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

November 8, 2012

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 05000456/2012004; 05000457/2012004 AND NOTICE OF VIOLATION

Dear Mr. Pacilio:

On September 30, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an 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 October 3, 2012, with Mr. D. Enright and other members of your staff.

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

Four NRC-identified findings of very low safety significance and a Severity Level IV issue were identified. Two of the four NRC-identified findings and the Severity Level IV issue 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 two of these violations as Non-Cited Violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. The remaining violation is cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding this violation are described in detail in the enclosed report. Although determined to be of very low safety significance (Green), in accordance with Section 2.3.2 of the NRC Enforcement Policy, this violation is being cited because you failed to restore compliance within a reasonable time after the violation was identified in NRC Inspection Report 05000456/2010006; 05000457/2010006. Additionally, a licensee-identified violation is listed in Section 4OA7 of this report. The NRC Enforcement Policy is included on the NRC's Web site at (http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol-html).

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

If you contest the subject or severity of these violations 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 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:
1. Notice of Violation
2. Inspection Report 05000456/2012004; 05000457/2012004
   w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

NOTICE OF VIOLATION

Exelon Generation Company, LLC	Docket Nos. 50-456, 50-457
Braidwood Station Units 1 and 2	License Nos. NPF-72, NPF-77

During an NRC inspection conducted from July 1, 2012, to September 30, 2012, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> Title 10 of the Code of Federal Regulations Part 50 (10 CFR 50), Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying the adequacy of the design, and that the design basis is correctly translated into procedures and instructions.
>
> Contrary to the above, from initial plant construction to September 30, 2012, the licensee failed to verify the adequacy of the design of the Braidwood Unit 1 and Unit 2 recycle holdup tanks, which are safety-related components subject to the requirements of 10 CFR 50, Appendix B, Criterion III, and failed to correctly translate the design basis of the Braidwood Unit 1 and Unit 2 recycle holdup tanks into procedures and instructions. Specifically, the license failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 residual heat removal system suction relief valves that discharge to the recycle holdup tanks and, as a result, failed to verify the adequacy of the recycle holdup tank design to withstand design loads that would result from a discharge of residual heat removal system suction relief valves into the recycle holdup tanks.

This violation is associated with a Green Significance Determination Process finding.

Pursuant to the provisions of 10 CFR 2.201, Exelon Generation Company, LLC is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the Braidwood facility, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation;" and should include for the violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an Order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, or proprietary information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information).

In accordance with 10 CFR 19.11, you may be required to post this Notice within 2 working days of receipt.

Dated this 8th day of November 2012

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2012004; 05000457/2012004
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	July 1 through September 30, 2012
Inspectors:	J. Benjamin, Senior Resident Inspector A. Garmoe, Resident Inspector B. Bartlett, Senior Resident Inspector, Byron T. Go, Health Physicist R. Langstaff, Senior Reactor Inspector V. Meghani, Reactor Inspector R. Ng, Project Engineer J. Robbins, Resident Inspector, Byron D. Szwarc, Reactor Inspector M. Perry, Resident Inspector Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000456/2012004, 05000457/2012004; 07/01/2012 – 09/30/2012; Braidwood Station, Units 1 & 2; Equipment Alignment; Operability Determination and Functionality Assessments; Identification and Resolution of Problems; Follow-up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Four NRC-identified findings of very low safety significance and a Severity Level IV issue were identified. One NRC-identified finding and the Severity Level IV issue involved a Non-Cited Violation (NCV) of NRC requirements. Also, one of the violations of NRC requirements was cited in a Notice of Violation (NOV). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Assigned cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very low safety significance (Green) when licensee personnel failed to implement a Caution Note in Emergency Operating Procedure (EOP) 2BwEP ES-0.1, "Reactor Trip Response," during a July 30, 2009, Unit 2 reactor trip; failed to identify that deficiency during a "4.0 Crew Critique" to evaluate Operation's response to that event; and failed to adequately evaluate a concern identified during this inspection period that was entered into the Corrective Action Program (CAP) related to the requirement to follow the EOP guidance. In particular, licensee personnel incorrectly concluded that a reactor trip involving reactor coolant system (RCS) natural circulation would not require the initiation of an RCS cooldown within 2 hours following the shutdown despite the licensee's Analysis of Record (AOR) and Technical Specification (TS) bases documents that required a cooldown be initiated within 2 hours to ensure that an adequate volume of water was available in the Condensate Storage Tank (CST) to cool down the RCS without utilizing the Ultimate Heat Sink (UHS). Corrective actions included revising 1/2BwEP ES-0.1 to relocate the Caution Note in the procedure and alleviate any future confusion with the cooldown requirement. Additionally, the Caution Note was modified to be consistent with the Current Licensing Basis (CLB) analysis of the CST and Operations management discussed the issue with the Operations crew staff and supervision to ensure that the Caution Note would be performed as required by 1/2BwEP ES-0.1.

The inspectors determined that the failure to follow the EOP Caution Note during the July 30, 2009 Unit 2 reactor trip; the failure to identify this deficiency during the 4.0 Crew Critique assessment associated with this reactor trip, and the failure to adequately evaluate an issue entered into the CAP regarding this requirement was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the Human Performance and Design Control attributes of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). The inspectors evaluated this finding using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," which directed the finding to be screened using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power." The inspectors determined that because the station operated and nominally maintained CST level significantly above the minimum CST TS level prior to the June 30, 2009 Unit 2 reactor trip, the CST maintained its operability and functionality, and therefore this finding was of very low safety significance (Green). This finding had a cross-cutting aspect in the CAP component of the Problem Identification and Resolution cross-cutting area because the licensee failed to adequately evaluate Operations' response to the July 30, 2009, reactor trip and subsequently failed to adequately evaluate an issue identified within the CAP (P.1(c)). (Section 1R04.2.b)

Green. The inspectors identified a finding of very low safety significance (Green) when licensee personnel failed to adhere to Corrective Action and Operability Determination Program standards after identifying a non-conforming condition associated with reduced steam generator (SG) power-operated relief valve (PORV) flow capacities. Specifically, in April 2012, the licensee identified that the station SG PORV relief capacities were lower than what was assumed in the CLB. This condition was identified during laboratory testing to support a power uprate application. Throughout the licensee's operability assessment spanning from April to September 2012, the inspectors identified that the licensee did not adequately and effectively utilize station standards to evaluate Unit 2 CST operability after initially identifying the issue in April 2012; when processing a formal Operability Evaluation; after receiving new information from a sensitivity study performed by a contractor; and after the inspectors directly identified an issue of concern to the licensee that was addressed through the CAP. Specifically, the licensee did not ensure that the Unit 2 CST was capable of performing its TS function after identifying a non-conservative condition that ultimately resulted in requiring nearly double the CST volume from what was assumed in the CLB. The inspectors determined that such a significant decrease in available margin provided a cause for reasonable doubt of Unit 2 CST operability. Corrective actions include a revision to the Operability Evaluation that addressed the deficiency and re-confirmed CST operability.

The inspectors determined the failure to evaluate the effect the reduced Unit 2 SG PORV flow rate capacities would have on the Unit 2 CST's ability to perform its specified TS function was a performance deficiency. The inspectors determined that the performance deficiency 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). The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings," which directed the finding to be screened using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power." The inspectors determined that because the CST maintained its operability and functionality within the CLB that this finding was of very low safety significance (Green). This finding had a cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area because the licensee failed to use conservative decision-making and verify the validity of underlying assumptions when evaluating the effect of reduced Unit 2 SG PORV flow capacities on CST operability (H.1(b)). (Section 1R15.1b)

Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of Braidwood Operating License Condition 2.E, “Fire Protection Program,” when licensee personnel failed to ensure that fire brigade members retained knowledge provided in fire brigade initial training. Specifically, station Fire Chiefs and fire brigade members did not have an adequate knowledge or continuing training on the proper methods and implementation for the use and control of elevators during a fire as demonstrated during a fire drill on June 14, 2012. Corrective actions included ensuring all elevator keys were adequately stored, informing the Fire Chiefs and fire brigade members of the key locations, and initiating a training request to provide the Fire Chiefs and fire brigade members with adequate training covering elevator key usage and elevator control during a fire response.

The inspectors determined that the failure to ensure Fire Chiefs and fire brigade members had the knowledge to perform their duties was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the External Factors (Fire) 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. Specifically, the turbine building and auxiliary building elevators could be utilized in the licensee’s Fire Protection Program to transport fire brigade members and their equipment in response to a fire. Safety-related equipment was in (or adjacent to) these fire zones. Therefore, if elevators were not controlled in the correct manner, the elevator may not be available for fire brigade use or may place personnel in danger by stopping at an undesirable elevation. The inspectors screened the finding in accordance with IMC 0609, Attachment 4, “Initial Characterization of Findings.” Based on Table 2, the inspectors concluded the issue represented a weakness in the External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded) function of the Mitigating Systems Cornerstone. The inspectors reviewed the questions in Table 3 of IMC 0609, Attachment 4, and answered ‘No’ to Questions A-D and ‘Yes’ to Question E.1, “Does the finding involve discrepancies with the fire brigade?” As a result, the inspectors transitioned to IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings at Power.” The inspectors reviewed IMC 0612, Appendix A, Exhibit 2, and answered ‘No’ to Question B - External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded), “Does the finding involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event (e.g., seismic snubbers, flooding barriers, tornado doors)?” As a result, the finding screened as having very low safety significance (Green). This finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because the licensee failed to ensure Fire Chiefs and fire brigade members had an adequate knowledge or continuing training on the proper methods and implementation for the use and control of elevators during a fire as demonstrated during a fire drill on June 14, 2012 (H.2(b)). (Section 4OA2.6.b)

Cornerstone: Barrier Integrity

Green. The inspectors identified a finding of very low safety significance (Green) and an associated cited violation (VIO) of 10 CFR 50, Appendix B, Criterion III, “Design Control,” when licensee personnel failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 Residual Heat Removal (RHR) suction relief valves that discharge to the Recycle Holdup Tank (RHUT); and, as a result, failed to verify the adequacy of the RHUT design to withstand design loads that resulted from a discharge from RHR system suction relief valves into the RHUT. As of September 30, 2012, IR 649581, Assignment 8 to resolve the potential over-pressurization of the RHUT had not been completed. At the end of the inspection period, licensee efforts to complete and refine a model to determine whether physical modifications were necessary were still in progress. It remained unclear whether a physical modification would be necessary; when that determination would be made; and if a physical modification was necessary, when that modification would be completed.

The inspectors determined that the licensee's failure to evaluate the effect of dynamic water hammer loads on inlet piping from Unit 1 and Unit 2 RHR suction relief valves that discharge to the RHUT was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the Design Control attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the licensee's existing design and piping configuration had not addressed water hammer effects when the Unit 1 and Unit 2 RHR suction relief valves were aligned to discharge to the RHUT, which could rupture the inlet piping and potentially affect offsite dose consequences. The NRC Senior Reactor Analysts (SRAs) concluded that the risk significance associated with the finding was of very low safety significance (Green). This finding had a cross-cutting aspect in the Corrective Action Program component of the Problem Identification and Resolution cross-cutting area because the licensee failed to take timely corrective actions to address a previously issued NCV (P.1(d)). (Section 4OA2.5.b)

Cornerstone: Miscellaneous

Severity Level IV. The inspectors identified a Severity Level IV NCV of 10 CFR 50.72(b)(3)(v) and 10 CFR 50.73(a)(2)(v) when licensee personnel failed to report a condition that resulted in a loss of safety function after the UHS was declared inoperable after exceeding the TS limit of 100 degrees Fahrenheit (°F). Specifically, on July 7, 2012, the licensee had identified and entered TS 3.7.9, "Ultimate Heat Sink," Condition (A), "Ultimate Heat Sink Inoperable," after the UHS lake temperature exceeded the TS 3.7.9.2 Surveillance Requirement value of less than or equal to 100°F. The inspectors determined that although this condition represented a loss of safety function in accordance with the 10 CFR 50.72 and 10 CFR 50.73 reporting requirements and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 10 CFR 50.73," Revision 2, the condition was not reported as required. This issue was entered into the licensee's CAP as IR 1422296. Corrective actions included an action to report this event in accordance with NRC requirements.

The inspectors determined that the failure to submit a report required by 10 CFR 50.72 and a Licensee Event Report (LER) required by 10 CFR 50.73 for a loss of safety function after the UHS was declared inoperable on July 7, 2012, was a performance deficiency. This violation had the potential to impact the regulatory process based, in part, on the generic communications that 10 CFR 50.72 and 10 CFR 50.73 reports serve, the required ROP inspection reviews that the NRC performs on all LERs, and the potential impact on licensee performance assessment. The inspectors determined that this issue was a Severity Level IV violation based on similar examples referenced in Section 6.9 of the NRC Enforcement Policy. Specifically, Example 9, "The licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73," and Example 10, "A failure to identify all applicable reporting codes on a Licensee Event Report that may impact the completeness or accuracy of other information (e.g., performance indicator data) submitted to the NRC." Because cross-cutting aspects do not apply to traditional enforcement issues, no cross-cutting aspect was assigned. (Section 4OA3.3)

B. Licensee-Identified Violations

A violation of very low safety significance that was identified by the licensee was reviewed by inspectors. Corrective actions planned or taken by the licensee were entered into the licensee's CAP. This violation and corrective action tracking number is 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.

Unit 2 operated at or near full power during the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

During the week of July 26, 2012, the inspectors verified that plant features and procedures for the operation and continued availability of offsite and alternate alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

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

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

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

- The communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment. The inspectors also reviewed Corrective Action Program (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.

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

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Condition – Severe Thunderstorm Warnings

a. Inspection Scope

Since thunderstorms and high winds were forecast in the vicinity of the facility for July 24 and August 4, 2012, the inspectors reviewed the licensee's overall preparation for the expected weather conditions. The inspectors walked down the Independent Spent Fuel Storage Installation (ISFSI) Pad, in addition to the licensee's AC power systems, because their safety-related functions could be affected or required as a result of high winds or tornado generated missiles or the loss of offsite power. The inspectors compared the licensee staff's preparations with site procedures and determined whether staff actions were adequate. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of CAP items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment.

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

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Unit 1 “A” Auxiliary Feedwater (AF) System with the Unit 1 “B” Auxiliary Feedwater (AF) System Inoperable for Maintenance;
- Unit 1 “A” Containment Spray System with the Unit 1 “B” Containment Spray Inoperable for Maintenance; and
- Unit 2 “A” Auxiliary Feedwater System During an Operational Reactor Trip Risk Scaffold Building Activity.

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

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

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

The inspectors performed a complete system alignment inspection of the Unit 2 condensate storage tank (CST) system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors walked down the system and reviewed mechanical lineups; system level and temperature indications; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. In addition, the inspectors reviewed the CAP database to ensure that system problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

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

b. Findings:

Failure to Adequately Evaluate Operation Crew Performance for a Reactor Trip and Failure to Adequately Evaluate Emergency Operating Procedure Standards

Introduction: The inspectors identified a finding of very low safety significance (Green) when licensee personnel failed to implement a Caution Note in EOP 2BwEP ES-0.1, "Reactor Trip Response," during a July 30, 2009, Unit 2 reactor trip; failed to identify that deficiency during a "4.0 Crew Critique" to evaluate Operations' response to that event; and failed to adequately evaluate a concern identified during this inspection period that was entered into the CAP related to the requirement to follow the EOP guidance. In particular, licensee personnel incorrectly concluded that a reactor trip involving reactor coolant system (RCS) natural circulation would not require the initiation of a RCS cooldown within 2 hours following the shutdown despite the licensee's Analysis of Record (AOR) and TS bases documents that required a cooldown be initiated within 2 hours to ensure that an adequate volume of water was available in the CST to cool down the RCS without utilizing the Ultimate Heat Sink (UHS).

Description: During their review of Operability Evaluation 07-008, Revision 5, regarding steam generator (SG) power-operated relief valve (PORV) flow coefficient non-conservatisms, the inspectors noted that the reduced flow capacity for the SG PORVs would result in a longer time to cooldown the RCS than previously assumed. Additionally, a longer cooldown time would require more water from the CST than previously assumed. The inspectors reviewed recent historical plant performance and identified that a natural circulation cooldown occurred on July 30, 2009, following a Unit 2 loss of offsite power event. The inspectors reviewed the event since it provided actual data to review against analysis results as part of the Operability Evaluation. During this review, the inspectors identified that the licensee had not adhered to a Caution Note in EOP ES-0.1, "Reactor Trip Response," during the July 30, 2009, Unit 2 reactor trip. In particular, following the completion of 2BwEP ES-0.1, Step 13, Operators encountered the following Caution Note:

Caution

If SG PORVs are being utilized, cooldown should be initiated within 2 HOURS to ensure an adequate auxiliary feedwater water supply.

On July 30, 2009, at 8:59 p.m., the Unit 2 reactor tripped due to a Unit 2 "C" reactor coolant pump trip, which occurred due to a loss of offsite power and an unsuccessful automatic bus transfer. Additionally, complications resulted in a tripping of the remaining three reactor coolant pumps and establishment of RCS natural circulation flow conditions. Operations entered EOP 2BwEP-0, "Reactor Trip," and performed the required procedural steps. At 9:01 p.m., Operations transitioned to a second EOP, 2BwEP ES-0.1, "Reactor Trip Response." At 10:45 p.m., Operations transitioned to a third EOP, 2BwEP ES-0.2, “Natural Circulation Cooldown.” Operations performed an RCS cooldown in accordance with procedural requirements at 12:42 a.m. on July 31, 2012.

The inspectors reviewed the EOP procedural requirements, timeline of actions performed in accordance with the EOP procedures based upon logs and historical plant data from the plant process computer, and the TSs and TS Bases documents. Because the cooldown was a natural circulation cooldown requiring the use of SG PORVs, the inspectors identified that the licensee did not commence a plant cooldown within 2 hours as directed by the Caution Note after Step 13 of procedure 2BwEP ES-0.1. Specifically, 3 hours and 43 minutes passed from the time of the reactor trip (8:59 p.m.) to the time plant cooldown was initiated (12:42 a.m.). The inspectors discussed this issue with the licensee’s Engineering and Operations department staff and management and provided all available information utilized to identify the concern, including the EOP procedures and all applicable Current Licensing Basis (CLB) documents including the TSs, TS Bases, and Design Analysis CN-RRA-00-47, Revision 2, “Byron/Braidwood Natural Circulation Cooldown TREAT Analysis for the RSG and Uprating Program.”

Braidwood TS 3.7.6 stated that the CST level shall be maintained greater than or equal to 66 percent in Modes 1, 2, and 3. Braidwood TS Bases Section 3.7.6 stated the following, “*The specified level assures the required usable volume of approximately 212,000 gallons is met. This volume is sufficient to maintain the RCS in Mode 3 at normal operating pressure and temperature for 2 hours, followed by a cooldown to residual heat removal (RHR) entry conditions at 50 degrees Fahrenheit per hour, followed by a period not longer than 1-hour to allow warm-up of the RHR pumps prior to placing the RHR system into service in shutdown cooling mode.”* Design Analysis CN-RRA-00-47, “Byron/Braidwood Natural Circulation Cooldown TREAT Analysis for the RSG and Uprating Program,” Revision 2, specifically addressed the need to commence plant cooldown within 2 hours in the following sections:

- *4.0 Acceptance Criteria*

  Since Byron and Braidwood have high capacity Seismic Category I auxiliary feedwater backup supplies via ESW [Essential Service Water] that would be available to satisfy the 4-hour hot standby requirements, there is a constraint only on the normal CST supply:

  - *For the CST, the inventory used should be less than the TS usable volume <u>212,000 gallons</u> (consistent with Reference 33 and amounts used in References 29 and 30). The plant EOPs also limit the time at hot standby: there is a <u>2-hour hot standby restriction</u> if the SG PORVs are to be used for cooldown based on using the normal non-safety related auxiliary feedwater supply (i.e., CST). See reference 7 and 34, steps at the end of ES-0.1).*

- *6.0 Calculations*

  The final cooldown to 350 F is delayed until 2 hours, the longest expected delay per ES-0.1. This will maximize CST depletion, an important consideration for the analysis.

The licensee entered the inspectors' concern into the CAP as Issue Report (IR) 1378105, "Documentation of NRC Questions on IR 1382564." The IR documented numerous NRC questions including, "Question 5. In the Braidwood plant trips from 2009 and 2010, was the cooldown initiated within 2 hours (Ref. 1, 2BwEP ES-0.1)? Is this a requirement?" The licensee evaluated and answered Question 5 of IR 1378105 with the following statement, "*Braidwood operating logs show that the cooldown for U-2 was initiated at longer than 2 hours following the shutdown. Initiating plant cooldown within 2 hours of the shutdown is not a requirement*."

The inspectors reviewed the IR response following the completion of the required CAP reviews by representatives of Engineering, Operations, and the Station Onsite Review Committee. Once the IR response was approved through the licensee's CAP approval process, the inspectors noted that the response to IR 1390874, Question 5, did not discuss the aspects of the CLB provided by the inspectors. When asked, the licensee responded that a "should" statement in a procedure was not a requirement and as such the Caution Note in 2BwEP ES-0.1, "*If SG PORVs are being utilized, cooldown* ***should*** [emphasis added] *be initiated within* <u>*2 HOURS*</u> *to ensure an adequate auxiliary feedwater water supply,*" was not required to be followed.

The inspectors again reviewed the applicable CLB requirements and were not satisfied with the licensee's response to IR 1390874, Question 5. Several discussions between the inspectors and the licensee were subsequently held to gain a more complete understanding of the licensee's position. The inspectors were informed that there was no minimum CST water inventory requirement for a natural circulation cooldown beyond that of a station blackout (approximately 79,000 gallons). The inspectors again noted that CLB documentation supported the direction to initiate plant cooldown within 2 hours based on ensuring CST inventory was sufficient to support decay heat removal until RHR system shutdown cooling was placed in service. On August 21, 2012, the licensee initiated IR 1396040 to again document the issue.

At this point, the inspectors discussed this issue directly with the Operations Director. On September 14, 2012, the Operations Director originated IR 1403298 and discussed the question with the Regulatory Assurance Manager. During their review, the licensee identified that the Caution Note to initiate a cooldown within 2 hours was, in fact, a necessary step based, in part, upon the CLB information that the inspectors had provided during prior discussions. The licensee implemented an procedure change to relocate the Caution Note in 1/2BwEP ES-0.1 and revise the word "should" to "shall" to alleviate any future confusion with the cooldown requirement. Additionally, the Caution Note was modified to revise the start of the 2 hour clock from the time of the reactor trip to when CST level reached the minimum TS value of greater than or equal to 66 percent, which was consistent with the CLB analysis of the CST. Additionally, Operations discussed this requirement with the Operations crew staff and supervision to ensure that the Caution Note would be performed as required by 1/2BwEP ES-0.1.

The inspectors noted that the licensee's screening and evaluation of IR 1390874 was not performed in accordance with procedure LS-AA-120, "Issue Identification and Screening Process." The operability assessment was documented in IR 1390874 as, "*The auxiliary feedwater is capable of being supplied water from the safety-related essential service supply during all accident conditions. The AF pumps have passed all required surveillance and are all within periodicity, therefore remains operable.*" Steps 4.4.6.2 and 4.4.6.3 of procedure LS-AA-120 stated that a condition that impacts a

TS function should be documented and that if the condition potentially affects the operability of a system, structure, or component (SSC), then operability should be determined. The inspectors noted that the operability of the CST, which was a TS SSC, was not determined or documented in IR 1390874. The inspectors also noted that IR 1390874 was assigned a Significance Level 5 because no deficiency was identified in the IR. However, the IR was specifically generated to document a deficiency identified by the inspectors since a Caution Note was not followed and was not identified by the licensee as not being followed.

In addition to the review described above, the inspectors reviewed the "4.0 Crew Critique" assessment that was performed on August 1, 2009, to evaluate Operations response to the July 30, 2009, Unit 2 reactor trip. Procedure OP-AA-113-1006, "4.0 Crew Critique Guidelines," stated that the purpose of the critique was to review the crew's response to plant transients and compare that response to a "4.0, i.e. perfect" response to identify gaps between standards/fundamentals and actual performance. The licensee's 4.0 critique of the crew's response to the July 30, 2009, reactor trip and natural circulation event did not identify a gap associated with the procedural fundamental of "Controlling Plant Evolutions Precisely" and inappropriately concluded that *"Placekeeping procedures/proper procedure use and adherence was adequate."* Based on a detailed review of the 4.0 crew critique procedural requirements and the facts surrounding the July 30, 2009, reactor trip, the inspectors concluded that this review should have identified that a cooldown was not started within 2 hours as required.

<u>Analysis</u>: The inspectors determined that the failure to follow the EOP Caution Note during the July 30, 2009, Unit 2 reactor trip; the failure to identify this deficiency during the 4.0 Crew Critique assessment associated with this reactor trip; and the failure to adequately evaluate an issue entered into the CAP regarding this requirement was a performance deficiency. Specifically, requirements contained in procedures ES-0.1, OP-AA-113-1006, and LS-AA-120 were not met.

The performance deficiency was screened in accordance with Inspection Manual Chapter (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 performance deficiency was more than minor because it was associated with the Human Performance and Design Control attributes 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, on July 30, 2009, the licensee did not adequately implement a EOP Caution Note that was required to be implemented in the current licensing basis (CLB) analysis; had not identified this deficiency during a focused evaluation of the crew's performance; and had inadequately evaluated the issue, including the operability of TS SSCs, through CAP, once raised by the inspectors.

The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings," which directed the finding to be screened using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power." The inspectors determined that because the station operated and nominally maintained CST level significantly above the minimum CST TS level prior to the June 30, 2012 Unit 2 reactor trip, the CST maintained its operability and functionality, and therefore this finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the CAP component of the Problem Identification and Resolution cross-cutting area because the licensee failed to adequately evaluate Operations' response to the July 30, 2009 reactor trip and subsequently failed to adequately evaluate an issue identified within the CAP (P.1(c)).

Enforcement: This issue does not involve enforcement action because no regulatory requirement was violated. Because this issue does not involve a violation and has very low safety significance, it is identified as a finding. **(FIN 05000456/2012004-01; 05000457/2012004-01, Failure to Adequately Evaluate Operations Crew Performance for a Reactor Trip and Failure to Adequately Evaluate Emergency Operating Procedure Standards)**

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:

- Bus 141 Switchgear Room - Fire Zone 5.1-1;
- Bus 142 Switchgear Room - Fire Zone 5.1-2;
- Bus 241 Switchgear Room - Fire Zone 5.2-1;
- Bus 242 Switchgear Room - Fire Zone 5.2-2; and
- Unit 2 Cable Tunnel - Fire Zone 3.1-2.

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

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

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment. 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 Lower Cable Spreading Room.

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

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07)

.1 Annual Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's inspection activities for bryozoa in the safety-related UHS system throughout this inspection period to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. The inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. The inspectors discussed any issues identified with licensee management and staff to ensure that the issue was effectively being managed within the CAP. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification

a. Inspection Scope

On July 24, 2012, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations, procedural compliance, and 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 71111.11-05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk

a. Inspection Scope

On August 24, 2012, the inspectors observed a Unit 2 primary dilution activity and a pre-job brief for a planned stroke time test for Unit 2 Containment Spray system valve 2CS019A. These activities were selected because they required a heightened awareness and were related to increased risk. 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 procedures;
- control board manipulations; and
- oversight and direction from supervisors.

The 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 one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Water Tight Doors;
- Unit 1 SG PORV Batteries and Inverters; and
- Unit 2 “B” Control Rod Drive Motor Generator System Phase Voltage Contact Issue.

The inspectors independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- crediting 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 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/or safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- UHS Temperature Greater than the TS Allowable Temperature – Emergent Risk Review;
- Auxiliary Building Exhaust Plenum Damper Failed Open and Resulted in an Unplanned TS 3.0.3 Entry - Emergent Risk Review;
- Severe Weather (Thunderstorm) During a Unit 1 ”A” Safety Injection System Maintenance Window – Emergent Risk Review;
- Unit 2 “B” Containment Spray Pump Out-of-Service - Planned Yellow Risk; and
- Scaffold Construction Over the Unit 2 Control Rod Drive Motor Generators – Planned Operational Risk.

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

This inspection constituted five maintenance risk assessments and emergent work control activities 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:

- Unit 1 ”A” Auxiliary Feedwater Pump Suction Pressure Meter Discovered Out-of-Tolerance;
- Unit 1 “B” Steam Generator Bowl Drain Class 2 Material Non-Conformance;
- Main Steam Isolation Valve Accumulator Relief Valve/High Energy Line Break Issue; and
- SG PORV Non-Conservative Flow Rate.

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 sample of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment.

This inspection constituted four operability determination and functionality assessment samples as defined in IP 71111.15-05.

b. Findings

Failure to Adequately Evaluate the Specified TS CST Function After the Identification of a Non-Conforming Condition Adversely Affecting SG PORV Flow Capacities

Introduction: The inspectors identified a finding of very low safety significance (Green) when licensee personnel failed to adhere to Corrective Action and Operability Determination Program standards after identifying a non-conforming condition associated with reduced SG PORV flow capacities. Specifically, in April 2012, the licensee identified that the station SG PORV relief capacities were lower than what was assumed in the CLB. This condition was identified during laboratory testing to support a power uprate application. Throughout the licensee’s operability assessment spanning from April to September 2012, the inspectors identified that the licensee did not adequately and effectively utilize station standards to evaluate Unit 2 CST operability after initially identifying the issue in April 2012; when processing a formal Operability Evaluation; after receiving new information from a sensitivity study performed by a contractor; and after the inspectors directly identified an issue of concern to the licensee that was addressed through the CAP.

Description: On April 23, 2012, during efforts to resolve SG tube rupture margin-to-overfill (MTO) issues for a power uprate application, the licensee identified that based upon flow rate data from a laboratory test, the actual individual station SG PORV relief capacities could be less than designed and assumed in the CLB. The licensee estimated that the Unit 1 and Unit 2 SG PORV relief capacities could be reduced by about 11 percent and 35 percent, respectively. The licensee entered this issue into their CAP as IR 1358008, “MS [Main Steam] PORV Test Flow Rate Less Than

Expected." Operations evaluated SSC operability in this IR and did not identify any issues. However, a formal Operability Evaluation was assigned. The Unit 1 SG PORV flow rate was restored back to the design limits during Spring 2012 Refueling Outage A1R16 by installing a larger valve trim.

Subsequently, IR 1359217, "Probable Reduced Capacity for the SG PORVs," was initiated on April 26, 2012, and documented the licensee's efforts to validate the data from the laboratory test and, if valid, identify a cause. The licensee confirmed that the SG PORV flow rate results were valid and that the cause was related to a non-conservative valve flow coefficient provided by the original equipment manufacturer. This condition existed since original plant licensing and was reported as a 10 CFR Part 21 notification following the identification at Braidwood (ML12160A364). The licensee identified and documented in IR 1359217 that the reduction in relief valve capacities would extend the cooldown period and time needed to remove reactor decay heat following an event. The licensee evaluated how this cooldown would affect the SG MTO CLB, but did not evaluate how a longer cooldown could affect the ability of the CST to perform its specified TS safety function. The inspectors reviewed IR 1358008 and IR 1359217 and the associated operability bases. The inspectors identified that Operations and the Station Onsite Review Committee did not adequately evaluate CST TS Operability in accordance with LS-AA-120, "Issue Identification and Screening Process." Specifically, LS-AA-120 required that Operations determine and document whether the non-conforming condition impacted any TS function and to document the results of this review in the associated IR. Procedure OP-AA-108-115-1002, "Supplemental Consideration for On-Shift Immediate Operability Determinations," included a specific consideration for an SSC (i.e. CST) to fulfill its mission/duty cycle (i.e. cooldown the plant to RHR cut-in conditions). LS-AA-120 required the Station Onsite Review Committee to verify the results documented in the IR and to document this review.

On May 1, 2012, the licensee completed Operability Evaluation 07-008, Revision 5. In this evaluation, the licensee correctly identified that the natural circulation cooldown analysis would be adversely affected by the non-conforming Unit 2 SG PORV flow rate conditions. However, the evaluation non-conservatively assumed that the SG tube rupture analysis was the most limiting event because of the limiting time for operators to take actions to prevent a SG overfill condition. The evaluation correctly identified that the CST TS function was to cool down the plant from Mode 3 to RHR cut-in conditions without relying on the safety-related UHS system. However, the evaluation did not adequately determine the effect that a non-conforming SG PORV flow rate would have on the ability for the CST to perform this function. The inspectors determined that the Operability Evaluation should have reviewed this aspect because this level of review was discussed in Section 4.4.2 of OP-AA-108-115, "Operability Determinations," as follows:

"As a minimum the following items should be addressed, as applicable in describing the SSC specified safety function(s):

- *Does the SSC provide required support to a TS required SSC?*
- *Have all specified safety functions described in TSs been included?*
- *Have all safety functions of the SSC required during normal operation and potential accident conditions been included?*

The licensee contracted Westinghouse to perform a sensitivity study related to this issue. With respect to natural circulation, Westinghouse calculated an increase from 9.5 hours to greater than 24 hours to cool down the RCS to RHR cut-in conditions assuming the limiting single failure of a SG PORV. Additionally, Westinghouse stated that the increased cooldown time would require additional water inventory in the CST. The licensee evaluated CST operability and determined that the CST remained operable because the station had an adequate CST water inventory to meet the current TS CST requirement (i.e., 212,000 usable gallons). Additionally, the licensee determined that NRC Branch Technical Position (RSB 5-1) was part of the CLB and required the cooldown during a natural circulation event to be less than 72 hours. These results were documented in IR 1378105, "Potential Impact From Reduced Unit 2 SG PORV Relief Capacity."

The licensee documented in IR 1382564, "Potential Impact From Reduced Unit 2 SG PORV Relief Capacity," the results of follow up discussions with Westinghouse regarding the sensitivity study and impact on a natural circulation plant cooldown. As a result, the licensee determined that there were no new discoveries that would change the conclusions in IR 1378105. Nonetheless, the inspectors determined that the operability basis in the IRs did not meet LS-AA-120 standards for reviewing operability. Specifically, IR 1378105 and IR 1382564 did not evaluate and document if the CST TS inventory was adequate to perform its specified TS function assuming more water was needed than previously assumed.

The inspectors performed a comprehensive review of the licensee's applicable IRs, Operability Evaluation 07-008, TSs, TS Bases documents, and the AOR and questioned if the CST could perform its CLB TS function. The inspectors held numerous discussions with Operations and Engineering staff and were provided with responses that did not adequately address CST operability. The licensee documented these responses in IR 1390874, "Documentation of NRC Questions on IR 1382564." The inspectors provided the licensee with the same CLB information that was reviewed by the inspectors.

The licensee's response to the inspectors' questions concerning CST TS operability was consistently not adequate as before because the specified CST TS function to cool down the RCS to RHR cut-in conditions following a reactor trip with natural circulation conditions was not adequately addressed. In particular, the following question was asked and responded to by the licensee as follows:

- Inspectors' Question: IR 1390874, Question #2: What is the CST required for?
- Licensee's Response: the CST provides the normal and preferred supply to the AF system; however, this function is not required to maintain plant safety because the essential service water (SX) system provides a safety-related backup to the AF system; the CST is not required to achieve safe reactor shutdown conditions or for accident mitigation with the exception of Station Blackout of 79,000 gallons.

The inspectors discussed the issue of concern and quality of responses received by the inspectors directly with licensee senior management. The inspectors were informed that their issue would be addressed in a revision to the Operability Evaluation.

On September 7, 2012, Operability Evaluation 07-008, Revision 6 evaluated the Unit 2 non-conforming SG PORV flow rate condition against the Unit 2 CST TS CLB provided by the inspectors. The licensee's evaluation estimated that an increase in the cooldown time to RHR entry conditions of up to 21 additional hours would be needed for Unit 2. This additional time to cooldown the RCS would require a total Unit 2 CST cooling water volume of about 405,000 gallons. This volume represented nearly double the volume previously assumed within the CLB. This evaluation concluded that approximately 2000 gallons of margin remained available before the safety-related backup UHS system would be needed to complete the cooldown to RHR cut-in conditions. Therefore, the licensee concluded that the CST remained operable.

Analysis: The inspectors determined the failure to evaluate the effect the reduced Unit 2 SG PORV flow rate capacities would have on the Unit 2 CST's ability to perform its specified TS function was a performance deficiency. Standards not followed included CAP standards for Operations to immediately and adequately determine TS operability after a non-conforming condition was identified and as new information becomes available, the Station Onsite Review Committee standard for verifying the conclusions documented by Operations in IRs, and Operability Evaluation program standards for performing a more detailed evaluation of TS operability and addressing supported TS equipment.

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. This 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 licensee did not ensure that the Unit 2 CST was capable of performing its specified TS function after identifying a non-conservative SG PORV flow rate non-conforming condition that ultimately resulted in requiring nearly double the CST volume than what was previously assumed in the CLB (i.e. 405,000 gallons vice 212,000 gallons). The inspectors determined that this significant decrease in available CST margin was sufficient cause for the reasonable doubt of CST operability.

The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings," which directed the finding to be screened using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power". The inspectors determined that because the CST maintained its operability and functionality within the CLB (i.e. approximately 2000 gallons of margin) that this finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area because the licensee failed to use conservative decision-making and verify the validity of underlying assumptions when evaluating the effect of reduced Unit 2 SG flow rate capacities on CST operability (H.1(b)).

Enforcement: This issue does not involve enforcement action because no regulatory requirement was violated. Because this issue does not involve a violation and has very low safety significance, it is identified as a finding. **(FIN 05000457/2012004-02, Failure**

to Adequately Evaluate the Specified TS CST Function After the Identification of a Non-Conforming Condition Adversely Affecting SG PORV Flow Rates)

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- Unit 2 “A” RHR Pump Re-Test Following 51-Hour Maintenance Window;
- Unit 2 “A” Containment Spray Pump Re-Test Following 2-Day Maintenance Window;
- Valve 2CS019A Re-Test Following a Thermal Overload Maintenance Activity;
- 1C SG PORV Uninterruptable Power Supply Alarm Repair Activity; and
- Unit 2 Station Air Compressor High Vibration Issue Resolution Activity.

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 adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Outage Activities

a. Inspection Scope

During this quarter, the inspectors observed new fuel receipt inspections in anticipation of Unit 2 refueling outage 2AR16, which was scheduled to begin in October 2012. The inspectors verified that the licensee performed inspections in accordance with their procedures and that any issues were appropriately dispositioned.

This inspection did not constitute an outage sample as defined in IP 71111.20-05, but will be a part of the Unit 2 refueling outage sample planned for next quarter.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- Unit 1 SG PORV (A,B,C,D) Operational Test (Routine);
- Unit 1 SG PORV Battery Visual Inspection Activity (Routine);
- Unit 2 Auxiliary Feedwater Undervoltage Simulated Start Operational Test (Routine);
- Unit 1 Emergency Diesel Generator (EDG) Auto Trip Bypass Surveillance and Monthly Operational Test (Routine);
- Unit 2 EDG Monthly Operational Test (Routine)
- Unit 2 “A” RHR Pump Operational Test (Inservice Testing); and
- Unit 1 “A” AF Pump American Society of Mechanical Engineers (ASME) Operational Test (Inservice Testing).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, 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, procedures, and applicable commitments;

- was measuring and test equipment calibration current;
- was 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 after testing;
- where applicable for inservice testing activities, was testing performed in accordance with the applicable version of Section XI, ASME Code, and reference values consistent with the system design basis;
- 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 reference setting data accurately incorporated into the test procedure;
- where applicable, were actual conditions encountering high resistance electrical contacts such that the intended safety function could still be accomplished;
- had prior procedure changes not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- was equipment returned to a position or status required to support the performance of its safety functions; and
- were all problems identified during the testing appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment. This inspection constituted five routine surveillance testing samples and two inservice testing samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of routine licensee emergency drills on July 25, 2012, and August 8, 2012, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment.

This inspection constituted two emergency preparedness drill samples as defined in IP 71114.06-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation (71124.08)

This inspection constituted one complete sample as defined in IP 71124.08-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the solid radioactive waste system description in the UFSAR, the process control program, and the recent radiological effluent release report for information on the types, amounts, and processing of radioactive waste disposed.

The inspectors reviewed the scope of any quality assurance audits in this area since the last inspection to gain insights into the licensee's performance and inform "smart sample" inspection planning.

b. Findings

No findings were identified.

.2 Radioactive Material Storage (02.02)

a. Inspection Scope

The inspectors selected areas where containers of radioactive waste were stored, and evaluated whether the containers were labeled in accordance with 10 CFR 20.1904, "Labeling Containers," or controlled in accordance with 10 CFR 20.1905, "Exemptions to Labeling Requirements," as appropriate.

The inspectors assessed whether the radioactive material storage areas were controlled and posted in accordance with the requirements of 10 CFR Part 20, "Standards for Protection against Radiation." For materials stored or used in the controlled or unrestricted areas, the inspectors evaluated whether they were secured against unauthorized removal and controlled in accordance with 10 CFR 20.1801, "Security of Stored Material," and 10 CFR 20.1802, "Control of Material Not in Storage," as appropriate.

The inspectors evaluated whether the licensee established a process for monitoring the impact of long-term storage (e.g., buildup of any gases produced by waste decomposition, chemical reactions, container deformation, loss of container integrity, or re-release of free-flowing water) that was sufficient to identify potential unmonitored, unplanned releases or nonconformance with waste disposal requirements.

The inspectors selected containers of stored radioactive material, and assessed these containers for signs of swelling, leakage, and/or deformation.

b. Findings

No findings were identified.

.3 Radioactive Waste System Walkdown (02.03)

a. Inspection Scope

The inspectors walked down accessible portions of selected radioactive waste processing systems to assess whether the current system configuration and operation agreed with the descriptions in the UFSAR, Offsite Dose Calculation Manual, and process control program.

The inspectors reviewed administrative and/or physical controls (i.e., drainage and isolation of the system from other systems) to assess whether the equipment which was not in service or abandoned in place would contribute to an unmonitored release path and/or affect operating systems, or be a source of unnecessary personnel exposure. The inspectors assessed whether the licensee reviewed the safety significance of systems and equipment abandoned in place in accordance with 10 CFR 50.59, “Changes, Tests, and Experiments.”

The inspectors reviewed the adequacy of changes made to the radioactive waste processing systems since the last inspection. The inspectors evaluated whether changes from what was described in the UFSAR were reviewed and documented in accordance with 10 CFR 50.59, as appropriate, and to assess the impact on radiation dose to members of the public.

The inspectors selected processes for transferring radioactive waste resin and/or sludge discharges into shipping and/or disposal containers, and assessed whether the waste stream mixing, sampling procedures, and methodology for waste concentration averaging were consistent with the process control program, and provided representative samples of the waste product for the purposes of waste classification as described in 10 CFR 61.55, “Waste Classification.”

For those systems that provided tank recirculation, the inspectors evaluated whether the tank recirculation procedures provided sufficient mixing.

The inspectors assessed whether the licensee’s process control program correctly described the current methods and procedures for dewatering and waste stabilization (e.g., removal of freestanding liquid).

b. Findings

No findings were identified.

.4 Waste Characterization and Classification (02.04)

a. Inspection Scope

The inspectors selected the following radioactive waste streams for review:

- Radwaste Barrel Processing;
- Radwaste Water Generation Processing; and
- Solid Radwaste Processing.

For the waste streams listed above, the inspectors assessed whether the licensee's radiochemical sample analysis results were sufficient to support radioactive waste characterization as required by 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste." The inspectors evaluated whether the licensee's use of scaling factors and calculations to account for difficult-to-measure radionuclides was technically sound and based on current 10 CFR Part 61 analyses for the selected radioactive waste streams.

The inspectors evaluated whether changes to plant operational parameters were taken into account to: (1) maintain the validity of the waste stream composition data between the annual or biennial sample analysis update; and (2) assure that waste shipments continued to meet the requirements of 10 CFR Part 61 for the waste streams selected above.

The inspectors evaluated whether the licensee had established and maintained an adequate quality assurance program to ensure compliance with the waste classification and characterization requirements of 10 CFR 61.55 and 10 CFR 61.56, "Waste Characteristics."

b. Findings

No findings were identified.

.5 Shipment Preparation (02.05)

a. Inspection Scope

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness. The inspectors assessed whether the requirements of applicable transport cask certificates of compliance had been met. The inspectors evaluated whether the receiving licensee was authorized to receive the shipment packages. The inspectors evaluated whether the licensee's procedures for cask loading and closure procedures were consistent with the vendor's current approved procedures.

The inspectors observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation and receipt activities. The inspectors assessed whether the shippers were knowledgeable of the shipping regulations and whether shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to:

- the licensee’s response to NRC Bulletin 79-19, “Packaging of Low-Level Radioactive Waste for Transport and Burial,” dated August 10, 1979; and
- 49 CFR Part 172, “Hazardous Materials Table, Special Provisions, Hazardous Materials Communication, Emergency Response Information, Training Requirements, and Security Plans,” Subpart H, “Training.”

Due to limited opportunities for direct observation, the inspectors reviewed the technical instructions presented to workers during routine training. The inspectors assessed whether the licensee’s training program provided training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

b. Findings

No findings were identified.

.6 Shipping Records (02.06)

a. Inspection Scope

The inspectors evaluated whether the shipping documents indicated the proper shipper name; emergency response information and a 24-hour contact telephone number; accurate curie content and volume of material; appropriate waste classification, transport index, and UN number for the following radioactive shipments:

- RMS-12-122; Radioactive Material, LSA-1, 7, UN2912; 40’ Sea Van Containing Outage Equipment to Byron Station;
- RMS-11-009; Radioactive Material, LSA-1, 7, UN2912; Fissile Excepted; Containing Barrel of Resin Inside a Sea Van to Bear Creek, Oak Ridge, Tennessee;
- RMS-11-011; Radioactive Material, LSA-1, 7, UN2912; Fissile Excepted; Radwaste Material to Bear Creek; and
- RMS-11-017; Radioactive Material, LSA-1, 7, UN2912; Fissile Excepted; Resin Sand Media to Bear Creek, Oak Ridge, Tennessee.

Additionally, the inspectors assessed whether the shipment placarding was consistent with the information in the shipping documentation.

b. Findings

No findings were identified.

.7 Identification and Resolution of Problems (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with radioactive waste processing, handling, storage, and transportation, were being identified by the licensee at an appropriate threshold, were properly characterized, and were properly addressed for resolution in the licensee’s CAP. Additionally, the inspectors evaluated whether the corrective actions were appropriate for a selected sample of problems documented by the licensee that involve radioactive waste processing, handling, storage, and transportation.

The inspectors reviewed results of selected audits performed since the last inspection of this program and evaluated the adequacy of the licensee’s corrective actions for issues identified during those audits.

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 Transients Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients Per 7000 Critical Hours performance indicator (PI) for Unit 1 and Unit 2 for the period from the first quarter of 2011 to the second quarter of 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, dated October 2009, were used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, maintenance rule records, event reports, and NRC Integrated Inspection Reports for the period of January 1, 2011, through June 30, 2012, to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two unplanned transients per 7000 critical hours samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Specific Activity PI for Braidwood Station Units 1 and 2 for the period from the first quarter 2011 through the first quarter 2012. The inspectors used PI definitions and guidance contained in NEI 99-02, Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s RCS chemistry samples, TS requirements, issue reports, event reports and NRC Integrated Inspection

Reports to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze an RCS sample. Documents reviewed are listed in the Attachment.

This inspection constituted two RCS Specific Activity samples as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

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

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of January 2012 through June 2012, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

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

b. Findings

Adverse Trend in Adequately Resolving Previously Identified NRC Identified Findings

Based on a review of the CAP, plant performance, and inspection results over the past year, the inspectors identified an adverse trend in the licensee's evaluation and quality of response to NRC questions and concerns. This adverse trend was also considered a potential contributor to a number of NRC violations that have been repetitive or not adequately corrected in a timely manner. These issues include the following:

- Notice of Violation (VIO) 05000456/2012004-04; 05000457/2012004-04, "Failure to Analyze RHUT Inlet Piping Loads," which was the result of inadequate corrective actions taken for NCV 05000456/2010006-02; 05000457/2010006-02, "Untimely Corrective Action for Lack of Water Hammer Analysis on the Recycle Holdup Tank," and NCV 05000456/2008005-05; 05000457/2008005-05, "Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT Quench Volume;"
- VIO 05000457/2012008-01, "Failure to Install Foam-Water Sprinklers In Accordance With Sprinkler Standard," which was the result of inadequate

corrective actions taken for NCV 05000457/2010002-04, “Diesel Oil Storage Tank Room Sprinkler Obstructions;”

- NCV 05000456/2012007-01, “Non-Conforming Piping Condition Not Corrected,” which was the result of inadequate corrective actions taken for NCV 05000456/2011008-02, “Permanent Lead Shielding Added to Safety Injection and Chemical Volume and Control System Piping;”

- NCV 05000456/2012007-02, “Surveillance Procedure Not Followed,” which was the result of inadequate corrective actions taken for NCV 05000456/2010007-01; 05000457/2010007-01, “Diesel Driven Auxiliary Feedwater Pump Battery Racks Were Not Restored to Their Design Basis Seismic Category I;”

- FIN 05000456/2012007-03; 05000457/2012007-03, “Untimely Completion of a Corrective Action to Prevent Recurrence,” which was the result of inadequate corrective actions taken for FIN 05000456/2010010-03; 05000457/2010010-03, “Failure To Identify and Correct Water Discharged to the Turbine Building Floor During Condensate Reject;”

- FIN 05000456/2012003-04; 05000457/2012003-04, “Operability Determination Standards Not Followed for High Energy Line Breaks (HELB) Related Structural Issues Identified by the NRC,” which was a repeat occurrence of the issues identified in FIN 05000456/2011005-04; 05000457/2011005-04, “Operability Evaluation Not Performed in Accordance with Station Standards;”

- FIN 05000456/2011005-06; 05000457/2011005-06, “Failure to Adhere to Maintenance Rule Implementation Procedures,” which was a repeat occurrence of the issues identified in NCV 05000456/2011004-08; 05000457/2011004-08, “Failure to Follow Maintenance Rule Procedure;”

- FIN 05000456/2011004-01; 05000457/2011004-01, “Failure to Adhere to Standards of Outdoor Secured Material Zones,” which was the result of inadequate corrective actions taken for FIN 05000456/2011003-01; 05000457/2011003-01, “Failure to Follow Procedural Standards Related to the Storage of Outside Material that Could Impact Offsite Power Availability;”

<u>Adverse Trend in Adequately Evaluating Issues of Concern Raised by NRC Inspectors</u>

Along with repetitive findings or violations, the inspectors noted other instances where NRC questions that involved regulatory concerns were not adequately evaluated. These issues, some of which were documented as more than minor findings or violations, required repeated and extensive interactions to address issues that the inspectors assessed as straightforward. As a result, adequate resolution of these issues was often not timely and typically required several attempts by the licensee. Some recent examples include the following:

- Numerous Operability Evaluation revisions regarding turbine building HELB and SG PORV issues driven by NRC questions and concerns;
- Inadequate face to face fatigue assessments;
- Control and usage of elevators and elevator keys during fire drills;

- Plant Cooldown timeliness requirements in Emergency Operating Procedure ES-0.1;
- Storage of a spent fuel pool skimmer hose on or near spent fuel pool fuel racks;
- Functionality of spring-loaded fire dampers with room ventilation running; and
- Procedural guidance regarding fire extinguisher usage in security enclosures.

The inspectors determined that there was a general weakness in the timeliness, quality, and overall adequacy of site responses to observations and concerns from external oversight. In particular, the inspectors concluded that licensee responses to NRC questions were typically narrowly focused, which challenged effective communication and resulted in additional effort for the inspectors and licensee staff to fully understand the issues such that an adequate resolution could be achieved.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the operator workarounds (OWAs) on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

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

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

b. Findings

No findings were identified.

.5 Selected Issue Follow-Up Inspection: Recycle Holdup Tank Corrective Actions

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting recycle holdup tank corrective actions.

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

b. Findings

Failure to Analyze Recycle Holdup Tank (RHUT) Inlet Piping Loads

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated cited violation (VIO) of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 RHR suction relief valves that discharge to the RHUT; and, as a result, failed to verify the adequacy of the RHUT design to withstand design loads that resulted from a discharge from RHR system suction relief valves into the RHUT.

Description: On June 20, 2007, NRC inspectors identified a concern that the licensee had not established or maintained an adequate RHUT cold water volume for quenching Unit 1 and Unit 2 RHR suction piping relief valve discharges into the RHUT to ensure that the design pressure and temperature of the RHUT was not exceeded. On July 12, 2007, the licensee generated IR 649581 documenting the inspectors' concerns. The licensee also generated IR 677075 on September 28, 2007, which documented additional NRC concerns with the lack of an analysis of dynamic water hammer loads on RHUT inlet piping. Assignment 8 of IR 649581, initially due on August 15, 2008, was created to track ultimate resolution of the potential RHUT over-pressurization issue. Assignment 9 of IR 677075, initially due on July 31, 2009, was created to track a revision to UFSAR Chapter 15 accident analyses for a ruptured RHUT.

On February 9, 2009, the NRC issued NCV 05000456/2008005-05; 05000457/2008005-05 for the failure to evaluate and maintain the required water volume necessary to quench RHR system suction relief valve discharges to the RHUT; to incorporate appropriate minimum water level requirements into the RHUT level control procedure; and to evaluate the effect of dynamic water hammer loads on inlet piping from RHR suction relief valves that discharge to the RHUT.

On July 30, 2009, the licensee extended the due date of IR 677075, Assignment 9 to June 18, 2010, based on emergent Engineering priorities and a corporate Engineering re-organization. On August 5, 2009, the licensee extended the due date for IR 649581 Assignment 8 to September 18, 2009, due to the need for vendor support. On September 22, 2009, IR 649581 Assignment 8 was again extended to October 28, 2009, based on losing project support due to corporate re-structuring. On October 28, 2009, the due date for IR 649581, Assignment 8 was extended to December 17, 2009, based on a lack of progress due to refueling outages at Braidwood and Byron. On June 18, 2010, the licensee documented in IR 649581, Assignment 8 and IR 677075, Assignment 9 that a preliminary evaluation revealed a possible need for physical modifications, with more detailed analyses planned for fall 2010.

In September 2010, the biennial NRC Problem Identification and Resolution inspection was conducted at Braidwood. At the time of the inspection, IR 649581, Assignment 8 and IR 677075, Assignment 9 had not been completed. As a result, NCV 05000456/2010006-02; 05000457/2010006-02 was issued on October 27, 2010, for failing to address potential water hammer effects on the RHUT in a timely manner. The licensee indicated to the inspectors that they planned to accelerate the completion schedule of the analyses. On September 22, 2010, the licensee extended the due date for IR 677075, Assignment 9 to July 2011 based on additional analysis scope. Notes added to IR 649581, Assignment 8 on September 29, 2010, stated that, "delaying completion of this assignment will result in a delay in closure of an open NRC green NCV identified in fourth quarter 2008 … Although this item has been rescheduled eight times previously, this item was recently (July 2010) converted from a 4D ACIT tracking item to a Corrective Action (CA) assignment. This is the first reschedule of the CA." In addition, on September 29, 2010, the licensee extended the due date on IR 649581, Assignment 8 to January 20, 2011.

During this inspection period, the inspectors noted the following additional extensions to IR 649581, Assignment 8.

- On January 19, 2011, a licensee Management Review Committee (MRC) approved an extension for the CA assignment to July 20, 2011.
- On July 19, 2011, the MRC approved an extension for the CA assignment to May 25, 2012. Following this extension, on July 25, 2011, the licensee also extended the due date for IR 677075, Assignment 9 to December 6, 2011, at which point the UFSAR Chapter 15 update was completed.
- On May 23, 2012, the MRC approved an extension for the CA assignment to June 29, 2012.
- On June 28, 2012, the MRC approved an extension for the CA assignment to August 30, 2012.
- On August 28, 2012, the MRC approved an extension for the CA assignment to November 28, 2012. At this point it was also determined that if a physical modification was required to address the issues, a new target completion date would be determined.

As of September 30, 2012, IR 649581, Assignment 8 to resolve the potential over-pressurization of the RHUT had not been completed. At the end of the inspection period, licensee efforts to complete and refine a model to determine whether physical modifications are necessary were in progress. It remained unclear whether a physical modification would be necessary; when that determination would be made; and if a physical modification was necessary, when that modification would be completed.

<u>Analysis</u>: The inspectors determined that the licensee's failure to evaluate the effect of dynamic water hammer loads on inlet piping from Unit 1 and Unit 2 RHR suction relief valves that discharge to the RHUT was an issue of concern that was not related to a potentially willful violation. Because the issue of concern was the result of the licensee's failure to meet a requirement or standard and could have reasonably been prevented by the licensee, the inspectors determined that the issue of concern was a performance deficiency.

The performance deficiency was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," because the finding was associated with the Design Control attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the licensee's existing design and piping configuration had not addressed water hammer effects when the Unit 1 and Unit 2 RHR suction relief valves were aligned to discharge to the RHUT, which could rupture the inlet piping and potentially affect offsite dose consequences.

The NRC Senior Reactor Analysts concluded that the risk significance associated with the performance deficiency could be determined by two plant conditions.

<u>Case 1: Unit Shutdown with the Residual Heat Removal System In-Service in the Shutdown Cooling Mode</u>

The RHR suction relief valves are designed to be isolated from the RCS by a motor-operated valve (MOV) when the RHR system is not in-service (and interlocked to prevent opening if RCS pressure is greater than 360 pounds per square inch gauge (psig)). The finding would not affect the likelihood of core damage, but had potential implications for the integrity of the containment (i.e., Large Early Release Frequency (LERF)). The finding was determined to be a Type B finding as defined in IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." Westinghouse previously completed an evaluation and determined that the RHUT would not exceed design pressures or temperatures under the conditions of an RHR relief valve lifting. Also, the discharge from the RH suction relief valve would only potentially adversely affect the downstream relief valve piping if the RCS temperature was above 212°F.

The SRAs reviewed IMC 0609, Appendix H, and IMC 0308, Attachment 3, Appendix H, "Technical Basis - Containment Integrity Significance Determination Process (IMC 0609, Appendix H) For Type A and Type B Findings – Full Power and Shutdown Operations," to determine the impact of the finding on LERF. According to Table B.3 of IMC 0308, Attachment 3, Appendix H, the annualized core damage frequency (CDF) with the reactor head bolted on the reactor vessel flange (as is the case with the plant in Mode 4) for an in-depth shutdown mitigation capability that would exist for the plant in Mode 4 (an in-depth shutdown mitigation capability is defined in Table 6.8 of IMC 0609, Appendix H) was 1.0E-7/yr. To provide an upper bound on the change in LERF, it was conservatively assumed that one-tenth of the core damage events were associated with an RHR suction relief valve failing to open. In addition, in Braidwood Integrated Inspection Report 05000456/2008005;05000457/2008005, it was stated that Braidwood Unit 1 had experienced a lift of an RHR suction relief valve and had not experienced damage to downstream piping and pipe supports. This one RHR suction relief valve result was used to calculate a mean failure probability for the piping with a lift of an RHR suction relief valve (using a Bayesian update with a Jeffrey's non-informative prior). The result was a mean failure probability of the downstream relief valve piping of 0.25. Using a LERF factor of 1.0 (i.e., all core damage events result in a large early release), an upper bound estimate for the ΔLERF associated with the performance deficiency for Case 1 was therefore calculated to be about 2.5E-9/year.

<u>Case 2: Unit in Recirculation Mode or on Shutdown Cooling Following Loss of Coolant Accident (LOCA) or Steam Generator Tube Rupture (SGTR)</u>

As stated above, the performance deficiency would not affect the likelihood of core damage, but had potential implications for the integrity of the containment (i.e., LERF). To provide an upper bound on LERF associated with a LOCA or SGTR, it was conservatively assumed that during each core damage event associated with a LOCA or SGTR the RHR suction relief valves in both RHR trains would lift once while the plant was either in the emergency core cooling system recirculation mode or while aligned for shutdown cooling. Using the Braidwood Standardized Plant Analysis Risk (SPAR) model, version 8.21, and the associated risk analysis software (SAPHIRE version 8.0.8.0), the total CDF associated with LOCA (large, medium, and small LOCAs) and SGTR events was determined to be 3.24E-6/year. Using Table 24 from NUREG/CR-7037, "Industry Performance of Relief Valves at U.S. Commercial Power Plants through 2007," the probability of an RHR relief valve to fail to close once it is actuated is 1.05E-3. Per the discussion above, the mean probability failure for the failure of relief valve discharge piping with a lift of an RHR suction relief valve was 0.25. Using a LERF factor of 1.0 (i.e., all core damage events result in a large early release), an upper bound estimate for the ΔLERF associated with the performance deficiency for Case 2 was therefore calculated to be about 1.7E-9/year.

An upper bound estimate for the LERF associated with the performance deficiency is estimated by adding the results from Case 1 and Case 2 above, which results in 4.2E-9/year. As a result, the finding was determined to be of very low safety significance (Green).

This finding had a cross-cutting aspect in the Corrective Action Program component of the Problem Identification and Resolution cross-cutting area because the licensee failed to take timely corrective actions to address a previously issued NCV (P.1(d)).

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying the adequacy of the design and that the design basis is correctly translated into procedures and instructions.

Contrary to the above, from initial plant construction until September 30, 2012, the licensee failed to verify the adequacy of the design of the Braidwood Unit 1 and Unit 2 RHUTs, which are safety-related components subject to the requirements of Title 10 CFR Part 50, Appendix B, Criterion III, and failed to correctly translate the design basis of the Braidwood Unit 1 and Unit 2 RHUTs into procedures and instructions. Specifically, the licensee failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 RHR system suction relief valves that discharge to the RHUTs; and, as a result, failed to verify the adequacy of the RHUT design to withstand design loads that would result from a discharge of RHR system suction relief valves into the RHUTs. In this case, the licensee had not restored compliance within a reasonable period of time (i.e. in a time frame commensurate with the significance of the violation) after the violation was identified (i.e., a non-cited violation of Title 10 CFR 50, Appendix B, Criterion III, "Design Control," previously issued in February 2009 and an additional non-cited violation of Title 10 CFR, Appendix B, Criterion XVI, "Corrective Action," previously issued in October 2010). As a result, the conditions for considering the violation as non-cited, as identified in Section 2.3.2(a)(2) of the Enforcement Policy, were not met. Therefore, the violation is being cited in the attached Notice of Violation.

(VIO 05000456/2012004-03; 05000457/2012004-03, Failure to Analyze RHUT Inlet Piping Loads)

.6 Selected Issue Follow-Up Inspection: Evaluation of Fire Brigade Elevator Training

a. Inspection Scope

The inspectors reviewed the extent of condition for a previous NRC-identified issue associated with the June 14, 2012, fire drill conducted within the station's turbine building (IR 1378314, IR 1403621, and IR 1398598). The inspectors identified that fire brigade responders had not received the necessary permission from the Fire Chief prior to utilizing the turbine building elevator to transport equipment and personnel during the drill. Additionally, the inspectors had identified that this deficiency was not discussed during the post drill critique. During conversations following the fire drill, the licensee staff had informed the inspectors that elevator control keys were not utilized at the station. This inspection effort focused on broadly reviewing the extent of condition pertaining to the requirements for elevator usage and control contained within the CLB and ensuring that the licensee had met and maintained those requirements.

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

b. Findings

Failure to Train Fire Brigade Members on Use of Elevators

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of Braidwood Operating License Condition 2.E, "Fire Protection Program," when licensee personnel failed to ensure that Fire Chiefs and fire brigade members retained knowledge provided in fire brigade initial training. Specifically, station Fire Chiefs and fire brigade members did not have an adequate knowledge or continuing training on the proper methods and implementation for the use and control of elevators during a fire, as demonstrated during a fire drill on June 14, 2012.

Description: The elevators at Braidwood are equipped with devices known as Phase I and Phase II controls that allowed firefighters to override normal elevator controls. When initiated, a Phase I control is designed to cause the elevator to move directly to a predetermined floor, open the doors, and remain there to allow anyone in the elevator to safely exit the elevator and prevent others from using it. When initiated, a Phase II control is designed to disregard external elevator call buttons and allow fire brigade members or offsite firefighters to operate the elevator from inside the elevator. These controls were designed to allow the elevator to be utilized safely and effectively during a fire by transporting fire brigade members and firefighting equipment to the necessary location as determined by the Fire Chief. If the elevators are not controlled in this manner, the elevator may not be available for fire brigade use or could place personnel in danger by stopping at an undesirable elevation.

During a fire drill conducted on June 14, 2012, the inspectors identified that two fire brigade members and one support person were inside an elevator when the doors opened at the scene of the simulated fire. The inspectors questioned this practice since the fire brigade members in the elevator could have become casualties had the fire brigade members been responding to an actual fire. This would have complicated the fire response due to the necessity to rescue the individuals. In the post-drill critique, it was determined that the Fire Chief was not aware that the fire brigade members had used the elevator. The licensee performed a work group evaluation of the issue and identified three causes:

- A gap in the knowledge of the use of building elevators by fire brigade members who did not display the appropriate risk awareness when using the elevator to respond to the fire. The evaluation noted that training document FB-11 stated that fire brigade members were to use elevators only after the Incident Commander verifies them to not be in close proximity to the fire;

- The drill guide was inadequate in providing normal and expected cues for all access points to the elevator. The evaluation attributed this to not posting drill cues regarding smoke inside the elevator so that fire brigade members would realize the close proximity of the fire to the elevator. However, the inspectors determined that, by design, smoke would not enter the elevator until the doors opened at the area where the fire was burning; and

- A possible gap in the clarity of OP-AA-201-003, "Fire Drill Performance."

For this sample, the inspectors reviewed the extent of condition and corrective actions associated with the inspector's June 14, 2012 identified issue. The inspectors reviewed the results of the work group evaluation and procedure BwAP 1100-5, "Fire Department Response, Notification and Mutual Aid Agreements and Expected Chain of Events During a Fire," which instructed the Fire Brigade Leader to use elevator keys to control elevator use during a fire. Procedure BwAP 1100-5, Revision 10, included the following Note in Section C.5, which described the expected sequence of events during a fire.

1. *Two (2) keys are required to operate any elevator for use during a fire. One key must be placed in the lock outside of the elevator on the ground floor elevation (401'). Once this key is activated, the elevator car will be called to that elevation. Once inside the car, the second key must be placed in the fire service lock and turned. At this point, full control of the elevator is from inside the elevator <u>only</u>. Four keys for this use are in the shift office in the key box and the Fire Chief carries a set.*

2. *A guard should be requested to the 401' elevation at the elevator in use to ensure the key is not removed.*

The inspectors asked the Operations Work Execution Center staff, and then the on-duty Fire Chief where the elevator keys were located and how the keys would be utilized during a fire. The Work Execution Center staff and Fire Chief could not validate with certainty where the keys were located or how they would be utilized in the event of a fire. The inspectors raised this issue of concern to the Operations Director and IR 1410273 was generated. In addition to the apparent knowledge gap, the licensee's CAP review identified two broader issues. First, the elevator control keys for the auxiliary building and turbine building elevators were not available in the Operations shift office key box or on the Fire Chief's key ring as required by procedure BwAP 1100-5, and the Operations Shift Manager key inventory list was not effective in maintaining this requirement. Second, while adequately covered in initial training, periodic refresher training had been ineffective in providing the Fire Chiefs and fire brigade members with adequate knowledge of the location and use of elevator control keys.

The licensee determined that a knowledge gap existed in how elevators were keyed. Each elevator is keyed differently and the key thought to be a master elevator key by Operations personnel actually only controlled the Service Building elevator. Corrective actions included ensuring all elevator keys were adequately stored, informing the Fire Chiefs and fire brigade members of the key locations, and initiating a training request to provide the Fire Chiefs and fire brigade members with adequate training covering elevator key usage and elevator control during a fire response.

Analysis: The inspectors determined that the failure to ensure fire brigade members retained knowledge provided in fire brigade initial training was an issue of concern that constituted a performance deficiency since it represented a failure to meet a standard (Braidwood Operating License) and was reasonably within the licensee's ability to foresee and correct. Specifically, station Fire Chief and fire brigade members did not have adequate knowledge or continuing training on the proper methods and implementation for the use and control of elevators during a fire, as demonstrated during a fire drill on June 14, 2012.

The finding was evaluated using IMC 0612, Appendix B, "Issue Screening." The inspectors determined the finding was more than minor because it was associated with the Protection Against External Factors (Fire) 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. Specifically, the turbine building and auxiliary building elevators could be utilized in the licensee's Fire Protection Program to transport fire brigade members and their equipment in response to a fire. Safety-related equipment was in (or adjacent to) these fire zones. Therefore, if elevators were not controlled in the correct manner, the elevator may not be available for fire brigade use or may place personnel in danger by stopping at an undesirable elevation.

The inspectors screened the finding in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings." Based on Table 2, the inspectors concluded the issue represented a weakness in the External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded) function of the Mitigating Systems Cornerstone. The inspectors reviewed the questions in Table 3 of IMC 0609, Attachment 4, and answered 'No' to Questions A-D and 'Yes' to Question E.1, "Does the finding involve discrepancies with the fire brigade?" since the finding involved discrepancies with the fire brigade. As a result, the inspectors transitioned to IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power." The inspectors reviewed IMC 0612, Appendix A, Exhibit 2, and answered 'No' to Question B - External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded), "Does the finding involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event (e.g., seismic snubbers, flooding barriers, tornado doors)?" As a result, the finding screened as having very low safety significance (Green).

This finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because the licensee failed to ensure station Fire Chiefs and fire brigade members had an adequate knowledge or continuing training on the proper methods and implementation for the use and control of elevators during a fire, as demonstrated during a fire drill on June 14, 2012 (H.2(b)).

Enforcement: Braidwood Operating License Condition 2.E requires that the licensee implement and maintain in effect all provisions of the approved Fire Protection Program as described in the UFSAR. Appendix A of the Braidwood Fire Protection Report contained the requirements of the 1979 version of 10 CFR 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," which applied to Braidwood Station. Section III.I.1.a(8) of the Braidwood Fire Protection Report stated, in part, that initial classroom training of the fire brigade shall include the direction and coordination of the fire fighting activities and a detailed review of fire fighting strategies and procedures. Section III.I.1.e of the Braidwood Fire Protection Report stated, in part, that periodic refresher training sessions shall be held to repeat the classroom instruction program for all brigade members over a two year period. Contrary to the above, the licensee's initial and periodic refresher training of the fire brigade members did not include the proper control and use of elevator keys during fires, as prescribed in site procedures. Corrective actions included ensuring all elevator keys were adequately stored, informing the Fire Chiefs and fire brigade members of the key locations, and initiating a training request to provide the Fire Chiefs and fire brigade members with adequate training covering elevator key usage and elevator control during a fire response. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 1398598, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000456/2012004-04; 05000457/2012004-04, Failure to Train Fire Brigade Members on the Use of Elevators)

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

.1 Notice of Enforcement Discretion 12-3-001: Technical Specification 3.7.9 Ultimate Heat Sink Average Water Temperature Limit

a. Inspection Scope

On July 7, 2012, at approximately 6:00 a.m., the licensee's UHS temperature prediction computer model first predicted that the UHS temperature would exceed the TS 3.7.9 limit of 100°F that afternoon. Below average precipitation throughout the spring and summer combined with a record 3 consecutive days above 100°F air temperature from July 4 through July 6, 2012, resulted in UHS temperatures elevated above historical averages. Despite the elevated UHS temperatures, prior modeling had predicted that the UHS temperature would remain below 100°F.

At 3:56 p.m. on July 7, the UHS temperature exceeded 100°F and the licensee entered TS 3.7.9, Required Action A.1, which required both Units to be in Mode 3 within 6 hours. Because a cold front was approaching the area that was expected to result in sustained cooler air and lake temperatures within hours, the licensee verbally requested a Notice of Enforcement Discretion (NOED) via teleconference at 4:30 p.m. The licensee specifically requested that the NRC allow an extension of Required Action A.1 for 18 additional hours and allow an increase in the Surveillance Requirement (SR 3.7.9.2) from 100°F to 102°F for a period of 24 hours. At 5:05 p.m., the NRC approved the request. During the teleconference a number of compensatory actions were discussed that would be implemented by the licensee. At 3:55 a.m. on July 8, 2012, the conditions causing the need for the NOED no longer existed and the licensee exited the NOED.

The inspectors responded to the site on the morning of July 7 based on the potential for the UHS temperature exceeding 100°F. The inspectors reviewed plant conditions, weather conditions and forecasts, attended licensee meetings, observed preparations for shutting down both units, and reviewed licensee technical documents. Regional and Headquarters NRC management and staff were involved in communications with the inspectors throughout the day to ensure agency senior management was fully aware of and understood the issue. The inspectors reviewed the compensatory actions that were discussed during the NOED teleconference. The licensee's subsequent written NOED request was also reviewed by the inspectors to ensure it accurately reflected the verbal NOED request and approval.

Documents reviewed are listed in the Attachment. This event follow-up review constituted one inspection sample as defined in IP 71153-05.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report 05000456/2012-002-00, Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Attributed to Primary Water Stress Corrosion Cracking

On April 23, 2012, the licensee identified an indication on the Unit 1 reactor head penetration 69 during the performance of a volumetric examination. The flaw was located on the outside diameter of the penetration tube and was axially oriented with a linear extent of 0.600 inches and a through-wall depth of 0.216 inches (approximately 33.5 percent through wall).

On June 22, 2012, the licensee submitted Licensee Event Report (LER) 05000456/2012-002-00, "Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Attributed to Primary Water Stress Corrosion Cracking," reporting this event to the NRC in accordance with 10 CFR 50.73(a)(2)(ii)(A), any event or condition that resulted in the condition of the nuclear power plant, including its principal safety barriers, being seriously degraded.

The licensee attributed the apparent cause of the flaw to primary water stress corrosion cracking. The licensee repaired the penetration prior to returning the reactor head to service. Additionally, the frequency of the Unit 1 bare metal visual and the volumetric reactor head exams was changed to every refueling outage.

The inspectors reviewed this LER and determined that it was completed in accordance with NRC regulations. No findings were identified. This LER is closed.

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

.3 (Closed) Licensee Event Report 05000456/2012-004-00; 05000457/2012-004-00, Notice of Enforcement Discretion Received for Ultimate Heat Sink Temperature Exceeding Technical Specification Requirements Due to Prolonged Hot Weather

This LER was reported on September 5, 2012 as a voluntary LER and documented an unplanned entry into the Unit 1 and Unit 2 TS 3.7.9, "Ultimate Heat Sink," Limiting Condition of Operation (LCO) based on exceeding the 100°F TS Surveillance Requirement temperature limit. Additionally, this LER described and documented NRC Enforcement Discretion described in Section 4OA3.1 of this report.

The inspectors reviewed this LER and reviewed the basis for not making a 10 CFR 50.72 report for this condition to ensure the report was made in accordance with NRC regulations.

Failure to Submit a 10 CFR 50.72(b)(3)(v) and a 10 CFR 50.73(a)(2)(v) Report, Inoperable UHS

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR 50.72(b)(3)(v) and 10 CFR 50.73(a)(2)(v) when licensee personnel failed to report a condition that resulted in a loss of safety function after the UHS was declared inoperable after exceeding the TS limit of 100°F. Specifically, on July 7, 2012, the licensee had identified and entered TS 3.7.9, "Ultimate Heat Sink," Condition (A), "UHS Inoperable," after the UHS lake temperature exceeded the TS 3.7.9.2 Surveillance Requirement value of less than or equal to 100°F. The inspectors determined that although this condition represented a loss of safety function in accordance with the 10 CFR 50.72 and 10 CFR 50.73 reporting requirements and NUREG-1022, "Event Reporting Guidelines: 10 CFR 50.72 and 10 CFR 50.73," Revision 2, the condition was not reported as required.

Description: From July 4 through July 6, 2012, unusually hot weather and drought conditions affected the northern Illinois area and resulted in elevated water temperatures for the Braidwood Station UHS system and lake. On July 7, 2012, at 3:56 p.m., the licensee identified that the average discharge temperature of the limiting running SX system pump exceeded 100°F. This condition resulted in the licensee declaring the Unit 1 and Unit 2 UHS system inoperable and entering TS 3.7.9, Condition A. Condition A, "UHS Inoperable," required the licensee to be in Mode 3 within 6 hours and Mode 5 within the following 36 hours.

The licensee entered the issue into their CAP as IR 1386277 and determined that the condition was not reportable in accordance with 10 CFR 50.72 and 10 CFR 50.73 requirements. However, on September 5, 2012, the licensee submitted a voluntary LER describing this condition and the associated NOED action approved by the NRC.

The inspectors reviewed IR 1386277, the submitted voluntary LER, and reporting guidance contained in NUREG-1022, Revision 2, and discussed the issue with NRC Nuclear Reactor Regulation (NRR) subject matter experts. The inspectors determined that this event represented a condition that as a result of a single cause could have prevented the fulfillment of a safety function needed to remove residual heat. Specifically, the UHS for both Braidwood Unit 1 and Unit 2 is comprised of a single system (i.e. a single body of water.), and exceeding the UHS temperature limit rendered the UHS system inoperable for both units. The UHS is credited in the licensee's CLB to remove decay heat during both normal and accident shutdown conditions.

The NRC guidance document for 10 CFR 50.72 and 10 CFR 50.73 is contained in NUREG-1022, "Event Reporting Guidelines: 10 CFR 50.72 and 50.73," Revision 2. Section 3.2.7 of NUREG-1022 stated the following:

- *There are a limited number of single-train systems that perform safety functions (e.g. High Pressure Coolant Injection System in Boiling Water Reactors). For such systems, loss of the single train would prevent the fulfillment of the safety function of that system and, therefore, is reportable even though the plant technical specifications may allow such a condition to exit for a limited time.*

- *Reportable conditions under these criteria include the following…Whenever an event or condition exists where the system could have been prevented from fulfilling its safety function because of one or more reasons for equipment inoperability or unavailability, it is reportable under these criteria. This would include cases where one train is disabled and a second trains fails a surveillance test.*

This issue was entered into the licensee's CAP as IR 1422296. Corrective actions included an action to report this event in accordance with NRC requirements.

Analysis: The inspectors determined that the failure to submit a report required by 10 CFR 50.72 and an LER required by 10 CFR 50.73 for a loss of safety function after the UHS was declared inoperable on July 7, 2012, was a performance deficiency.

The inspectors determined that this issue had the potential to impact the regulatory process based, in part, on the generic communications that 10 CFR 50.72 and 10 CFR 50.73 reports serve, the required inspection reviews that the NRC performs on all LERs, and the potential impact on licensee performance assessment. Since the issue impacted the regulatory process, it was dispositioned through the Traditional Enforcement process. The inspectors determined that this issue was a Severity Level IV violation based upon similar examples in the NRC Enforcement Policy. Specifically, Example 6.d.9 for the failure to submit the 10 CFR 50.72 report and Example 6.d.10 for the failure to submit a complete 10 CFR 50.73 report (LER) as follows:

- Example 6.d.9: "The licensee fails to make a report requirement by 10 CFR 50.72 or 10 CFR 50.73," and

- Example 6.d.10: "A failure to identify all applicable reporting codes on a Licensee Event Report that may impact the completeness or accuracy of other information (e.g., performance indicator data) submitted to the NRC."

The inspectors evaluated the technical issue associated with exceeding the TS Surveillance Requirement limit and did not identify a performance deficiency. Therefore, this finding was not processed through the ROP. Because cross-cutting aspects do not apply to traditional enforcement issues, no cross-cutting aspect was assigned.

Enforcement: Title 10 CFR 50.72(b)(3), "Eight-hour reports," requires, in part, that "If not reported under paragraphs (a), (b)(1) or (b)(2) of this section, the licensee shall notify the

NRC as soon as practical and in all cases within eight hours of the occurrence of any of the following…(v) Any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to…(B) Remove residual heat.”

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 Title 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:…(B) Remove residual heat.”

Contrary to the above, between 11:56 p.m. on July 7, 2012, and September 30, 2012, the licensee failed to notify the NRC operations center via the emergency notification system within 8 hours of the discovery (3:56 p.m. on July 7, 2012) that the UHS was unable to fulfill its safety function, which is needed to remove residual heat; and between September 5, 2012, and September 30, 2012, the licensee failed to submit an LER describing the condition within 60 days of discovery. Corrective actions included the planned issuance of an updated LER. Because this violation was entered into the licensee’s CAP as IR 1422296, it is being treated as a Severity Level IV NCV consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2012004-05; 05000457/2012004-05, Failure to Submit a 10 CFR 50.72(b)(3)(v) and a 10 CFR 50.73(a)(2)(v) Report, Inoperable Ultimate Heat Sink)**

4OA5 Other Activities

Institute of Nuclear Power Operations Assessment Report Review

a. Inspection Scope

The inspectors reviewed the Institute of Nuclear Power (INPO) Accreditation Report for the Braidwood Operations Training Program on October 21, 2012. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to determine if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 3, 2012, the inspectors presented the inspection results to Mr. D. Enright and other members of the licensee’s 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 inspection results for the areas of radioactive solid waste processing and radioactive material handling, storage, and transportation; and RCS specific activity PI verification with D. Enright, Braidwood Site Vice President, on August 24, 2012.

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

4OA7 Licensee-Identified Violations

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

Cornerstone: Barrier Integrity, Mitigating Systems

Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by instructions, procedures, or drawings of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures, or drawings. Quality procedure MA-AA-716-025, "Scaffold Installation, Modification, and Removal Request Process," Revision 9, required the following:

- *2.14 Non-Permanent Scaffold - These temporary access structures are not intended to be left in place for more than 90 days of at power plant operations.*

- *4.7.1 The Scaffold Coordinator/Designee shall perform a monthly review to ensure that Scaffolds do not remain in place greater than or equal to 90 days.*

Contrary to the above, the licensee identified six scaffolds that had been built and installed in the plant for a time period greater than 90 days. This finding was determined to be of very low safety significance (Green) because none of the scaffolds resulted in the loss of operability of an SSC. The licensee entered this issue into their CAP as IR1388785. Corrective actions included performing a 10 CFR 50.59 evaluation for the continued installation of one of the scaffolds and the immediate removal of the remaining five scaffolds.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Enright, Site Vice President
M. Kanavos, Plant Manager
M. Marchionda-Palmer, Director, Site Operations
P. Boyle, Director, Site Maintenance
A. Ferko, Director, Site Engineering
B. Schipiour, Maintenance Planning Director
S. Butler, Manager, Corrective Action Program
G. Dudek, Manager, Operations Training
B. Finlay, Manager, Site Security
J. Gerrity, Manager, Site Emergency Preparedness
R. Leasure, Manager, Site Radiation Protection
D. Lesnick, Manager, Site Emergency Preparedness
J. Odeen, Manager, Site Project Management
R. Radulovich, Manager, Site Nuclear Oversight
J. Rappeport, Manager, Site Chemical Environment & Radwaste
P. Raush, Manager, Design Engineering
M. Sears, Manager, Program Engineer
D. Stiles, Manager, Operations Training
C. VanDenburgh, Manager, Site Regulatory Assurance
L. Young, Manager, Maintenance
D. Palmer, Radiation Protection Superintendent
J. Basher, Special Projects
P. Bernier, Business Manager
E. Cieszkiewick, Chemistry Support
M. Gagnon, Chemistry Support
S. McKinney, Emergency Preparedness Coordinator
M. Abbas, NRC Coordinator

Nuclear Regulatory Commission

E. Duncan, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2012004-01; 05000457/2012004-01	FIN	Failure to Adequately Evaluate Operations Crew Performance for a Reactor Trip and Failure to Adequately Evaluate Emergency Operating Procedure Standards (Section 1R04.2.b)
05000457/2012004-02	FIN	Failure to Adequately Evaluate the Specified TS CST Function After the Identification of a Non-Conforming Condition Adversely Affecting SG PORV Flow Rates (Section 1R15.1.b)
05000456/2012004-03; 05000457/2012004-03	VIO	Failure to Analyze RHUT Inlet Piping Loads (Section 4OA2.5.b)
05000456/2012004-04; 05000457/2012004-04	NCV	Failure to Train Fire Brigade Members on the Use of Elevators (Section 4OA2.6.b)
05000456/2012004-05; 05000457/2012004-05	NCV	Failure to Submit a 10 CFR 50.72(b)(3)(v) and a 10 CFR 50.73(a)(2)(v) Report; Inoperable UHS (Section 4OA3.3.b)

Closed

05000456/2012004-01; 05000457/2012004-01	FIN	Failure to Adequately Evaluate Operations Crew Performance for a Reactor Trip and Failure to Adequately Evaluate EOP Standards (Section 1R04.2.b)
05000457/2012004-02	FIN	Failure to Adequately Evaluate the Specified TS CST Function After the Identification of a Non-Conforming Condition Adversely Affecting SG PORV Flow Rates (Section 1R15.b)
05000456/2012004-04; 05000457/2012004-04	NCV	Failure to Train Fire Brigade Members on the Use of Elevators (Section 4OA2.6.b)
05000456/2012004-05; 05000457/2012004-05	NCV	Failure to Submit a 10 CFR 50.72(b)(3)(v) and a 10 CFR 50.73(a)(2)(v) Report; Inoperable UHS (Section 4OA3.3.b)

Discussed

05000456/2010006-02 05000457/2010006-02	NCV	Untimely Corrective Action for Lack of Water Hammer Analysis on the Recycle Holdup Tank (Section 4OA2.3.b)
05000456/2008005-05; 05000457/2008005-05	NCV	Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT Quench Volume (Section 4OA2.3.b)
05000457/2012002-04	NCV	Diesel Oil Storage Tank Room Sprinkler Obstructions (Section 4OA2.3.b)
05000456/2012007-01	NCV	Nonconforming Piping Condition Not Corrected (Section 4OA2.3.b)
05000456/2011008-02	NCV	Permanent Lead Shielding Added to Safety Injection and Chemical Volume and Control System Piping (Section 4OA2.3.b)

05000456/2012007-02	NCV	Surveillance Procedure Not Followed (Section 4OA2.3.b)
05000456/2010007-01; 05000457/2010007-01	NCV	Diesel Driven Auxiliary Feedwater Pump Battery Racks Were Not Restored to Their Design Basis Seismic Category I (Section 4OA2.3.b)
05000456/2012007-03; 05000457/2012007-03	FIN	Untimely Completion of a Corrective Action to Prevent Recurrence (Section 4OA2.3.b)
05000456/2010010-03; 05000457/2010010-03	FIN	Failure to Identify and Correct Water Discharged to the Turbine Building Floor During Condensate Reject (Section 4OA2.3.b)
05000456/2012003-04; 05000457/2012003-04	FIN	Operability Determination Standards Not Followed for HELB Related Structural Issues Identified by the NRC (Section 4OA2.3.b)
05000456/2011005-04; 05000457/2011005-04	FIN	Operability Evaluation Not Performed in Accordance with Station Standards (Section 4OA2.3.b)
05000456/2011005-06; 05000457/2011005-06	FIN	Failure to Adhere to Maintenance Rule Implementation Procedures (Section 4OA2.3.b)
05000456/2011004-08; 05000457/2011004-08	NCV	Failure to Follow Maintenance Rule Procedure (Section 4OA2.3.b)
05000456/2011004-01; 05000457/2011004-01	FIN	Failure to Adhere to Standards of Outdoor Secured Material Zones (Section 4OA2.3.b)
05000456/2011003-01; 05000457/2011003-01	FIN	Failure to Follow Procedural Standards Related to the Storage of Outside Material that Could Impact Offsite Power Availability (Section 4OA2.3.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

- IR 1021908; 345kV OCB Grid Block Issues in the Switchyard; January 27, 2010
- IR 1033512; Grid Transient Causes Numerous Unexpected Annunciators; February 21, 2010
- IR 1122506; OCB BT7-8 Grid Block Pin Found Broken; October 5, 2010
- IR 1140659; Replace Grid Blocks on OCB BT9-15; November 15, 2010
- IR 1212870; 2B DG VARS Swings During Loading After Sync to Grid; May 6, 2011
- IR 1334277; 4kV ESF Voltage Setpoint Questions; February 29, 2012
- IR 1341892; SOER 99-1 Loss of Grid - Recommendation #5; March 16, 2012
- IR 1381543; SAT 242-2 SPR Relay is Disabled, Engineering to Prepare TCCP; June 25, 2012
- IR 1382850; Action from CA - Replace 1AP03EA COM-5 Relays; June 28, 2012
- IR 1382851; Action from CA - Replace 1AP04EE COM-5 Relays; June 28, 2012
- IR 1385672; 2TIS-AP232 - SAT 242-2 Winding X2 Reading Low; July 5, 2012
- IR 1390426; As Found Time Delay Relay Out of Tolerance; July 19, 2012
- WR 00351604; Switchyard Circuit Breaker BT9-15 (Oil); November 15, 2010
- WR 00367575; 2B Diesel Generator Assembly; May 6, 2011
- 0BwOA ELEC-1; Abnormal Grid Conditions Unit 0; Revision 8
- 1BwOA ELEC-4; Loss of Offsite Power Unit 1; Revision 104
- BwOP MP-27; Monitoring of Generator Output Voltage for NERC Compliance; Revision 3
- OP-AA-108-107; Switchyard Control; Revision 2
- OP-AA-108-107-1001; Station Response to Grid Capacity Conditions; Revision 4
- WC-AA-8000; Interface Procedure Between ComEd/PECO and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities; Revision 6
- WC-AA-8003; Interface Procedure Between ComEd/PECO and Exelon Generation (Nuclear/Power) for Design Engineering and Transmission Planning Activities; Revision 3
- Braidwood Operations Log; January 1, 2008 through July 25, 2012
- Braidwood Operations Log; June 5, 2012
- PWR Initial License Training/Simulator Phase-NOPS; 0BwOA ELEC-1 - Abnormal Grid Conditions; Module I1-OA-XL-01a

1R04 Equipment Alignment

- IR 1332227; Standing Order Makes for an Operator Burden; February 26, 2012
- IR 1336324; Unit 2 CST Level Indication Muds Vs. MCR; March 5, 2012
- IR 1359703; NRC Identified Floor Plate Improperly Stored; April 27, 2012
- IR 1376722; Degraded Open/Close Hardware on CST Valve Pit Hatch Doors; May 29, 2012
- IR 1376728; Degraded Structural Components in U1 & U2 CST Doghouses; May 29, 2012
- IR 1376742; Degraded Equipment in U1 CST Doghouses/Valve Pits; May 29, 2012
- IR 1376748; Unit 2 CST Doghouse Door Degraded; May 29, 2012
- IR 1477310; Degraded Equipment in Unit 2 CST Doghouse/Valve Pit; May 29, 2012
- IR 1408567; Revise CST Level Low BwARs; September 4, 2012
- IR 1423094; Condensate Storage Tank Drawings Not Updated; October 5, 2012
- BwOP-AF-E1; Operating Electrical Lineup Unit 1; Revision 14

- BwOP-AF-E2; Operating Electrical Lineup Unit 2; Revision 9
- BwOP-AF-M1; Operating Mechanical Lineup Unit 1; Revision 16
- BwOP-AF-M2; Operating Mechanical Lineup Unit 2; Revision 14
- BwOP-CS-M1; Operating Mechanical Lineup Unit 1; Revision 9
- BwOP-CS-E1; Electrical Lineup - Unit 1 Containment Spray System Electrical Lineup; Revision 3

1R05 Fire Protection

- IR 1398598; NRC Identified Issues with June 14, 2012 Fire Drill; August 8, 2012
- EC 396035; Force on Force Security Project Turbine Building Elevator Controls
- BwAP 1100-5; Fire Department Response, Notification and Mutual Aid Agreements and Expected Chain of Events During a Fire; Revision 10
- WO 01321203 09; PMG OHC33G Turbine Building Elevator FOF Modifications
- OP-AA-201-003; “Sample” - Fire Drill Record
- New York Fire Alarm Association; Interfacing Fire Alarm, Sprinkler and Elevator System; November 17, 2010
- Elevators in Emergencies; The Firefighter’s Perspective by Larry Pigg
- Elevator Usage During a Building Fire by John Degenkolb
- Older Elevators: Few Jurisdictions Adopt ASME A17.3 As Code by Casey Laughman; May 2012
- September-Newsletter-Elevator Dangers by Deputy Chief D.D.N.Y. Vincent Dunn
- OSHA Part 1910.156; Fire Brigades
- Branch Technical Position APCSB 9.5-1; Guidelines for Fire Protection for Nuclear Power Plants
- Braidwood Station Pre-Fire Plan #41; SWGA 426’ Division 12 ESF Switchgear Room - FZ 5.1-1
- Braidwood Station Pre-Fire Plan #42; SWGA 426’ Division 22 ESF Switchgear Room - FZ 5.1-2
- Braidwood Station Pre-Fire Plan #43; SWGA 426’ Division 11 ESF Switchgear Room - FZ 5.2-1
- Braidwood Station Pre-Fire Plan #44; SWGA 426’ Division 22 ESF Switchgear Room - FZ 5.2-2
- Braidwood Station Pre-Fire Plan #71; TB 426’ Unit 1, Mezzanine Floor (SE); FZ 8.5-1
- Braidwood Pre-Fire Plan Layout; TB 426’ Unit 1 Turbine Bldg. Mezzanine Floor (SE) FZ 88.5-1(SE); Revision 0
- CAP102 Report; CR 1404541 4D - NOS ID Required Template Not Used for Fatigue Assessment IR; August 24, 20121
- Reg Guide 1.120; Fire Protection Guidelines for Nuclear Power Plants; Revision 1
- Reg Guide 1.189; Fire Protection for Operating Nuclear Power Plants; August 15, 2001

1R06 Flood Protection Measures

- IR 1393098; LCSR Floor Drain Lines Plugged; July 25, 2012
- IR 1395248; Puddles of Water in Unit 2 Lower Cable Spreading Room; July 31, 2012
- IR 1395995; NRC ID Small Junction Box with Water Intrusion; August 1, 2012

1R07 Heat Sink Performance

- IR 1399547; Bryozoa As Found Condition in 1A Circ Water Bay; August 10, 2012
- IR 1401040; Bryozoa Report for 1C Circulating Water Bay; August 15, 2012

- IR 1402133; Bryozoa Report for 2B Circulating Water Bay; August 17, 2012
- IR 1403656; Bryozoa Report for 1B Circulating Water Bay; August 22, 2012
- IR 1406274; Lessons Learned from 2012 Forebay Cleanings and Bryozoa Inspections: August 26, 2012

1R11 Licensed Operator Requalification Program and Licensed Operator Performance

- IR 1386656; NEI Rev. 5 EAL Interpretations; July 9, 2012
- IR 1409730; NRC Question About CT7 Containment Failure; September 4, 2012
- PORC Meeting 12-021; 50.59 Review for LSH Traveling Screen Level Control; September 6, 2012
- NEI 99-01 Rev 5 EALs; LORT Lesson Plan - P1-SP-11-44; Cycle 6, 2011
- Braidwood August 8, 2012 Mini-Drill Scenario

1R12 Maintenance Effectiveness

- IR 0218024; Door SD-193 and SD0194 Door Seal Failure; April 23, 2004
- IR 0237564; Operability of SX PPS with Both SX PP Rooms Flood Door Inop; July 21, 2004
- IR 0351881; Broken Welds on Linkage Pins on Door SD-191; July 11, 2005
- IR 0352160; Door Seal is Degraded and Needs to be Replaced on SD-002; July 12, 2005
- IR 0352215; Gasket Separated at the Joint on Door SD-003; July 12, 2005
- IR 0352224; Handwheel Bushing on SD-001 Worn and Needs to be Replaced; July 12, 2005
- IR 0352474; Linkage Pins Have Cracked Welds for Door Latch Bars; July 13, 2005
- IR 1055979; NOS ID Enhancement for Watertight Doors MRFF Definitions; April 13, 2010
- IR 1109413; Byron/Braidwood TIM - RD MG Set Bus Overvoltage; September 3, 2010
- IR 1206004; Deficiency Found During PM on RD MG Set Breaker UTC#1354753; April 21, 2011
- IR 1310331; Potential PORV UPS Installation Project Delay; January 6, 2012
- IR 1311047; Temporary Storage Battery Charger Faulty - PORV UPS; January 9, 2012
- IR 1319843; Evaluate Additional Procedure Changes for SG PORV UPS Mods; January 30, 2012
- IR 1323524; Update Shop Spare MS PORV Actuator Per EC380046; February 6, 2012
- IR 1341929; Test Lab Facility Significant Event Impacts A1R116 PORV TRIM; March 16, 2012
- IR 1347854; Repair Nutherm Main Steam PORV Controller; March 30, 2012
- IR 1358008; MS PORV Test Flow Rate Less Than Expected; April 24, 2012
- IR 1361162; Extent of Condition Review for SG PORV Capacity Issue; May 1, 2012
- IR 1361733; Debris Noted in 1MS018JCE - SG PORV Inverter Battery; May 2, 2012
- IR 1361735; Debris Noted in 1MS018JDE - SG PORV Inverter Battery; May 2, 2012
- IR 1361737; Broken Separator in 1MS018JDE - SG PORV Inverter Battery Cell; May 2, 2012
- IR 1361739; Loose Connector on 1MS018JDE SG PORV Inverter Fan; May 2, 2012
- IR 1361799; Mystery Bucket of White Powder on AB 414 Near SG PORV Battery; May 2, 2012
- IR 1362836; 1MS018JCE PORV UPS Failed Acceptance Criteria; May 4, 2012
- IR 1363797; Unit 1 SG PORV Power Modification Issues/Confusion; May 8, 2012
- IR 1363876; Unexpected Alarm 1C SG PORV Trouble; May 9, 2012
- IR 1365110; 1C MS PORV UPS Output Volts Higher Than Acceptance Criteria; May 10, 2012
- IR 1365116; 1B RD MG Generator Line Amps Meter Degraded Display; May 10, 2012
- IR 1365280; 1D Steam Generator PORV Trouble Alarm 1-15-D10 in Alarm; May 11, 2012
- IR 1368478; 1B Rod Drive MG Output Breaker Tripped Open; May 20, 2012
- IR 1373501; Received 1D SG PORV Trouble Alarm - 1MS018D; June 1, 2012
- IR 1376269; Unexpected Alarm 1C Steam Generator PORV Trouble; June 9, 2012

- IR 1376344; Unexpected 1D Steam Generator PORV Trouble Alarm; June 10, 2012
- IR 1378073; MCR Received 1D SG PORV Trouble Alarm (1-15-D-10); June 14, 2012
- IR 1378105; Potential Impact from Reduced Unit 2 SG PORV Relief Capacity; June 14, 2012
- IR 1379364; Additional Information for 1C SG PORV UPS Inverter; June 19, 2012
- IR 1379861; Unit 1 SG PORV UPS Required by TS With No TS Surv; June 20, 2012
- IR 1381033; Potential Impact from Reduced Unit 2 SG PORV Relief Capacity; June 22, 2012
- IR 1382242; 1C PORV Inverter Repairs Will Make Valve Inoperable; June 27, 2012
- IR 1382564; Potential Impact from Reduced Unit 2 SG PORV Relief Capacity; June 27, 2012
- IR 1388903; 1C SG PORV Trouble Alarm - 1MS018JCE; July 15, 2012
- IR 1389200; 1C PORV Tailpipe Cover Appears to Have Blown Off Tailpipe; July 16, 2012
- IR 1391215; Need Forced Outage WR for MG-Set Balancing; July 20, 2012
- IR 1405592; 1B RD MG-Set C Phase (IRV) Paddle is Fluttering; August 27, 2012
- WO 01169487 01; Insp of Watertight Doors, November 12, 2008
- WO 01237255 01; Insp of Watertight Doors; August 22, 2009
- WO 01386316 01; Insp of Watertight Doors; February 11, 2011
- WO 01445850 01; Insp of Watertight Doors; August 9, 2011
- WO 01477267 01; MM-Perform Maintenance Work for the UHS
- WO 01491058 01; Insp of Watertight Doors; February 16, 2012
- WO 01518770 01; Insp of Watertight Doors; May 14, 2012
- WO 01569286 01; 1B RD MG Set Circulating Current Balance (1RD02E)
- WR 00401800; 1B MG Set Amp Selector Switch Assembly; May 10, 2012
- WR 00402464; MG Output Breaker Tripped Open (8); May 20, 2012
- WR 00407468; Need Forced Outage WR for MG-Set Balancing; July 23, 2012
- WR 00410477; 1B RD MG-Set C Phase (IRV) Paddle is Fluttering; August 27, 2012
- BwMS 3350-004; Quarterly Watertight Door Surveillance; Revision 5
- AD-AA-2001; Management and Oversight of Supplemental Workforce; Revision 11
- CC-AA-402; Maintenance Specification: Installation of Temporary Rigging; Revision 5
- EN-AA-103-0003; Spill Prevention; Revision 2
- EN-AA-103-F-02; Environmental Screening Checklist #01477267-01; Dredge Ultimate Heat Sink; Revision 0
- EN-AA-403; Dredging; Revision 1
- ER-AA-310-1004; Maintenance Rule - Performance Monitoring; Revision 10
- ER-AA-450; Structures Monitoring; Revision 1
- HU-AA-1211; Pre-Job Briefings; Revision 7
- MA-AA-716-004; Complex Troubleshooting Data Sheet; Revision 11
- MA-AA-716-008; FME Zone 1 (High Risk Systems); Revision 7
- MA-AA-716-009; Maintenance Environmental Impact Control; Revision 3
- MA-AA-716-021; Conditions When a Rigging and Lifting Plan is Recommended; Revision 19
- MA-BR-773-523; Braidwood Rod Drive Motor Generator Relay Routine; Revision 3
- SA-AA-116-2124; Job Hazard Analysis; Revision 3
- WC-AA-104; Industrial Safety Risk Screening #01477267-01; Dredge Ultimate Heat Sink; Revision 18
- WANO Significant Event Report SER 2001-3; Intake Structure Blockage Results in Multi-Unit Transients and Potential Loss of Heat Sink; December 2001

1R13 Maintenance Risk Assessments and Emergent Work Control

- IR 1386277, NOED for UHS TS 3.7.9; July 7, 2012
- IR 1391369; 0VA084Y Closes Slowly; July 20, 2012
- IR 1391609; 0VA84YA and B Damper Found Failed Open; July 22, 2012
- IR 1397137; Severe Thunderstorm Warning Causes Entry into BwOA Env-1; August 4, 2012

- Clearance 00103577 001; 0VA084YB Inaccessible Filter Plenum A Inlet Isolation Damper; July 23, 2012
- 0A NAC Plenum Work (0VA084Y); July 2012
- DC-AA-1014, Revision 2, Risk Management
- ER-AA-600-1011, Revision 1, Risk Management Program
- WC-AA-104; Revision 8, 1Integrated Risk Management Program
- ER-AA-600-1042, Revision 7, On-Line Risk Management
- ER-AA-600-1043; Revision 5, Shutdown Risk Management

1R15 Operability Determinations and Functionality Assessments

- IR 0662874; Potential Issue with Westinghouse Modeling of SG PORV Relief; August 21, 2007
- IR 0947908; Unit 2 Tripped and Loss of Offsite Power; July 30, 2009
- IR 0948535; Entry Into 2BwGP 100-5 From 2BwEP ES-0.2; August 1, 2009
- IR 0951207; 4.0 Critique of U2 RX Trip/Loss of Offsite Power; July 30, 2009
- IR 1358008; MS PORV Test Flow Rate Less than Expected; April 23, 2012
- IR 1359217; Probable Reduced Capacity for the SG PORVs; April 26, 2012
- IR 1378105; Potential Impact From Reduced Unit 2 SG PORV Relief Capacity; June 14, 2012
- IR 1381033; Potential Impact From Reduced Unit 2 SG PORV Relief Capacity; June 22, 2012
- IR 1382564; Potential Impact From Reduced Unit 2 SG PORV Relief Capacity; June 27, 2012
- IR 1390874; Documentation of NRC Questions on IR 1382564; July 18, 2012
- IR 1396040; Follow-up NRC Questions on IR 1390874; August 1, 2012
- IR 1396992, Class 2 Material Installed in Class 1 System; August 8, 2012
- IR 1400961; 2FT-AF-12 Calibration Requires Validation to Due OOT M&TE; August 15, 2012
- IR 1403298; NRC Questions Regarding CST Assumptions; August 21, 2012
- IR 1409900; Potential Unidentified Condition with MSIV Accumulator; September 6, 2012
- IR 1401502; OVH12C Control Switch Found Off; August 16, 2012
- IR 1415299; Incorrect 'Reset' Time Provided During A1R16 (WHR Near Miss); April 29, 2012
- IR 1416124; Conservative Discrepancy in Attachment 1 to OE 07-008; September 6, 2012
- 1BwEP ES-0.1; Reactor Trip Response Unit 1; Revision 202 WOG 2
- 1BwEP ES-0.2; Natural Circulation Cooldown Unit 1; Revision 202 WOG 2
- Braidwood Operations Log; July 29 to August 1, 2009
- Braidwood Operations Log; August 16 to August 18, 2010
- Braidwood Operations Log; August 16 to August 20, 2010
- CC-AA-309-1001; Evaluation of CST TS at Braidwood Station; Revision 00
- CC-AA-309-1001; Byron/Braidwood Unit 2 Auxiliary Feedwater Storage Volume for Uprating to 3600.6 MWt NSSS Power; Revision 0
- CC-AA-309-1001; Byron/Braidwood Natural Circulation Cooldown TREAT Analysis for the RSG and Uprating Program; Revision 6
- EC 380047; SGTR Margin to Overfill - PORV UPS Mod Main Steam System 1MS018J(C&D); Revision 002
- EC 390484; Op Eval 12-006 MSIV Hydraulic Accumulator Heatup Concerns; September 12, 2012
- LS-AA-120; Issue Identification and Screening Process; Revision 14
- NEP-12-02; Validation of Residual Decay Heat Input for the UFSAR RHR Cooldown Curves; November 9, 1998
- NUREG-0800; Auxiliary Feedwater System (PWR); Revision 2 - July 1981
- OE-07-008; U2 Total Required Volume; Revision 1
- OP-AA-101-113-1006; 4.0 Crew Critique Guidelines; Revision 3
- OP-AA-108-115; Operability Determinations (CM-1); Revision 11

- OP-AA-108-115; Potential Issue with Westinghouse Modeling of SG PORV Relief Capacity; Revision 11
- Draft Ultimate Heat Sink Dredge Project; Revision 0
- Drawing 101537-2-11; Spec #L-2878 Reinstall 20 Diameter Bottom Nozzle 45-0 X 55-0 (New HT) Aluminum C
- RT Mods to Equip #1CD01T Unit 1; February 27, 1999

1R19 Post-Maintenance Testing

- WO 1418303 01; Thermal Overload Surveillance for 2AO21E-K2; August 28, 2012
- WO 1553657 01; Perform 2BwOSR 5.5.8.CS-1A Valve Stroke Surveillance; August 28, 2012
- MA-BR-723-380; Inspection and Testing of 480 Volt Motor Control Center (MCC) Draw-Out Units; Revision 6

1R20 Refueling and Other Outage Activities

- OU-AP-201, Revision 9, New Fuel Receipt Inspection

1R22 Surveillance Testing

- IR 1394167; 1MS018JCE Has Cells High in Electrolyte Level; July 28, 2012
- IR 1394168; 1MS018JDE Has Cells High in Electrolyte Level; July 28, 2012
- 1BwOSR DC-9; Unit 1 1C SG PORV UPS Battery Bank Surveillance; Revision 0
- 1BwOSR 3.7.4.1; Unit 1 Main Steam MS018A/B/C/D Isolation and Indication Testing; Revision 2
- 2BwOSR 3.7.5.6-1, Unit 2 Train A Auxiliary Feedwater Pump Emergency Actuation Verification; Revision 10
- 1BwOSR 3.8.1.13-1, Unit 1 A Emergency Diesel Generator Automatic Bypass Trip Surveillance Revision 15
- 2VwOSR 3.8.1.2-2, Unit 2 B Emergency Diesel Generator Operability Surveillance; Revision 15
- 2BwOSR 3.3.2.3; Unit 2 Undervoltage Simulated Start of 2A Auxiliary Feedwater Pump Surveillance; Revision 5
- 2BwOSR 3.5.2.5, Emergency Core Cooling Subsystem Actuation Surveillance; Revision 17
- 1BwOSR 3.7.5.4-1, Unit 1 Motor Driven Auxiliary Feedwater Pump Surveillance; Revision 12
- 2BwOSR DC-M2; Unit 2 2C S/G PORV UPS Battery Bank Monthly Surveillance; Revision 1
- WO 01552740 01; 1BwOS DC-10 Unit 1 1D SG PORV UPS Battery Bank Surveillance; July 28, 2012
- WO 01552741 01; 1BwOS DC-9 Unit 1 1C SG PORV UPS Battery Bank Surveillance; July 28, 2012
- C&D Technologies, Inc; RS-1476, Standby Battery Vented Cell Installation and Operating Instructions; Section 12-800
- Letter from Duke Power to USNRC; Subject: McGuire Nuclear Station, Unit 2 LER 370/2005-05, Revision 0, Problem Investigation Process M-05-00841; June 22, 2005
- Letter from STP Nuclear Operating Company to USNRC; Subject: Docket No. STN 50-498 Revision to LER 1-2009-002, Main Steam Isolation Valve Blocked from Closing; March 25, 2010

1EP6 Drill Evaluation

- IR 1386656; NEI Rev. 5 EAL Interpretations; July 9, 2012
- IR 1409730; NRC Question About CT7 containment Failure; September 4, 2012
- PORC Meeting 12-021; 50.59 Review for LSH Traveling Screen Level Control; September 6, 2012
- NEI 99-01 Rev 5 EALs; LORT Lesson Plan - P1-SP-11-44; Cycle 6, 2011
- Braidwood August 8, 2012 Mini-Drill Scenario

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation

- RP-AA-600-1005; Radioactive Material and Non Disposal Site Waste Shipments; Revision 14
- RP-AA-600; Radioactive Material/Waste Shipments; Revision 12
- RP-AA-602; Packaging of Radioactive Material Shipments; Revision 18
- RP-AA-600-1006; Notification Requirements for Radioactive Shipments Greater Than the Radioactive Material Quantities of Concern; Revision 8
- RP-AA-603; Inspection and Loading Radioactive Material Shipments; Revision 7
- RP-AA-600-1004; Radioactive Waste Shipments to Energy Solutions' Clive Utah Disposal Site Containerized Facility; Revision 11
- RP-AA-605; 10 CFR 61; Program; Revision 4
- RP-AA-601; Surveying Radioactive Material Shipments; Revision 14
- RP-AA-602-1001; Packaging of Radioactive Material Waste Shipments; Revision 14
- RP-AA-600-1011; Package Creation and Characterizations; RADMAN Software; Revision 0
- Waste Stream Results Review; 2011 DAW; DAW Smears: October 3, 2011
- Waste Stream Results Review; 2011 DAW; ALPS Radwaste Filters: October 7, 2011
- Form of Current RAM Containers Located Outside; August 21, 2012
- RP-BR-500-2002; Control and Surveillance of Outdoor RAM Containers and Indoor RAM Areas; Revision 5
- RP-AA-500-1001; Requirements for Radioactive Materials Stored Outdoors; Revision 2
- RMS12-122; 40 Feet Sea Van Containing Outage Equipment to Byron; Radioactive Material, Low Specific Activity (LSA-1), 7, UN2912; August 8, 2012
- RWS 12-006; Thirty Gallon Drum Containing RAM Sources to Bear Creek, Oak Ridge, TN; UN2915, RAM, Type A Package
- RWS 11—009; Barrel of Resin in a Sea Van; RAM, LSA-1, 7, UN2912; Fissile Excepted; April 22, 2011
- RWS 11-011; Sea Van to Duratek, Bear Creek, Oak Ridge, TN; RAM, LSA-1, 7, 2912; Fissile Excepted; May 16, 2011
- RWS 11-017; Resin Sand Media; Sea Van to Duratek, Bear Creek, Oak Ridge, TN; RAM, LSA-1, 7, 2912; Fissile Excepted; August 22, 2011
- RWS 11-002; Sea Van to Duratek, Bear Creek, Oak Ridge, TN; RAM, LSA-1, 7, 2912; Fissile Excepted; January 6, 2011
- RWS 11-001; Sea Van Containing DAW to Duratek, Bear Creek, Oak Ridge, TN; RAM, LSA-1, 7, 2912; Fissile Excepted; January 5, 2011
- IR 1499797; Radwaste ARM 0AR068J Fails Check Source-0RE-AR045; August 15, 2012
- IR 1097797; Emergent Dose Requested Because RE-AR045 Failed Leaving Operation Without a Radiation Indication in the Radwaste Area; August 4, 2010
- IR 1168270; 383' Radwaste Blowdown Valve Aisle Room Flooded; January 28, 2011
- IR 1176573; Sample Analysis Discrepancy Affects RW Filter Processing; February 17, 2011
- IR 1199647; Adverse Trend in Rad Monitor Issues While Performing Liquid Radwaste Release; April 8, 2011

- IR 1207013; Wrong Water Used to Fill Resin; April 24, 2011
- IR 1210988; Compromised Drum Found in Radwaste Valve Rooms/Tunnels; May 6, 2011
- IR 1356991; Outside RAM to be Dispositioned; April 21, 2012

4OA1 Performance Indicator Verification (71151)

- LS-AA-2090; Monthly Data Elements for NRC RCS Specific Activity; Revision 4
- Data Elements from January 2011 through April 2012
- Unplanned Power Changes Per 7000 Critical Hrs; Power Reduction for Repairs to PZR Spray Bypass Valve; July 16, 2011
- Unplanned Power Changes Per 7000 Critical Hrs; Power Reduction Due to Throttle Valve Failure; September 2, 2011

4OA2 Problem Identification and Resolution

- IR 0251060; Placards for Recycle Hold Up Tank Level Admin Control; October 1, 2007
- IR 0649581; Potential Vulnerability with RH Suction Relief Disch to HUT; July 12, 2007
- IR 0677075; Recycle Hold Up Tank Level Administrative Controls; September 28, 2007
- IR 0680626; NRC Potential Green Finding and Associated NCV - HUT Level; October 4, 2007
- IR 0831252; Byron RHUT NRC Inspection Issues; October 10, 2008
- IR 0833241; Byron RHUT P&IR Inspection Lessons Learned; October 10, 2008
- IR 0850880; NRC P&IR HUT Inspection - Procedure Enhancement; December 1, 2008
- IR 1117296; NRC Exited Green NCV for RHUT Analysis; September 17, 2010
- IR 1182479; Maintenance (Shaw) Use of WHR Waiver; March 2, 2011
- IR 1182584; Maintenance (Shaw) Use of WHR Waiver; March 2, 2011
- IR 1182828; NOS ID Maint Did Not Properly Adhere to WHR Requirements; March 3, 2011
- IR 1183060; Maintenance (Shaw) Use of Waiver; March 2, 2011
- IR 1279246; Untimely Completion of CA Assignments Associated with HUTS; July 20, 2011
- IR 1317853; Fatigue Assessment (Security); January 17, 2012
- IR 1324576; Post Event Fatigue Assessment for OSHA Recordable Injury; February 8, 2012
- IR 1326359; Fatigue Assessment (EMD); February 13, 2012
- IR 1338930; PI&R FASA Id'd - Potential Repeat NCV for Untimely CA; March 9, 2012
- IR 1356733; NOS ID Inattentive Individual in RCA; April 20, 2012
- IR 1357117; IR to Document Fatigue Assessment; April 20, 2012
- IR 1360079; Work Hour Waiver Required for Crane Operator During A1R16; April 29, 2012
- IR 1360981; Work Hour Waiver Required for Crane Operator During A1R16; April 29, 2012
- IR 1366343; Face-to-Face Fatigue Assessment Not Performed for Waiver; April 29, 2012
- IR 1366533; 3Q10 NRC Green Finding - Lack of RHUT Analysis; October 27, 2010
- IR 1366161; Results of NRC Containment Walkdown; May 11, 2012
- IR 1371994; Documentation Errors in Completing WHR Waiver Forms; May 30, 2012
- IR 1382564; Potential Impact From Reduced Unit 2 SG PORV Relief Capacity; June 27, 2012
- IR 1387107; 2A CV PP Flow Barely Adequate During Pressurizer Level Restoration; July 10, 2012
- IR 1387274; RWST Level Channel Discrepancy; July 1, 2012
- IR 1387378; Tighten Cam Cover Bolts for 1A DG; July 11, 2012
- IR 1387379; VPP Action-Signage Needed to Identify Discharge Lines; July 10, 2012
- IR 1287387; Inspect the 1A DG Valve Stems for Carbon Buildup; March 23, 2012
- IR 1387388; Inspect the 1B DG Valve Stems for Carbon Buildup; March 23, 2012
- IR 1387389; Inspect the 2A DG Valve Stems for Carbon Buildup; March 23, 2012
- IR 1387390; Inspect the 2B DG Valve Stems for Carbon Buildup; March 23, 2012
- IR 1378314; LL-NRC 6/14 Fire Drill Observation; June 15, 2012

- IR 1388354; 1BwOSR 3.6.3.5.AF-1A/B & 1BwOSR 5.5.8.AF-2A/B Need Revisions; July 13, 2012
- IR 1388512; NOS ID CA Closure Documentation Quality Potent Deficiencies; July 12, 2012
- IR 1388608; U2 MSPI Cooling Water System Potentially White for 2Q 2012; July 13, 2012
- IR 1388620; Manually Tripped 1A VP Chiller Due to Excessive Amps; July 13, 2012
- IR 1388631; 0FP11BA-12" Guided Wave Inspection Results Requires NDE; July 13, 2012
- IR 1388679; Security Procedure Revisions Implemented Early; July 11, 2012
- IR 1388785; No 50.59 Evaluation on 11 Scaffolds in Shaw Scaffold Log; July 14, 2012
- IR 1388809; Switchgear Room Temperature Alarm in Early - 2TS-VX002; July 14, 2012
- IR 1388827; Need Action to Visit All Accessible Permanent Scaffolds; July 14, 2012
- IR 1388881; Enhancement to 0BwOS FP.B.5.B.W-1 Surveillance; July 14, 2012
- IR 1388898; Fire Door SD 172 Will Not Open From Both Sides; July 15, 2012
- IR 1388903; 1C SG PORV Trouble Alarm - 1MS018JCE; July 15, 2012
- IR 1388909; Ramp Computer Point BRW01V - DEHDM034 Didn't Toggle; July 15, 2012
- IR 1388930; Security - Inadequate Plans for Loss of Power to all BRE's; July 15, 2012
- IR 1388994; CCP, Valve Labeled Incorrectly - 0SH001; July 15, 2012
- IR 1389071; U2 Drop 3 System Trouble (Possible Test Pilot Leakage); July 16, 2012
- IR 1398598; NRC Identified Issues with 6/14/2012 Fire Drill; August 8, 2012
- IR 1403621; Lessons Learned From 6/14/2012 Fire Drill Critique; August 22, 2012
- IR 1404575; Additional Delay in Resolution of RHUT NCV; August 24, 2012
- IR 1408567; Revise CST Level Low BwARs; September 4, 2012
- IR 1408638; Braidwood-Byron Procedure Differences and Potential Enhancement; September 4, 2012
- IR 1408795; Revise BwOP IC-9; September 4, 2012
- IR 1408835; A2R16 EC Revision for MPT Replacement Not Issued By Due Date; September 4, 2012
- IR 1408871; Braidwood Unit 1/Byron Unit 1 Zinc Issue; July 13, 2012
- IR 1408964; BwAP 1110-1A7 Will Expire on 9/07/12 at 0751; September 5, 2012
- IR 1408984; BwOA ENV-1 Entry Due to Severe Thunderstorm Warning; September 4, 2012
- IR 1409011; Procedure Enhancements for BwISR 3.3.1.10-M234; September 5, 2012
- IR 1414402; NRC/IEMA Question Regarding 1MS018C; September 17, 2012
- IR 1414459; Scheduled PMT Unable to be Completed; September 17, 2012
- IR 1414778; Non Safety Related & Incorrect Material Ordered & Installed VS SR; September 14, 2012
- IR 1414794; Relief Valve Removed Per WO 1221492-01 Needs to be Rebuilt; September 18, 2012
- IR 1414822; 1B DG LCO Lessons Learned; September 12, 2012
- IR 1414903; 2CS016A/2CS012A Leaking By; August 29, 2012
- IR 1414923; NOS ID: Operator Crossed Red and White Safety Rope; September 18, 2012
- IR 1414967; Inspect Pool-Side Transfer System HPU 1FH01P; September 18, 2012
- IR 1414978; CCP: Robust Barrier for MCC 231X3; September 18, 2012
- IR 1414979; CCP: Robust Barrier for MCC232X5; September 18, 2012
- IR 1415079; 0A Fire Pump Relief Valve Has Stem Leakage - PMT Failed; September 19, 2012
- IR 1415090; Multiple Unauthorized Items in Ops Chem Locker 426 P-12; September 19, 2012
- IR 1415115; DSA: Scheduled PMT Unable to be Completed (OPS); September 19, 2012
- BwOP RH-6; Placing the RH System in Shutdown Cooling; Revision 48
- 0BwOS VA-1a; AAR Auxiliary Building Ventilation; Revision 0
- LS-AA-119; Fatigue Management and Work Hour Limits Familiarization Briefing; Revision 1
- LS-AA-119; Fatigue Management and Work Hour Limits; Revision 9
- LS-AA-119-1001; Fatigue Management; Revision 1

- LS-AA-119-1001; Fatigue Assessment; Revision 1
- LS-AA-119-1004; Reviews and Reporting; Revision 1
- LS-AA-119-1005; Contractor/Vendor Compliance with Fatigue Management and Work Hour Limits; Revision 0
- OP-AA-102-103; Operator Work-Around Program; Revision 3
- Braidwood Operations Log; July 10 to July 11, 2012
- Memo No. BR-40; Resolve Potential RHUT Over-Pressurization Issue; Revision 6
- Flowserve Report RAL-4817; Discussion & Methodology to Answer Extended Temperature Pre-charge Curve Conclusions and Accumulator Pressures and Oil Margin Results; February 27, 2008
- NSLD Calc. 3C8-1284-002; Byron/Braidwood Units 1 & 2 MST Analysis - Heat Transfer Study for the MSIV Actuator Components; February 14, 1985
- S&L Interoffice Memo; Evaluation of Environmental Effects of Main Steam Line Break Outside Containment; June 24, 2988
- NEI 06-11; Managing Personnel Fatigue at Nuclear Power Reactor Sites; Revision 1, October 2008
- 10 CFR Part 26; Fitness for Duty Programs
- 10 CFR 26.207; Waivers and Assessments
- Braidwood Outage Control Center Log; April 28, 2012 to April 29, 2012
- Braidwood Operations Log; July 9, 2012 to July 10, 2012
- Regulatory Guide 5.73; Fatigue Management for Nuclear Power Plant Personnel; March 2009

<u>4OA3 Follow Up of Events & Notices of Enforcement Discretion</u>

- IR 1357298; UT Indication of Unit 1 CRDM Penetration 69; April 23, 2012
- IR 1386306; NOS ID: CW Flowpath Not Listed on Protected Pathway; July 7, 2012
- IR 1388212; Fish Losses in Braidwood Lake; July 8, 2012
- EC 337423; Provide Alternate Means of Verifying Lake (SX Water Discharge Header) Temperature 0BwOA ENV-7; Adverse Cooling Lake Conditions Unit 0; Revision 6
- EC 389753; Evaluate Impact of Increased UHS Temperature (from 100 Degrees F to 102 Degrees F) on UFSAR Chapter 15 Safety Analysis for Braidwood Units 1 and 2; Revision 0
- LER 05000456/2012-002-00; Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Attributed to Primary Water Stress Corrosion Cracking; April 23, 2012
- High Lake Temperature NOED; CW Condenser Air Removal, SX, CC, AF, SX to CC Flowpath, AF to SG Flowpath, CC Flowpaths; July 2012
- OP-AA-102-104; UHS NOED Actions - Log # 12-012; Revision 2
- PORC Meeting 12-020; 50.59 Review for LSH Traveling Screen Level Control; August 23, 2012
- Discussion of Changes Associated with Draft NUREG-1022, Revision 3; June 8 & 9, 2010
- CS2-NT3-2012-07m-07d-06h-Output Data; July 7, 2012
- ESS SW Pump 1A, 1B, 2A and 2B Disch HDR T; June 29 thru July 6, 2012
- ESS SW Pump 1A, 1B, 2A and 2B Disch HDR T; June 29 thru July 7, 2012
- ESS SW Pump 1A, 1B, 2A and 2B Disch HDR T; July 2 thru July 9, 2012
- ESS SW Pump 1A, 1B, 2A and 2B Disch HDR T; July 6 thru July 9, 2012
- Exelon Letter to NRC; Follow-up Reply to Notice of Violation; May 6, 2002
- Westinghouse Letter; Impact Evaluation of Increased Service Water Temperature on Containment Analysis Results, Braidwood Units 1 and 2; July 7, 2012

4OA5 Other Activities

- INPO Operations Accreditation Assessment Report, September 2012

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater
AOR	Analysis of Record
ASME	American Society of Mechanical Engineers
CA	Corrective Action
CAP	Corrective Action Program
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CST	Condensate Storage Tank
°F	Degrees Fahrenheit
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESW	Essential Service Water
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
ISFSI	Independent Spent Fuel Storage Installation
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
MOV	Motor-Operated Valve
MRC	Management Review Committee
MTO	Margin to Overfill
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NOED	Notice of Enforcement Discretion
NOV	Notice of Violation
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OWA	Operator Workaround
PARS	Publicly Available Records System
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PORV	Power-Operated Relief Valve
psig	Pounds Per Square Inch Gauge
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHUT	Recycle Holdup Tank
SDP	Significance Determination Process
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SPAR	Standardized Plant Analysis Risk

SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
SX	Essential Service Water
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
WO	Work Order

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

If you contest the subject or severity of these violations 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:
1. Notice of Violation
2. Inspection Report 05000456/2012004; 05000457/2012004
   w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

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Letter to M. Pacilio from E. Duncan dated November 8, 2012

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000456/2012004; 05000457/2012004 AND NOTICE OF VIOLATION

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