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

May 9, 2013

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 05000456/2013002; 05000457/2013002

Dear Mr. Pacilio:

On March 31, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Braidwood Station, Units 1 and 2. The enclosed inspection report documents the results of this inspection, which were discussed at an exit meeting on April 3, 2013, with Mr. M. Kanavos, 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.

Two NRC-identified findings of very low safety significance were identified during this inspection. Both of these findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating these violations as Non-Cited Violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. Additionally, four licensee-identified violations are listed in Section 4OA7 of this report.

If you contest 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 Resident Inspector Office at the Braidwood Station.

If you disagree with a cross-cutting aspect assignment 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 Resident Inspector Office at the Braidwood Station.

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 Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site 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 and 50-457
License Nos. NPF-72 and NPF-77

Enclosures: Inspection Report 05000456/2013002; 05000457/2013002
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:	05000456/2013002; 05000457/2013002
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	January 1 through March 31, 2013
Inspectors:	J. Benjamin, Senior Resident Inspector A. Garmoe, Resident Inspector T. Daun, Reactor Engineer M. Holmberg, Reactor Inspector R. Jickling, Senior Emergency Preparedness Inspector R. Ng, Project 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 3

Summary of Plant Status 3

1. REACTOR SAFETY 3
- 1R01 Adverse Weather Protection (71111.01) 3
- 1R04 Equipment Alignment (71111.04) 4
- 1R05 Fire Protection (71111.05) 12
- 1R06 Flooding (71111.06) 13
- 1R11 Licensed Operator Requalification Program (71111.11) 15
- 1R12 Maintenance Effectiveness (71111.12) 17
- 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) 22
- 1R19 Post-Maintenance Testing (71111.19) 23
- 1R22 Surveillance Testing (71111.22) 24
- 1EP2 Alert and Notification System Evaluation (71114.02) 25
- 1EP3 Emergency Response Organization Staffing and Augmentation System (71114.03) 26
- 1EP5 Maintenance of Emergency Preparedness (71114.05) 26

4. OTHER ACTIVITIES 27
- 4OA1 Performance Indicator Verification (71151) 27
- 4OA2 Identification and Resolution of Problems (71152) 29
- 4OA3 Followup of Events and Notices of Enforcement Discretion (71153) 30
- 4OA5 Other Activities 32
- 4OA6 Management Meetings 34
- 4OA7 Licensee-Identified Violations 35

SUPPLEMENTAL INFORMATION 1

Key Points of Contact 1

List of Items Opened, Closed, And Discussed 2

List of Documents Reviewed 4

List of Acronyms Used 13

SUMMARY OF FINDINGS

Inspection Report (IR) 05000456/2013002; 05000457/2013002; 01/01/13 - 03/31/13; Braidwood Station, Units 1 & 2; Equipment Alignment.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two Green findings of very low safety significance and an associated Severity Level IV violation were identified by the inspectors. These findings involved Non-Cited Violations (NCVs) of NRC requirements. The significance of inspection findings is indicated by their color (i.e. Greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)," dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross-Cutting Areas," dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process (ROP)," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

Green/Severity Level IV. The inspectors identified a finding of very low safety significance (Green) and an associated Severity Level IV NCV of 10 CFR 50.59 when licensee personnel failed to perform an adequate 10 CFR 50.59 safety evaluation that revised the Updated Final Safety Analysis Report (UFSAR) to permit the Chemical Volume Control System (CVCS) positive displacement pump (PDP) to be isolated and removed from service for an extended, but undefined, period of time. The licensee entered this issue into their Corrective Action Program (CAP) as Issue Report (IR) 1477923. As part of their corrective actions, the licensee planned to re-perform the 10 CFR 50.59 evaluation to include a review of the direct effects that this change had on the CVCS PDP functions that were important to safety.

The finding 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, in 1997, the licensee failed to evaluate whether there was an increase in the probability of a malfunction for the PDP functions important to safety prior to isolating and removing the PDPs from service. The finding was evaluated using IMC 0609, "Significance Determination Process." Using Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," the inspectors answered 'No' to Questions 1, 2, 3 and 4 and, as a result, determined the finding was of very low safety significance (Green). The finding was also determined to be a Severity Level IV NCV in accordance with Section 6.1.d.2 of the NRC Enforcement Policy because the resulting changes were evaluated by the SDP as having very low safety significance (Green). There was no cross-cutting aspect associated with the finding because it was not indicative of current licensee performance. (Section 1R04.1.b.1)

Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to account for pressurizer (PZR) power operated relief valve (PORV) accumulator system leakage when establishing a design operability limit. Specifically, procedures BwAR 1-12-D7 (Unit 1) and BwAR 2-12-D7 (Unit 2), "PZR PORV Supply Pressure High/Low," established a minimum PZR PORV air accumulator operability pressure limit of 85 pounds per square inch gauge (psig). However, this pressure limit did not account for allowable accumulator system leakage, which could be as high as 15 psig per hour, during a postulated Steam Generator Tube Rupture (SGTR) event with a loss of the nonsafety-related air supply to the valves. The licensee entered this issue into their CAP as IR 1493170. Corrective actions to address this issue included a revision to Unit 1 BwAR 1-12-D7 and Unit 2 BwAR 2-12-D7 to require Operations to declare the PZR PORVs inoperable at a higher minimum accumulator pressure limit of 94 psig.

The finding was determined to be more than minor because it was associated with the Design Control 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, the operability limit of 85 psig failed to account for the licensing basis conditions of a postulated Chapter 15 SGTR event, loss of nonsafety-related instrument air to the containment and PZR PORVs, and acceptable loss of air from the safety-related accumulators through normal leakage and valve strokes. The finding was evaluated using IMC 0609, "Significance Determination Process." Using Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," the inspectors answered 'No' to Questions 1, 2, 3 and 4 and, as a result, determined the finding was of very low safety significance (Green). There was no cross-cutting aspect associated with the finding because it was not indicative of current licensee performance. (Section 1R04.1.b.2)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power during the inspection period with one exception. On January 24, 2013, reactor power was lowered in response to an increasing and adverse 1C Reactor Coolant Pump (RCP) lower radial bearing temperature trend. The licensee suspended the power reduction at approximately 60 percent after verifying and correcting the adverse RCP bearing temperature trend, which was the result of an instrumentation issue. Reactor power returned to 100 percent later that day.

Unit 2 operated at or near full power during the inspection period with one exception. On March 15, 2013, reactor power was lowered to approximately 85 percent to perform a transfer of the operating main feedwater pumps. Reactor power returned to 100 percent the following day.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather – Heavy Snowfall Conditions

a. Inspection Scope

On February 24, 2013, a winter weather advisory was issued for an impending winter storm. The inspectors observed the licensee's preparations and planning for the potentially significant adverse weather. The inspectors reviewed licensee procedures and discussed potential compensatory measures with control room personnel. The inspectors focused on plant management's actions for implementing the station's procedures for ensuring adequate personnel for safe plant operation and emergency response would be available. The inspectors conducted a site walkdown including walkdowns of various plant structures and systems to check for maintenance or other apparent deficiencies that could affect system operations during the predicted significant adverse weather. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. 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

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:

- Unit 1 “B” (1B) Auxiliary Feedwater (AFW) Pump with 1B Emergency Diesel Generator (EDG) Out-of-Service (OOS);
- Unit 1 and Unit 2 Pressurizer (PZR) Power Operated Relief Valves (PORVs);
- Unit 1 and Unit 2 Chemical Volume Control System (CVCS) Positive Displacement Pumps (PDPs); and
- Unit 1 and Unit 2 Remote Shutdown Panels.

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 Updated Final Safety Analysis Report (UFSAR), Technical Specification (TS) requirements, outstanding work orders (WOs), issue reports (IRs), 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.

This inspection constituted four partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

(1) Failure to Perform an Adequate 10 CFR 50.59 Evaluation for Removing the Positive Displacement Pump from the Current Licensing Basis

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated Severity Level IV NCV of 10 CFR 50.59 when licensee personnel failed to perform an adequate 10 CFR 50.59 safety evaluation that revised the UFSAR to permit the CVCS PDPs to be isolated and removed from service for an extended, but undefined, period of time. Specifically, a licensee 10 CFR 50.59 evaluation performed in 1997 examined a number of indirect consequences, but failed to adequately evaluate the direct consequences that isolating and removing the CVCS PDPs from service would have on the CVCS PDP-supported safety functions as described in the UFSAR.

Description: Notice of Violation (NOV) 05000456/1997005-01; 05000457/1997005-01 documented a violation of TS 6.8.1.a when on March 25, 1997, NRC inspectors identified that station Emergency Operating Procedures (EOPs) had not been properly maintained. Specifically, the applicable EOPs directed operators to start the CVCS PDP if either of the CVCS centrifugal charging pumps (CCPs) could not be started. In part, since the CVCS PDP had been out of service for approximately 10 years, the NRC concluded that the applicable TS 6.8.1.a procedures had not been maintained.

In response to this NOV, the licensee revised the UFSAR to reflect a change to the current licensing basis (CLB) that permitted the CVCS PDP to be isolated and removed from service for extended periods of time. This change was made through the licensee's 10 CFR 50.59 process, which concluded the change could be made without prior NRC approval because it did not result in an Unreviewed Safety Question (USQ). The change reflecting the updated CLB status of the CVCS PDP was added to the UFSAR in numerous sections that discussed the CVCS PDP functions that were important to safety. For example, UFSAR Table 5.4-18, "Single Failure Evaluations of Systems Required to Reach Cold Shutdown Conditions Per BTP 5-1," Section II.F, stated the following:

Flow control valve (CV121 - This valve fails open on loss of air to the valve operator.) If CV121 closes spuriously, the centrifugal charging pumps can safely operate on their miniflow circuits. Efforts would be made to open it. Boration can be accomplished by starting the positive displacement pump or by using the cold leg injection flow path. (The positive displacement charging pump can be expected to be isolated administratively for extended periods of time.)

In addition to the above example related to reaching cold shutdown conditions following an abnormal condition, such as a seismic event, the UFSAR discussed the following PDP functions that were important to safety:

- The function to provide normal charging flow to the reactor coolant system (RCS) and associated capability to control pressurizer level through a pump speed controller (Reference: UFSAR Chapter 9 Section 3);
- The function to borate the RCS from normal operating conditions to cold shutdown conditions using the CVCS system (Reference: UFSAR Chapter 9 Section 3);
- The function to maintain RCS temperature during normal power operation through CVCS boration and dilution flow paths (Reference: UFSAR Chapter 9 Section 3); and
- The function to supply RCP seal injection flow (UFSAR Table 9.3.5, "Failure Mode and Effects Analysis Chemical and Volume Control System Active Components – Normal Plant Operations and Load Follow").

The inspectors questioned the apparent contradiction in the UFSAR which continued to describe and credit the CVCS PDP functions required by the CLB, but recognized that the CVCS PDP could be isolated and removed from service for an extended and undefined period of time. The inspectors concluded that from a safety perspective this

isolation was equivalent to abandoning the CVCS PDP because the CVCS PDP had not been operated after the UFSAR revision in 1997.

The inspectors subsequently reviewed 10 CFR 50.59 evaluation BRW-SE-1997-676 that approved this change. The inspectors concluded that the 10 CFR 50.59 evaluation did not adequately determine if a new USQ was created because the licensee failed to evaluate the direct impact that isolating the CVCS PDP from service would have on the functions important to safety described above. Specifically, BRW-SE-1997-676, Question 11.a asked: "May the probability of a malfunction of equipment important to safety increase?" The evaluation concluded the answer to this question was 'No' based upon a review of the indirect effects the change would have upon the CVCS CCPs' reliability, the ability to test the Emergency Core Cooling System (ECCS) portion of CVCS as required by the TSs, and the probability of a CVCS CCP piping failure.

The licensee entered this issue into their CAP as IR 1477923, "NRC Identified PDP 50.59 Enhancement Required." As part of their corrective actions, the licensee planned to re-perform the 10 CFR 50.59 evaluation and include a review of the direct effects that this change had upon the CVCS PDP functions that were important to safety.

<u>Analysis</u>: The inspectors determined that the licensee's failure to perform an adequate 10 CFR 50.59 evaluation was a performance deficiency. In particular, the licensee failed to evaluate if there was an increase in the probability of a malfunction for the PDP functions that were important to safety prior to implementing the CLB change.

The inspectors determined that the finding was 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, the change permitted the PDP to be removed from service for the life of the plant, and therefore the PDP was not available or capable of performing its mitigating functions associated with both normal and abnormal operations.

This issue impeded the ability of the NRC to perform its regulatory oversight function since the issue involved the failure to perform an adequate evaluation pursuant to 10 CFR 50.59, "Changes, Tests, and Experiments," that failed to identify a USQ and as a result the change was not submitted to the NRC for approval, as required. Because the issue impeded the NRC's ability to perform its regulatory oversight function, the enforcement aspects of this issue were processed using the NRC's Traditional Enforcement process.

This violation is associated with a finding that has been evaluated by the Significance Determination Process (SDP) and communicated with an SDP color reflective of the safety impact of the deficient licensee performance. The SDP, however, does not specifically consider the regulatory process impact. Thus, although related to a common regulatory concern, it is necessary to address the violation and finding using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated finding.

The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings." The inspectors determined that the finding affected the Mitigating Systems Cornerstone and evaluated the finding using

Appendix A, “The Significance Determination Process for Findings At-Power,” Exhibit 2, “Mitigating Systems Screening Questions,” for the Mitigating Systems Cornerstone. The inspectors answered ‘No’ to Questions 1, 2, 3 and 4 and, as a result, determined the finding was of very low safety significance (Green).

Title 10 CFR Part 50.59(a)(1), 1997 edition, states that licensees may make changes to their facility without prior Commission approval, provided the proposed change does not involve a USQ. In 1997, the licensee made a change to the facility associated with permitting the CVCS PDP to be isolated and removed from service for extended periods of time that involved potential USQs and the licensee failed to obtain prior NRC approval before the change was made.

In determining the significance of the tradition enforcement aspects of this issue, the inspectors identified that subsection d.2 of Section 6.1, “Reactor Operations,” of the NRC Enforcement Policy listed a 10 CFR 50.59 violation that results in conditions evaluated by the SDP as having very low safety significance (Green) as an example of a Severity Level IV violation. Therefore, the traditional enforcement aspects of this issue were determined to be at the Severity Level IV level.

There was no cross-cutting aspect associated with the finding because it was not indicative of current licensee performance. Specifically, the 10 CFR 50.59 evaluation was performed in 1997.

Enforcement: Title 10 CFR Part 50.59(a)(1), 1997 edition, states, in part, that licensees may make changes in the facility as described in the Safety Analysis Report (SAR) without prior Commission approval, provided the proposed change does not involve a USQ. Title 10 CFR 50.59(a)(2) states, in part, that a proposed change involves a USQ if the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the SAR may be increased.

Contrary to the above, on June 4, 1997, the licensee made a change to the facility, as described in the UFSAR, Section 9.3 and Table 5.4-18, associated with permitting the CVCS PDP to be isolated and removed from service for extended periods of time that involved potential USQs and the licensee failed to obtain prior NRC approval before the change was made. Specifically, 10 CFR 50.59 Safety Evaluation BRW-SE-1997-676 failed to evaluate the direct effect of revising the CLB to permit isolation and removal from service of the CVCS PDP for an extended and undetermined period of time on functions important to safety, including normal and emergency RCS boration, RCS inventory control, and reactor coolant pump seal injection.

The licensee entered this issue into their CAP as IR 1477923, “NRC Identified PDP 50.59 Enhancement Required.” As part of their corrective actions, the licensee planned to re-perform the 10 CFR 50.59 evaluation to include a review of the direct effects that this change had upon the CVCS PDP functions that were important to safety.

Because this violation was of very low safety significance and because the issue was entered into the licensee’s CAP as IR 1477923, this violation is being treated as a Severity Level IV NCV, consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000456/2013002-01; 05000457/2013002-01, Failure to Perform an Adequate 10 CFR 50.59 Evaluation Removing the Positive Displacement Pump from the Current Licensing Basis)**

In addition, the associated SDP finding is identified as a FIN. **(FIN 05000456/2013002-02; 05000457/2013002-02, Positive Displacement Pumps Not Available to Perform Their Mitigating Functions Associated with Both Normal and Abnormal Operations)**

(1) <u>Failure to Establish an Adequate Quality Instruction for Determining Pressurizer Power Operated Relief Valve Operability</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, “Design Control,” when licensee personnel failed to account for PZR PORV accumulator system leakage in establishing a design operability limit.

<u>Description</u>: At Braidwood, the PZR PORVs are air-operated valves and credited in the licensee’s UFSAR Chapter 15 Accident Analysis as a system necessary to mitigate a SGTR event. The air to the PZR PORVs is normally supplied by the nonsafety-related Instrument Air system that penetrates containment. Since the Instrument Air system is not designed as a safety-related system, it is not assumed to be available, and thus not credited in the licensee’s accident analysis. When Instrument Air is not available to the PZR PORVs, operation of the PZR PORVs is dependent upon local safety-related air accumulators. Pressure in the safety-related air accumulators is normally maintained by the nonsafety-related Instrument Air system. In the case of a loss of Instrument Air, safety-related check valves isolate the safety-related accumulators from the nonsafety-related Instrument Air system to maintain the accumulators pressurized. For a SGTR event, the air accumulators are relied upon to support two credited PZR PORV cycles for event mitigation.

The inspectors reviewed procedures BwAR 1-12-D7 (Unit 1) and BwAR 2-12-D7 (Unit 2), “PZR PORV Supply Pressure High/Low.” These procedures would be entered for a low or high PZR PORV safety-related air accumulator pressure. For a low PZR PORV air accumulator pressure, the procedure directed Operations to declare the PZR PORVs inoperable if their associated accumulator pressure dropped below 85 pounds per square inch gauge (psig).

The inspectors reviewed the licensee’s periodic PZR PORV safety-related accumulator system surveillance, 1/2BwOSR 3.4.11.3, “PZR PORV IA [Instrument Air] Accumulator Check Valve Test and Accumulator System Integrity Test.” The purpose of this surveillance was to verify that the PZR PORVs were capable of performing their credited safety function for mitigating a SGTR event, in accordance with TS 3.4.11, “Pressurizer PORVs,” and UFSAR Chapter 15. The surveillance accomplished this verification by determining the leak tightness of the safety-related portion of the PZR PORV Air Accumulator system and then comparing that value to a pre-established acceptable range. Specifically, the surveillance established an initial PZR PORV accumulator pressure between 95 psig and 105 psig. The associated PZR PORV accumulator was then isolated from the nonsafety-related air supply and maintained in this configuration for 1 hour. An acceptable final pressure after 1 hour of decay time was 90 psig or greater. Therefore, the acceptable leak rate of the surveillance was not a fixed value since it was dependent upon the initial accumulator pressure. If the initial accumulator pressure was 105 psig, the acceptable leak rate could be as high as 15 psig per hour, but if the initial accumulator pressure was 95 psig, the acceptable leak rate could be as low as 5 psig per hour.

The inspectors identified that the PZR PORV safety-related air accumulator operability value of 85 psig, established in procedures BwAR 1-12-D7 and BwAR 2-12-D7, was not adequate to support operability following a postulated SGTR event, loss of instrument air to containment, and assumption of any air leakage from the safety-related accumulator or any usage of air from the accumulator as a result of PZR PORV cycling.

The licensee entered this NRC-identified issue into the CAP as IR 1493170, "PZR PORV Operability Criterion in BwARs Needs Revision." The licensee determined that the error of not accounting for PZR PORV accumulator air leakage and usage occurred when the procedures were revised in March 1991 to include the 85 psig operability criterion per vendor drawing D-268832, Revision 5. The licensee did not identify the specific reason for not considering the decay rate or valve usage amounts and concluded that a less than adequate technical rigor used during the procedure revision process was an apparent cause. The licensee determined that additional margin could be gained by accounting for RCS pressure assistance in opening the PZR PORVs and, as a result, the minimum pressure required to support PORV operation could be lowered from 85 psig to 83.3 psig. The licensee determined that if the pressure in the PZR PORV accumulator system were to fall to 85 psig, and the accumulator system pressure decay rate was equal to the maximum allowed rated of 12 psig per hour, then the pressure in the accumulators would not be sufficient to fully open the PZR PORVs as credited in the Safety Analysis. *(Note: The licensee utilized the 12 psig per hour instead of the maximum allowed surveillance 15 psig per hour based upon the maximum air tank pressure of 102 psig that has been documented in the surveillances from the last three refueling outages.)* Specifically, for the UFSAR Chapter 15 SGTR Margin to Overfill case, two credited manual cycles of the PZR PORVs occur within the first hour. A 12 psig per hour pressure decay rate would result in an accumulator pressure drop of about 7 psig before the first cycle and about 10 psig before the second cycle. Accordingly, if the initial accumulator pressure was 85 psig, the pressure would be 78 psig prior to the first cycle and 75 psig prior to the second cycle. Based upon a previous evaluation, the licensee had determined that a PZR PORV cycle results in a maximum pressure drop in the PZR PORV accumulator of 0.3 psig (Reference: Operability Determination 2013-01). The licensee concluded that 78 psig and 75 psig air pressure would not be sufficient to fully open the PZR PORVs. Corrective actions include a revision to procedures BwAR 1-12-D7 and BwAR 2-12-D7 to require Operations to declare the PZR PORVs inoperable and enter the TS 3.4.11 Limiting Condition for Operation if the PZR PORV accumulator pressure were to fall below 94 psig.

Analysis: The inspectors determined that the establishment of an unacceptable PZR PORV air accumulator operability limit in the applicable annunciator response procedures was a performance deficiency. Specifically, the operability limit of 85 psig did not take into account the license bases conditions of a postulated Chapter 15 SGTR event, loss of nonsafety-related instrument air to the containment and PZR PORVs, and loss of air from the safety-related accumulators through normal leakage and valve strokes.

The performance deficiency was screened in accordance with IMC 0612, Appendix B, "Issue Screening." The inspectors determined that the performance deficiency did not involve a violation that impacted the regulatory process or contribute to actual consequences. The inspectors determined that the finding was more than minor because it was associated with the Design Control 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, the licensee had established a procedure to respond to low PZR PORV accumulator pressure conditions that was inadequate to ensure that the PZR PORVs would be able to perform their safety function for a design basis SGTR event.

The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings." The inspectors determined that the finding affected the Mitigating Systems Cornerstone and evaluated the finding using Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," for the Mitigating Systems Cornerstone. The inspectors answered 'No' to Questions 1, 2, 3 and 4 and, as a result, determined the finding was of very low safety significance (Green).

There was no cross-cutting aspect associated with the finding because it was not indicative of current licensee performance.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that the applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, and as specified in the licensee's application, for those structures, systems, and components to which this appendix applies are correctly translated in specifications, drawings, procedures, and instructions.

Contrary to the above, in March 1991, the licensee failed to correctly translate a safety-related PZR PORV accumulator air pressure value that would maintain PZR PORV operability based upon the credited UFSAR Chapter 15 assumptions to support the design basis SGTR event during a revision to quality procedures BwAR 1-12-D7 and BwAR 2-12-D7. Corrective actions to address this issue included a revision to procedures BwAR 1-12-D7 and BwAR 2-12-D7 to require Operations to declare the PZR PORVs inoperable at a higher minimum accumulator pressure value of 94 psig.

Because this violation was of very low safety significance and because the issue was entered into the licensee's CAP as IR 1493170, this violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy.
(NCV 05000456/2013002-03, 05000457/2013002-03, Failure to Establish an Adequate Quality Instruction for Determining Pressurizer Power Operated Relief Valve Operability)

.2 Semiannual Complete System Walkdown

a. Inspection Scope

The inspectors performed a complete system alignment inspection of the Unit 1 and Unit 2 Boric Acid Storage system to verify functional capability. This system was selected because the boration capability of this system is relied upon for abnormal events. The inspectors walked down the system and reviewed mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and ancillary equipment or debris to ensure there was no interference with equipment operation. A review of a

sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

This inspection constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

(Unresolved Item) Boric Acid Transfer Pump Electrical Power Supply Not Safety-Related

Introduction: The inspectors identified an Unresolved Item (URI) regarding the crediting of nonsafety-related equipment to meet design basis requirements. Braidwood Station is licensed to the standards of NRC Branch Technical Position (BTP) Reactor Safety Branch (RSB) 5-1, "Design Requirements of the Residual Heat Removal System," Revision 2, dated July 1981. One aspect of these licensing and design requirements is that the plant can be transitioned from normal operating conditions to cold shutdown using only safety-related systems. Braidwood Station credits the boric acid transfer pumps in accomplishing the boration function necessary to reach cold shutdown conditions, however, the boric acid transfer pumps are powered by nonsafety-related electrical equipment.

Description: Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System," includes the following relevant Functional Requirements (Reference: BTP 5-1, Revision 2, July 1981, Page 5.4.7-13):

1. *The design shall be such that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems. These systems shall satisfy General Design Criteria 1 through 5.*

2. *The system(s) shall be capable of bringing the reactor to cold shutdown conditions, with only offsite or onsite power available, within a reasonable period of time following shutdown, assuming the most limiting single failure.*

Per BTP 5-1, the processes involved in cooldown are heat removal, depressurization, flow circulation, and reactivity control. The cold shutdown condition, as described in the Standard TSs for a pressurized water reactor, refers to a subcritical reactor with a reactor coolant temperature no greater than 200 degrees Fahrenheit.

The licensee's CLB discussed that since the Instrument Air system is not a safety-grade (i.e. safety-related) system, it was not considered available for the purpose of the analysis. One consequence of losing instrument air is a CVCS letdown isolation since numerous air-operated valves fail to their closed position. Since letdown is isolated, the available RCS volume available for boration is limited and accommodated by the usable volume within the PZR both prior to the cooldown and following the cooldown. To accomplish shutdown boration, the station utilizes the highly concentrated boric acid storage tanks (BASTs) [~7000 parts per million (ppm) boron] relative to the less concentrated refueling water storage tank [~2000 ppm boron]. The Braidwood design required the use of the boric acid transfer pumps to pump water from the BASTs to the

suction of the CVCS CCPs as part of the required flow path. Therefore, the BAST boric acid transfer pumps are credited in the licensee's CLB and supporting analysis for achieving the necessary RCS boric acid concentration to reach cold shutdown conditions.

The BAST boric acid transfer pumps were discussed in the approved Safety Evaluation Report. The licensee stated that the BAST boric acid transfer pumps (and CCPs) are train-oriented and can be powered from the EDGs. The licensee also stated that the BAST boric acid transfer pumps are not powered from engineered safety feature (ESF) buses. The inspectors questioned the apparent conflict between the two statements and subsequently determined that both statements are, in fact, correct. The BAST boric acid transfer pumps can be powered by the EDGs through the safety-related 4 kilovolt (kV) vital bus via a cross-tie breaker to a nonsafety-related 4 kV bus, cross-tied to a nonsafety-related 4 kV to 480 Volt (V) transformer, cross-tied to a nonsafety-related 480V bus and associated conductors and breakers. Braidwood Station was licensed as a Class 2 plant with regard to BTP RSB 5-1, which allows for a deviation from full compliance if it can be demonstrated that correction for single failure by manual actions inside or outside of containment or return to hot standby until manual actions (or repairs) were found to be acceptable for the individual plant.

Therefore, the inspectors identified that the licensee was taking credit for nonsafety-related equipment, which appeared to be an apparent conflict with the CLB BTP RSB 5-1 functional requirements. The inspectors reviewed numerous CLB documents and could not identify any discussion on the acceptability of crediting manual action or repairs as discussed in the preceding paragraph.

At the end of the inspection period, a detailed review of the CLB was in progress. This URI will remain open pending the completion of this review and determination of whether the current plant design is in conformance with NRC regulations. **(URI 05000456/2013002-04, 05000457/2013002-04, Boric Acid Transfer Pump Electrical Power Supply Not Safety-Grade)**

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 the availability, accessibility, and condition of firefighting equipment in the following risk-significant plant areas:

- 1B AFW Pump Room;
- Unit 1 and Unit 2 Train A Essential Service Water (SX) Room;
- 1A EDG Room;
- Unit 2 Miscellaneous Electrical Equipment Room;
- Unit 1 Remote Shutdown Panel; and
- Unit 2 Remote Shutdown Panel.

The inspectors reviewed these areas and determined whether 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.

This inspection constituted six 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:

- Unit 1 and 2 Train A SX Pump Room (Flooding Zone G1-B).

Documents reviewed are listed in the Attachment.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

(Unresolved Item) NonSafety-Related Turbine Building Waste Disposal System to Safety-Related Essential Service Water Pump Room Sump Design Interaction

Introduction: The inspectors identified an URI regarding the separation of the Turbine Building (TB) Waste Disposal system and the SX pump room sumps through nonsafety-related check valves. Specifically, the inspectors evaluated whether the operablility basis documented in IR 1473152, “Single Point Vulnerability for SX Pump Room Flooding,” adequately addressed the CLB of a postulated TB flooding event and subsequent backflow of water into the safety-related Unit 1 and Unit 2 “A” train SX pump rooms. During a licensing basis Circulating Water system pipe break or condenser inlet expansion joint failure, a portion of the water from the resulting flood in the TB could backflow from the TB into the SX pump room sumps if the nonsafety-related SX sump pump discharge check valve(s) are leaking and the nonsafety-related SX sump pump(s) were not available. In the condition identified and discussed in IR 1473152, at least one nonsafety-related check valve was found to be stuck open.

Description: On January 21, 2013, the licensee documented in IR 1465027, “1WF040A Not Seating Properly,” that SX sump pump discharge check valves 1WF040A and/or 1WF040B might be leaking by based on data that indicated that when the TB sump pump(s) operated, the Unit 1 and Unit 2 “A” train SX pump room sump pump(s) would start shortly after. This condition suggested that the TB sump pump(s) were filling the Unit 1 and Unit 2 “A” train SX sump to a level that caused the SX sump pump(s) to start. The licensee’s prompt operability evaluation was documented in IR 1473152, “Single Point Vulnerability for SX Pump Room Flooding,” and concluded that the SX pumps were operable since the SX pump room sump pumps can pump water out of the SX pump room sumps and, therefore, prevent water from accumulating in the SX pump room. However, the inspectors noted that previous IRs indicated degraded performance of both “A” train SX pump room sump pumps (IR 1426946, “1WF06PB Does Not Develop Adequate Discharge Pressure,” and IR 1464644, “1WF06PA and B Degraded – Insufficient Urgency to Correct.”)

On February 13, 2013, the licensee updated their operability review to credit isolating the TB from the SX pump rooms by closing nonsafety-related isolation valves 1WF055 and 2WF055 until the final operability evaluation was complete. On February 14, 2013, the licensee documented that alarm response procedure BwAR OPL02J-2-A6, “TB Floor Drain Sump Level High High,” was being revised to provide operator direction to align the SX pump room sump to the Radioactive Waste system in the event of TB flooding. Additionally, credit was given to the nonsafety-related SX pump room sump high level alarm to alert operators to an off-normal level condition. The licensee credited the SX pump room sump pumps to be able to pump against the head pressure from the flood water in the TB, though reference was not given to their degraded condition. Issue Report 1473152 referenced UFSAR 10.4.5, “Circulating Water System,” and identified that the worst case flood in the TB could theoretically reach 396 feet. The lowest elevation of the SX sump pumps was 322 feet. The IR stated that the discharge of the SX room sump pumps was given as 100 gpm at 106 feet which would prevent inflow from the TB. The IR also stated that the NRC Standard Review Plan (SRP) requirement to prevent flooding of a safety-related area was maintained. On March 18, 2013, WO 1497423 was performed and identified that the disc for 1WF040B (SX sump discharge check valve) was stuck in the mid-position.

NRC SRP 3.6.1, "Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment, BTP SPLB 3-1 B.3.b," stated, "In analyzing the effects of postulated piping failures, the following assumptions should be made with regard to the operability of systems and components: (1) Offsite power should be assumed to be unavailable if a trip of the turbine-generator system or reactor protection system is a direct consequence of the postulated piping failure; (2) A single active component failure should be assumed in systems used to mitigate consequences of the postulated piping failure and to shut down 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 unit trip and loss of off-site power (LOOP)."

Additionally, SRP 9.3.3, "Equipment and Floor Drainage System," required that the equipment and floor drainage system be capable of preventing a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment. SRP 10.4.5, "Circulating Water System," required compliance with General Design Criteria 4, "Environmental and Dynamic Effects Design Bases," based on meeting the following: 1) Means should be provided to prevent or detect and control flooding of safety-related areas so that the intended safety function of a system or component will not be precluded due to leakage from the Circulating Water system; and 2) Malfunction or a failure of a component or piping of the Circulating Water system including an expansion joint should not have unacceptable adverse effects on the functional performance capabilities of safety-related systems or components.

Based on the above, the inspectors questioned whether the failure of the 1WF040B check valve would result in water from a postulated TB flood to backflow into the common Unit 1 and Unit 2 "A" train SX pump room sumps resulting in the loss of the 1A and 2A SX Pumps. The inspectors were unable to determine during the inspection whether the licensee's justification was acceptable and therefore this issue will be considered an URI pending further NRC review. **(URI 05000456/2013002-05; 05000457/2013002-05, NonSafety-Related Turbine Building Waste Disposal System to Safety-Related Essential Service Water Pump Room Sump Design Interaction)**

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On February 28, 2013, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training 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 simulator sample as defined in IP 71111.11

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On January 16, 2013, the inspectors observed entry into 1BwOA INST-2 to address main feedwater pump speed oscillations and on January 24, 2013, the inspectors observed a down power to address an elevated 1C reactor coolant pump lower radial bearing temperature trend. These were activities that required heightened awareness or were related to increased risk. The inspectors evaluated overall crew performance in the following areas:

- licensed operator performance;
- 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 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, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment.

This inspection constituted two quarterly licensed operator heightened activity/risk samples as defined in IP 71111.11.

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:

- PZR PORV and Safety Valves;
- Steam Generator PORVs; and
- Remote Shutdown Panel Performance Monitoring.

The inspectors reviewed events including those in which ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance issues 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 Systems, Structures, 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 three 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 appropriate risk assessments were performed prior to removing equipment for maintenance:

- Planned Operational Risk Maintenance Activity on the Unit 2 Station Auxiliary Transformers;
- Unit 1 Yellow Risk for Planned 1A SX System Out of Service;
- Unit 1 Yellow Risk for Planned 1A EDG Work Window;
- Planned Impairment of Unit 1 125 VDC [Volt Direct Current] Battery Room Doors to Support High Energy Line Break (HELB) Damper Maintenance;
- Unit 2 Yellow Risk for Planned 2B Residual Heat Removal (RHR) Maintenance;
- Unplanned Unit 2 Yellow Risk for Motor-Driven Fire Water Pump and Auxiliary Building Ventilation Maintenance;
- Unplanned Unit 2 Operational Risk Condition for 2B Reactor Coolant Pump #2 Seal Leak-By; and
- Unplanned Unit 2 Yellow Risk for 2A EDG Work Window.

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 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 eight samples as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Flood Door SD-192 Found Open and Unattended;
- Safety-Related 125 VDC Battery Rack Concrete Mounting Anchors;
- Operability Evaluation 2013-01, Natural Circulation Cooldown and PZR PORVs;
- Upper Cable Spreading Room Dampers “S” Hooks Installed Backwards;
- Auxiliary Building Piping Medium Energy Line Break Crack Not Considered/Non-Conformance;

- Unit 1 Control Rod Drive Mechanism Penetration Number 4 Missed Volumetric Examination; and
- 2B RCP Number Two Seal Degraded.

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

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

b. Findings

(Unresolved Item) Current Licensing Bases Requirements for RCS Pressure Control Function During a Postulated Seismic Event in Reference to NRC RSB BTP 5-1

Introduction: The inspectors identified an URI regarding the licensee's interpretation of their CLB requirements pertaining to the RCS Pressure Control Safety Function during a postulated seismic event and assumed 2 hour period in hot standby. Specifically, the inspectors identified three issues of concern that questioned the licensee's ability to maintain RCS pressure control without the reliance of the primary safety valves and in a manner that could accomplish an RCS cooldown within a timeframe required by RSB BTP 5-1.

Description: The licensee's CLB utilized the standards in NRC BTP RSB 5-1, "Design Requirements of the Residual Heat Removal System," Revision 2, dated July 1981, to meet aspects of 10 CFR Part 50, Appendix A, General Design Criteria (GDC) 19 and GDC 34. In summary, the station was licensed to demonstrate the capability to reach a cold shutdown condition assuming a design basis earthquake resulting in a LOOP and the failure of all non-safety, non-seismically qualified equipment. Design functions necessary to maintain hot standby and cold shutdown conditions include inventory control, reactivity management, decay heat removal, and RCS pressure control. The three issues of concern discussed in this URI are related to the RCS pressure control function during the assumed 2 hour hot standby period.

The licensee's Analysis of Record (AOR) assumed the following: 1) the time spent in hot standby will be limited to 2 hours, 2) the safety-related PZR PORV and associated instrument air accumulators could maintain RCS pressure in hot standby without the reliance on the RCS code safety valves, and 3) every attempt would be made to open key CVCS valves needed for auxiliary spray in the case that the PZR PORVs were not available. Since instrument air was considered nonsafety-related, instrument air was

assumed to be unavailable during this postulated seismic event. The licensee's UFSAR stated, however, that every attempt would be made to either restore the instrument air compressors (in the case of a LOOP) or to utilize nitrogen bottles to open the necessary air valves to restore the nonsafety-related auxiliary spray system if the PZR PORVs were not available.

Issue of Concern 1: Inadvertent Removal of the Design Basis Requirement to Commence a Cooldown within 2 Hours Following the Establishment of Natural Circulation Conditions and Loss of Instrument Air to Containment.

NRC Finding 05000456/2012004-01; 05000457/2012004-01 documented a deficiency in the licensee's interpretation of a Cautionary Note in the station EOPs. Specifically, the Note required that an RCS cooldown be initiated within 2 hours if the Steam Generator PORVs were being utilized to cooldown the unit. The licensee entered this issue into the CAP and completed a corrective action to address the Finding by revising a "should" to a "shall" in the Cautionary Note and adding additional criteria. Specifically, the licensee revised the start of the 2 hour period from the beginning of the event to after reaching the condensate storage tank TS minimum level as follows:

Prior Instruction: *"If Steam Generator PORVs are being utilized, Natural Circulation cooldown SHOULD be initiated within 2 HOURS."*

Revised Instruction: *"If Steam Generator PORVs are being utilized, Natural Circulation cooldown SHALL be initiated within 2 HOURS after CST reaches 70 percent to ensure an adequate AF water supply."*

The inspectors identified that the 2 hour cooldown period limited the number of PZR PORV cycles to a value less than the design value of 50 cycles. The analyzed 2 hour period with respect to PZR PORVs was based on the Prior Instruction and not the Revised Instruction, which would extend the overall cooldown timeframe since additional PORV cycles would occur since the cooldown would be delayed as a result of the Revised Instruction. Thus, the inspectors determined that this change was potentially non-conservative. The licensee entered the issue into the CAP, and concluded that even if the time in hot standby was doubled to 4 hours, the number of postulated PZR PORV cycles, which was over 50, would be acceptable based on the results of a pre-operational test that cycled the PZR PORVs over a 10 minute timeframe. Additionally, the licensee's position was that operating procedures did not need to include guidance to begin the cooldown within 2 hours because operators had demonstrated on the plant simulator that a cooldown would be initiated if instrument air was lost to the containment. The inspectors questioned the licensee's acceptance of procedural guidance that did not ensure CLB assumptions were satisfied.

Issue of Concern 2: Failure to Account for Allowable PZR PORV Accumulator Air Leakage During 2 Hour Hot Standby Period.

The inspectors identified that the licensee's AOR did not account for any PZR PORV accumulator air system leakage or air leakage due to PZR PORV operation during an assumed 34 cycles. The licensee had established an allowable leakage value of up to 15 psig per hour during routine surveillance testing based upon the PZR PORV safety function for a SGTR/LOOP event with the final PZR PORV cycle occurring about 1 hour after the onset of the event. In addition to accumulator air system leakage, each PZR

PORV cycle could expend up to 0.29 psig (Ref: Operability Evaluation 2013-001), which for 34 cycles assumed in hot standby represented about a 10 psig pressure drop. The BTP RSB 5-1 CLB bases assumed that the PZR PORVs function without nonsafety-related instrument air for up to 2 hours in hot standby. The inspectors identified that the accumulator pressure could drop below the minimum PZR PORV operability value of 85 psig in less than an hour following a design basis earthquake. Thus, the pre-established accumulator pressure limit was not conservative with respect to ensuring the PZR PORVs would operate under the assumptions discussed in BTP RSB 5-1, and the 2 hour mission time in hot standby could not be ensured. This could require RCS pressure control using the RCS safety valves, which do not have the ability to be isolated if stuck open or if excessive leak-by occurs. The inspectors discussed this issue of concern with licensee staff and management prior to September 26, 2012. The licensee entered this issue into the CAP under numerous IRs. Ultimately, the licensee performed an operability evaluation to comprehensively address this issue. In summary, the licensee's final position was that the PZR PORV function would remain available because the CLB permits manual action to recover air to the accumulator system within this 2 hour period, and the UFSAR discussed that if the PZR PORVs would not function, every attempt would be made to restore PZR auxiliary spray utilizing portable nitrogen bottles.

Issue of Concern 3: No Procedures for Crediting the Use Auxiliary Spray Utilizing Portable Nitrogen Bottles.

The licensee's SER stated that for Braidwood and Byron, the auxiliary spray system is nonsafety-related and is assumed not to be available for the purposes of BTP RSB 5-1. However, the licensee's UFSAR stated that if the PZR PORVs were not available, every attempt would be made to restore PZR auxiliary spray either by restoring instrument air compressor power through the EDGs for a LOOP event or by utilizing portable nitrogen bottles to open the associated CVCS valves locally for a seismic event that prevented timely restoration of instrument air. The inspectors verified that the licensee had established procedures to supply power to the station air compressors through safety-related to nonsafety-related electrical cross-ties and associated implementing instructions within the EOPs. In the case of portable nitrogen bottles, however, neither an instruction to direct the activity to begin nor instructions to direct how the activity would be accomplished existed. The inspectors discussed this issue with licensee management. The licensee questioned whether these procedures were required by NRC regulations.

Based on the above, the inspectors questioned whether the licensee had appropriately addressed the issues both individually and collectively to the standards required by NRC regulations. At the conclusion of the inspection period, the inspectors were reviewing the licensee's CLB. This URI will remain open pending additional review.
(URI 05000456/2013002-06, 05000457/2013002-06, Current Licensing Basis Requirements for RCS Pressure Control Function During a Postulated Seismic Event in Reference to NRC RSB BTP 5-1)

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following plant modifications:

- Permanent Modification: HELB Damper – 1B EDG Room;
- Permanent Modification: SI 8811 Valve Containment Assembly Inspection Ports; and
- Temporary Modification: Station Motor-Driven Fire Pump and Temporary Elimination of the Non-Reverse Coupling Ratchet Pin Spring.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design bases, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and were consistent with 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 procedures, and 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 operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment.

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

b. Findings

(Unresolved Item) Current Licensing Basis Requirements for the Unit 1 and Unit 2 Containment Sump Isolation Valves

Introduction: The inspectors identified an URI regarding the licensing and design requirements of the ECCS sump suction valve 1/2SI8811A/B enclosures. Specifically, the inspectors' questioned whether the valve enclosures were considered a part of the reactor containment structure or containment integrity, what requirements were applicable to the valve enclosures and the associated vent and drain valves, and what periodic testing was required.

Description: The normally closed 1/2SI8811A/B valves are located several feet outside the primary containment wall and isolate the open-ended ECCS containment sump suction pipes from the ECCS system. The ECCS containment sump suction pipe is double-walled and each valve body and bonnet is contained in an enclosure with normally closed vent and drain valves. This configuration is prescribed in American National Standard (ANS) 56.2/American Nuclear Standards Institute (ANSI) N271-1976, "Containment Isolation Provisions for Fluid Systems."

The licensee generated IR 1463476, "RH01SA/B Enclosure Classification Appears Overly Conservative," on January 15, 2013, to document a similar question regarding

the classification of the valve enclosure. The question was raised due to upcoming planned work to install inspection ports to allow for inspection inside the enclosures. The inspectors noted that one of the valve enclosures had inspection ports previously installed. The licensee also generated IR 1480240, "1/2RH01SA/SB Leak Tightness Not Challenged for NUREG 0737," on February 26, 2013, documenting that their NUREG-0737 program had inappropriately excluded the 1/2SI8811A/B valve enclosures from pressure testing to potential accident conditions. Through a Work Group Evaluation in IR 1480240, the licensee concluded that pressure testing was required in accordance with NUREG-0737 since the potential existed for pressurizing the valve enclosures under accident conditions.

Separately, the licensee identified that there had been leakage inside the enclosure of valve 1SI8811A. The source of the leakage was suspected by the licensee to be body-to-bonnet leakage, but that could not be confirmed without a visual inspection. The licensee had been opening the enclosure vent and drain valves weekly to drain existing water or validate that no water was present. Identification of this leakage source was the impetus for the planned installation of inspection ports, which had since been deferred.

At the end of the inspection period, the inspectors were continuing to review the licensee's determination of the testing requirements for the valve enclosure, whether an adequate post-maintenance test was performed following installation of inspection ports, and what requirements applied to the valve enclosures and associated vent and drain valves. **(URI 05000456/2013002-07, 05000457/2013002-07, Current Licensing Basis Requirements for the Unit 1 and Unit 2 Containment Sump Isolation Valves)**

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 2A EDG 6L Fuel Injector Metering Rod Replacement;
- 1B AFW Pump Following the Replacement of the Batteries;
- Ultimate Heat Sink Depth After Dredging Activity; and
- SI8811 Valve Containment Assembly Inspection Ports.

These activities were selected based upon the SSC'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 ensured that the equipment met the licensing bases 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 whether problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

This inspection constituted four 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:

- 2BwOS MS-2 Steam Generator PORV Valve Strokes (Routine);
- 2A EDG Monthly Run (Routine);
- 2B EDG Engineered Safety Feature Relay Start (Routine);
- Unit 2 Reactor Containment Fan Cooler Quarterly Surveillance (Routine);
- American Society of Mechanical Engineers (ASME) 2A SX Pump D/P [Differential Pressure] and Flow (Inservice Testing (IST)); and
- Unit 2 RCS Identified Leakage and 2B Reactor Coolant Pump Increased Number 2 Seal Leak-Off Condition (RCS).

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, demonstrate operational readiness, and consistent with the system design basis;
- was plant equipment calibration correct, accurate, and properly documented;
- were as left setpoints within required ranges; and was the calibration frequency in accordance with TSs, the UFSAR, plant procedures, and applicable commitments;
- was measuring and test equipment calibration current;
- was the test equipment used within the required range and accuracy;

- were applicable prerequisites described in the test procedures satisfied;
- did test frequencies meet TS requirements and demonstrate operability and reliability;
- were tests performed in accordance with the test procedures and other applicable procedures;
- were jumpers and lifted leads controlled and restored where used;
- were test data and results accurate, complete, within limits, and valid;
- was test equipment removed following testing;
- where applicable for IST activities, was testing performed in accordance with the applicable version of Section XI of the ASME Code, and reference values consistent with the system design basis;
- was the unavailability of the tested equipment appropriately considered in the performance indicator data;
- where applicable, were test results not meeting acceptance criteria addressed with an adequate operability evaluation, or was the system or component declared inoperable;
- where applicable for safety-related instrument control surveillance tests, was the reference setting data accurately incorporated into the test procedure;
- was equipment returned to a position or status required to support the performance of its safety function following testing;
- were all problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- where applicable, were annunciators and other alarms demonstrated to be functional and annunciator and alarm setpoints consistent with design documents; and
- where applicable, were alarm response procedure entry points and actions consistent with the plant design and licensing documents.

Documents reviewed are listed in the Attachment. This inspection constituted four routine surveillance testing samples, one IST sample, and one RCS leak detection inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Evaluation (71114.02)

.1 Alert and Notification System Evaluation

a. Inspection Scope

The inspectors reviewed documents and held discussions with Emergency Preparedness (EP) staff and management regarding the operation, maintenance, and periodic testing of the back-up and primary Alert and Notification System (ANS) in Braidwood Station's plume pathway Emergency Planning Zone (EPZ). The inspectors reviewed monthly trend reports and the daily and monthly operability records from January 2011 through December 2012. Information gathered during document reviews and interviews was used to determine whether the ANS equipment was maintained and

tested in accordance with Emergency Plan commitments and procedures. Documents reviewed are listed in the Attachment.

This ANS inspection constituted one sample as defined in IP 71114.02-06.

b. Findings

No findings were identified.

1EP3 Emergency Response Organization Staffing and Augmentation System (71114.03)

.1 Emergency Response Organization Staffing and Augmentation System

a. Inspection Scope

The inspectors reviewed and discussed with plant EP management and staff the Emergency Plan commitments and procedures that addressed the primary and alternate methods of initiating Emergency Response Organization (ERO) on-shift and augmented staffing. The inspectors reviewed reports and a sample of CAP records of the 2011 drive-in drill and unannounced off-hours augmentation call-in tests, which were conducted between February 2011 and May 2012, to determine the adequacy of the drill critiques and associated corrective actions. The inspectors also reviewed a sample of the EP training records of approximately 31 ERO personnel, who were assigned to key and support positions, to determine the status of their training as it related to their assigned ERO positions. Documents reviewed are listed in the Attachment.

This ERO augmentation testing inspection constituted one sample as defined in IP 71114.03-06.

b. Findings

No findings were identified.

1EP5 Maintenance of Emergency Preparedness (71114.05)

.1 Maintenance of Emergency Preparedness

a. Inspection Scope

The inspectors reviewed a sample of Nuclear Oversight staff's 2011 and 2012 audits of Braidwood Station's EP Program to determine whether the independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed samples of CAP records associated with the 2012 Biennial Exercise, as well as various EP drills conducted in 2011 and 2012, to determine whether the licensee fulfilled drill commitments and to evaluate the licensee's efforts to identify and resolve identified issues. The inspectors reviewed a sample of EP items and corrective actions related to the facility's EP Program and activities to determine whether corrective actions were completed in accordance with the site's CAP. Documents reviewed are listed in the Attachment.

This correction of EP weaknesses and deficiencies inspection constituted one sample as defined in IP 71114.05-06.

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 Unplanned Scrams Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams Per 7000 Critical Hours Performance Indicator (PI) for Braidwood Unit 1 and Unit 2 from the first quarter 2012 through the fourth quarter 2012. 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, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, event reports and NRC Inspection Reports for the period of January 1, 2012 through December 31, 2012 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR 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 unplanned scrams per 7000 critical hours samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications PI for Braidwood Unit 1 and Unit 2 from the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, event reports and NRC Inspection Reports for the period of January 1, 2012 through December 31, 2012 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR 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 unplanned scrams with complications samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Drill/Exercise Performance

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill/Exercise Performance (DEP) PI for the period from the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the DEP indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; assessments of PI opportunities during pre-designated control room simulator training sessions, performance during the 2012 Biennial Exercise, and performance during other drills. Documents reviewed are listed in the Attachment.

This inspection constitutes one DEP sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Emergency Response Organization Drill Participation

a. Inspection Scope

The inspectors sampled licensee submittals for the ERO Drill Participation PI for the period from the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; performance during the 2012 biennial exercise and other drills; and revisions of the roster of personnel assigned to key ERO positions. Documents reviewed are listed in the Attachment.

This inspection constitutes one ERO drill participation sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.5 Alert and Notification System

a. Inspection Scope

The inspectors sampled licensee submittals for the ANS PI for the period from the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI Guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI and results of periodic ANS operability tests. Documents reviewed are listed in the Attachment.

This inspection constitutes one ANS sample 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 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 whether identification of the problem was complete and accurate; whether timeliness was commensurate with the safety significance of the issue; whether the 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 whether the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue

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 followup, 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 IR 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.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report 05000456/2012-001-00: Two Main Steam Safety Valves Failed Pre-Outage Setpoint Testing Due to Abnormal Spring Geometry

Licensee Event Report (LER) 05000456/2012-001-00 documented the failure of two Unit 1 Main Steam Safety Valves (MSSVs) to meet the as-found lift set pressure acceptance criteria of plus or minus 3 percent during surveillance testing. Specifically, on April 11, 2012, MSSV 1MS015D lifted at a 5.08 percent lower pressure than required (i.e., -5.08 percent or 1143.79 psig) and on April 12, 2012, MSSV 1MS014D lifted at a 3.31 percent lower pressure than required (i.e., -3.31 percent or 1179.64 psig) which was outside of the 3 percent acceptance criteria. The licensee performed an apparent cause evaluation and identified that the 1MS015D MSSV spring had a much thinner coil cross-section on the top coil than the bottom coil which was significant and could impact valve performance due to off-center loading of the spindle disk. The MS014D MSSV spring had a gap between the top coil of the spring that was wider than recommended based on the statistical evaluation of the Byron and Braidwood MSSV springs over a 10-year history. The licensee entered these issues into the CAP and corrected the issues by refurbishing the valves.

This LER was reviewed. No findings or violations of NRC requirements were identified. Documents reviewed are listed in the Attachment. This LER is closed.

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

.2 (Closed) Licensee Event Report 05000456/2012-003-00; 05000457/2012-003-00 and 05000456/2012-003-01; 05000457/2012-003-01: Fuel Handling Incident Area Radiation Monitors Inoperable Due to Incorrect Alarm Setpoints

On August 2, 2012, the licensee submitted LER 05000456/2012-003-00; 05000457/2012-003-00 in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation or condition prohibited by the plant's TSs. It was also determined that this condition existed since initial startup. However, the licensee did not report this event as a condition that as a result of a single cause could have prevented the fulfillment of a safety function

needed to isolate containment. This condition was also applicable to Byron Station, another nuclear power station owned by Exelon Generation.

Due to a setpoint error, the licensee determined that containment isolation would only be delayed. Using the methods established in the Offsite Dose Calculation Manual (ODCM), both fuel handling incident area radiation monitors would have provided a containment isolation signal prior to containment atmosphere radiation levels reaching a level that would result in exceeding 10 percent of the offsite dose release limits. Therefore, the licensee concluded that there was no loss of safety function from this event. Exelon also submitted LER 05000454/2012-003-00; 05000455/2012-003-00 for Byron Station describing the same reasoning, that the event was not a condition that as a result of a single cause could have prevented the fulfillment of a safety function needed to isolate containment.

The inspectors at Byron Station reviewed the Byron LER and reporting guidance contained in NUREG-1022, Revision 2, and discussed the issue with the NRC Office of Nuclear Reactor Regulation subject matter expert. The inspectors determined that the event represented a condition that as a result of a single cause could have prevented the fulfillment of a safety function needed to isolate containment. Specifically, both containment area radiation monitors were inoperable with non-conservative setpoints to isolate containment ventilation. This issue was documented in NRC inspection Report 05000454/2012005, 05000455/2012005 for Byron.

After the Byron report was issued, the licensee at Braidwood re-evaluated the event and determined the event to be reportable under 10 CFR 50.73(a)(2)(v)(C), as a condition that as a result of a single cause could have prevented the fulfillment of a safety function. LER 05000456/2012-003-01; 05000457/2012-003-01 was subsequently issued on February 18, 2013.

The inspectors evaluated both LERs and determined that a licensee-identified violation of 10 CFR 50.73 existed. The regulatory aspects of this violation are documented in Section 4OA7 of this report. These LERs are closed.

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

.3 <u>(Closed) Licensee Event Report 05000456/2012-005-00: Incorrect Procedure Guidance Due to a Lack of Technical Rigor Resulted in the Unplanned Inoperability of the 1A and 1B Emergency Diesel Generators</u>

On December 13, 2013, the inspectors identified that the licensee's Plant Barrier Impairment (PBI) procedure contained an inadequate pre-evaluated compensatory action for the impairment of a Diesel Oil Storage Tank (DOST) watertight door. Specifically, the PBI procedure permitted a DOST watertight door to be inoperable if the other train DOST watertight door was operable. Under these conditions, the PBI procedure associated with the impaired DOST watertight door required the EDG to be declared inoperable. The inspectors identified that since the door separating the two DOST rooms was a fire door and therefore not a watertight barrier, both EDGs should be declared inoperable.

The licensee conducted a 3 year work history review and identified that on September 11, 2013, a PBI was in effect for the watertight door for the 1B DOST while the 2B EDG was OOS for maintenance. Therefore, the licensee concluded that this

condition was reportable under 10 CFR 50.72(a)(2)(v)(D) as a condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident (i.e., safety-related power).

The licensee entered this issue into their CAP and the inspectors documented a Green finding and an associated NCV in NRC Inspection Report 05000456/2012005-002. This LER was reviewed. No findings or violations of NRC requirements were identified. Documents reviewed are listed in the Attachment. This LER is closed.

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

4OA5 Other Activities

.1 (Closed) Temporary Instruction 2515/182 - Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks

a. Inspection Scope

Leakage from buried and underground pipes has resulted in ground water contamination incidents with associated heightened NRC and public interest. The industry issued NEI 09-14, “Guideline for the Management of Buried Piping Integrity,” (ADAMS Accession No. ML1030901420) to describe the goals and required actions (commitments made by the licensee) resulting from this underground piping and tank initiative. On December 31, 2010, NEI issued Revision 1 to NEI 09-14, “Guidance for the Management of Underground Piping and Tank Integrity,” (ADAMS Accession No. ML110700122), with an expanded scope of components which included underground piping that was not in direct contact with the soil and underground tanks. On November 17, 2011, the NRC issued Temporary Instruction (TI) 2515/182, “Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks,” to gather information related to the industry’s implementation of this initiative.

From January 7 to January 10, 2013, the inspectors conducted a review of records and procedures related to the licensee’s program for buried pipe, underground pipe, and tanks in accordance with Phase II of TI 2515/182. This review was performed to confirm that the licensee’s program contained attributes consistent with Sections 3.3 A and 3.3 B of NEI 09-14, and to confirm that these attributes were scheduled and/or completed by the NEI 09-14, Revision 1, deadlines. To determine if the program attributes were accomplished adequately, the inspectors interviewed licensee staff responsible for the buried pipe program and observed buried pipe program related activities. Specifically, the inspectors observed the licensee excavate a buried fire protection system pipe segment to locate and repair the source of a pipe leak. Additionally, the inspectors performed a walkdown of rectifiers, anode beds, and test points used for the operation and maintenance of the cathodic protection system.

Based upon the scope of the review described above, Phase II of TI 2515/182 was completed.

b. Observations

The licensee’s buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.a of the TI and it was confirmed that activities which correspond to completion dates specified in the program that have passed since the

Phase I inspection was conducted have been completed. Additionally, the licensee's Buried Piping and Underground Piping and Tanks Program was inspected in accordance with Paragraph 03.02.b of the TI and responses to specific questions were submitted to the NRC Headquarters staff.

c. Findings

No findings were identified.

.2 (Closed) NRC Temporary Instruction 2515/187 – Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns

a. Inspection Scope

As discussed in NRC Integrated Inspection Report 05000456/2012005; 05000457/2012005, the inspectors previously verified that licensee walkdown packages for the Unit 2 Auxiliary Feedwater (AF) Pipe Tunnel, Unit 1 Residual Heat Removal (RHR) and Containment Spray (CS) Pump Rooms, and Fuel Handling Building contained the elements specified in NEI 12-07, "Guidelines for Performing Walkdowns of Plant Flood Protection Features."

During the previous quarter, the inspectors accompanied the licensee on their walkdowns of the Unit 1 RHR and CS Pump Rooms and Unit 0 (Common) Spent Fuel Pit Cooling Pump and Heat Exchanger Rooms, and verified that the licensee confirmed the following flood protection features:

- Visual inspection of the flood protection feature was performed if the flood protection feature was relevant. External visual inspection for indications of degradation that would prevent its credited function from being performed was performed;
- Critical SSC dimensions were measured;
- Available physical margin, where applicable, was determined; and
- Flood protection feature functionality was determined using either visual observation or by review of other documents.

During this quarter, the inspectors conducted additional independent walkdowns to verify licensee compliance with inspection guidance contained in TI 2515/187. The areas selected were the Unit 2 AF Pipe Tunnel and the Unit 1 Curved Wall Area 401' elevation.

The inspectors verified that non-compliances with current licensing requirements and issues identified in accordance with the 10 CFR 50.54(f) letter, Item 2.g of Enclosure 4, were entered into the licensee's CAP. In addition, issues identified in response to Item 2.g that could challenge risk-significant equipment and the licensee's ability to mitigate the consequences of flooding will be subject to additional NRC evaluation.

b. Findings

One licensee-identified violation related to this inspection is documented in Section 4OA7 of this report.

.3 (Closed) Unresolved Item 05000456/2012002-04; 05000457/2012002-04, Maintenance Rule Performance Monitoring of High Energy Line Break Dampers

a. Inspection Scope

As discussed in NRC Integrated Inspection Report 05000456/2012002; 05000457/2012002, the inspectors reviewed the licensee's performance monitoring criteria for the dampers identified in NCV 05000456/2012002-03; 05000457/2012002-03 and identified an URI pertaining to the licensee's decision to monitor HELB damper preventative maintenance performance by conducting a periodic 18-month visual inspection activity. Specifically, the inspectors questioned if it was appropriate and adequate to rely only on the visual inspection activities absent some level of periodic demand testing to provide assurance that HELB dampers would shut within required time limits.

The inspectors reviewed the licensee's maintenance rule monitoring program, the licensee's CAP, current operating experience across the fleet, and the specific actions being taken by the licensee during these 18-month visual inspections. Through the licensee's CAP, the inspectors did not identify any component failures that would indicate program inadequacies. This URI is considered closed.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 3, 2013, the inspectors presented the inspection results to Mr. M. Kanavos, Braidwood Plant Manager, 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 Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (TI 2515/182) with Mr. M. Kanavos, Braidwood Plant Manager, and other members of the licensee staff on January 10, 2013.

- The results of the EP Program inspection with Mr. D. Enright, Braidwood Site Vice President, and other members of the licensee staff on February 15, 2013.

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

4OA7 <u>Licensee-Identified Violations</u>

The following violations of very low safety significance (Green) or Severity Level IV were identified by the licensee and are violations of NRC requirements which meet the criteria of the NRC Enforcement Policy, for being dispositioned as a Non-Cited Violation (NCV).

- Title 10 CFR Part 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires, in part, that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to SSCs that a risk-informed evaluation process has shown to be significant to public health and safety.

  Contrary to the above, on January 24, 2013, the licensee failed to properly assess and manage the increase in risk from Unit 2 maintenance activities involving the unavailability of the motor-driven fire pump and Unit 2 exhaust building vent fans. Specifically, the licensee assumed the risk configuration was Green based upon a conversation with a licensee expert; however, the licensee's formal assessment concluded that the risk configuration should have been elevated to Yellow. The inspectors determined that this issue was of very low safety significance (Green) after reviewing IMC 0609, Appendix K, "Maintenance Risk Assessment and Risk Significance Determination Process Assessment". Specifically, the increase in risk was evaluated to be less that E-6 for ICDP and less than E-7 for ILERF. The licensee entered this issue into their CAP as IR 1467237, "Online Risk Status Inappropriately Changed to Green."

- Braidwood Operating License Condition 2.E requires, in part, that the licensee implement and maintain in effect all provisions of the approved Fire Protection Program as described in the UFSAR, as supplemented and amended, and as approved in the Safety Evaluation Report, dated November 1983, and its supplements. The Approved Fire Protection Report described an automatic Halon Suppression System as the primary method of fire suppression in the Upper Cable Spreading Room (UCSR) with a manual Carbon Dioxide Backup Suppression system.

  Contrary to the above, from December 20, 2012 through January 5, 2013, the UCSR Halon Suppression System discharge panel was unknowingly de-energized due to the inadequate restoration of a previous clearance order, which would have prevented halon discharge into the UCSR. The manual backup suppression system was not adversely affected or removed from service during the subject time period. The inspectors screened the issue in accordance with IMC 0612, Appendix B, "Issue Screening," and IMC 0609, Appendix F, "Fire Protection Significance Determination Process," and determined the finding was of very low safety significance (Green). This issue was entered into the licensee's CAP as IR 1459013, "Control Power Light Not On for 0FP05J."

- Title 10 CFR Part 50.55a(g)(6)(ii)(D), "Reactor Vessel Head Inspections," required that all licensees of pressurized water reactors augment their inservice inspection program with American Society of Mechanical Engineers (ASME)

Code Case N-729-1 subject to the conditions specified in paragraphs (g)(6)(ii)(D)(2) through (6) of this section.

Contrary to the above, the licensee failed to perform a required volumetric examination for Unit 1 Control Rod Drive Mechanism Penetration Number 4 during their Spring 2012 Unit 1 refueling outage. This issue was identified during this inspection period when Braidwood Station was notified by Westinghouse that due to equipment issues not known at the time, the inspection data was not fully collected for Penetration Number 4. This issue was determined to be of very low safety significance (Green), in part, because the licensee performed a technical evaluation that provided assurance that Penetration Number 4 would provide its pressure boundary function assuming an indication and maximum projected growth until the Fall 2013 Unit 1 refueling cycle. The licensee entered this issue into their CAP as IR 1479975, “A1R16 CRDM [Control Rod Drive Mechanism] Penetration #4 Inspection Volume Coverage Not Met.”

- Title 10 CFR 50.73(a), “Reportable Events,” requires, in part, that, “The holder of an operating license under this part or a combined licensee under Part 52 of this chapter (after the Commission had made the finding under 52.103(g) of this chapter) for a nuclear power plant (licensee) shall submit a LER for any event of the type described in this paragraph within 60 days after the discovery of the event,” including in accordance with 10 CFR 50.73(a)(2)(v), “Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to:…(C) Control the release of radioactive material.”

  Contrary to the above, between August 4, 2012, and February 17, 2013, the licensee failed to submit a LER within 60 days of discovery that Unit 1 and Unit 2 containment area radiation monitors 1/2AR11J and 1/2AR12J were unable to perform their safety function to control the release of radioactive materials. Corrective actions included the issuance of an updated LER and re-evaluation of the Safety System Functional Failure performance indicator input. Because this issue was entered into the licensee’s CAP and was similar to Example 6.d.10 of the NRC Enforcement Policy, it is being treated as a Severity Level IV NCV consistent with Section 2.3.2 of the Enforcement Policy.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Enright, Site Vice President
M. Kanavos, Plant Manager
K. Aleshire, Director, Exelon Emergency Preparedness
L. Antos, Manager, Security Operations
P. Boyle, Director, Work Management
S. Butler, Manager, Corrective Action Program
A. Ferko, Director, Site Engineering
B. Finlay, Manager, Site Security
R. Leasure, Manager, Site Radiation Protection
D. Lesnick, Manager, Emergency Preparedness
M. Marchionda-Palmer, Director, Site Operations
J. Odeen, Manager, Site Project Management
D. Palmer, Superintendent, Radiation Protection
D. Poi, Manager, Emergency Preparedness
R. Radulovich, Manager, Site Nuclear Oversight
J. Rappeport, Manager, Site Chemical Environment & Radwaste
K. Sahadewan, Manager, Reactor Engineering
D. Stiles, Manager, Operations Training
C. VanDenburg, Manager, Site Regulatory Assurance
L. Young, Manager, Maintenance

Nuclear Regulatory Commission

E. Duncan, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2013002-01; 05000457/2013002-01	NCV	Failure to Perform an Adequate 10 CFR 50.59 Evaluation Removing the Positive Displacement Pump from the Current Licensing Basis (Section 1R04.1.b.1)
05000456/2013002-02; 05000457/2013002-02	FIN	Positive Displacement Pumps Not Available to Perform Their Mitigating Functions Associated with Both Normal and Abnormal Operations (Section 1R04.1.b.1)
05000456/2013002-03; 05000457/2013002-03	NCV	Failure to Establish an Adequate Quality Instruction for Determining Pressurizer Power Operated Relief Valve Operability (Section 1R04.1.b.2)
05000456/2013002-04; 05000457/2013002-04	URI	Boric Acid Transfer Pump Electrical Power Supply Not Safety-Grade (Section 1R04.2.b)
05000456/2013002-05; 05000457/2013002-05	URI	NonSafety-Related Turbine Building Waste Disposal System to Safety-Related Essential Service Water Pump Room Sump Design Interaction (Section 1R06.1.b)
05000456/2013002-06; 05000457/2013002-06	URI	Current Licensing Basis Requirements for RCS Pressure Control Function During a Postulated Seismic Event in Reference to NRC RSB BTP 5-1 (Section 1R15.1.b)
05000456/2013002-07; 05000457/2013002-07	URI	Current Licensing Basis Requirements for the Unit 1 and Unit 2 Containment Sump Isolation Valves (Section 1R18.1.b)

Closed

05000456/2013002-01; 05000457/2013002-01	NCV	Failure to Perform an Adequate 10 CFR 50.59 Evaluation Removing the Positive Displacement Pump from the Current Licensing Basis (Section 1R04.1.b.1)
05000456/2013002-02; 05000457/2013002-02	FIN	Positive Displacement Pumps Not Available to Perform Their Mitigating Functions Associated with Both Normal and Abnormal Operations (Section 1R04.1.b.1)
05000456/2013002-03; 05000457/2013002-03	NCV	Failure to Establish an Adequate Quality Instruction for Determining PZR PORV Operability (Section 1R04.1.b.2)
05000456/2012-001-00	LER	Two Main Steam Safety Valves Failed Pre-Outage Setpoint Testing Due to Abnormal Spring Geometry (Section 4OA3.1)
05000456/2012-003-00; 05000457/2012-003-00	LER	Fuel Handling Incident Area Radiation Monitors Inoperable Due to Incorrect Alarm Setpoints (Section 4OA3.2)
05000456/2012-005-00	LER	Incorrect Procedure Guidance Due to a Lack of Technical Rigor Resulted in Unplanned Inoperability of the 1A and 1B Emergency Diesel Generators (Section 4OA3.3)
TI 2515/182	TI	Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (Section 4OA5.1)
TI-2515/187	TI	Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns (Section 4OA5.2)
05000456/2012002-04; 05000457/2012002-04	URI	Maintenance Rule Performance Monitoring of HELB Dampers (Section 4OA5.3)

Discussed

05000456/97005-01 05000457/97005-01	VIO	Failure to Properly Maintain Emergency Operating Procedures (Section 1R04.2)
05000456/2012004-01 05000457/2012004-01	FIN	Failure to Adequately Evaluate Operation Crew Performance for Reactor Trip and Failure to Adequately Evaluate Emergency Operating Procedure Standards (Section 1R15.1.b)

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

- 0BwOA ENV-1, Adverse Weather Conditions, Revision 113
- 1BwOA ENV-1, Adverse Weather Conditions Unit 1, Revision 99
- 2BwOA ENV-1, Adverse Weather Conditions Unit 2, Revision 99

1R04 Equipment Alignment

- IR 0104163; Prior Inoperability of Unit 1 and 2 Pressurizer PORVs; April 16, 2002
- IR 0156607; NRC Questions Concerning Surveillance 1BwOSR 3.4.11.3; April 29, 2003
- IR 0333781; 2RY456 Has Small Internal Leakage; May 9, 2005
- IR 0894087; 1/2RY8000A/B IST Testing Requirements; March 17, 2009
- IR 1122680; 1RY455A Supply Air Leaks Found During VT-2 Inspection; October 6, 2010
- IR 1122684; 1RY456 Supply Air Leaks Found During VT-2 Inspection; October 6, 2010
- IR 1123579; RY PORV Accumulator IA Check Valve Test Failure; October 7, 2010
- IR 1210639; 2RY456 Stroked at Max Allowed Limit; May 2, 2011
- IR 1314631; 1A DG Cam Cover Oil Leaks - 1DG01KA; January 18, 2012
- IR 1315229; Braidwood Lake Alkalinity Exceeds Goal; January 19, 2012
- IR 1323647; 1A DG Need to Replace Fuel Line with Hose - 1DG01KA-AA; February 7, 2012
- IR 1329109; Replace 1A DG Overspeed Trip Actuation Cable; February 20, 2012
- IR 1331568; 1A DG Piping Contact Needs Corrected; February 24, 2012
- IR 1336370; 1st Lake Softening for 2012; March 2, 2012
- IR 1337021; NRC and IEMA Identified Error in BwOP DG-M4; March 6, 2012
- IR 1337661; Compensatory Measure for Op Eval 11-011 Not Being Performed; March 7, 2012
- IR 1337923; Refurbish EDG Jacket Water CLR Lower Stationary Channel; March 7, 2012
- IR 1341011; Entered 0BwOA ENV-7 Due to Cooling Lake Softening; March 14, 2012
- IR 1341023; 2nd Lake Softening - 2012; March 14, 2012
- IR 1353863; Received Unexpected Annunciator, SX Pump Discharge Pressure Low; April 14, 2012
- IR 1354117; 3rd Lake Softening of 2012; April 13, 2012
- IR 1358712; 1A DG Unexpected Low Jacket Water Pressure Alarm; April 25, 2012
- IR 1358715; 1A DG Crankcase Pressure Indications Do Not Agree; April 25, 2012
- IR 1359894; 1A DG Crankcase Pressure Indications Do Not Agree; April 28, 2012
- IR 1359967; 1A DG Power Meter 1JI-DG711 Error; April 26, 2012
- IR 1370084; 1A DG Rebuild Crankcase Explosion Covers - 1DG01KA; May 23, 2012
- IR 1370090; 1A DG Fittings Leak 1DG5218A - 1DG5281A; May 23, 2012
- IR 1427987; 2RY455A Diaphragm Air Leak During 2BwOSR 3.4.11.3; October 18, 2012
- IR 1430960; Calcium Carbonate Scaling of the Unit 2 CW System; October 24, 2012
- IR 1435273; 2RY456 Valve Leaking at Actuator; November 2, 2012
- IR 1435382; 2RY456 Would Not Show Full Open During PMT Stroke Testing; November 3, 2012
- IR 1435523; 2RY456 Exceeded Its Operability Stroke Time; November 3, 2012
- IR 1437799; Discrepancy Noted During Performance of WO 01568122-01; November 9, 2012

- IR 1451835; NRC Raised a Concern About BwAP 1110-3 with DOST Room Doors; December 13, 2012
- IR 1472138; 2A CS Pump Room Has Signs of Ground Water In-Leakage; February 6, 2013
- IR 1472155; NRC Questions Regarding Plant Equipment; February 6, 2013
- IR 1477923; NRC Identified PDP 50.59 Enhancement Required; February 20, 2013
- IR 1490112; First Lake Softening for 2013; March 20, 2013
- IR 1496523; NRC Id'd - Loss of Safety FCN Not Reported for DOST Door; April 2, 2013
- 1BwOA PRI-2; Emergency Boration; Revision 101
- BwOP AB-M1; Operating Mechanical Lineup Unit 0 Boric Acid Operating; Revision 10
- BwOP AB-M2; Operating Mechanical Lineup Unit 0 HUTS Operating; Revision 10
- BwOP DG-11; Diesel Generator Startup; Revision 40
- BwOP DG-24; Diesel Generator Air Receiver Pressure Control; Revision 1
- BwOP DG-E1; Electrical Lineup 1A Diesel Generator; Revision 7
- BwOP DG-M1; Operating Mechanical Lineup 1A DG; Revision 17
- BwOP DG-M11; Operating Mechanical Lineup DG 1A Fuel Oil; Revision 3
- BwOP CV-16; PZR Auxiliary Spray Operation; Revision 5
- CY-BR-120-412; Braidwood Station Lake Chemistry Control; Revision 9
- OP-AA-101-113-1004; 1A Turbine Oil Cooler (1TO01AA) Inlet/Outlet Head Upper Plug Released From Cooler Causing Non-Essential Service Water Leak; March 19, 2013
- OP-AA-108-115; Potential Issue with Westinghouse Modeling of SG PORV Relief Capacity; Revision 6
- CY-AP-120-150; Boric Acid Storage Tank Boric Acid Mix Tank Chemistry; Revision 5
- CY BR-120-4120; Braidwood Station Lake Chemistry Strategic Plan; Revision 5
- NUMARC 93-01; Industry Guideline for Monitoring Effectiveness of Maintenance at Nuclear Power Plants; Revision 2
- Transmittal of Commonwealth Edison Special Process Procedures Manual Volume IIIA-1-NSWP's; Revision 30, November 6, 1997
- Safety Evaluation by NRR Relating to Natural Circulation Cooldown; November 4, 1988
- 10 CFR 50.59 Safety Evaluation; PDP, Centrifugal Charging Pump; Revision 0
- Test Report Package 21-0102; Calibration of Boric Acid Storage Tank Level; Revision 005

1R05 Fire Protection

- Braidwood Station Pre-Fire Plans
- Braidwood Station Fire Protection Program

1R06 Flood Protection Measures

- IR 0245518; Alarm for Hi Level in 2SI8811B Canister; August 18, 2004
- IR 0509194; 2SI8811B Canister Level High Did Not Clear After Drain; July 14, 2006
- IR 0530942; Body to Bonnet Leak Identified on 2SI8811B; September 13, 2006
- IR 1122684; 1RY456 Supply Air Leaks Found During VT-2 Inspection; October 6, 2010
- IR 1123181; PZR Safety As Left Test During A1R15; October 7, 2010
- IR 1373903; Received Unexpected Alarm 1-5-E7; June 3, 2012
- IR 1414264; Containment Recirc Sump Valve Canister Level High Annunciator; September 17, 2012
- IR 1426946; 1WF06PB Does Not Develop Adequate Discharge Pressure; October 16, 2012
- IR 1454336; Received Hi Level Alarm on 1SI8811A Canister; December 20, 2012
- IR 1461230; Received 1SI8811A High Canister Level Alarm; January 20, 2013
- IR 1463353; Install Inspection Ports in 2RH01SA Per EC 361752; January 16, 2013

- IR 1463476; RH01SA/B Enclosure Classification Appears Overly Conservative; January 15, 2012
- IR 01464644; 1WF06PA and B Degraded – Insufficient Urgency to Correct; January 19, 2013
- IR 1465027; 1WF040A Not Seating Properly; January 21, 2013
- IR 1473152; Single Point Vulnerability for SX Pump Room Flooding; February 8, 2013
- 0BwOA WS; System Malfunction
- 0BwOA-PRI-8; Aux Building Flooding; Revision 6
- 0BwOA-PRI-8; Essential Service Water Malfunction, Revision 104
- BwAR OPLO1J-9-A1; Revision 6
- BwAR OPL02J-2-A6; Turb Bldg Floor Drain Sump Level High High; Revision 8
- BwOP WF-9; Operation of the Essential Service Water Sump; Revision 4
- Braidwood Auxiliary Building Flood Level Calculations; Revision 2; Analysis No. 3C8-0685-002
- ATI 1449644-02; Review of Calculations Related to Flooding in Turbine Building; January 24, 2013
- ATI 1473152-04; Leaking Sump Pump Discharge Check Valve; February 28, 2013
- EC 365103; Containment Recirculation Sump 2B Isolation Valve Assembly; June 15, 2007
- WR 0422864; Troubleshoot 1WF06PA and B to Identify Cause of Problems
- Braidwood UFSAR; Revision 13 (2011); 9.3.3 Equipment and Floor Drainage System (pages 9.3-19 – 9.3-24)
- Braidwood UFSAR; Revision 13 (2011); 9.2.1.2 Essential Service Water System (Pages 9.2-2 – 9.2-6)
- Braidwood UFSAR; Revision 13 (2011); 10.4.5 Circulating Water System (Pages 10.4-12 – 10.4-13)
- Byron UFSAR; Revision 13 (2011); 10.4.5 Circulating Water System (Pages 10.4-9 – 10.4-11)
- Drawing M-11; General Arrangement Floor Plan at RL. 346’-0” Units 1 & 2
- Drawing M-48; Miscellaneous Sumps and Pumps
- Drawing M-48-16; Diagram of Waste Disposal Turbine Building Floor Drains
- Drawing M-48-19; Diagram of Miscellaneous Sumps & Pumps
- Drawing M-60; Reactor Coolant (PZR PORV Accumulators)
- Drawing M-2195; Recirculating Sump and IEST Piping Plan and Section
- Drawing 99640; Spec.# L-2763 Installation Details of 3000 Duplex Bilge Pumps (N-162) Units 1 & 2
- NUREG-0800; Equipment and Floor Drainage System; Revision 2 – July 1981
- NUREG-0800; Flood Protection; Revision 2 – July 1981
- NUREG-0800; Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment; Revision 2 – October 1990
- NRC Information Notice No. 83-44; Potential Damage to Redundant Safety Equipment As a Result of Backflow Through the Equipment and Floor Drain System; July 1, 1983
- NRC Information Notice No. 83-44, Supplement 1; Potential Damage to Redundant Safety Equipment As a Result of Backflow Through the Equipment and Floor Drain System; August 30, 1990

<u>1R11 Licensed Operator Requalification Program and Licensed Operator Performance</u>

- LORT Training Scenario, February 28, 2013

<u>1R12 Maintenance Effectiveness</u>

- IR 1122680; 1RY455A Supply Air Leaks Found During VT-2 Inspection; October 6, 2010
- IR 1395277; IEMA Question: Clarify Requirements for Leak Tight Barriers; July 31, 2012

- IR 1413150; Procedure Enhancement: Water Tight Door Inspection LMS-ZZ-04; September 14, 2012
- IR 1418222; U2 Natural Circ Cooldown - Impact on PZR PORV Cycles; September 25, 2012
- IR 1419787; Natural Circ Cooldown - NRC Question on PZR PORV Cycles; September 28, 2012
- IR 1459353; NRC Question Re 1BwOSR 3.4.22.3 Acceptance Criteria; January 7, 2013
- IR 1467206; 2MS018A Failed to Close; January 25, 2013
- IR 1465166; Hydraulic Oil Leak on S/G PORV Actuator; January 22, 2013
- IR 1467503; As Found Condition at 2MS018A PCV-3; January 27, 2013
- IR 1469333; Recent SG PORV Issues and Trends; January 30, 2013
- IR 1472156; Slave Start of 2A DG Was At 9.79 Seconds; February 6, 2013
- IR 1478437, NRC Questions in Operability Evaluation 12-006; February 19, 2013
- IR 1478544, NRC Question Regarding PZR PORV Accumulator Leakage; February 21, 2013
- IR 1479799; Decision Made to Not Follow Current Procedure Revision; February 23, 2013
- EC 392546; Increasing Frequency of Performing UTS at RWST Header Locations; February 21, 2013
- 2BwFR-S.1; Response to Nuclear Power Generation/ATWS Unit 2; Revision 202, WOG 2
- 1BwOA SEC-4; Loss of Instrument Air; Revision 103
- BwOP AB-M1; Operating Mechanical Lineup Unit 0 Boric Acid Operating; Revision 10
- BwOP AB-M2; Operating Mechanical Lineup Unit 0 HUTS Operating; Revision 10
- Braidwood Fire Protection Report; Amendment 24, December 2010
- 1BwOSR 3.4.11.3; Pressurizer PORV Instrument Air Accumulator Check Valve Test and Accumulator System Pressure Integrity Test; Revision 12
- 2BwOSR 3.4.11.3; Pressurizer PORV Instrument Air Accumulator Check Valve Test and Accumulator System Pressure Integrity Test; Revisions 8 and 9
- 2BwOSR 3.6.3.5.MS-1; Main Steam System Containment Isolation Valve Stroke Surveillance; Revision 13
- WC-MW-114; 1BwOSR 3.4.11.3 U1 PZR PORV Instrument Air Accumulator Check Valve Test and Accumulator System Pressure Integrity Test; October 24, 2007
- WC-AA-114; 2BwOSR 3.4.11.3 PZR PORV Instrument Air Accumulator Check Valve Test and Accumulator System Pressure Integrity Test; May 14, 2008
- WO 0972937 01; IST-CO-2RY085A/B & 086A/B-PZR PORV IA Accumulator Check Valve Test; April 25, 2008
- WO 1138761 01; IST-CO-2RY085A/B & 086A/B-PZR PORV IA Accumulator Check Valve Test; October 25, 2009
- WO 1282281 01; IST-CO-2RY085A/B & 086A/B-PZR PORV IA Accumulator Check Valve Test; May 5, 2011
- WO 1382007 01; IST-CO-1RY085A/B & 086A/B-PZR PORV IA Accumulator Check Valve Test; April 21, 2012
- WO 1438216 01; IST-CO-2RY085A/B & 086A/B-PZR PORV IA Accumulator Check Valve Test; November 2, 2012
- Braidwood Failure Report; February 19, 2009 through February 19, 2013
- IST-BWD-BDOC-V-14; Inservice Test Bases Document for SG PORV 1/2MS018A-D
- Main Steam System Maintenance Rule Evaluation; January 1, 2011 through December 31, 2012
- Primary Containment Maintenance Rule Evaluation; January 1, 2011 through December 31, 2012
- MRC Review ACE; Engineering IR 1467209; February 1, 2013

1R15 Operability Determinations and Functionality Assessments

- IR 1409900; Potential Unidentified Condition with MSIV Accumulator; September 6, 2012
- IR 1467206; 2MS018A Failed to Close; January 25, 2013
- IR 1472511; Linkage Strap Installed Backwards (DUP); February 7, 2013
- IR 1472524; Linkage Strap Installed Backwards (DUP); February 7, 2013
- IR 1472527; Linkage Strap Installed Backwards on 0VV55Y; February 7, 2013
- IR 1472535; Found “S” Hooks Installed Backwards on 0VV24Y; February 7, 2013
- IR 1472554; 0VV115Y “S” Hooks Found to be Installed Backwards; February 7, 2013
- 1BwEP-0; Reactor Trip or Safety Injection, Unit 1; Revision 204
- 1BwEP-2; Faulted Steam Generator Isolation, Unit 1; Revision 202
- 1BwEP ES-0.1; Reactor Trip Response, Unit 1; Revision 203
- BwMP 3300-052; 18 Month Visual Inspection of All Safety-Related Fire Dampers; Revision 12
- BwMP 3300-052A6; Work Performance Checklist for Damper 0VL28Y; Revision 3
- EC-EVAL # 350550; Evaluation of Fire Damper S-Hook Orientation Impact; Revision 0
- Op Eval 12-006; MSIV Hydraulic Accumulator Heatup Concerns; Revision 0
- Westinghouse Letter LTR-TA12-160; Assessment of Failed MSIVs on the Byron/Braidwood Units 1 and 2 Core Response Steam Line Break Analysis; September 11, 20121R13
- Maintenance Risk Assessments and Emergent Work Control

1R18 Plant Modifications

- IR 0509194; 2SI8811B Canister Level High Did Not Clear After Drain; July 14, 2006
- IR 1480240; 1/2RH01SA/SB Leak Tightness Not Challenged for NUREG 0737; February 26, 2012
- Assignment Report 01385826 05; Training Request Model, Operability/Reportability Reviews; February 10, 2013
- Assignment Report 01463476 02; Review Current Basis and Applicable GDC Requirements; March 14, 2013
- WO 00942164 01; 2RH01SB Install In-Section Ports Per Alt Det. on Dwg. 35874; December 13, 2006
- WO 00942164 05; 2RH01SB Install In-Section Ports Per Alt Det. on Dwg. 35874; September 7, 2006
- WO 00942164 11; 2RH01SB Install In-Section Ports Per Alt Det. on Dwg. 35874; October 11, 2006
- WO 01566439 06; OPS-Perform PMT Testing, Verify No Leaks; August 20, 2012
- ANS-56.2 ANSI N27101976; Containment Isolation Provisions for Fluid Systems; June 28, 1976
- ANSI/ASME Code Reconciliation for Replacement Material, Parts, and Components; Revision 5, November 10, 2004
- ASTM A105/A105M-12; Standard Specification for Carbon Steel Forgings for Piping Applications; March 22, 2013
- CC-AA-102; Maintenance Department Configuration Change Review Checklist # 361725; Revision 12
- CC-AA-103; Engineering Change Material List #361752; Revision 0
- CC-AA-501-1028; High Risk/High Value Welding Screening Checklist; Revision 1
- EN-MW-501; Special Chemical Use Permit/Waiver # 06-046; Revision 5
- ER-AA-330-009; ASME Section XI Repair/Replacement Plan; Revision 4
- ER-AA-335-014; VT1 Visual Examination Record; Revision 2
- ER-AA-335-015; VT2 Visual Examination Record; Revision 5

- LS-MW-107-1001; Change Request 9-038; Provide Clarification for Recirc Sump Guard Pipe Config; Revision 1
- MA-AA-716-008; WO 00942164-01 Work Package Forms; Revision 2
- MA-AA-716-010; WI 00942164-05; Work Package Revision Sheet; Revision 7
- MA-AA-716-011; Maintenance Material List; Revision 7a
- MA-AA-716-012; Post-Maintenance Testing; Revision 17
- MA-MW-796-101; ASME Weld Data Record; Revision 2
- Process Pipe (PTY) Ltd.; Forged Steel Pipe Fittings Screwed and Socket Weld Pressure Temperature Tables (in PSI); March 22, 2013
- WC-AA-104; Hydrolaze Valve Containment - WO 00942164-11; Revision 10
- Drawing 35869; Valve Containment General Arrangement
- Drawing 35874; General Assembly & Bill of Material Valve Containment Assembly
- Drawing M-61; Diagram of Safety Injection Unit 1

1R19 Post-Maintenance Testing

- IR 1471690, 2A DG 6L Fuel Injector Pump Metering Rod Stuck, February 1, 2013
- IR 1475916, Replace One Battery Block for 2B AF Pump Battery Replacement Activity; February 15, 2013

R22 Surveillance Testing

- IR 1469110; 2A SX Pump DP is in the Alert Range; January 30, 2013
- IR 1478045; 2RC01PB #2 Seal Leakoff Oscillating with S/D of 2D RCFC; February 20, 2013
- IR 1478073; 2B RCP #2 Seal Leakoff Does Not Indicate Flow; February 20, 2013
- 1BwOA RCP-1; Reactor Coolant Pump Seal Failure; Revision 106
- 2B RCP Seal Contingency Actions; RCFC Fan Cooler ANS SX Flow Surveillance; Revision 0
- 2BwOSR 3.7.4.1; Main Steam System Isolation 2MS018A/B/C/D Valve Travel; Revision 2
- 2BWOSR 3.8.1.20, 2B EDG Simultaneous Start; Revision 4
- 2BWOSR 3.8.1.2, Unit 2 EDG Surveillance, Revision 34
- 2BWOSR 3.7.8.1, Unit 2 SC Pump Surveillance, Revision 18
- OP-AA-106-101-1006; 2B RCP #2 Seal Performance (IR 1478045-10); Revision 11
- OP-AA-108-111; 2B RCP #2 Seal Leak Off and #2 SLO Flow; February 28, 2013
- OP-SS-108-115; Operability Determinations (CM-1); Revision 11
- Reg Guide 1.45; Reactor Coolant Pressure Boundary Leakage Detection Systems; May 1973

1EP2 Alert and Notification Evaluation

- Offsite Emergency Plan Alert and Notification System Addendum for Braidwood Station; November 2009
- U. S. Department of Homeland Security, FEMA Letter; Backup Alert and Notification System; December 10, 2012
- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan Section E; Revision 23
- EP-AA-1001; Exelon Nuclear Radiological Emergency Plan Annex for Braidwood Station, Section 4; Revision 30
- Siren Daily Operability Reports; January 1, 2011 through December 31, 2012
- Exelon Semi-Annual Siren Reports; January 1, 2011 through December 31, 2012
- IR 1361177; Monthly Full Volume Test Failure Will County; May 1, 2012
- IR 1294009; Final Rule – Enhancements to EP Regulations (Backup ANS); November 23, 2011

1EP3 Emergency Response Organization Augmentation Testing

- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan, Sections B and N; Revision 23
- EP-AA-1001; Exelon Nuclear Radiological Emergency Plan Annex for Braidwood Station, Section 2; Revision 30
- MA-BR-723-140; Test of the Station Public Address System; Revision 11
- TQ-AA-113; ERO Training and Qualification; Revision 20
- Quarterly Unannounced Off-Hours Call-In Augmentation Drill Results; February 2011 through December 2012
- August 23, 2011, Off-Hours Unannounced Drive-In Augmentation and Performance Indicator Drill Report; September 20, 2011
- Emergency Response Organization Call-Out Roster; February 13, 2013
- IR 1397240; Not All PA Speaker Locations Could Be Found; August 5, 2012

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

- Braidwood Station Revision of March 24, 2011, Unusual Event Report; July 12, 2011
- Braidwood Station June 8, 2011, Unusual Event Report; June 30, 2011
- Braidwood 2012 NRC Graded Exercise Evaluation Report; March 7, 2012
- NOSA-BRW-12-03; Emergency Preparedness Procedure Adequacy and Adherence Objective Evidence Report; April 13, 2012
- NOSA-BRW-12-03; Emergency Preparedness Offsite Agency Interface; April 13, 2012
- NOSA-BRW-11-03; Emergency Preparedness Offsite Agency Interface Objective Evidence Report; April 8, 2011
- NOSA Objective Evidence Report, P21-1; EP Offsite Agency Interface; April 13, 2012
- NOSA Objective Evidence Report, P21-1; EP Offsite Agency Interface; April 8, 2011
- Letters of Agreement for 2013 and 2014; December 13, 2012
- IR 1424858; RP Technician Qualification Training Not Clear For Rapid Dose Assessment; October 10, 2012
- IR 1402552-08; Braidwood Station 2013 NRC Pre-Inspection; November 30, 2012
- IR 1353156; EP Inventory Discrepancies Not Entered In CAP; April 12, 2012
- IR 1353148; Incomplete, Inaccurate, and Conflicting EP Inventory and Testing Checklists; April 12, 2012
- IR 1353007; Offsite Agency Questions (10 CFR 50.54(t)) To Be Addressed; April 12, 2012
- IR 1341513; Braidwood Exercise EOF Issues; March 15, 2012
- IR 1199930; NRC Special Inspection Team Questions Unusual Event Declaration Time; April 8, 2011

4OA1 Performance Indicator Verification (71151)

- Braidwood Monthly Siren Availability Reports; January – December 2012
- LS-AA-2110; Monthly Data Elements for ERO Drill Participation; March 2012 – December 2012
- LS-AA-2120; Monthly Data Elements for NRC Drill/Exercise Performance; January – December 2012
- IR 1454583; DEP Failure By Communicator in LORT; December 20, 2012
- IR 1450616; Potential Trend in DEP Failures/Issues in Training; December 11, 2012
- IR 1449530; DEP Classification in LORT; December 7, 2012
- IR 1426970; Incorrect ANS Performance Indicator Data Reported; October 16, 2012

- IR 1398074; Errors in NRC PI Data For 5 Sites from Cantera; August 7, 2012
- IR 1342596; DEP Notification Failure During Out-of-Box Scenario; March 19, 2012

4OA2 Problem Identification and Resolution

- IR 1444726; Fukushima Available Physical Margin (APM); November 27, 2012
- IR 1462344; Results of Unit 2 Pressurizer Heater Trouble Shooting; January 14, 2013
- IR 1462384; TSC NARS Phone Ringer Failed; January 14, 2013
- IR 1462955; 2CV121 Demanded at 100 Percent During Steady State Ops; January 15, 2013
- IR 1463295’ 2DG5048B Replaced Without Section XI Repair/Replacement; January 14, 2013
- IR 1463476; RH01SA/B Enclosure Classification Appears Over-Conservative; January 15, 2013
- IR 1466971; 1B DG #2 Air Dryer Switch Found in Off; January 25, 2013
- IR 1467141; NRC Raised Question for BwAP 1110-1A4 Applicability to UCSR; January 25, 2013
- IR 1467442; PMT for 1DG01SB-D Re-Performed Due to Toggle Switch Position; January 26, 2013
- IR 1467948; Request Work Hour Rules Clarification (PMT’s/Surv.); January 28, 2013
- IR 1469789; Unit 2 Heat Trace Circuit 1 and 2 Temps Not Similar; January 31, 2013
- IR 1469953; Due Date Extension for Op Eval 13-001; January 31, 2013
- IR 1475569; 1B Feed Pump Swapped to Speed Setter Mode; February 14, 2013
- IR 1477864; NRC Inspector Identified Cyclic Noise at 2B Dg Cylinder 4L; February 20, 2013
- IR 1478884; Oil Dark on Outboard Pump Bearing on 0CC1P; February 22, 2013
- RP-BR-980; Containment Vent and Mini Purge Gaseous Effluents; Revision 13, March 10 and March 13, 2013

4OA5 Temporary Instruction 2515/182

- IR 1166169; 2010 Cathodic Protection Survey Results and Recommendations; January 24, 2011
- IR 1390265; Buried Pipe Degradation Trend Identified; July 18, 2012
- IR 1375677; Buried Pipe 2CDA4A-8” 0.013 Inch Wall Measurement; June 7, 2012
- IR 1422046; Cathodic Protection Survey PM Frequency; October 3, 2012
- Buried Pipe Inspection Plan; June 29, 2011
- Buried Pipe and Raw Water Systems Long Term Asset Management Strategy; Revision 4
- Buried Pipe and Raw Water Program Health Report; 4th Quarter 2011
- Cathodic Protection Survey for the Underground Structures; December 2010
- Drawing 20E-0-3541; Cathodic Protection Test Point Sites; Revision 0
- Drawing M-900-1J-3; Outdoor Piping Arrangement; Revision R
- Drawing M-900-1H-7; Outdoor Piping Arrangement; Revision J
- Drawing M-900-1F-27; Outdoor Piping Arrangement; Revision AJ
- EC 384417; Justify Deferral of Mitigation Plan for Buried CD Piping; Revision 0
- EC 385316; Braidwood TF and OD Buried Pipe Leakage Mitigation; Revision 1
- EN-AA-407; Response to Inadvertent Releases of Licensed Materials to Groundwater, Surface Water of Soil; Revision 4
- Engineering Training Certification Guide N-AN-ENG-CERT-PG19, Buried Pipe and Raw Water Corrosion Program; October 25, 2012
- ER-AA-335-004; Ultrasonic Measurement of Material Thickness and Interfering Conditions; Revision 6
- ER-AA-5400; Buried Piping and Raw Water Corrosion Program Guide; Revision 5.
- ER-AA-5400-1002; Buried Pipe Examination Guide; Revision 4

- ER-AA-5400-1003; Buried Piping and Ray Water Corrosion Performance Indicators; Revision 4
- Guided Wave Test No. 1047; OCW2A-30”; August 9, 2012
- Guided Wave Test No. 1027; 1CDA4A-8”; August 7, 2012
- Guided Wave Test No. 1026; 1CDA4A-8”; August 7, 2012
- IMP-GWT-01N; Long Range Guided Wave Ultrasonic Pipe Screening System; Revision 5
- LS-AA-126-1001; Self-Assessment Control Degradation of Underground Piping/Tanks TI-182 Phase 2; November 5, 2012
- NES-MS-15.2; Guidance for Determining Reasonable Assurance for Structural and/or Leakage Integrity for Buried Piping; Revision 0
- 0BwOS GD-M1; Unit Common Cathodic Protection Surveillance; Revision 9
- Program Health Report; Buried Piping and Raw Water Corrosion Program; 3rd quarter 2012
- Program Health Report; Buried Piping and Raw Water Corrosion Program; 2rd quarter 2012
- Report 2012-265; Ultrasonic Thickness Results-1CD19A-20”; August 13, 2012
- Report 2012-259; Ultrasonic Thickness Results-OCWC2A-36”; August 13, 2012
- Report 2012-258; Ultrasonic Thickness Results-OCW09C-48”; August 13, 2012
- Specification 02; Anode Bed Replacement-New Anode Bed; June 1, 1998
- WO 01546747; IST for 2SX002A- ASME SRV Requirements for 2A ESW Service Water Pumps; August 1, 2012

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
AFW	Auxiliary Feedwater
ANS	Alert and Notification System
AOR	Abnormal Occurrence Report
ASME	American Society of Mechanical Engineers
BAST	Boric Acid Storage Tank
BTP	Branch Technical Position
CAP	Corrective Action Program
CCP	Centrifugal Charging Pump
CFR	Code of Federal Regulations
CLB	Current Licensing Bases
CRDM	Control Rod Drive Mechanism
CVCS	Chemical Volume Control System
DEP	Drill/Exercise Performance
DOST	Diesel Oil Storage Tank
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedures
EP	Emergency Preparedness
EPZ	Emergency Planning Zone
ERO	Emergency Response Organization
GDC	General Design Criteria
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
IST	Inservice Testing
kV	Kilovolt
LER	Licensee Event Report
LOOP	Loss of Offsite Power
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NOV	Notice of Violation
NRC	U.S. Nuclear Regulatory Commission
OOS	Out-of-Service
PARS	Publicly Available Records System
PBI	Plant Barrier Impairment
PDP	Positive Displacement Pump
PI	Performance Indicator
PORV	Power Operated Relief Valve
psig	Pounds Per Square Inch Gauge
PZR	Pressurizer
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RSB	Reactor Safety Branch
SAR	Safety Analysis Report

SDP	Significance Determination Process
SGTR	Steam Generator Tube Rupture
SRB	Standard Review Plan
SSC	Systems, Structures, and Components
SX	Essential Service Water
TB	Turbine Building
TI	Temporary Instruction
TS	Technical Specification
UCSR	Upper Cable Spreading Room
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USQ	Unreviewed Safety Questions
V	Volt
WO	Work Order

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 Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site 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 and 50-457
License Nos. NPF-72 and NPF-77

Enclosures: Inspection Report 05000456/2013002; 05000457/2013002
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

DOCUMENT NAME: G:\DRPIII\BRAI\BRA 2013 002.docx
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive
To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy

OFFICE	RIII		RIII		RIII		RIII	
NAME	TDaun:dtp		EDuncan					
DATE	5/09/13		5/09/13					

OFFICIAL RECORD COPY

Letter to M. Pacilio from E. Duncan dated May 9, 2013.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000456/2013002; 05000457/2013002

DISTRIBUTION:
Doug Huyck
RidsNrrDorlLpl3-2 Resource
RidsNrrPMBraidwood Resource
RidsNrrDirsIrib Resource
Chuck Casto
Cynthia Pederson
Steven Orth
Allan Barker
DRPIII
DRSIII
Christine Lipa
Carole Ariano
Linda Linn
Patricia Buckley
Tammy Tomczak
ROPreports.Resource@nrc.gov