from the Operations Department website. The spreadsheet was organized by surveillance procedure, such that restoration actions for a surveillance procedure were documented under the procedure number. The supervisor briefing the surveillance briefed the restoration actions in the spreadsheet to the workers during the pre-job briefing. While observing the surveillance, the inspectors obtained a copy of the documented restoration actions for procedure 2BwOSR 5.5.8.AF-3B, and questioned the information contained in the restoration actions spreadsheet. Specifically, the spreadsheet listed the following documented restoration actions for Procedures BwOSR 5.5.8.AF-3A and BwOSR 5.5.8.AF-3B as follows:

- SURV(s): BwOSR 5.5.8.AF-3A and BwOSR 5.5.8.AF-3B.

Pre Job Brief topics: The operator assigned to perform the following actions on AF01PA must be in continuous communications with the control room:

- Operate SX2102 as required;
- Operate SX2103A as required; and
- See BwOP Auxiliary Feedwater-5 and 6 or BwOP AF-7 and 8.

The inspectors and licensee personnel noted that, while the surveillance affected the 2B AF pump, the documented restoration actions directed operators to manipulate valves associated with only the 2A AF pump. There were no documented restoration actions for the 2B AF pump. Licensee personnel indicated that operators verbally discussed restoration actions for the 2B AF pump during the pre-job brief and that the operators understood the restoration actions.

The inspectors reviewed the surveillance history. In 2009, procedure BwOSR 5.5.8.AF-3B superseded Procedure BwVSR 5.5.8.AF.2, which dated back to the 1990's and included the same four valves that would render the 'B' train AF pump unavailable absent RMAs. The inspectors also reviewed prior revisions to the Pre-Job Brief Excel spreadsheet. The inspectors noted that all versions of the spreadsheet, including the current revision (Revision 8), omitted the 'B' train restoration actions when performing the AF 'B' train ASME surveillance. Based on this historical review, the inspectors determined the issue dated back to at least 2006. Performance of the procedure steps that would result in unavailability of the 'B' train AF pump absent RMAs occurred once per year for each pump. Thus, the inspectors concluded that procedure BwOSR 5.5.8.AF-3B or BwVSR 5.5.8.AF.2 were performed at least 12 times without documented restoration actions. The inspectors were not aware of any CAP documents regarding the missing restoration actions and could not determine whether the required RMAs were appropriately briefed and understood during prior performances of the surveillance.

The inspectors concluded that the lack of documented restoration actions for the 'B' train AF ASME surveillance procedures, combined with crediting operator restoration actions for availability, resulted in a failure to meet the procedure definition of unavailability in licensee procedure ER-AA-310. Per procedure ER-AA-310, equipment unavailable for testing cannot be considered available without restoration actions in a written procedure.

The licensee entered this issue into the CAP as IR 1251652 on August 15, 2011, and took immediate corrective actions to revise the applicable portion of the Excel spreadsheet that documented restoration actions. The licensee was also considering a more robust process for documentation of restoration actions to credit equipment availability.

Analysis: The inspectors determined that the failure to adhere to Procedure ER-AA-310, "Implementation of the Maintenance Rule," was a performance deficiency.

The performance deficiency was determined to be more than minor because it was associated with the Procedure Quality attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of system that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, procedural requirements to credit the availability of the Unit 1 and Unit 2 'B' train AF pumps were not met.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase - 1 Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. The inspectors answered 'No' to all of the Mitigating Systems Cornerstone questions in Table 4a of IMC 0609.04 and, as a result, the finding screened as having very low safety significance (Green).

This finding had a cross-cutting aspect in the Work Control component of the Human Performance cross-cutting area [H.2(c)] since during performance of the 1B and 2B AF pump surveillances that involved the manual cycling of cooling water valves, the licensee did not have complete and accurate documentation related to the implementation of RMAs for these surveillances.

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Licensee Procedure ER-AA-310, "Implementation of the Maintenance Rule," stated, in part, that "SSCs out-of-service for testing are considered unavailable, unless the test configuration is automatically overridden by a valid start signal, or the function can be restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair."

Contrary to the above, as of August 15, 2011, the licensee failed to have a documented procedure which addressed restoration of the 2B AF pump, a safety-related component, during surveillances. Specifically, the licensee credited pump 2B AF as being available during surveillances BwOSR 5.58.AF-3B and BwVSR 5.58.AF.2; however, no restoration steps were documented to meet the availability criteria specified in Procedure ER-AA-310.

The licensee took immediate corrective actions to revise the applicable portion of the Excel spreadsheet that documented restoration actions. The licensee was also considering a more robust process for documentation of restoration actions to credit equipment availability. Because this violation was of very low safety significance and because this issue was entered into the licensee's CAP as 1251652, this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2011004-08; 05000457/2011004-08, Failure to Follow Maintenance Rule Procedure)**

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 September 14, 2011, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Technical Support Center and Operations 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 CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment.

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

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI for both Unit 1 and Unit 2 for the period from the third quarter 2010 to the second quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, and NUREG-1022, “Event Reporting Guidelines 10 CFR 50.72 and 10 CFR 50.73," definitions and guidance, were used. The inspectors reviewed the licensee’s operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, event reports and NRC Integrated Inspection Reports for the period of July 1, 2010, through June 30, 2011, to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s Issue Report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two safety system functional failures samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency Alternating Current (AC) Power System performance for both Unit 1 and Unit 2 for the period from the third quarter 2010 to the second quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, was used. The inspectors reviewed the licensee’s operator narrative logs, MSPI derivation reports, issue reports, event reports, and NRC Integrated Inspection Reports for the period of July 1, 2010, through June 30, 2011, to validate the accuracy of the submittals. The inspectors

reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's Issue Report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Heat Removal System PI for both Unit 1 and Unit 2 for the period from the third quarter 2010 to the second quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of July 1, 2010, through June 30, 2011, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's Issue Report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Residual Heat Removal System PI for both Unit 1 and Unit 2 for the period from the third quarter 2010 to the second quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of July 1, 2010, through June 30, 2011, to validate the accuracy of the submittals.

The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's Issue Report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI residual heat removal system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for both Unit 1 and Unit 2 for the period from the third quarter 2010 to the second quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period July 1, 2010, through June 30, 2011, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's Issue Report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151-05.

b. Findings

No findings 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. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities

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

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Selected Issue Follow-up Inspection: Auxiliary Feedwater Essential Service Water Supply Voided Zone Root Cause

a. Inspection Scope

The inspectors reviewed the root cause evaluation for voids that were included by design in the AF alternate suction piping, which was previously discussed in Byron Special Inspection Report 05000454/2011015; 05000455/2011015; and Braidwood Special Inspection Report 05000456/2011012; 05000457/2011012. The root cause evaluation characterized the root cause as "failure to perform an adequate technical evaluation resulted in inappropriate delays correcting a non-compliance with industry standards (e.g., GL [Generic Letter] 2008-01, Industry Operating Experience, IN [Information Notice] 2007-18, and other operating experience) for quantitatively evaluating void impact on the AF pumps." The licensee developed corrective actions to

prevent recurrence that included training of engineering personnel on the use of quantitative rather than qualitative inputs to evaluations, the risk of using dated technical information and timely effective communication using CAP.

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

b. Findings

(Closed) Unresolved Item 05000456/2011012-01; 05000457/2011012-01, Design of Auxiliary Feedwater System Included Voids in Safety Related Alternate Suction Flow Paths

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors when licensee personnel failed to properly analyze the configuration of the SX connections to the AF pumps. Specifically, a section of the piping was intentionally maintained empty (voided), but had not been previously analyzed. This condition existed since initial plant construction.

Description: While observing a routine surveillance of the Byron Unit 2 Train B AF pump, the Byron resident inspectors identified that a section of pipe was voided. This section of pipe was maintained empty per the plant design to allow for the detection of leakage past either of the two isolation valves, 2AF006B and 2AF0017B. This issue was applicable to Braidwood Station and was the subject of a special inspection (See NRC Special Inspection Report 05000454/455/2011016; 05000456/05000457/2011012).

Conversations with the system engineer revealed that the licensee had investigated this issue in 1993. In correspondence between the licensee and the pump vendor, dated May 28, 1993, the vendor indicated that there would be no loss of net positive suction head due to the SX pressure at the suction of the AF pump being approximately 80 pounds per square inch gauge (psig). The vendor stated that a 1.5 cubic foot slug of air at 80 psig would not damage the pump as it passed through it. The correspondence made no mention of system performance or an assessment of system impacts. The correspondence did make reference to a position that was established on August 27, 1987, for a different licensee with unknown equipment and with an unknown configuration. That position concluded that 1.5 cubic feet of air at 80 psig would not damage the AF pump. The reference neither cited an analysis, calculation, or test as the basis for these conclusions. Licensee staff believed that tests were performed around the 1987 timeframe, but were unable to provide any information regarding the purpose of the tests, the configuration of equipment during the tests, type and qualification of equipment used, or copies of test reports and results. The licensee contacted the pump vendor who was also unable to locate any documentation to support the 1993 reference or the 1987 reference. In summary, the licensee failed to locate any calculations or test reports produced during original plant construction and installation onsite or evidence of analysis or testing prior to construction and installation onsite. The licensee entered this issue into the CAP as IR 1173517 and completed filling the voided pipe sections on February 15, 2011.

In order to address the lack of an analysis, test, or record, the licensee elected to perform testing of equipment of a similar type and configuration. The inspectors reviewed the new AF test methodology and results. The inspectors concluded that

the test provided reasonable assurance the AF pumps would not have been adversely affected by the presence of the voids previously located between isolation valves 1/2AF006A/B and 1/2AF017A/B. Therefore, the pumps were and remained operable regarding this issue. However, the test did not provide an adequate degree of certainty to be used for either design purposes nor to bound voids that could potentially be identified in the future under different circumstances. Specifically, the inspectors noted a number of limitations of the test including the following:

- Test methodology MPR 3575, "AF Pump Test Methodology," stated "Each test shall be repeated thrice to show repeatability." However, the actual test was not repeated for each test case. Therefore, the uncertainty associated with the test data could not be established for a number of the test cases.

- Test methodology MPR 3575 stated "After testing is complete, the test pump will be disassembled and inspected to determine its condition." The intent was to determine if the AF pumps had received any damage that would have prevented them from meeting their mission time. However, the licensee did not disassemble and inspect the test pump. The only rotor-dynamic parameters considered during the test were vibration and seal temperature, which were not sufficient to determine the axial and torsional impact of the void. However, because the pump was able to run for multiple short periods of time with multiple voids, there was reasonable assurance the pumps would have remained operable. That is, the pump likely would not have experienced adverse rotor-dynamic effects due to one void followed by a continuous operation for a relatively longer period of time, which was the condition of concern.

- The test data reported in MPR 3602, "Braidwood and Byron AF Pump Air Ingestion Test," indicated that pump performance degraded significantly for some test cases as the void passed through the pump and the head was quickly re-developed once the void exited the pump. However, the test did not directly simulate the effect of steam generator (SG) back pressure. Specifically, the SGs were at a relatively high pressure of about 1000 pounds per square inch absolute (psia). The pump's discharge check valve would close if its discharge pressure fell below that value. Some test cases indicated that the discharge pressure would have significantly decreased below the SG back pressure value. For past operability purposes, it appeared the void self-vented due to the piping configuration and SX system pressure. However, based on the testing methodology, it was not clear whether this would occur under all circumstances.

Analysis: The inspectors determined that the configuration of the SX connections to the AF pump was not verified analytically or by testing, which was contrary to design requirements and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of Design Control and affected the cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the unverified configuration might have rendered each of the AF pumps inoperable.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 4a, for the Mitigating Systems Cornerstone. The inspectors answered ‘Yes’ to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that the finding did not to result in a loss of operability. This conclusion was reached after reviewing tests performed by the licensee. The tests demonstrated there was reasonable assurance that the AF system would perform its safety function under the installed configuration. Based upon this Phase 1 screening, the inspectors concluded that the finding was of very low safety significance (Green). Additionally, the licensee filled the voided sections of pipe, restoring compliance with the licensed design basis.

Due to the age of this issue, it was not reflective of current licensee performance and therefore the inspectors did not assign a cross-cutting aspect to this finding.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures be provide for verifying the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Where a test program is used to verify the adequacy of a specific design feature in lieu of other verifying or checking processes, it shall include suitable qualifications testing of a prototype unit under the most adverse design conditions. Braidwood UFSAR, Section 3.2, "Classification of Structures, Components, and Systems," identified that Safety Category I Systems are intended to meet the requirements of 10 CFR Part 50, Appendix B. Table 3.2-1 identified the AF pumps as Safety Category I equipment.

Contrary to the above, prior to February 15, 2011, the licensee failed to establish measures to assure the adequacy of the design of the installed safety-related AF configuration. Specifically, no design reviews, calculations or suitable tests were performed to show that the presence of a voided section in the AF suction piping would not impact the ability of the AF system to perform its design function. To address this issue, the licensee filled the voided sections of piping.

Because this violation was of very low safety significance and it was entered into the licensee’s CAP as IR 1173517, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2011004-09; 05000457/2011004-09, Design of Auxiliary Feedwater System Included Voids in Safety Related Alternate Suction Flow Paths)**

Unresolved Item 05000456/2011012-01; 05000457/2011012-01 is closed.

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

.1 Unit 1 Down Power to Investigate Unidentified Leakage

The inspectors reviewed the licensee’s response to an increase in Unit 1 unidentified leakrate and containment airborne tritium levels. Specifically, over about a 1 week period, the Unit 1 unidentified leakrate increased from a baseline value of 0.053 gallons per minute (gpm) to approximately 0.189 gpm. Correspondingly, containment airborne tritium levels increased from a baseline value of approximately 0.264 derived air concentration (DAC) to approximately 0.580 DAC. In addition the license observed a positive increasing containment particulate radiation trend. The licensee performed

walkdowns of accessible areas of containment and used a robot to inspect inaccessible areas. The robot identified an area with suspected leakage and on July 13, 2011, the licensee reduced Unit 1 reactor power to approximately 20 percent to allow personnel to enter the non-accessible areas. Leakage was observed from Pressurizer Spray Bypass Valve 1RY8050, which was then isolated to stop the leakage. As a consequence to isolating valve 1RY8050, Pressurizer Spray Valve 1RY455B was also isolated. An Operations Standing Order was implemented to address operational consequences of an isolated pressurizer spray valve. Documents reviewed are listed in the Attachment.

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

.2 (Open) Licensee Event Report 05000456/2010-006-00; 05000457/2010-006-00, Technical Specifications Allowed Outage Time Extension Request for Component Cooling System Contained Inaccurate Design Information that Significantly Impacted the Technical Justification

The licensee submitted this LER on January 11, 2011 after identifying that a 1987 license submittal contained inaccurate information. Based on CC system design discrepancies that were known to exist since the mid-1980's, an incorrect modeling of the CC system was used in an early PRA. The PRA was one of the main justifications utilized by the licensee in a request to extend the TS LCO AOT for the CC system.

Administrative controls were implemented by the licensee as short-term corrective actions. These controls consisted of reducing the CC system AOT from 7 days to 72 hours, reducing the AOT for an inoperable residual heat removal train from 7 days to 72 hours, and prohibiting the Unit Common CC pump from being aligned as either unit's "B" train of CC. Additional corrective actions include proposed modifications to restore compliance with the current licensing basis. Pending partial or complete implementation of the proposed modifications, this LER will remain open.

After discussions with the Office of Enforcement, there was no violation of NRC requirements associated with the licensee's submittal of inaccurate information in the 1987 TS change request as the issue predates the effective date of 10 CFR 50.9 (EA-11-166).

.3 (Closed) Licensee Event Report 05000457/2011-001-00, Asiatic Clam Shells in Essential Service Water Supply Piping to the 2A Auxiliary Feedwater Pump Resulted in Auxiliary Feedwater System Inoperability

On May 9, 2011, the licensee performed a routine actuation test of the 2AF007A and 2AF016A valves, which isolated the SX suction piping from the 2A AF pump. During this testing, approximately 41 square inches of asiatic clam shells were identified in the suction piping. The licensee removed all the shells, declared the system operable since they believed all shells were removed and initiated a past operability determination.

On May 20, 2011, the past operability review concluded that the 2A AF train was not operable with the larger amount of shells found in the piping. The shells had the potential to pass through the 2A AF pump and block flow through the downstream flow control valves. The licensee made an Event Notification to the NRC under 10 CFR 50.72(b)(3)(ii)(B) as an unanalyzed condition and submitted LER 05000457/2011-001-00 on July 19, 2011.

The regulatory aspect of this issue is documented in Section 1R15.1.b of this report. Documents reviewed are listed in the attachment. This LER is closed.

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

.4 (Closed) Licensee Event Report 05000457/2011-002-00, Auxiliary Feedwater System Inoperability due to Additional Asiatic Clam Shells in Essential Service Water Supply Piping

On July 14, 2011, the licensee flushed the 2A AF pump suction piping between the 2AF006A and 2AF017A valves as an extent of condition activity following the discovery of asiatic clam shells earlier in the year. During the flushing activity, more than 41 square inches of shells were identified in the piping. That amount did not support past operability of the 2A AF train. The licensee performed troubleshooting that included additional flushing, borescope inspection inside the piping, and hydrolazing to remove remaining shells from the piping. On July 16, 2011, the 2A AF train was declared operable.

The licensee submitted LER 05000457/2011-002-00 on September 12, 2011, in accordance with 10 CFR 50.73(a)(2)(i)(B) and 10 CFR 50.73(a)(2)(v)(B) for a condition prohibited by TSs and an unanalyzed condition.

The regulatory aspect of this issue is documented in Section 1R15.1.b of this report. Documents reviewed are listed in the Attachment. This LER is closed.

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

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 5, 2011, the inspectors presented the inspection results to Mr. D. Enright and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of the LORT program inspection were discussed with Mr. D. Enright, Site Vice President, on September 2, 2011.

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

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Enright, Site Vice President
M. Kanavos, Plant Manager
P. Boyle, Maintenance Manager
S. Butler, Corrective Action Program Manager
R. Camerron, Licensed Operator Requalification Training Program Lead
P. Daly, Radiation Protection Manager
A. Daniels, Corporate Emergency Preparedness Manager
A. Ferko, Engineering Director
B. Finlay, Security Operations Manager
R. Hall, Environmental Supervisor
D. Lesnick, Emergency Preparedness Manager
M. Marchionda-Palmer, Operations Director
J. Moser, Radiation Protection Manager
R. Radulovich, Nuclear Oversight Manager
C. VanDenburg, Regulatory Assurance Manager

Nuclear Regulatory Commission

E. Duncan, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2011004-01 05000457/2011004-01	FIN	Failure to Adhere to Standards of Outdoor Secured Material Zones (Section 1R01.1.b)
05000456/2011004-02 05000457/2011004-02	URI	Use of Mesh Strainer Bags in Auxiliary Building Floor Drains (Section 1R06.1.b)
05000456/2011004-03 05000457/2011004-03	NCV	Failure to Control HELB Barrier Doors (Section 1R15.1.b.1)
05000456/2011004-04 05000457/2011004-04	URI	Operability Evaluation Not Performed in Accordance with Station Standards (Section 1R15.1.b.2)
05000457/2011004-05	NCV	Asiatic Clams Identified in the Essential Service Water System Supply to the Auxiliary Feedwater System (Section 1R15.1.b.3)
05000456/2011004-06 05000457/2011004-06	NCV	Modification of the Auxiliary Feedwater System Without Prior NRC Approval (Section 1R18.1.b)
05000456/2011004-07 05000457/2011004-07	FIN	Modification of the Auxiliary Feedwater System Without Prior NRC Approval (Section 1R18.1.b)
05000456/2011004-08 05000457/2011004-08	NCV	Failure to Follow Maintenance Rule Procedure (Section 1R22.1.b)

05000456/2011004-09 05000457/2011004-09	NCV	Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths (Section 4OA2.3.b)
05000456/2010-006-00 05000457/2010-006-00	LER	Technical Specifications Allowed Outage Time Extension Request for Component Cooling System Contained Inaccurate Design Information that Significantly Impacted the Technical Justification (Section 4OA3.2)

Closed

05000456/2011004-01 05000457/2011004-01	FIN	Failure to Adhere to Standards of Outdoor Secured Material Zones (Section 1R01.1.b)
05000456/2011004-03 05000457/2011004-03	NCV	Failure to Control HELB Barrier Doors (Section 1R15.1.b.1)
05000456/2011003-06; 05000457/2011003-06	URI	Asiatic Clams Identified in the Essential Service Water System Supply to the Auxiliary Feedwater System (Section 1R15.1.b.3)
05000457/2011004-05	NCV	Asiatic Clams Identified in the Essential Service Water System Supply to the Auxiliary Feedwater System (Section 1R15.1.b.3)
05000456/2011004-06 05000457/2011004-06	NCV	Modification of the Auxiliary Feedwater System Without Prior NRC Approval (Section 1R18.1.b)
05000456/2011004-07 05000457/2011004-07	FIN	Modification of the Auxiliary Feedwater System Without Prior NRC Approval (Section 1R18.1.b)
05000456/2011004-08 05000457/2011004-08	NCV	Failure to Follow Maintenance Rule Procedure (Section 1R22.1.b)
05000456/2011012-01 05000457/2011012-01	URI	Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths (Section 4OA2.3.b)
05000456/2011004-09 05000457/2011004-09	NCV	Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths (Section 4OA2.3.b)
05000457/2011-001-00	LER	Asiatic Clam Shells in Essential Service Water Supply Piping to the 2A Auxiliary Feedwater Pump Resulted in Auxiliary Feedwater System Inoperability (Section 4OA3.3)
05000457/2011-002-00	LER	Auxiliary Feedwater System Inoperability Due to Additional Asiatic Clam Shells in Essential Service Water Supply Piping (Section 4OA3.4)

Discussed

05000456/2010007-04 05000457/2010007-04	NCV	Adverse Impact on Flood Drain Strainer Design Modification on Flooding Analysis (Section 1R06.2)
05000456/2010-006-00 05000457/2010-006-00	LER	Technical Specifications Allowed Outage Time Extension Request for Component Cooling System Contained Inaccurate Design Information that Significantly Impacted the Technical Justification (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

IR 1246104; Loss of River Screen House CW Makeup Pumps; July 31, 2011
IR 1246999; 2PR17J Tripped Offline – High Temperature Alarm; August 2, 2011
IR 1247459; ASME Sect. XI, Grease Leakage Identified in Unit 1 Containment Wall; August 3, 2011
IR 1246870; IEMA Informed WEC of Unsecured Material in Secured Zone; August 2, 2011
IR 1249354; Work Rescheduled Due to Hot Weather Alert for the B-1-11 Wk; August 1, 2011
0BwOA ENV-1; Adverse Weather Conditions; Revision 13
1BwOA ENV-1; Adverse Weather Conditions; Revision 5

1R04Q Equipment Alignment

IR 1232672; NRC and IEMA Questions about GOCAR BWAP1110-1A2; June 24, 2011
IR 1232338; FHB Fire Hose Station Partially Obstructed; June 23, 2011
BwOP DC-E2; Electrical Lineup – Unit 1 - Operating 125V DC Division 11; Revision 7
BwOP DC-E5; Electrical Lineup – Unit 2 - Operating 125V DC Division 21; Revision 9
BwOP FPM1; Fire Protection Operating Mechanical Lineup in the Lake Screen House; Revision 13
BwOP FP-4; Startup and Shutdown of the Motor Driven Fire Pump; Revision 3
BwOP DG-11; Diesel Generator Startup; Revision 39

1R04S Equipment Alignment

IR 1227073; Potential Conflict Between DG & DO Tech Specs; June 09, 2011
IR 1230715; NRC Question Regarding 2A DG; June 20, 2011
IR 1231420; 1A DG Jacket Water Leak; June 21, 2011
IR1247281; NRC Identified that DG-11 Diesel Generator Startup Procedure Acceptance Criteria Frequency Band was Incorrect; August 3, 2011
IR 1258573; Fuel Oil Filter on 1A DG is Leaking; September 01, 2011
IR 1258653; Byron IR for DG 24 Hour Run Applicable to Braidwood; September 02, 2011
IR 1258666; Byron IR for DG Full Load Reject Applicable to Braidwood; September 02, 2011
IR 1261520; 1A DG Governor Response; September 10, 2011
BwOP DG-11; Diesel Generator Startup; Revision 39
BwOP DG-E1; Electrical Lineup Unit 1 1A Diesel Generator; Revision 007
BwOP DG-M1; Operating Mechanical Lineup Unit 1 1A Diesel Generator; Revision 16
BwOP DG-M2; Operating Mechanical Lineup Unit 1 1B D/G; Revision 16
1BwOSR 3.8.1.2-1; Unit One 1A Diesel Generator Operability Surveillance; Revision 31
1BwOSR 3.8.1.14-1; 1A Diesel Generator 24 Hour Endurance Run; Revision 4
1BwOSR 3.8.1.19-2; 1B Diesel Generator ECCS Sequence Surveillance; Revision 13

1R05 Fire Protection

IR 1232338; FHB Fire Hose Station Partially Obstructed; June 23, 2011
IR 1245929; 0B FP Revisit Issue 1235953; June 30, 2011
Braidwood Fire Protection Program
BwOP FP-100; Fire Response Guidelines; Revision 9
BwOP FP-100T41; Auxiliary Building Fire Zone 11.7-0; Revision 0
BwOP FP-100T44; Fire Zones 11.3B-1, 11.3E-1, 11.3B-2, 11.3E-1, (1A, 2A, 1B, 2B, RHR Heat Exchanger Rooms); Revision 1
BwOP FP-100T6; Auxiliary Building Fire 11.4-0, 11.4A-1, 11.4A-2, 11.4B-0; Revision 6

1R06 Flooding

IR 1039335; CDBI- Are Floor Drain Strainers Addressed in the Flood Calc?; March 5, 2010
IR 1043396; CDBI-Basket Strainers May Adversely Affect Some Floor Drains; March 16, 2010
IR 1044572; CDBI: NRC ID – More Actions for Revision to Flood Level Calc; March 17, 2010
IR 1057855; Floor Drains Undersized; April 17, 2010
IR 1067626; Receipt of NRC NCV DCBI – Aux Building Floor Drain Strainers; May 10, 2010
IR 1076410; Backed Up Floor Drain Causes Water to Enter Electric Cable Tray; June 25, 2010
IR 1230829; Water in VA Inlet Plenum Following Storm; June 27, 2011
IR 1236929; Increasing Water Levels in Cable Vaults; July 6, 2011
IR 1252938; NOS ID – Untimely Action for Submerged MR Cables; August 18, 2011
IR 1272144; Replace Degraded Wireways in Cable Vaults 1J and 2J; October 4, 2011
EC 379355; Auxiliary Building Floor Drain Strainer Baskets; Revision 0
M-72; Diagram of Station Heating Sys. Aux. & Fuel Handling Buildings. Unit 1 & 2; December 19, 1977
M-1317; Auxiliary Building HVAC Equipment Room Plan El. 451'-0"; August 9, 1978
M-1382; Containment Purge Vent. System Equip. Rm. Area 7 Plan El. 467'-0"; October 31, 1979
A-271; Auxiliary Building Main Floor Plan Area 6 Units 1 & 2; February 18, 1977
A-272; Auxiliary Building Main Floor Plan El. 451'-0"; November 26, 1985
EC 378880; Install a Permanent De-Watering System for the Unit 1 Duct Runs Out to the Lake Screen House

1R07 Heat Sink Performance

IR 1258896; 2CC-01A – PM Inspection Finds Tube Heavily Sealed; September 26, 2011
WO 1277613; Unit 2 CC HX Inspection

1R11 Licensed Operator Requalification Program

IR 01121659; Braidwood Operating Exam Failure; September 15, 2010
IR 01129809; Reschedule OPS Crew 5 Requal Training; October 22, 2010
IR 01234943; LORT SIM Scenario Complexity; June 30, 2011
Scenario Number BR-1; Respond to SGTR and Miscellaneous Functions; Revision 2011
BWAP 340-1; Use of Procedures for Operating Department; Revision 26
HU-AA-104-101; Procedure Use and Adherence; Revision 4
OP-AA-101-111; Roles and Responsibilities of On-Shift Personnel; Revision 5
OP-AA-103-102; Watch-Standing Practices; Revision 8
OP-AA-105-102; NRC Active License Maintenance; Revision 9
OP-BR-103-102-1002; Strategies for Successful Transient Mitigation; Revision 1
OP-AA-101-1003; Operations Department Standards; Revision 2

OP-BR-108-101-1002; Operations Department Standards; Revision 22
OP-BR-108-102-1002; Strategies for Successful Transient Mitigation; Revision 1
TQ-AA-150; Operator Training Programs; Revision 5
TQ-AA-201; Examination Security and Administration; Revision 14
TQ-AA-201-F-03; Exam Security Briefing Checklist; Revision 0
TQ-AA-201-F-06; Exam Security Briefing Form; Revision 0
TQ-AA-201-F-07; LORT Exam Security Agreement; Revision 2
TQ-AA-224; Exelon Nuclear Training – Implementation Phase; Revision 5
TQ-AA-225; Exelon Nuclear Training – Evaluation Phase; Revision 1
TQ-BR-302-0102; Normal Operations Testing; Revision 1
TQ-BR-302-0103; Braidwood Simulator Steady State Testing (SS-1); Revision 1
TQ-BR-302-0106; Manual Reactor Trip; Revision 1
TQ-BR-302-0110; Trip of Any Single Reactor Coolant Pump; Revision 1
TQ-BR-302-0112; Maximum Rate Power Ramp; Revision 1
MF-ED04; Failure of System Aux Transformer (SAT); Revision 0
MF-EG09; D/G Differential Over Current Trip; Revision 0
MF-FW13; FW Isolation Valve Failure; Revision 1
MF-FW23; FW Heater Bypass Valve Failure (1CB025); Revision 1
MF-FW32; FW Heater Tube Leak (15 DC); Revision 1
MF-HV02; Aux Building Charcoal Booster Fan Failure to Start/Trip; Revision 0
MF-IA03; Instrument Air Leak Inside Containment; Revision 1
MF-MS01; Failure of Main Steam Isolation Valves; Revision 0
2011/2012 Licensed Operator Requalification Long Range Training Plan
LORT Curriculum Review Committee Minutes – 2010 Cycle 6 and 2011 Cycles 1 through 5
2011 Licensed Operator Requalification Annual Operating Test – Simulator Scenarios and Job Performance Measures for the Week of August 29, 2011
2010 Licensed Operator Requalification Biennial Written Examinations (Crews 1 & 4 Reactor Operator and Senior Reactor Operator Exams)
2011 LORT Cycle 1-5 End of Cycle Reports
NOS Objective Evidence Report, NOSPA-BW-11-2T
Braidwood Pre-71111.11 FASA 2011, Assessment 01134181-03
Scenario BR-7; Response to SGTR with LOCA and Miscellaneous Malfunctions
Scenario BR-8; Response to RCS LOCA and Miscellaneous Malfunctions
Scenario BR-25; Response to a Vapor Space LOCA and Miscellaneous Malfunctions
Scenario BR-29; Respond to a SGTR with a Loss of PZR Pressure Control
LORT Cycle 11-4 Required Reading; LO-11-04
Simulator Evaluation Forms for August 30, 2011 and August 31, 2011
End-of-Cycle Report, Cycle 3, 2011

1R12 Maintenance Effectiveness

IR 1242915; Westinghouse Issued NSAL 11-3 for CETC/RVLIS Power Supplies; July 22, 2011
IR 1244758; Bus 156 B-C Phase Indicates Zero Volts AC; July 28, 2011
IR 1157534; 0A RSH Air Compressor Has Not Been Restored; January 01, 2011
IR 1161464; U-0 SAC Tripped During Start Up; January 11, 2011
IR 1163173; U-0 SAC Uncoupled Run Improvement Opportunity; January15, 2011
IR 1185986; A(1) Determination Required on U0 SAC Due to RMPFF; March 10, 2011
IR 1188937; Service Air Pressure Low Caused Entry into 0BwOA SEC-4; March 17, 2011
IR 1191320; U-0 SAC CPU Does Not Capture 10 PT Trip; March 23, 2011
IR 1193101; SA- Adverse Trend in SA System Performance; March 28, 2011
IR 1218760; 0A RSH Air Compressor Repairs Need to Be Accelerated; May 21, 2011

IR 1253847; Auto Start of U-0 and U-2 SAC Due to Lowering SA Pressure; August 21, 2011
IR 1264310; Unit 2 SAC Tripped During Startup – 2SA01C; September 17, 2011
IR 1277443; Need Maintenance Rule (A)(1) Determination Performed; October 17, 2011
EC 385406; Defeat Undervoltage Relay PR 11A, PR 11C for Bus 156 and Overcurrent Relay PR20-551 for 1RC01PB; Revision 0
OP-AA-106-101-1006; Bus 156 (1AP74E) Potential Transformer; Revision 10
Design Consideration Summary Braidwood Station Unit 1; Modify Tripping Logic for RCP KD-10 Relays, EC 367563; Revision 000
Drawing 20E-1-4030RC02; Reactor Coolant Pump 1B 1RC01PB; April 23, 1985
Drawing 20E-1-4017A; 6900V Switchgear Bus 156; January 11, 1977

1R13 Maintenance Risk Assessments and Emergent Work Control

IR 1190850; Unit 0 Station Air Compressor Trip; Mach 23, 2011
IR 1188947; Unit 0 Station Air Compressor Unloader Valve Malfunction; Mach 23, 2011
IR 1161464; Unit 0 SAC Tripped During Startup; January 11, 2011
BwISR 3.3.2.10-217; Operational Test/Surveillance Calibration of Auxiliary Feedwater Pump Suction Loop P-AF051; Revision 6
1A DG Work Window – August 2011
WC-AA-101; Online Work Control Process; Revision 18
NUMARC 93-01; Section 11, Assessment of Risk Resulting From Performance of Maintenance Activities; Revision 2-22-2000
Action Plan to Remove Unit 0 Station Air Compressor From MR (a)(1); April 4, 2011
Action Plan to Remove Unit 1 Station Air Compressor From MR (a)(1); November 17, 2010
System Health Report for Common Unit Service Air for 2nd Quarter CY2011
System Health Report for Unit 1 Service Air for 2nd Quarter CY2011
System Health Report for Unit 2 Service Air for 2nd Quarter CY2011
Equipment Apparent Cause Evaluation 1190850-04; Unit 0 Station Air Compressor Trip; May 19, 2011
Equipment Apparent Cause Evaluation 1188947-02; Unit 0 Station Air Compressor Unloader Valve Malfunction; May 19, 2011
Equipment Apparent Cause Evaluation 1161464; Unit 0 SAC Tripped During Startup; April 27, 2011

1R15 Operability Evaluations

IR 0165551; Environmental Conditions Review for DG HELB Analysis; June 24, 2003
IR 1184508; Drain Line Plugged (2WF55AA); March 7, 2011
IR 1185016; Non-Conservatisms in the Turbine Building HELB Analyses; March 8, 2011
IR 1185019; NRC Questions on Braidwood Stack Up Calculation; March 8, 2011
IR 1194353; AF Tell Tale Drain Line Plugged – 2AF03AA; March 30, 2011
IR 1194620; Maintenance Planning Late for E-20 Meeting; March 30, 2011
IR 1194703; HELB Concerns with ESF SWGR Room Will Prevent Breaker Swaps; March 30, 2011
IR 1194744; Lack of Ops Support Results in Scaffold Delays; March 30, 2011
IR 1194758; Late Scope Add CR for 2D DC/DB PP Work; March 30, 2011
IR 1194815; PARS Meeting Not Attended by the Chemistry Department; March 30, 2011
IR 1194911; Actions Taken Per IRS 1144356 and 1144357 Not Successful; March 31, 2011
IR 1199223; HELB Past Operability Review; April 7, 2011
IR 1201265; Deficiencies Noted During Breaker Swap – 1AP04EG; April 7, 2011
IR 1217803; Request Actions to Support Flushing of 2A AF Pump Suction; May 19, 2011

IR 1237395; NRC Resident Inspector Questions on IR 1237140; July 7, 2011
IR 1238611; Inoperability of ESF Components Due to HELB; July 11, 2011
IR 1238789; Extension Re-question for Op Eval 1237140; July 11, 2011
IR 1234710; Non-Conservative Input to HELB Analysis; July 6, 2011
IR 1240173; OP Eval Completion Date Extended; July 15, 2011
IR 1263108; Gas Void Identified on 1SI06BB at 1SI059B; September 14, 2011
BwAP 1110-03; Plant Barrier Impairment Program; Revision 21
1BwOS SX-1; AF Pump SX Suction Line Flush 18 Month Surveillance; Revision 0E2
GL-89-13; Service Water System Problems Affecting Safety-Related Equipment; July 18, 1989
Reg Guide 1.89; Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants; Revision 1; June 1984
NUREG 0800; Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment; Revision 2; October 1990
NUREG 0800; Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping; Revision 1; July 1981
CC-AA-103-1003; Design Analysis No. BRW-11-0101-M/BYR11-036; Revision 0
CC-AA-201; Plant Barrier Control Program; Revision 8
CC-AA-309-1001; Turbine Building HELB & Room Heat Up Analyses for MUR PU; June 2, 2011
EC 371695; SI System GL08-01 Design Evaluation; Revision 0
EC 384507; 2A Train of AF System Called into Question Based on Clam Shells in Piping; Revision 00
WR 0360954; 2WF55AA Drain Line Plugged; March 9, 2011
OP-AA-108-115; Operability Determinations (CM-1); Revision 0
S&L Inter-Office Memo; Moody's Critical Flow Tables (RELAP 4); October 22, 1976
S&L Calc No. 9-10-1; For Turbine Building Siding Pressure; Revision 0
GDS Calc No. EQC-BB-007; Diesel Generator Electrical Component Thermal Endurance Evaluation; Revision 02; April 8, 1992
Bonney Forge Catalog; Stress Intensification Factors: Weldolet, Sockolet, Thredolet, Sweepolet, Latrolet, Insert Weldolet
Braidwood Operability Evaluation 11-006; Turbine Building HELB Analysis Input Errors; Revision 0
Braidwood Operability Evaluation 11-006; Turbine Building HELB Analysis Input Errors; Revision 2
Braidwood NRC & NOS Inquiry – HELB Response 2011; Issue Number 037-00; August 4, 2011
Braidwood NRC & NOS Inquiry – HELB Response 2011; Issue Number 038-00; August 4, 2011
Braidwood NRC & NOS Inquiry – HELB Response 2011; Issue Number 050-00; August 4, 2011
Braidwood NRC & NOS Inquiry – HELB Response 2011; Issue Number 051-00; August 4, 2011
Braidwood NRC & NOS Inquiry – HELB Response 2011; Issue Number 052-00; August 4, 2011
QTR# N1399-FL-1; Fusible Link Performance Test Results Fusible Links Used on Dropout Registers at Davis-Besse Nuclear Plant; Revision 0
Calc. NAI-1419-001; Evaluation of Gas Accumulation in Byron Unit 1ECCS Suction Piping; Revision 2
Report 2011-173; Ultrasonic Fluid Solid/Sedimentation Report; September 16, 2011
Drawing 1SI-24; Inservice Inspection Isometric of Safety Injection Lines 1SI06BA – 14" & 1SI106BB – 24" Auxiliary Building; Revision H
Drawing M-6; Main Floor at EL 451'-0" Units 1 & 2; Revision L
Drawing M-7; Mezzanine Floor at El 426'-0" Units 1 & 2; May 12, 1978
Drawing M-8; Grade Floor at El 401'-0" Units 1 & 2; May 12, 1978
Drawing M-35; Diagram of Main Steam Unit 1; July 19, 1978
Drawing M-41; Diagram of Feedwater Drains Turbine Cycle; September 18, 1976
Drawing M-98; Diesel Generator Rooms 2A & 2B Ventilation System; December 29, 1977

Drawing M-115; Essential & Non-Essential Switch Gear Miscellaneous Electrical Equipment Room Ventilation System; Revision V
Drawing 5789-L; 295 Gallon High Pressure Re-heater Drain Tank; Revision 3
Drawing 5791-L; 470 Gallon Moisture Separator Shell Drain Tank; Revision 5
Drawing 13989-02; Air Cylinder, Balanced Shaft, Integral Stuff Box; December 9, 1977
Drawing 13989-05; F.F.R.C.V. w/Side Air Cyl. – Lever & Weight Outside Stuffing Box w/Leakoff – Tapered; October 19, 1977
Drawing 13989-07; F.F.R.C.V. w/Side Air Cyl.-Lever & Weight - Outside Stuffing Box w/Leakoff - Tapered; May 23, 1978
Drawing 35869; Valve Containment General Arrangement 1RH01SA, 1RH01SB, 2RH01SA, and 2RH01SB; Revision B

1R18 Permanent and Temporary Plant Modifications

EC385412; Bus 156 Temporary PT C-Phase Feed; Approved August 2, 2011
LS-AA-104-1001; TCC – Temporary HELB Barriers EC 385154; Revision 3
LS-AA-104-1003; 50.59 Screening No., BRW-S-1022-92, EC 385154; Revision 2
LS-AA-104-1004; 50.59 Evaluation No., BRW-E-1008-159, Activity 369972/DRP12-075; Revision 3
50.59 Review; EC 385165 Temporarily Remove VE and VX Fans High Differential Pressure Trip Due to Turbine Building HELB as a Compensatory Action for a Degraded Condition; Revision 0
TCCP 385165; Purpose of this TCCP is to Defeat the 1/2VE01C, 1/2VE04C, 1/2VE05C, 1/2VX01C, and 1/2VX04C High Pressure Fan Trips to Address HELB Concerns; Revision 0
IR 1258017; 1A/2A AF Pump Discharge Crosstie Regulatory Concern; August 31, 2011

1R19 Post-Maintenance Testing

IR 1356964; 1DG5045A Valve Body Cracked; August 29, 2011
IR 1258958; 1A DG Fuel Oil Pump Has 30 DPM Seal Leak; September 2, 2011
EC 385798; Evaluation of Linear Indication in Valve 1DG5045A
Exelon Power Labs Field Report on the Inspection of a Linear Indication on the Gasket Sealing Surface of the Braidwood 1DG5045A Valve; September 1, 2011
Structural Integrity Associates, Inc. Letter; Flaw Evaluation of Thermostatic Valve 1DG5045A for Braidwood Nuclear Power Station Emergency Diesel Generator, 1DG01KA; September 1, 2011
BwOP AP-74; Unit 2 Isolating and Restoring System Auxiliary Transformers 242-1 and 242-2 with Unit 2 UATS Energized; Revision 0

1R22 Surveillance Testing

IR 1214170; 2A RCFC As-Left Vibration; May 10, 2011
IR 1221547; 0WO03CA – “A” Aux Bldg Chlr: Asiatic Clams @ Cond. Troubleshoot; May 27, 2011
IR 1237617; Shells Id’d in 2A AF Pipe 2AF03AA During Troubleshoot Flush; July 7, 2011
IR 1237637; Determine if an ACM Plan is Needed for 2A RCFC; July 7, 2011
IR 1240583; Results 2A AF SX Crosstie Troubleshooting Clam Shell Flush; July 16, 2011
IR 1249723; NRC Question; August 10, 2011
IR 1251652; NRC Question on PRA for 2B AFW ASME Testing; August 15, 2011
BwAP 1205-3T1; Revise TS Bases for Surveillance Requirement 3.6.6.3 to Clarify Intent of Surveillance; February 22, 2006
BwAP 1205-3T1; Review of Technical Requirements Manual Revision of Appendix W Regarding Removing Note in Section 1.5 of Appendix W Pertaining to Prohibition of Changes to

Frequency of Surveillances Pending Implementation of Procedures Consistent with the Requirements of NEI 04-10, Revision 1; July 7, 2011
BwOP AF-M2; Operating Mechanical Lineup, Auxiliary Feedwater, Unit 2; Revision 14
1BwOSR 3.3.2.8-611A; ESFAS Instrumentation Slave Relay Surveillance (Train A Automatic Safety Injection – K611); Revision 8
2BwOSR 3.3.2.8-611A; ESFAS Instrumentation Slave Relay Surveillance (Train A Automatic Safety Injection – K611); Revision 8
1BwOSR 3.6.6.2; Reactor Containment Fan Cooler Surveillance; Revision 20 & 20a
1BwOSR 3.8.1.15-1; 1A Diesel Generator Hot Restart Test; Revision 3
1BwOSR 5.5.8.AF-3B; Group A IST Requirements for Unit One Diesel Driven Auxiliary Feedwater Pump; Revision 8
1BwOSR 5.5.8.AF-3B; Group A IST Requirements for Unit Two Diesel Driven Auxiliary Feedwater Pump; Revision 9
2BwOS SX-1; AF Pump SX Suction Line Flush 18 Month Surveillance; Revision 0E3
AD-AA-101-F-01; 1BwOSR 3.6.6.2 Reactor Containment Fan Cooler Surveillance; Revision 20a
AD-AA-101-1002; 1BwOSR 3.6.6.3-1 SX System Flow Balance Surveillance; Revision 5
EC 385123; Determination of Minimum Acceptable SX Flow During Execution of Surveillance 1BwOSR 3.6.6.2 with Flow Through the Containment Chiller Condenser; Revision 000
ER-BR-425; Implementation of the Technical Specification Surveillance Frequency Control Program; Revision 0
ER-BR-425-1000; Selecting a Candidate to be Evaluated for a Proposed Surveillance Test Interval Change; Revision 0
ER-BR-425-1001; Surveillance Test Interval Evaluation Form; Revision 0
ER- BR-425-1002; Engineering Evaluation of Proposed Surveillance Test Interval Changes; Revision 0
ER-BR-425-1003; Surveillance Frequency Control Program – Integrated Decision Making Panel Roles and Responsibilities; Revision 0
ER-BR-425-1004; Implementing an Approved Surveillance Frequency Change; Revision 0
ER-BR-425-1005; Monitoring the Effects of Changes to the Surveillance Frequency Control Program; Revision 0
LS-BR-1000; Surveillance Frequency Control Program List of Surveillance Frequencies Change Process; Revision 0
MA-AA-716-004; Conduct of Troubleshooting; Revision 10
MA-AA-716-004; Troubleshooting Log (IR1223481, WO 1450744, 2A AF Pump SX Crosstie Line 2AF03AA); Revision 10
WC-AA-101; Online Work Control Process; Revision 18
WC-AA-111; Predefine Process; Revision 3
WC-MW-114; 1BwOSR 3.6.6.2 Reactor Containment Fan Cooler Surveillance; Revision 0
WO 1301988 01; 1A Diesel Generator Hot Restart Test 18 Month; August 10, 2011
WO 1354708 01; U2 Train A AF Pump SX Suction Line Flush 18 Mo Surveillance; July 7, 2011
WO 1417317 01; 1A Diesel Generator Operability Semiannual Surveillance; August 10, 2011
WO 1443731 01; U1 Reactor Containment Fan Cooler Monthly Surveillance; July 8, 2011
WO 1447176 01; U1 Train A Relay Surveillance K611; August 10, 2011
WO 1456924 01; IST-1A DG Operability Monthly; August 10, 2011
NRC Inspection Manual Part 9900; Technical Guidance; Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety; April 16, 2008

1EP6 Drill Evaluation

IR 1263087; NOS Id Inappropriate Drill Evaluator/Controller Behavior; September 14, 2011
IR 1263555; Several Issues Were Id with FSEP Readers During OYE; September 14, 2011
IR 1263608; NOS Id TSC EP Drill Observation Issues; September 14, 2011

4OA1 Performance Indicator Verification

IR 1102278; Unable to Energize Train A SVAG Valves on U1; August 16, 2010
IR 1172963; 2A DG Normal Shutdown Due to Vent Fan Trip on Ionization; February 9, 2011
IR 1245198; NEI 99-02 Performance Indicator MS05 is Challenged; July 28, 2011
1BwEP ES-1.4; Transfer to Hot Leg Recirculation; Revision 201 WOG 2
BwMSPI-001; Emergency AC Power System (DG); Revision 5
NEI 99-02; Mitigating System Performance Index; Revision 6

4OA2 Identification and Resolutions of Problems

IR 00519141; Determined No Effect on Byron from NRC Dresden EDG Test Violation; August 11, 2006
IR 629351; CDBI FASA Identified EDG Frequency Variation Not Supported by Calculations; May 11, 2007
IR 816619; NRC Concerned with EDG Frequency Issues; September 9, 2008
IR 856043; EDG Frequency Variation Evaluation Inadequate; December 12, 2008
IR 1018119; CDBI FASA EDG Frequency Deficiency Actions Required; January 19, 2010
IR 1058641; NRC CDBI - EDG TS Frequency Variation Not Supported by Fuel Calc; April 19, 2010
IR 1241194; RCFC SX Flow Verification Surveillance Strategy; July 18, 2011
IR 1241367; Extent of Condition Needed for Tech Spec Surv Processing; July 19, 2011
IR 1241531; Fireproofing Missing on Ceiling 15' Inside Door on 426 M-9; July 19, 2011
IR 1241703; Conflicting Info in 2BwOSR 5.5.8.RH-5B for RH ASME Gauge LOC; July 20, 2011
IR 1241747; Two Ops QHPIS Extended Without Proper Approvals; July 8, 2011
IR 1241804; NOS ID Action Plan discrepancies; July 20, 2011
IR 1241998; NOS ID: Issues From HELB OP Eval Review; July 15, 2011
IR 1242011; Tritium Guidelines in Work Packages; July 19, 2011
IR 1242014; 2B RH Pump Flow Reading Low Out of Tolerance During ASME; July 20, 2011
IR 1242062; TSC HVAC Condensing Unit Trip; July 20, 2011
IR 1242070; Biocide FAO Goal Not Met for CW, WS, and SX; July 20, 2011
IR 1242074; AC Not Working in MAF (SAS Affected With Climbing Temps); July 20, 2011
IR 1242093; Additional Ineffective Wire Identified (Tendon H-31-AC); July 20, 2011
IR 1242162; 2B DG #2 Air Compressor Running Excessively; July 20, 2011
IR 1242197; Monthly Temp Scaffold 90-day Review – KT&R 989925; July 21, 2011
IR 1242208; Unexpected Annunciator 2-1-B-5; July 20, 2011
IR 1242942; NRC Comments on Op Eval 11-006 Rev 1; July 22, 2011
IR 1242946; Effectiveness Review Identifies Ineffective CAPR; July 22, 2011
IR 1243020; Unsecured Extension Ladder Found in 2B Diesel Generator Room; July 22, 2011;
IR 1243038; Storage of Oil from RCP in the Fuel Handling Building; July 22, 2011
IR 1243057; Temporary Configuration Changes Procedure (TCCP) 378347 Removal Commitment Date Not Met; July 22, 2011
IR 1243060; Missing Sample; July 22, 2011
IR 1243063; GL 08-01 Field Activities: Braidwood Resource and Execution; July 22, 2011
IR 1243082; Leak Rate Action Level II Exceeded; July 22, 2011

IR 1243125; Supervisor Used to Fill Officer Overtime; July 22, 2011
IR 1243172; ECCS Vent and Valve; July 22, 2011
IR 1243186; Loose Debris in Secured Material Zone; July 23, 2011
IR 1243224; Halon Tank Did Not Meet Minimum Weight Criteria; July 23, 2011
IR 1243292; Various Issues Identified During Steam Dump PMT; July 23, 2011
IR 1243359; 0,1,2BwOA ENV-1 Entered for Severe Thunderstorm Warning; July 24, 2011
IR 1243397; Leak Rate Program Gives Variable Results; July 24, 2011
IR 1243422; Issued Identified During 0BwOS FP-A7 Performance; July 23, 2011
IR 1243475; Leakby on 2CV112A after Leakrate Performance; July 24, 2011
IR 1243482; Floor Drain in LCSR 1Z2 Plugged; July 25, 2011
IR 1243483; 2CV112A Leaks By When in Auto; July 25, 2011
IR 1244252; Enhancement Opportunities Identified Quarterly ECCS UT Exams; July 26, 2011
IR 1244277; Staged Equipment for Emergencies Continues to be Removed; July 26, 2011
IR 1244340; H-Ditch Has High Tritium; July 27, 2011
IR 1244372; Steam Header Pressure Transmitter Drift; July 17, 2011
IR 1244402; NOS Identified ANSI Qual Form Not Completed Within Timeframe; July 26, 2011
IR 1244474; Elevated Tritium in North Oil Separator; July 27, 2011
IR 1244546; Summer Readiness Work Not Done Leaves Station Vulnerable; July 27, 2011
IR 1244646; NOS ID Uncontrolled TCCP; July 27, 2011
IR 1244655; TCCP Log Discrepancies; July 27, 2011
IR 1244693; NOS ID 50.59 Review (MR90) Not Documented in WO or TCC Log; July 27, 2011
IR 1244726; Regulatory Compliance Benchmarking Identified Good Practice; July 27, 2011
IR 1248228; Corrosion Noted on Valve Body of 0SX064A; August 5, 2011
IR 1250080; Emergent LCO Entry 0A VC WO Flow Low – 0WO01PA; August 11, 2011
IR 1250269; Bus 156 Extent of Condition Inspection; August 11, 2011
IR 1250313; “Drafting” Issues Identified During B.5.B DLA; August 10, 2011
IR 1250317; NRC Question on Condensate Storage Tank Avail in Severe Weather; August 11, 2011
IR 1251119; A FP Jockey Pump Closed Into a Trip on Manual Start; August 14, 2011
IR 1251128; Three Dimensional Corrosion DC Battery 211; August 14, 2011
IR 1251131; Three Dimensional Corrosion DC Battery 212; August 14, 2011
IR 1251163; U-1 Steam Dumps Info; August 13, 2011
IR 1251535; 2B AF Pump ASME Delays; August 15, 2011
IR 1251576; TCCP 385016 Temp Power Limitations; August 15, 2011
IR 1251607; Lessons Learned IR for 2B AFW Pump ASME; August 15, 2011
IR 1251618; Results of Corrosion Inspection on 0SX064A; August 15, 2011
IR 1251631; Valve is Hard to Operate; August 15, 2011
IR 1251652; NRC Question on PRA for 2B AFW ASME Testing; August 15, 2011
IR 1251675; Unexpected Alarm FPR 2E MPT Combustible Gas; August 15, 2011
IR 1251709; Ditch-‘H’ Has High Tritium; August 15, 2011
IR 1251730; NRC “Red” Phone Failure (ENS Line); August 16, 2011
IR 1251764; 1B SX PP Bearing Temperature Spikes (1TE-SX002E); August 16, 2011
IR 1251767; Remove Insulation to Allow EOC Inspection; August 16, 2011
IR 1251769; PCRA Requested for EDMG-1, Rev 4; August 16, 2011
IR 1252033; PA System Testing Identified Failures: August 16, 2011
IR 1252573; Results of 0SX064A Corrosion Exams & Actions; August 17, 2011
IR 1252638; Safety Concern With Previously Identified leak; August 18, 2011
IR 1253070; Untimely Actions for Degraded S/R Equip. Additional Damage Identified; August 16, 2011
IR 1253093; NOS ID – CCA Cancelled Without Documenting Reason; August 18, 2011
IR 1253096; Independent Review of SX Clam Shell Root Cause Report; August 18, 2011

IR 1253113; RCFC Monthly Tech Spec Bases Clarification; August 11, 2011
IR 1253158; B VC Chiller Condenser Press Can't Be Maintained 20-30 PSIG; August 19, 2011
IR 1253169; 0SX063A Leaking 200 DPM; August 18, 2011
IR 1253208; Weeds by 'A' Ditch Chemistry Sample Location High; August 18, 2011
IR 1253233; High Voltage Power Supply Failure; August 10, 2011
IR 1253335; Scope Change for EC 384013 at the 90% Review Step; August 15, 2011
IR 1255409; Specify Steam Generator Level During Startup and Low Power; August 25, 2011
IR 1259165; Jockey Fire Pump Cycling Excessively; September 3, 2011
IR 1259321; Vacuum Breaker Vault Monitors Need Upgraded; September 4, 2011
IR 1259439; Two Expired Staging/Work Area Signs (MMD); September 4, 2011
IR 1259440; Expired Staging/Work Area Sign (MMD); September 4, 2011
IR 1259443; Expired Staging/Work Area Sign (EMD); September 3, 2011
IR 1259501; Ground Water Leak Behind MCC 134Y1; September 5, 2011
IR 1259568; PBI's Not Ready for Work at E-1; September 6, 2011
IR 1259578; PWR Range Upper Detector Flux Deviation Unexpected Alarm; September 6, 2011
IR 1259590; ACMP – Evaluate Issue 124906 on the 2D CD/CB Pump; September 6, 2011
IR 1259600; U1 MCR CRT Degrading; September 6, 2011

4OA3 Follow-up of Events & Notices of Enforcement Discretion

IR 1173517; AF Voided Section of SX to AF Piping – AF Pump Suction; February 10, 2011
IR 1176071; NRC Question Regarding Op Eval FO Aux Feed Pump Suction; February, 16, 2011
IR 1181373; Actions to Complete EC 383301, 2A AF Suction Vents; February 28, 2011
IR 1185743; Actions to Complete EC 383391, 2B AF Suction Vents; March 10, 2011
IR 1185759; Actions to Complete EC 383303, 1B AF Suction Vents; March 10, 2011
IR 1187191; Fast Track Mods Placed in Schedule; March 14, 2011
IR 1193357; NRC Questions on AF Suction Void Op Eval 11-03; March 25, 2011
IR 1194196; 2A AF Pump Suction Void; March 29, 2011
IR 1194353; AF Tell Tale Drain Line Plugged – 2AF03AA; March 30, 2011
IR 1197178; Unplanned Online Risk Orange (AF System); March 29, 2011
IR 1198532; Procedure Rev for AF Suction Valve Surv Requires New Actions; April 06, 2011
IR 1198950; Remove Paint on Piping to Allow UT Exam – 2AF017B; April 06, 2011
IR 1198952; Remove Paint on Piping to Support UT Exam; April 06, 2011
IR 1198954; Remove Paint on Piping to Allow UT Exam; April 06, 2011
IR 1202772; NRC Questions on Auxiliary Feedwater Pump Suction Piping; April 14, 2011
IR 1213669; 2AF018A and Downstream Line Blocked with Shells; May 09, 2011
IR 1217799; Request WO to Perform Additional Flushing of 2A AF Suction; May 09, 2011
IR 1217803; Request Actions to Support Flushing of 2A AF Pump Suction; May 09, 2011
IR 1218755; EC 384507 for Past Inoperability of the 2A AF Train; May 20, 2011
IR 1221618; Flush of 2B AF Pump Suction Line; May 27, 2011
IR 1221935; Flush of 1B AF Pump Suction Line; May 27, 2011
IR 1223444; 1A AF Suction: Need WO for Flushing Per Troubleshooting Plan; June 01, 2011
IR 1223481; 2A AF Suction: Need WO for Flushing Per Troubleshooting Plan; June 01, 2011
IR 1226195; 1A AF Pump Motor Wetted Due to SX Hose Rupture; June 08, 2011
IR 1226196; 2A AF Pump Motor Wetted Due to SX Hose Rupture; June 08, 2011
IR 1237617; Shells Id'd in 2A AF Pipe 2AF03AA During Troubleshoot Flush; July 7, 2011
IR 1238018; Train 2A AF Suction UT Shows Small Layer of Silt – 2AF03AA; July 8, 2011
IR 1240088; More Shells Id'd – 2A AF Pipe 2AF03AA During Troubleshooting; July 14, 2011
IR 1240583; Results 2A AF SX Crosstie Troubleshooting Clam Shell Flush; July 16, 2011
IR 1253096; Independent Review of SX Clam Shell Root Cause Report; August 18, 2011

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agency Wide Document Access Management System
AF	Auxiliary Feedwater
AOT	Allowed Outage Time
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CC	Component Cooling
CFR	Code of Federal Regulations
CNO	Chief Nuclear Officer
CST	Condensate Storage Tank
DAC	Derived Air Concentration
DDAFWP	Diesel Driven Auxiliary Feedwater Pump
EA	Enforcement Action
EC	Engineering Change
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
ETL	Electrical Thermal Link
GL	Generic Letter
gpm	gallons per minute
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
IST	Inservice Testing
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOOP	Loss of Offsite Power
LORT	Licensed Operator Requalification Training
MEER	Miscellaneous Electrical Equipment Room
MOV	Motor-Operated Valve
mph	Miles Per Hour
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OPEX	Operating Experience
PARS	Publicly Available Records System
PBI	Plant Barrier Impairment
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PRA	Probabilistic Risk Assessment
psig	Pounds Per Square Inch Gauge
RASP	Risk Assessment of Operational Events
RMA	Risk Management Action
SAT	Systems Approach to Training
SDP	Significance Determination Process

SG	Steam Generator
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	Structure, System, and Component
SX	Essential Service Water
TL	Thermal Link
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order
CDF	Delta Core Damage Frequency

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Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

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

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Letter to M. Pacilio from E. Duncan dated November 9, 2011.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000456/2011004; 05000457/2011004

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