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

July 31, 2014

Mr. Raymond Lieb
Site Vice President
FirstEnergy Nuclear Operating Co.
Davis-Besse Nuclear Power Station
5501 N. State Rte. 2, Mail Stop A–DB–3080
Oak Harbor, OH 43449–9760

SUBJECT: DAVIS-BESSE NUCLEAR POWER STATION NRC INTEGRATED INSPECTION REPORT 050000346/2014003

Dear Mr. Lieb:

On June 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Davis-Besse Nuclear Power Station. The enclosed report documents the results of this inspection, which were discussed on July 2, 2014, with Mr. Thomas Summers, the Director of Site Operations, and other members of your staff.

Based on the results of this inspection, five NRC-identified findings of very low safety significance were identified. Four of the findings also involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of any finding or NCV, 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 the NRC Resident Inspectors' Office at the Davis-Besse Nuclear Power Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspectors' Office at the Davis-Besse Nuclear Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, “Public Inspections, Exemptions, Requests for Withholding,” 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 Bruce Bartlett, Acting for/

Jamnes L. Cameron, Chief
Branch 4
Division of Reactor Projects

Docket No. 50–346
License No. NPF–3

Enclosure:
Inspection Report 05000346/2014003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–346
License No:	NPF–3
Report No:	05000346/2014003
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Davis-Besse Nuclear Power Station
Location:	Oak Harbor, OH
Dates:	April 1, 2014, through June 30, 2014
Inspectors:	D. Kimble, Senior Resident Inspector T. Briley, Resident Inspector J. Corujo-Sandin, Engineering Inspector G. O'Dwyer, Engineering Inspector L. Rodriguez, Inspector-in-Training J. Rutkowski, Project Engineer A. Shaikh, Engineering Inspector
Approved by:	J. Cameron, Chief Branch 4 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000346/2014003; 4/1/14–6/30/14; Davis-Besse Nuclear Power Station; Fire Protection; Heat Sink Performance; 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. Five Green findings were identified by the inspectors. Four of the findings were also considered non-cited violations of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross Cutting Areas" with an effective date of January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process" Revision 5, dated February 2014.

Cornerstone: Initiating Events

- Green. The Inspectors identified a finding of very low safety significance and an associated non-cited violation of Technical Specification (TS) 5.4.1(d) when the licensee failed to properly implement station procedures for control of ignition sources. Specifically, the inspectors identified that an assigned fire watch was not present to monitor post weld heat treatment (PWHT) activities on reactor coolant system (RCS) piping in containment.

  The finding was determined to be of more than minor significance because if left uncorrected would have the potential to lead to a more significant safety concern. In particular, uncontrolled ignition sources have the potential to start a fire that could impact risk significant plant equipment. The inspectors evaluated the finding using IMC 0609, Attachment 4, "Phase 1–Initial Screening and Characterization of Findings." Because the finding involved reactor shutdown operations and conditions, the inspectors transitioned to IMC 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process–Phase 1 Operational Checklists for Both PWRs and BWRs." Since the finding was associated with an issue that occurred during the time the reactor was in a defueled condition, the inspectors conservatively consulted all four PWR checklists (i.e., Checklists 1–4). The inspectors determined that the finding did not adversely impact any shutdown defense-in-depth or mitigation attributes on any checklist, nor did it meet any of the checklist specific requirements for a Phase 2 or Phase 3 Significance Determination Process (SDP) analysis. Consequently, the finding was determined to be of very low safety significance (Green). This finding had a cross-cutting aspect in the area of human performance associated with teamwork such that individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained. In particular, licensee-contract personnel did not adequately communicate to maintain or verify that a fire watch was stationed at an assigned position for the entire duration for which it was required. (H.4) (Section 1R05.1)

- Green. The Inspectors identified a finding of very low safety significance and an associated non-cited violation of TS 5.4.1(d) when the licensee failed to properly

implement station procedures for control of ignition sources. Specifically, an invalid hot work permit was being used to control steam generator (SG) replacement hot work activities in containment from April 6, 2014, to April 14, 2014.

The finding was determined to be of more than minor significance because if left uncorrected would have the potential to lead to a more significant safety concern. In particular, uncontrolled ignition sources have the potential to start a fire that could spread and impact risk significant plant equipment. The inspectors evaluated the finding using IMC 0609, Attachment 4, "Phase 1–Initial Screening and Characterization of Findings." Because the finding involved reactor shutdown operations and conditions, the inspectors transitioned to IMC 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process - Phase 1 Operational Checklists for Both PWRs and BWRs." Since the finding was associated with an issue that occurred during the time the reactor was in a defueled condition, the inspectors conservatively consulted all four PWR checklists (i.e., Checklists 1–4). The inspectors determined that the finding did not adversely impact any shutdown defense-in-depth or mitigation attributes on any checklist, nor did it meet any of the checklist specific requirements for a Phase 2 or Phase 3 SDP analysis. Consequently, the finding was determined to be of very low safety significance (Green). This finding had a cross-cutting aspect in the area of human performance associated with licensee personnel avoiding complacency. Specifically, the inspectors noted that aspect whereby individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risks even while expecting successful outcomes. (H.12) (Section 1R05.1)

Cornerstone: Mitigating Systems

- Green. The inspectors identified two examples representing one finding of very low safety significance and associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to ensure the auxiliary feedwater system (AFW) design bases were correctly translated into specifications, drawings, and procedures. Specifically, the licensee failed to ensure the loss of normal feedwater analysis, and AFW cooler assumptions would not be violated during limiting temperature and flow conditions. As part of their corrective actions, the licensee instituted a standing order to ensure the reactor operators had guidance to ensure transferring water from the hotwell to the condensate storage tank (CST) did not exceed the loss of normal feedwater analysis CST limit of 120 degrees Fahrenheit (ºF).

  The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control. Specifically, the inspectors were concerned the AFW system could potentially be operated in a manner which had not been previously evaluated. The finding screened as having very low safety significance because the finding was a deficiency affecting the design or qualification of a mitigating system, structure, or component (SSC) but the SSC maintained its operability. Specifically, the licensee reviewed the operating history of the CSTs and found no indication the CST water had been above 120 ºF in Modes 1 through 3. Also, the licensee reviewed the operating history of the AFW coolers and found no indication the AFW coolers had been inoperable due to excessive cooling water temperature or inadequate flow. The inspectors determined this finding had an associated cross-cutting aspect, avoid complacency, in the human performance cross-cutting area. (H.12) (Section 1R07.1)

- Green. The inspectors identified a finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for the licensee’s failure to follow the Generic Letter (GL) 89–13 program implementing procedure (NOP–ER–2006) to develop the emergency core cooling system (ECCS) room cooler inspection procedure. Specifically, the inspection procedure for inspecting the ECCS room cooler lacked quantifiable acceptance criteria. This finding was entered into the licensee’s corrective action program (CAP). The immediate actions taken included a discussion of the finding with engineering staff and GL 89–13 program owner and a review of other GL 89–13 heat exchanger inspection procedures.

  The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedure Quality and it adversely affected the associated cornerstone objective to ensure the availability, reliability, and capability of the system to respond to initiating events to prevent undesirable consequences. Specifically, the ECCS room cooler inspection procedure failed to ensure the reliability of the heat exchanger because it did not have quantifiable acceptance criteria, as required by the NOP–ER–2006 procedure. Since the finding did not represent a loss of safety function, the inspectors screened the finding as having very low safety significance (Green). The inspectors did not identify a cross-cutting aspect associated with this finding because it did not reflect current performance due to the age of the performance deficiency. (Section 1R07.1)

- Green. The Inspectors identified a finding of very low safety significance following review of licensee corrective actions for a previous occurrence of a reportable condition that took place on May 26, 2014. Specifically, on November 17, 2013, the licensee's control room overhead annunciator system suffered a malfunction similar to the May condition. That event was reported to the NRC as required (Event Notification 49546), and the licensee developed applicable corrective actions within their CAP. Several of corrective actions, however, were assigned the lowest possible priority within the licensee's work prioritization system, contrary to the licensee's established procedure guidance. No violation of NRC requirements was identified.

  This finding was of more than minor significance because it directly impacted the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, as a result of the low priority assigned to a licensee work order, the work wasn't performed and additional significant malfunctions of the control room overhead annunciator system were incurred. The inspectors evaluated the finding using IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power.” Using Exhibit 2, which contains the screening questions for the Mitigating Systems Cornerstone of Reactor Safety, the inspectors determined that the finding screened as very low safety significance (Green) because all questions were answered as “No.” This finding has a cross-cutting aspect in the area of problem identification and resolution, resolution aspect, because the licensee failed to take effective corrective actions to address issues in a timely manner commensurate with their safety significance. (P.3) (Section 4OA3.3)

REPORT DETAILS

Summary of Plant Status

As discussed in NRC Integrated Inspection Report 05000346/2014002 (ADAMS Accession No. ML14113A073) the unit began the inspection period shut down with the reactor defueled to facilitate steam generator (SG) replacement activities and the plant's scheduled 18th refueling outage (see Section 1R20) in progress. On May 6, 2014, the reactor was taken critical to begin its 19th operating cycle. Main electrical generator synchronization to the electrical power grid occurred on May 8, 2014, and the unit reached full power on May 12, 2014. The unit remained operating at or near full power through the end of 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

The inspectors verified that plant features and procedures for 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:

- Coordination between the TSO and the plant during off-normal or emergency events;
- Explanations for the events;
- Estimates of when the offsite power system would be returned to a normal state; and
- Notifications from the TSO to the plant when the offsite power system was returned to normal.

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

- 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;
- 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;

- 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
- 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 to this report. 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.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Alignment Verifications

a. Inspection Scope

The inspectors performed partial system physical alignment verifications of the following risk-significant systems:

- The station's electric fire pump while the station's installed diesel-driven fire pump was out-of-service for an unplanned maintenance condition during the week ending April 5, 2014;
- The station blackout diesel generator (SBODG) during a period when emergency diesel generator (EDG) No. 2 was out-of-service for scheduled periodic endurance testing during the week ending May 24, 2014;
- Decay heat (DH) train 1 when train 2 was unavailable for planned surveillance testing during the week ending May 24, 2014;
- EDG No. 1 when EDG No. 2 was out-of-service for planned maintenance during the week ending June 14, 2014; and
- The motor-driven feedwater pump (MDFP) when auxiliary feedwater train 1 was out-of-service for a planned maintenance work window during the week ending June 28, 2014.

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, Updated Safety Analysis Report (USAR), technical specification (TS) requirements, outstanding work orders (WOs), condition reports (CRs), 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 to this report.

These activities by the inspectors constituted five partial system alignment verification inspection samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Alignment Verification

a. Inspection Scope

During the period of May 19, 2014, through May 23, 2014, the inspectors performed a complete system alignment inspection of the high pressure injection (HPI) emergency core cooling system (ECCS) to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the licensee's CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

These activities constituted a single annual complete system alignment verification inspection sample as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours

a. Inspection Scope

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

- Steam generator west 'D' ring area–post weld heat treatment (PWHT) activities (containment, room 216);
- Steam generator east 'D' ring area–PWHT activities (containment, room 218); and
- The turbine building 623' elevation–fire area II (room 517).

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.

The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's individual plant examination of external events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, 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.

In addition to standard refueling outage (RFO) activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected reactor coolant system (RCS) piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Integrated Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

These activities constituted three quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

(1) Failure to Properly Perform Required Fire Watch

Introduction

An NRC-identified finding of very low safety significance (Green) and associated NCV of TS 5.4.1(d) were identified when the licensee failed to properly implement station procedures for control of ignition sources. Specifically, the inspectors identified that an assigned fire watch was not present to monitor PWHT activities on RCS piping in containment.

Description

On April 14, 2014, while PWHT on RCS north cold leg piping associated with the number one SG was in progress on the 565' elevation of containment, the inspectors

identified that an assigned fire watch was not present in the area. The PWHT process involves the use of electric heating elements that reached a peak temperature of approximately 1100 °F for which the licensee's control of ignition source procedure (DB–FP–00018) required a fire watch to be present. The licensee was notified of the condition and CRs 2014–06825 and 2014–06832 were initiated to document the issue.

Subsequent licensee investigation revealed that a fire watch had been established for the PWHT activity in containment on night shift. Radiography scheduled coincident with the ongoing PWHT precluded the fire watch from being present inside containment while radiography operations were in progress. With approval from the station fire marshal, a remote camera monitoring system setup outside containment was used for the fire watch to monitor the PWHT remotely. At approximately 6:30 a.m. when radiography operations were complete, the fire watch remotely monitoring the PWHT evolution made the incorrect assumption that since radiography operations had been completed his position was no longer required. The fire watch departed his remote location without verifying a replacement fire watch was present in containment and without informing his supervisor. Additionally, the dayshift supervisor responsible for managing the PWHT fire watch position did not follow up to ensure the fire watch position was either maintained or relocated to containment. Consequently, no fire watch was in place to monitor PWHT activities from approximately 6:30 a.m. until at least 2:00 p.m. after which the fire watch was no longer required.

Analysis

The inspectors reviewed this finding using the guidance contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The inspectors determined that the licensee's failure to properly implement plant procedures for controlling ignition sources was a performance deficiency that was reasonably within the licensee's ability to foresee and correct and should have been prevented. This finding was associated with the Initiating Events cornerstone of reactor safety and was of more than minor significance because if left uncorrected would have the potential to lead to a more significant safety concern. In particular, uncontrolled ignition sources have the potential to start a fire that could impact risk significant plant equipment.

The inspectors evaluated the finding using IMC 0609, Attachment 4, "Phase 1–Initial Screening and Characterization of Findings." Because the finding involved reactor shutdown operations and conditions, the inspectors transitioned to IMC 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process–Phase 1 Operational Checklists for Both PWRs and BWRs." Since the finding was associated with an issue that occurred during the time the reactor was in a defueled condition, the inspectors conservatively consulted all four PWR checklists (i.e., Checklists 1–4). The inspectors determined that the finding did not adversely impact any shutdown defense-in-depth or mitigation attributes on any checklist, nor did it meet any of the checklist specific requirements for a Phase 2 or Phase 3 SDP analysis. Consequently, the finding was determined to be of very low safety significance (Green).

This finding had a cross-cutting aspect in the area of human performance associated with teamwork such that individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained. In particular, licensee contract personnel did not adequately communicate

to maintain or verify a fire watch was stationed at an assigned position for the entire duration for which it was required. (H.4)

Enforcement

TS 5.4.1(d), requires, in part, the licensee to establish, implement, and maintain applicable written procedures covering fire protection program implementation. The fire protection program was implemented, in part, by Davis-Besse Procedure DB–FP–00018, "Control of Ignition Sources," Revision 12. Procedure DB–FP–00018, step 6.1.3, states that “the qualified fire watch shall be present at the work area with a fire extinguisher prior to work beginning, during the work that is being performed and for a minimum of either 30 minutes after the work has been completed, or 60 minutes after roofing activities.” Contrary to this requirement, on April 14, 2014, from approximately 6:30 a.m. to at least 2:00 p.m., the licensee failed to ensure that a fire watch was present at the work area with a fire extinguisher during the work being performed. Because this finding is of very low safety significance (Green), had been entered into the licensee’s CAP, and the licensee had taken or planned corrective actions under CRs 2014–06825 and 2014–06832, the associated violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. Corrective actions taken by the licensee include, but are not limited to, a modified turnover sheet noting specific fire watch positions, and communication of lessons learned during work group turnovers. **(NCV 05000346/2014003–01, “Failure to Properly Perform Required Fire Watch”)**

(2) Failure to Maintain an Approved Hot Work Permit for Containment

Introduction

An NRC-identified finding of very low safety significance (Green) and associated NCV of TS 5.4.1(d) were identified when the licensee failed to properly implement station procedures for control of ignition sources. Specifically, an invalid hot work permit was being used to control SG replacement hot work activities in containment from April 6, 2014, to April 14, 2014.

Description

As part of the investigation and extent of condition review for the issue involving NCV 05000346/2014003–01 described above, it was determined on April 14, 2014, that there was no valid hot work permit in place for ongoing SG replacement project activities in containment. Licensee contract personnel historically had maintained one permit for hot work inside containment associated with work on both SGs that was valid for a 7-day period. This hot work permit was then resubmitted and approved for a 7-day extension, on a weekly basis as needed, using the licensee's fire protection software.

On April 5, 2014, licensee contract personnel submitted a 7-day hot-work permit extension request. Due to either a software error or data entry error, the permit was approved with an expiration date of April 5, 2014, which was not realized at the time. On April 11, 2014, licensee contract personnel submitted another seven-day hot-work permit extension request. When the requester went to print the permit, the software system displayed an error message and the permit was never approved. The requester incorrectly assumed the hot work extension request was approved and that the error

was associated only with the printing function. Consequently, from April 6, 2014, to April 14, 2014, numerous hot work activities were performed in containment without a valid hot work permit. All hot work activities in containment were immediately stopped upon identification of the invalid hot-work permit until a new hot-work permit was approved. CR 2014–06830 was initiated to document the issue.

Analysis

The inspectors reviewed this finding using the guidance contained in Appendix B, “Issue Screening,” of IMC 0612, “Power Reactor Inspection Reports.” The inspectors determined that the licensee’s failure to properly implement plant procedures for controlling ignition sources was a performance deficiency that was reasonably within the licensee’s ability to foresee and correct and should have been prevented. This finding was associated with the initiating events cornerstone of reactor safety and was of more than minor significance because if left uncorrected would have the potential to lead to a more significant safety concern. In particular, uncontrolled ignition sources have the potential to start a fire that could impact risk significant plant equipment.

The inspectors evaluated the finding using IMC 0609, Attachment 4, “Phase 1–Initial Screening and Characterization of Findings.” Because the finding involved reactor shutdown operations and conditions, the inspectors transitioned to IMC 0609, Appendix G, Attachment 1, “Shutdown Operations Significance Determination Process–Phase 1 Operational Checklists for Both PWRs and BWRs.” Since the finding was associated with an issue that occurred during the time the reactor was in a defueled condition, the inspectors conservatively consulted all four PWR checklists (i.e., Checklists 1–4). The inspectors determined that the finding did not adversely impact any shutdown defense-in-depth or mitigation attributes on any checklist, nor did it meet any of the checklist specific requirements for a Phase 2 or Phase 3 SDP analysis. Consequently, the finding was determined to be of very low safety significance (Green).

This finding involved the cross-cutting area of human performance, the aspect of avoiding complacency, such that individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risk, even while expecting successful outcomes. Individuals implement appropriate error reduction tools. In particular, on two occasions licensee contract personnel did not verify the list of valid hot-work permits to ensure the submitted permit was approved and up-to-date. (H.12)

Enforcement

TS 5.4.1(d), requires, in part, the licensee to establish, implement, and maintain applicable written procedures covering fire protection program implementation. The fire protection program was implemented, in part, by Davis-Besse procedure DB–FP–00018, "Control of Ignition Sources," Revision 12. Procedure DB–FP–00018, step 6.1.1, states that “use of ignition sources within the protected Area of DBNPS, and all structures outside the Protected Area is prohibited unless a Hot Work Permit has been approved.” Contrary to the stated requirements, from April 6, 2014, to April 14, 2014, licensee contract personnel had performed hot-work activities inside of containment without a valid hot-work permit. Because this finding is of very low safety significance (Green), had been entered into the licensee’s CAP, and the licensee had taken or planned corrective actions under CR 2014–06830, the associated violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. Corrective actions

taken by the licensee include, but are not limited to, immediately stopping hot-work activities in containment until an approved hot-work permit was obtained and communicating the issue to station personnel for awareness.
(NCV 05000346/2014003–02, "Failure to Maintain an Approved Hot Work Permit for Containment")

1R07 Heat Sink Performance (71111.07)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed completed surveillance, vendor manual information, calculations, performance test and inspection results, and procedures associated with the ECCS room cooler E42–1, train 1 AFW pump turbine governor oil cooler and train 1 AFW pump turbine outboard bearing oil cooler. These heat exchangers were chosen based on their risk significance in the licensee's probabilistic safety analysis, their important safety-related support functions, and their operating history.

For the selected heat exchangers, the inspectors reviewed testing, inspection, maintenance, and monitoring of biotic fouling and macro-fouling programs relied upon to ensure proper heat transfer. This was accomplished by verifying:

- The selected test or inspection method was consistent with accepted industry practices or equivalent;
- The test or inspection conditions were consistent with the selected methodology; and
- The test or inspection acceptance criteria were consistent with the design basis values.

In addition, the inspectors reviewed the results of heat exchanger performance testing and verified the test results considered:

- The differences between testing conditions and design conditions; and
- Any test instrument inaccuracies.

The inspectors also verified trending of test results to confirm the test frequency was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values. In addition, the inspectors verified the condition and operation of the heat exchangers were consistent with design assumptions in heat transfer calculations and applicable descriptions in the USAR. The inspectors verified that the licensee evaluated the potential for water hammer and established controls and operational limits to prevent heat exchanger degradation due to excessive flow-induced vibration during operation. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger.

The inspectors assessed the performance of ultimate heat sink (UHS) and safety-related service water (SW) systems and their subcomponents by reviewing tests or other equivalent methods used by the licensee to ensure the availability and accessibility to cooling water systems. Specifically, the inspectors verified the licensee's inspection of the UHS was thorough and of significant depth to identify degradation of the shoreline

protection or loss of structural integrity. This included verification that vegetation present along the slopes was trimmed, maintained and was not adversely impacting the embankment. In addition, the inspectors verified the licensee ensured sufficient reservoir capacity by trending and removing debris or sediment buildup in the UHS. The inspectors performed a system walkdown of the SW intake structure to verify the licensee's assessment on structural integrity and component functionality. This included the verification that licensee ensured proper functioning of traveling screens and strainers, and structural integrity of component mounts. In addition, the inspectors verified that the SW pump bay silt accumulation was monitored, trended, and maintained at an acceptable level by the licensee, and the water level instruments are functional and routinely monitored. The inspectors also verified the licensee's ability to ensure functionality during adverse weather conditions. The inspectors also verified adequate water would still flow past sand-limiting underwater weir walls during periods of low lake level. The inspectors also verified the licensee had adequately protected against silt introduction during periods of low flow or low level. In addition, the inspectors reviewed a sample of condition reports related to the heat exchangers/coolers and heat sink performance issues to verify the licensee had an appropriate threshold for identifying issues and to evaluate the effectiveness of the corrective actions. The documents reviewed are included in the Attachment to this report.

The inspectors' reviews in this area constituted four heat sink inspection samples as defined in IP 71111.07–05.

b. Findings

(1) Failure to Ensure Auxiliary Feedwater Design Bases Were Correctly Translated Into Design Documents and Procedures

Introduction

The inspections identified two examples representing one finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to ensure the AFW system requirements and design bases were correctly translated into specifications, drawings, procedures, and instructions.

Description

The AFW system has a safety function to provide water to the secondary side of the steam generators in the event of a worst case loss of normal feedwater flow event. After a loss of feedwater (LOFW) event occurs, the AFW system is aligned to immediately take suction from the condensate storage tanks (CSTs), which are non-safety-related but preferred sources of water. The AFW system can be aligned to take suction from the SW system, which is the safety-related source of water if the CSTs become unavailable; however, this alignment requires an interruption of injection for the suction swap to occur.

During this inspection, the oil coolers for the AFW train 1 turbine outboard bearing and governor were selected as samples. The AFW coolers are normally supplied by the discharge of the associated AFW pump. The cooling water is piped from the pump discharge through an orifice used to lower the water pressure to within the cooler

piping's allowed pressure rating. Downstream of the orifice the cooling water flow is split between into three main flow paths:

- The governor oil cooler;
- The AFW turbine bearing coolers; and
- The AFW pump bearing coolers.

The total flow to all three flow paths is controlled by the orifice. Flow to the pump bearing coolers is controlled by the AFW pump bearing cooling water throttle valve, AF7, with the remainder feeding the governor and turbine bearing coolers. The AF7 valve is locked in position at one turn opened. The inspectors noted the USAR stated in Table 15.2.8–3, "Loss of Normal Feedwater Accident Parameters for Reanalysis," that the maximum temperature of the CST water injected by the AFW system was assumed in the analysis to be 120 ºF. The inspectors also noted USAR Section 15.2.8.4, "Reanalysis of Loss of Feedwater Event," indicated the LOFW event was a more severe transient than a feedwater line break and the limiting parameters occurred within the first ten minutes after the LOFW event initiation (e.g., maximum reactor power excursion and maximum pressurizer water level).

The inspectors reviewed CR 2002–06777 and calculation C–NSA–50.03–026, "Condensate Heating with Auxiliary Feed." Because the preferred source of water to the AFW system is the CST, the maximum inlet cooling water temperature to the coolers is dependent on the CST water temperature plus the heat added by the AFW pump. Heating of the water by the AFW pump had previously occurred when the operators aligned the AFW system to begin partial recirculation of the AFW discharge back to the CST. This phenomenon was confirmed during a previous event on June 24, 1998. A loss of offsite power occurred and both AFW pumps had been recirculating to the CST for about 26 hours. The maximum AFW discharge temperature increased to 111 ºF. Based on this, the licensee stated the AFW discharge could exceed 120 ºF under certain conditions, but did not expect this to happen during the first ten minutes of the event because the partial recirculation was not expected to be aligned until after the first ten minutes of the LOFW event.

Based on the above, the inspectors had the following concerns:

1. Procedure DB–OP–0622, "Condensate System Operating Procedure," enabled operators to transfer water from the hotwell to be transferred to the CSTs while in Modes 1 through 3. Although this transfer would not be typically desired (since it would introduce tritium containing water to the CSTs), the procedures for performing this action was active and available to the operators. The licensee confirmed that an allowed hotwell water transfer to the CST while online could raise the CST temperature above the bounded 120 ºF. The inspectors were concerned that since the CSTs' water temperatures were not directly monitored and the procedure did not warn the operators that the 120 ºF assumption could be exceeded without operators realizing it and measures were not proceduralized that the 120 ºF might be exceeded. The licensee documented the inspectors' concerns in CR 2014–11131. The licensee concluded current operability of the system remained intact because no hotwell transferred had occurred and ambient temperature in the CST room was about 82 ºF. Since the CSTs were uninsulated, the licensee believed the CST water would track closely with the CST room temperature. The licensee also initiated Standing Order 14–008, "Guidance to Address Maximum Allowed Condensate

Storage Tank Temperature and the Operability Impact on Auxiliary Feedwater," which directed CST temperature monitoring to ensure 120 ºF was not exceeded during or after a hotwell water transfer to the CST. The licensee also planned to revise DB–OP–06221, Section 3.14, to add a caution to warn of the potential to raise CST temperature above the 120 ºF assumed in the USAR analysis.

2. Calculation 069.002, Revision 2, "Auxiliary Feedwater System," was developed to determine the pressure reducing requirements for restriction orifices RO4979 and RO4980 (one per AFW train) and maintain the cooling water supply to the AFW coolers within limits. However, this calculation was based on current pump performance; it failed to consider the allowed pump degradation and did not establish the minimum cooling water flow rate at design bases specified performance. This concern was documented by the licensee in CR 2014–11017. Preliminary evaluations by the licensee determined that accounting for these errors they would still have enough margin to provide cooling water to the required loads.

3. The inspectors also identified a discrepancy in Calculation 069.002, Revision 2. Attachment 1 to the calculation contained information from the Terry turbine vendor representative which stated, "Cooling water flow for the turbine bearing oil would be 3 gallons per minute (gpm)," apparently referencing one Terry turbine with two bearing oil coolers. The licensee stated this letter confirmed the licensee's understanding that one turbine bearing oil cooler required 1.5 gpm. However, Section 4.1 of the calculation contradicted this letter by stating "each AFW turbine-driven pump bearing cooler requires a minimum flow rate of 3 gpm." The inspectors were concerned this ambiguity on the actual flow requirements could challenge whether the minimum cooling flows would be achieved under limiting design bases condition. The licensee documented the inspectors' concern in CR 2014–11017. In addition, the licensee contacted the vendor to confirm the requirement of 1.5 gpm per turbine bearing oil cooler and is awaiting their analysis. In the meantime, the licensee performed preliminary evaluations and determined enough margin exists at this time to provide adequate cooling water to the required loads when taking into account the potential increased flows.

4. The inspectors noted throttle valve AF7 was locked at one turn open. However, the licensee was unable to identify any basis for this position. The licensee's investigation determined this configuration has been maintained since Revision 1 of SP 1106.06, "Auxiliary Feedwater System Procedure," issued in 1978. This concern was documented in CR 2014–11018, which stated in the senior reactor operators (SRO) comments: "Both AFW pumps have passed previous testing. More importantly all bearing stabilization tests have shown appropriate temperatures, demonstrating proper flow through the AF7 and AF8 [valves]."

As stated above, the licensee entered these concerns into their CAP and initiated interim actions to ensure continued functionality.

Analysis

The inspectors determined the licensee's failure to correctly translate the AFW design requirements into the design documents and procedures to ensure the AFW pumps

were capable of performing their safety function under design bases conditions was a performance deficiency. Specifically, the licensee:

1. Failed to correctly translate design requirements into the hotwell transfer procedure to ensure the CST water temperature would not exceed the 120 ºF limit described in USAR Section 15.2.8.4; and

2. Failed to correctly and clearly translate pump and maximum cooling water temperature and minimum flow design requirements into Calculation 069.002, Revision 2, and into a specification documenting the basis of the throttling position of valve AF7.

The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control which ensures the availability, reliability and capability of the system to respond to initiating events and prevent undesirable consequences. Specifically, the inspectors were concerned that under design bases conditions the AFW system could potentially be operated in a manner which had not been previously evaluated.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings." Because the finding impacted the Mitigating Systems Cornerstone, the inspectors screened the finding through IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," using Exhibit 2, "Mitigating Systems Screening Questions." The finding screened as of very low safety significance (Green) because it did not result in the loss of operability or functionality. Specifically, the licensee reviewed the operating history of the CSTs and found no indication that the CST water had ever been above 120 ºF in Modes 1 through 3. Also, the licensee reviewed the operating history of the AFW coolers and found no indication that the AFW coolers had ever been inoperable due to excessive cooling water temperature or inadequate flow. The licensee also performed preliminary evaluations that indicated the AFW system had margin to compensate for the identified discrepancies.

The inspectors determined this finding had an associated cross-cutting aspect, avoid complacency, in the human performance cross-cutting area. This corresponds to the apparent cause identified by the inspectors for the finding: the licensee's lack of a questioning attitude in ensuring the correct translation of the design requirements for the AFW system into design documents and procedures. Specifically, when preparing to revise DB–OP–06221, "Condensate System," for Revision 25 (which was effective May 9, 2014), the licensee did not verify or question the need to include design bases information to Section 3.14, "Filling the Condensate Storage Tanks from the Condensate System," to ensure the CST water remained below 120 ºF. Also, when preparing to revise Calculation 069.002 on January 28, 2013, the licensee did not verify operating assumptions were consistent with design bases information, specifically related to the AF7 valve position. Licensee individuals were complacent that they were meeting the design bases of the AFW system, and did not question nor verify that the design bases would be met. (H.12)

Enforcement

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to this requirement, from the issuance of DB–OP–06221 on May 9, 2014, and Calculation 069.002, Revision 2, in January of 2013 until this inspection period, the licensee failed to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Specifically, the licensee failed to translate the following:

1. Adequate guidance into DB–OP–06221 to ensure hotwell water transfer to the CST would not cause the CST water to be more than 120 ºF, as required by the loss of normal feedwater event in USAR Section 15.2.8.4; and

2. Pump and maximum cooling water temperature and minimum flow design requirements into Calculation 069.002, Revision 2, and to document the basis of the throttling position of valve AF7.

As described above, the licensee entered these issues into the CAP, instituted Standing Order 14–008 to provide guidance to the operators regarding CST temperature requirements, and performed evaluations to ensure that the AFW coolers would perform as required.

Because this violation was of very low safety significance and it was entered into the licensee's CAP as CRs 2014–11017, 2014–11018, and 2014–11131, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000346/2014003–03, "Failure to Ensure Auxiliary Feedwater Design Bases Were Correctly Translated into Design Documents and Procedures")**

(2) Acceptance Criteria for Emergency Core Cooling System Room Cooler Inspection Was Not Specified in Inspection Procedure

Introduction

A finding of very-low-safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to follow their Generic letter (GL) 89–13 program implementing procedure (NOP–ER–2006) to develop the ECCS room cooler inspection procedure. Specifically, the inspection procedure for the ECCS room cooler did not have quantifiable acceptance criteria.

Description

On June 26, 2014, the inspectors identified the licensee's failure to follow procedure NOP–ER–2006, "Service Water Reliability Management Program," a procedure for activities affecting quality, because they did not incorporate quantifiable acceptance criteria into an ECCS room cooler inspection procedure. The licensee originally implemented NOP–ER–2006, a corporate procedure, in 2007. The procedure established the GL 89–13 management program for the licensee and provides

administrative requirements for the implementation and maintenance of the program. The objective of the GL 89–13 program was to prevent biofouling of SW system and intake structure components to ensure that the system is reliable, available, and remains capable of performing its design basis functions. In part, the program focuses on inspection, testing, and cleaning of safety-related piping and heat exchangers in the SW system that could adversely affect biofouling and reduce flow through the system.

Section 4.2.3 of procedure NOP–ER–2006 describes the process for inspecting GL 89–13 heat exchangers. Section 4.2.3.2 states that, "Inspection procedures shall have quantifiable acceptance criteria provided by Design Engineering. This shall include minimum allowable wall thickness, maximum allowable tube blockage, maximum allowed tube plugging and biofouling and silt deposit limits."

The inspectors reviewed WO 200542642, which was used for the most recent ECCS room cooler 1 (E42–1) inspection. The WO was generated on January 18, 2013, based on preventative maintenance (PM) templates developed in the 1990s. These templates outline the inspection procedure for the heat exchangers and are used to develop a WO each time a heat exchanger inspection is required. The inspectors noted the licensee had not incorporated quantifiable acceptance criteria into the WO as part of the inspection procedure for the heat exchanger. The inspectors determined licensee failed to revise the PM template in 2007, when corporate procedure NOP–ER–2006 was originally implemented. Therefore, WOs generated to support heat exchanger inspections used the unrevised PM template and were inconsistent with the latest program requirements.

The inspectors were concerned the ECCS room cooler inspection procedure used did not have quantifiable acceptance criteria as required by procedure NOP–ER–2006 to identify when corrosion, erosion, silting or biofouling could degrade heat exchanger performance. A lack of quantifiable acceptance criteria could lead to an unacceptable condition of the heat exchanger being deemed acceptable during an inspection. An unacceptable ECCS room cooler condition could render it inoperable, which in turn could make ECCS equipment inoperable and place the plant at an increased risk for core damage.

However, the inspectors noted the WO documented no blockage was identified in the tubes or spool pieces of the heat exchanger. The inspectors also interviewed the individual who performed the heat exchanger inspection to determine what acceptance criteria had been used for the inspection. The heat exchanger inspectors relied on his training and experience to determine that the heat exchanger was acceptable during the "as-found" inspection. In addition, the heat exchanger inspectors informed the NRC that the ECCS room cooler had historically not been subject to significant degradation from biofouling.

The licensee placed this issue into their CAP as CR 2014–10995 and discussed it with the engineering staff and GL 89–13 program owner. The licensee also reviewed a sampling of other GL 89–13 heat exchanger inspection procedures and determined that at least one more set of inspection procedures, those for the control room emergency ventilation, lacked quantifiable acceptance criteria.

Analysis

The inspectors determined that the failure to follow procedure NOP–ER–2006, “Service Water Reliability Management Program,” a procedure for activities affecting quality, was contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” and was a performance deficiency.

The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedure Quality, and it adversely affected the associated cornerstone objective to ensure the availability, reliability, and capability of the system to respond to initiating events to prevent undesirable consequences. Specifically, the ECCS room cooler inspection procedure failed to ensure the reliability of the heat exchanger because it did not have quantifiable acceptance criteria, as required by the NOP–ER–2006 procedure. Without quantifiable acceptance criteria, an ECCS room cooler inspection could incorrectly conclude that the heat exchanger condition is acceptable when it is not.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings.” Because the finding impacted the Mitigating Systems Cornerstone, the inspectors screened the finding through IMC 0609 Appendix A, “The Significance Determination Process for Findings At-Power,” using Exhibit 2, “Mitigating Systems Screening Questions.” The inspectors used Subsection A, “Mitigating SSCs and Functionality,” of Exhibit 2 and answered “No” to all of the screening questions because there was no loss of safety function for the ECCS room cooler. Therefore, the finding screened as having very low safety significance (Green).

The inspectors did not identify a cross-cutting aspect associated with this finding because it did not reflect current performance due to the age of the performance deficiency. Specifically, the licensee’s failure to revise the PM template occurred in 2007. Therefore, the performance deficiency had occurred more than 3 years ago.

Enforcement

Title 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstances and be accomplished in accordance with these procedures. The licensee established NOP–ER–2006, Revision 02, “Service Water Reliability Management Program,” as the implementing procedure for developing the GL 89–13 program heat exchanger inspection procedures, an activity affecting quality. Procedure NOP–ER–2006, Step 4.2.3.2, states, in part, that inspection procedures shall have quantifiable acceptance criteria provided by design engineering. Contrary to this requirement, since 2007, the licensee failed to follow Step 4.2.3.2 of procedure NOP–ER–2006. Specifically, the licensee failed to have quantifiable acceptance criteria in the inspection procedure for the ECCS room cooler.

The licensee is still evaluating its planned corrective actions. However, the inspectors determined that the continued non-compliance does not present an immediate safety concern because the last heat exchanger inspection did not identify any blockage of the heat exchanger, as documented in the WO carrying out the inspection.

Because this violation was of very low safety significance and was entered into the licensee's CAP as CR 2014–10995, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000346/2014003–04, "Acceptance Criteria for Emergency Core Cooling System Room Cooler Inspection Was Not Specified in Inspection Procedure")**

1R08 Inservice Inspection Activities (71111.08)

From February 10 through June 6, 2014, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the RCS, replacement SGs, emergency feedwater systems, risk-significant piping and components, and containment systems.

The inspectors' reviews of the licensee's inservice inspection activities described in sections 1R08.1 through 1R08.5 below constituted a single inspection sample as defined in IP 71111.08–05.

.1 Piping Systems Inservice Inspections

a. Inspection Scope

The inspectors observed or reviewed records of the following non-destructive examinations mandated by the American Society of Mechanical Engineers (ASME) Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement:

- System leakage test (VT–2) of containment vessel opening restoration weld;
- Magnetic particle (MT) examination of SG–2 36 inch hot leg pipe to SG inlet nozzle weld;
- Ultrasonic (UT) examination of SG–2 36 inch hot leg pipe to SG inlet nozzle weld;
- Nondestructive Examination (NDE) report no. 18–MT–086; "Magnetic Particle Examination of SG–2 36 inch Hot Leg Pipe to Pipe Weld"; April 9, 2014;
- UT examination of SG–2 36 inch hot leg pipe to pipe weld;
- MT examination of SG–1 36 inch hot leg pipe to SG inlet nozzle weld;
- UT examination of SG–1 36 inch hot leg pipe to SG inlet nozzle weld;
- MT examination of SG–1 36 inch hot leg pipe to pipe weld;
- UT examination of SG–1 36 inch hot leg pipe to pipe weld;
- MT examination of SG–2 28 inch cold leg outlet safe end to elbow weld;
- UT examination of SG–2 28 inch cold leg outlet safe end to elbow weld;
- MT examination of SG–2 28 inch cold leg outlet safe end to elbow weld;
- UT examination of SG–2 28 inch cold leg outlet safe end to elbow weld;
- MT examination of SG–1 28 inch cold leg outlet safe end to elbow weld;
- UT examination of SG–1 28 inch cold leg outlet safe end to elbow weld;
- MT examination of SG–1 28 inch cold leg outlet safe end to elbow weld;
- UT examination of SG–1 28 inch cold leg outlet safe end to elbow weld;
- Radiographic examination of SG–1 36 inch hot leg pipe to pipe weld;

- Radiographic examination of SG–1 36 inch hot leg pipe to SG inlet nozzle weld; and
- Radiographic examination of containment vessel opening weld.

During the prior outage non-destructive surface and volumetric examinations, the licensee did not identify any relevant/recordable indications. Therefore, no NRC review was completed for this IP attribute.

The inspectors observed and/or reviewed records of the following pressure boundary welds completed for a risk significant systems during the RFO to determine if the welding activities and any applicable NDE performed were completed in accordance with the ASME Code or NRC-approved alternative:

- Replacement Steam Generators 1–1 and 2–2 RCS Hot and Cold Leg Nozzle-to-Pipe and Pipe-to-Pipe Welds; Document No. 25539–000–GMX–GCE–00001; Bechtel Special Processes Manual for Davis Besse Steam Generator Replacement Project; Revision 3.

b. Findings

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the reactor pressure vessel head, a bare metal visual (BMV) examination was required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D).

The inspectors observed the BMV examination conducted on the reactor vessel head and penetration nozzles to determine if the activities were conducted in accordance with the requirements of ASME Code Case (CC) N–729–1 and 10 CFR 50.55a(g)(6)(ii)(D).

Specifically, the inspectors determined:

- If the required visual examination scope/coverage was achieved and limitations (if applicable) were recorded in accordance with licensee procedures;
- If the licensee criteria for visual examination quality and instructions for resolving interference and masking issues were adequate; and
- For indications of potential through-wall leakage, whether the licensee entered the condition into the CAP and implemented appropriate corrective actions.

b. Findings

No findings were identified

.3 Boric Acid Corrosion Control

a. Inspection Scope

On February 1, 2014, the inspectors observed the licensee staff performing visual examinations of the RCS within containment to determine if these examinations focused

on locations where boric acid (BA) leaks could cause degradation of safety significant components. Additionally, the inspectors conducted an independent Mode 3 containment “as-found” walkdown focusing on the identification of BA residue on plant systems, structures, and components (SSCs).

The inspectors reviewed the following licensee evaluations of RCS components with BA deposits to determine if degraded components were documented in the CAP. The inspectors also evaluated corrective actions for any degraded RCS components to determine if they met the component Construction Code, ASME Section XI Code, and/or an NRC-approved alternative:

- Boric Acid Corrosion (BACC) Evaluation No. 2013–10587; "BACC Evaluation for Boric Acid Leak on flange for Reactor Coolant Pump (RCP) 1–2 Seal";
- BACC Evaluation No. 2013–10569; "BACC Evaluation for Boric Acid Leak on Valve RC217A from Packing/Packing Follower"; and
- BACC Evaluation No. 2013–10061; "BACC Evaluation for Boric Acid Leak on P36–2 (RCP 1–1–2)".

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

- CR 2012–09384; "Packing Leak on RC1AAE (Flow Transmitter Valve)";
- CR 2014–01054; "Boric Acid Leak on SA536 (Isolation to Upper Containment Spray)";
- CR 2012–07981; "Packing Leak on RC1ABA (Flow Transmitter Source Valve)"; and
- CR 2012–10772; "Containment Spray Pump 1 Drain Has Boric Acid Around Pipe Cap Threads".

b. Findings

No findings were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

During this RFO, both SGs for the plant were replaced. As it is typically a part of this IP 71111.08 to perform a review of SG tube inspection activities, the pre-service eddy current examinations performed on these replacement SGs were reviewed during this inspection.

The NRC inspectors observed the following activities and/or reviewed the following documentation and evaluated them against the licensee’s TS, commitments made to the NRC, ASME Section XI, and Nuclear Energy Institute (NEI) 97–06 (Steam Generator Program Guidelines):

- Reviewed eddy current testing (ET) data summary report and samples of ET data;

- Reviewed the SG tube ET examination scope;
- Evaluated if the ET equipment and techniques used by the licensee to acquire data from the SG tubes were qualified or validated to detect the known/expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of Electric Power Research Institute (EPRI) "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 7; and
- Reviewed ET personnel qualifications

b. Findings

No findings were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI-related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if:

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

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

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Simulator Training

a. Inspection Scope

On April 9, 2014, the inspectors observed a crew of licensed operators in the plant's simulator. The training scenarios observed were part of the licensee's licensed operator training prior to reactor and unit restart from the 18th RFO, and involved multiple individual plant system startup operations, as well as complex integrated plant system startup exercises.

The inspectors verified that operator performance was adequate, that evaluators were identifying and documenting crew performance problems, and that training was being

conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance;
- The clarity and formality of communications;
- The ability of the crew to take timely and conservative actions;
- The crew's prioritization, interpretation, and verification of annunciator alarms;
- The correct use and implementation of abnormal and emergency procedures by the crew;
- Control board manipulations;
- The oversight and direction provided by licensed SROs; and
- The ability of the crew to identify and implement appropriate TS actions and emergency plan (EP) actions and notifications.

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

In addition to standard RFO activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected RCS piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Integrated Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

These observations and activities by the inspectors constituted a single quarterly licensed operator requalification program simulator training inspection sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Control Room Activities

a. Inspection Scope

During the course of the inspection period, the inspectors performed numerous observations of licensed operator performance in the plant's control room to verify that operator performance was adequate and that plant evolutions were being conducted in accordance with approved plant procedures. Specific activities observed that involved a heightened tempo of activities or periods of elevated risk included, but were not limited to:

- RCP motor testing during the week ending April 5, 2014;
- RCS fill and vent during the week ending April 26, 2014;
- RCS heatup and pressurization from cold shutdown during the week ending May 3, 2014;
- Reactor startup and zero power core physics testing during the week ending May 10, 2014;

- Reactor trip response and follow-up actions for control rod drive (CRD) high stator temperatures on rod drive No. 4–3 during the week ending May 10, 2014; and
- Main turbine roll, synchronization of the main generator to the electric power grid, and escalation to full plant power during the week ending May 10, 2014.

The inspectors evaluated the following areas during the course of the control room observations:

- Licensed operator performance;
- The clarity and formality of communications;
- The ability of the crew to take timely and conservative actions;
- The crew's prioritization, interpretation, and verification of annunciator alarms;
- The correct use and implementation of normal operating, annunciator alarm response, and abnormal operating procedures by the crew;
- Control board manipulations;
- The oversight and direction provided by on-watch SROs and plant management personnel; and
- The ability of the crew to identify and implement appropriate TS actions and notifications.

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

In addition to standard RFO activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected RCS piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Integrated Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

These observation activities by the inspectors of operator performance in the station's control room constituted a single quarterly inspection 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 performance issues involving the following risk-significant systems:

- The RCS; and
- The control room alarm and annunciator system and associated equipment.

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

- Implementing appropriate work practices;
- Identifying and addressing common cause failures;
- Scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- Characterizing system reliability issues for performance;
- Charging unavailability for performance;
- Trending key parameters for condition monitoring;
- Ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- Verifying appropriate performance criteria for 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 to this report.

The inspectors' reviews constituted two quarterly maintenance effectiveness inspection samples as defined in IP 71111.12–05.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Planned work activities associated with RCS fill and venting during the week ending April 12, 2014;
- Planned work activities and licensee actions in response to emergent issues associated with the station and instrument air systems during the weeks ending May 3, 2014, through May 17, 2014; and
- Licensee actions in response to emergent issues associated with the CRD system during the week ending May 3, 2014.

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.

In addition to standard RFO activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected RCS piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

These maintenance risk assessments and emergent work control activities constituted three inspection samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Operability of Station Vent train 1 and 2 with a sample flow discrepancy, as documented in CR 2014–06239, during the weeks ending April 19, 2014, and April 26, 2014;
- Operability of containment and the recirculation sump considering results of containment closeout inspections in preparation for plant entering Mode 4, as documented in CRs 2014–07843 and 2014–07864, during the week ending May 3, 2014;
- Operability of the pressurizer and reactor coolant pressure control system with the pressurizer spray valve, RC2, not fully closing, as documented in CR 2014–08650, during the weeks ending May 10, 2014, and May 24, 2014;
- Operability of the CR system and overall core reactivity control with axial power shaping rod (APSR) 8–2 uncoupled and misaligned from its rod group, as documented in CR 2014–08664, during the weeks ending May 17, 2014 through June 13, 2014; and
- Operability of reactor trip breakers (RTBs) 'A' and 'B' with the source interruption device and associated relaying temporarily removed, as documented in CR 2014–08679, during the weeks ending May 17, 2014, through May 24, 2014.

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 USAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

In addition to standard RFO activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected RCS piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

The review of these issues by the inspectors constituted five inspection samples as defined in IP 71111.15–05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modification

a. Inspection Scope

The inspectors reviewed the following temporary modification to the facility:

- Engineering Change Package (ECP) No. 14–0357: Temporary Modifications to Disable Source Interruption Devices A and B 94 Relays on RTBs A and B.

The inspectors reviewed the configuration changes and associated 10 CFR Part 50.59 safety evaluation documents against the design basis, the USAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of any safety-related systems, or systems important to safety. The inspectors observed ongoing and completed work activities to ensure that the modification was installed as directed and consistent with the design control documents; that the modification operated as expected; and that operation of the modification did not impact the operability of any interfacing systems. The inspectors verified that relevant procedure, design, and licensing documents were properly updated; both for the interim condition and after the temporary changes to the facility were restored to the original configuration. Lastly, the inspectors discussed the plant modification with Operations and Engineering personnel to ensure that the individuals were aware of how the operation with the modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

The inspectors' review of this temporary plant modification constituted a single inspection sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

.2 Permanent Plant Modification

a. Inspection Scope

The inspectors reviewed the following modification:

- ECP No. 12–0584: Replacement of Turbine Plant Cooling Water Heat Exchanger E8–2 Tube Bundle and Increase in Associated Vent and Drain Valve Size to 2 Inches.

The inspectors reviewed the configuration changes and associated 10 CFR Part 50.59 safety evaluation documents against the design basis, the USAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of any safety-related systems, or systems important to safety. The inspectors observed ongoing and completed work activities to ensure that the modification was installed as directed and consistent with the design control documents; that the modification operated as expected; and that operation of the modification did not impact the operability of any interfacing systems. The inspectors verified that relevant procedure, design, and licensing documents were properly updated. Finally, the inspectors discussed the plant modification with Operations, Engineering, Security, and Training Department personnel to ensure that the individuals were aware of how the operation with the modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

The inspectors' review of this permanent plant modification constituted a single inspection sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Quarterly Resident Inspector Observation and Review of Post-Maintenance Testing Activities

a. Inspection Scope

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

- Energized motor testing of RCP 1–1 following planned replacement of the motor during the week ending April 5, 2014;

- Energized motor testing of RCP 1–2 following planned replacement of the motor during the week ending April 5, 2014;
- Field and laboratory concrete testing following restoration of the shield building opening to facilitate SG replacement during the week ending April 5, 2014;
- Cycle 19 core fuel assembly location verification following core reload during the week ending April 26, 2014;
- Containment emergency sump visual inspections following planned removal of emergency sump suction blind flanges during the week ending April 26, 2014;
- Testing of the shield building train 2 emergency ventilation system following restoration of the shield building construction opening during the week ending April 26, 2014;
- Main turbine overspeed trip testing following planned digital electrohydraulic control system installation and turbine outage maintenance during the week ending May 10, 2014;
- Primary containment vessel post modification pressure/new weld leakage inspection test during the week ending May 3, 2014;
- RCS pressure and leakage testing during the weeks ending May 3, 2014 through May 17, 2014; and
- Control rod drop time testing during the week ending May 10, 2014.

These activities were selected based upon the systems, structures or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the USAR, 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 the PMTs 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.

In addition to standard RFO activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected RCS piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

The inspectors' reviews of these activities constituted ten PMT inspection samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors continued their review of the licensee's comprehensive outage plan, shutdown defense-in-depth plan, and contingencies for the plant's 18th RFO, which was in progress at the beginning of the inspection period, and ended on May 8, 2014, when the unit's main generator was synchronized to the electrical power grid. These reviews were performed to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the portion of the RFO that took place during the inspection period, the inspectors observed elements of the RCS heatup and pressurization from cold shutdown, reactor startup and zero power core physics testing, main turbine roll up, synchronization of the main generator to the electrical power grid, escalation to full plant power, and monitored licensee controls over the outage activities listed below:

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the shutdown defense-in-depth plan for key safety functions and compliance with the applicable TS when taking equipment out of service;
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- Installation and configuration of RCS pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- Controls over the status and configuration of electrical systems to ensure that TS and shutdown defense-in-depth plan requirements were met, and controls over switchyard activities;
- Monitoring of DH removal processes, systems, and components;
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- Controls over activities that could affect reactivity;
- Maintenance of containment and associated ventilation systems, as required by TS;
- Licensee fatigue management, as required by 10 CFR 26, Subpart I;
- Refueling activities, including fuel handling, spent fuel assembly inspections, and fuel assembly reconstitution; and
- Licensee identification and resolution of problems related to RFO activities.

In addition to standard RFO activities, activities during the site's 18th RFO also included replacement of the unit's two SGs and significant portions of the connected RCS piping. Inspection of the SG replacement and associated activities is covered under NRC IP 50001, "Steam Generator Replacement Inspection," and will be documented in a separate NRC Inspection Report 05000346/2013010. Applicable portions of the inspectors' reviews documented in this section also were credited toward completion of IP 50001. Documents reviewed are listed in the Attachment to this report.

In combination with the activities described in Section 1R20 of NRC Integrated Inspection Report 05000346/2014002 (ADAMS Accession No. ML14113A073), these RFO review activities completed a single RFO inspection sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the results for the following testing 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:

- SBODG normal periodic monthly function and operability testing during the week ending April 19, 2014 (Routine);
- Refueling interval operability and functionality testing of shield building emergency ventilation train 2 during the week ending April 26, 2014 (Routine);
- Main turbine overspeed trip testing during the week ending May 10, 2014 (Routine);
- Zero power core physics testing during the week ending May 10, 2014 (Routine);
- SW train 2 quarterly testing during the week ending May 17, 2014 inservice testing (IST); and
- RCS leakage test during the week ending May 3, 2014 through May 17, 2014 (RCS Leakage).

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

- Did preconditioning occur;
- The effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- Acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- Plant equipment calibration was correct, accurate, and properly documented;
- As-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- That measuring and test equipment calibration was current;
- That test equipment was used within the required range and accuracy;
- That applicable prerequisites described in the test procedures were satisfied;
- That test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- That test data and results were accurate, complete, within limits, and valid;

- That test equipment was removed after testing;
- Where applicable for IST activities, that testing was performed in accordance with the applicable version of Section XI, ASME Code, and reference values were consistent with the system design basis;
- Where applicable, that test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- Where applicable, that actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- That prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- That equipment was returned to a position or status required to support the performance of its safety functions; and
- That all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

These activities conducted by the inspectors constituted four routine surveillance testing inspection samples, one IST inspection sample, and one RCS Leakage inspection sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator (PI) for the period from the second quarter 2013 through the first quarter 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, and NUREG–1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance, were used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance WOs, issue reports, event reports and NRC Integrated Inspection Reports for the period of April 2013 through March 2014 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, and none were identified. Documents reviewed are listed in the Attachment to this report.

The inspectors' reviews of this PI data constituted a single Safety System Functional Failure inspection sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index–Emergency Alternating Current Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI)–Emergency AC Power System performance indicator for the period from the second quarter 2013 through the first quarter 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports and NRC Integrated Inspection Reports for the period of April 2013 through March 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. Documents reviewed are listed in the Attachment to this report.

The inspectors' reviews of this PI data constituted a single MSPI–Emergency AC Power System inspection sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index–High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI–High Pressure Injection Systems performance for the period from the second quarter 2013 through the first quarter 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of April 2013 to March 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's

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

The inspectors' reviews of this PI data constituted a single MSPI–High Pressure Injection System inspection sample as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

As part of the various baseline IPs discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: 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 to this report.

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 CR 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: Event Reporting Issues

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 inspectors 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 1 through June 30, 2014, although 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.

Observations

During the course of the review period for this inspection sample, the inspectors noted several recent examples where the licensee's organization had misidentified the reporting requirements associated with events that had occurred at the site. In all cases, the events in question were low-level events and did not constitute anything other than issues of very low safety significance. Nonetheless, the adverse trend in this area is readily apparent and warrants additional licensee attention to effect corrective actions. Specific examples associated with this trend included, but were not limited to:

- Event Notification 50086: "Manual Reactor Scram with Rod Motion While Shutdown." As discussed in Section 4OA3.1, the inspectors engaged with licensee management to discuss the licensee's conclusions regarding the need for any non-emergency notifications per applicable 10 CFR 50.72 requirements several hours after the event. Following these discussions, the licensee revised their conclusions and determined that the event required an 8 hour non-emergency report to the NRC per 10 CFR 50.72(b)(3)(iv)(A), as a valid actuation of the plant's reactor protection system (RPS). Although this report was completed by the licensee at 9:17 p.m. on the day of the event, and within the 8 hour timeframe specified by NRC requirements, it is likely that the reporting requirement would have been missed absent the inspectors' questions to the licensee. CR 2014–08344.

- Event Notification 50097: "Manual Initiation of the Reactor Protection System while Shutdown." As discussed in Section 4OA3.2, licensee personnel had initially determined that the event did not require any non-emergency notifications in accordance with 10 CFR 50.72 requirements. However, following their decision to report Event Notification 50086 (discussed above) under the requirements of 10 CFR 50.72(b)(3)(iv)(A) as a valid actuation of the plant's RPS, licensee personnel reevaluated their decision in this matter. The licensee concluded that this initiation of a manual reactor trip also constituted a valid actuation of the plant's RPS and an 8 hour non-emergency report to the NRC per 10 CFR 50.72(b)(3)(iv)(A) was required. The licensee completed this report, albeit several days after the eight-hour time requirement had passed. CRs 2014–08263 and 2014–08555.
- Event Notification 50143: "Control Room Overhead Annunciator Malfunction." As discussed in Section 4OA3.3, as part of their review of this event the inspectors also reviewed other similar instances involving failures of the control room overhead alarm annunciator system going back to late 2013. For one such instance that was reviewed, a failure that took place during the early morning hours on May 21, 2014, the inspectors noted that the licensee's justification for their decision to not report the event was lacking. During the exit meeting with the licensee for this inspection report (see Section 4OA6.1), the licensee acknowledged the inspectors' issues and stated that an 8 hour non-emergency report to the NRC per 10 CFR 50.72(b)(3)(xiii), albeit late, was forthcoming. CRs 2014–09280 and 2014–11234.

b. Findings

No findings were identified.

.4 NRC Inspection Report 05000346/2013009 Reactor Oversight Process Credit

On May 12, 2014, the NRC issued Inspection Report 05000346/2013009 (ADAMS Accession No. ML14132A259) to document the inspectors' reviews of certain licensee corrective actions associated with the identification of laminar cracking within the plant's shield building. Because this inspection began in late 2013, the inspection report was assigned a calendar year 2013 identification number. However, because the inspection was completed in 2014, the inspection sample documented in that report is being administratively credited to this report (IR 05000346/2014003) to ensure proper accounting within the 2014 reactor oversight process (ROP) inspection cycle.

As discussed in NRC Inspection Report 05000346/2013009, the inspectors' review of the issue constituted a single follow-up inspection sample for in-depth review as defined in IP 71152–05.

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

.1 Event Notification 50086: Manual Reactor Scram with Rod Motion While Shutdown

On May 5, 2014, the reactor was in a hot shutdown (Mode 3) condition and performance of control rod assembly insertion time testing was in progress. In parallel with this activity, maintenance personnel were working in containment on a position indication tube for the control rod in core location N12. Due to the congested nature of the work

location, the maintenance personnel had to move the flexible stainless steel cooling water hoses for several CRD mechanisms in order to gain proper access to the work area. During this activity, a quick disconnect unknowingly became disengaged and cooling water flow to nearby CRD 4–3 in core location L14 was isolated. The fitting, albeit now loose, stayed together and an integral double check valve design ensured that water did not leak from either end.

Plant operators in the control room quickly identified a rapidly rising temperature on CRD 4–3. With CRD 4–3 temperature at 180°F and still rising, control room operators initiated a manual reactor trip to de-energize the CRD mechanism and arrest the temperature rise in accordance with plant procedures. Only safety group 2 control rods were partially withdrawn for the testing that was being performed; all other control rods were fully inserted at the time of the event. Upon initiation of the manual reactor trip, all partially withdrawn control rods fully inserted as expected. The highest temperature noted on CRD 4–3 was 189°F. Operations personnel, suspecting that the quick disconnect in the cooling line for CRD 4–3 had become disengaged, entered containment and restored the cooling water to CRD 4–3 in short order by resetting the connection. Within several minutes of having the cooling water restored, CRD 4–3 temperatures were back to nominal values and consistent with the other CRDs in its group.

The inspectors reviewed the response to this event, including but not limited to:

- Status and performance of plant equipment;
- Non-emergency notifications made to state and local government agencies as required by 10 CFR 50.72; and
- Development and implementation of licensee repair actions.

Several hours after the event, the inspectors engaged with licensee management to discuss the licensee's conclusions regarding the need for any non-emergency notifications per applicable 10 CFR 50.72 requirements. Following these discussions, the licensee revised their conclusions and determined that the event required an 8 hour non-emergency report to the NRC per 10 CFR 50.72(b)(3)(iv)(A), as a valid actuation of the plant's RPS. This report was completed by the licensee at 9:17 p.m. on the day of the event, and within the 8 hour timeframe specified by NRC requirements.

In reviewing the event, the inspectors determined that the inadvertent disconnection of the cooling water supply to CRD 4–3 by licensee maintenance personnel constituted a performance deficiency that was reasonably within the licensee's ability to foresee, and which should have been prevented. However, in reviewing the significance of the event, the inspectors also determined that the performance deficiency was of minor safety significance and, as such, did not constitute a documentable finding. Specifically, while the performance deficiency did result in the need for the initiation of a manual reactor trip, the trip did not result in any upset to plant stability because of the Mode 3 operating conditions at the time. The licensee had entered this issue into their CAP under CR 2014–08344.

For additional discussion involving the non-emergency reporting of this event in accordance with the applicable requirements of 10 CFR 50.72, see section 4OA2.3 of this report. Documents reviewed are listed in the Attachment to this report.

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

.2 Event Notification 50097 : Manual Initiation of the Reactor Protection System While Shutdown

On May 4, 2014, the plant was in Mode 3 with various CRD pre-startup tests being performed. Group 8 APSRs, which are not part of the RPS and do not insert following a reactor trip signal, were being manipulated from the control room for CRD program verification testing. With CRD 8–8 selected for manipulation at the reactor controls, plant operators observed outward movement on the position indication for CRD 4–9 instead of CRD 8–8 when a "rods out" command was initiated. Control room operators immediately halted the test evolution and gave a "rods in" command at the reactor controls to return the indication for CRD 4–9 to the fully inserted position. The decision was then made by the control room crew to conservatively de-energize the CRD system by manually tripping the reactor from the control room. There was no control rod response; and none was expected following the initiation of the reactor trip, as all group 1 through 7 CRD mechanisms were already fully inserted.

After the event, troubleshooting revealed that five control rods had improper indication, such that the position indication for CRD 'x' would show movement during the manipulation of CRD 'y' instead. Further investigation by the licensee revealed that this issue could be traced back to maintenance that had been performed during the course of the current refuel outage on electrical instrumentation containment penetration PCC5V. Licensee technicians rewiring the penetration had inadvertently mixed the signals passing through the penetration for five CRD position indication channels. Corrective actions were developed by the licensee and the wiring in question was reworked. The following day, on May 5, 2014, operations personnel satisfactorily completed the CRD program verification testing that had been interrupted.

Initially, licensee personnel had determined that the event did not require any non-emergency notifications in accordance with 10 CFR 50.72 requirements. However, following their decision to report the event that occurred on May 5, 2014, (see section 4OA3.1 above) under the requirements of 10 CFR 50.72(b)(3)(iv)(A) as a valid actuation of the plant's RPS, licensee personnel reevaluated their decision in this matter. On May 8, 2014, the licensee concluded that the control room crew's initiation of a manual reactor trip on May 4, 2014, also constituted a valid actuation of the plant's RPS and an eight-hour non-emergency report to the NRC per 10 CFR 50.72(b)(3)(iv)(A) was required. The licensee completed this report, albeit several days after the 8 hour time requirement had passed, on May 8, 2014, at 5:46 p.m.

The inspectors reviewed the response to this event, including but not limited to:

- Status and performance of plant equipment;
- Non-emergency notifications made to state and local government agencies as required by 10 CFR 50.72; and
- Development and implementation of licensee repair actions.

In reviewing the event, the inspectors determined that the wiring error within containment penetration PCC5V that occurred during the site's refuel outage by licensee maintenance personnel constituted a performance deficiency that was reasonably within

the licensee's ability to foresee, and which should have been prevented. However, in reviewing the significance of the event, the inspectors also determined that the performance deficiency was of minor safety significance and, as such, did not constitute a documentable finding. Specifically, while the performance deficiency did result in the need for the initiation of a manual reactor trip, the trip did not result in any upset to plant stability because of the Mode 3 operating conditions at the time.

As discussed in the NRC Enforcement Policy dated July, 9, 2013, section 2.2.1, "Factors Affecting Assessment of Violations," subsection (c), the severity level of a violation involving the failure to make a required report to the NRC depends largely on the significance and circumstances surrounding the matter that should have been reported. Additionally, the severity level of an untimely report, in contrast to no report, may be reduced. With respect to this 8 hour non-emergency report per the requirements of 10 CFR 50.72(b)(3)(iv)(A) that was made several days after the event, the inspectors determined that the untimely nature of the report constituted a minor violation of NRC requirements due to the minor safety significance of the underlying issue. Violations of minor safety significance, such as this, are not subject to formal enforcement action in accordance with section 2.3 of the NRC Enforcement Policy.

For additional discussion involving the non-emergency reporting of this event in accordance with the applicable requirements of 10 CFR 50.72, see section 4OA2.3 of this report. Documents reviewed are listed in the Attachment to this report.

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

.3 Event Notification 50143: Control Room Overhead Annunciator Malfunction

a. Inspection Scope

The inspectors reviewed the plant's response to a station annunciator system malfunction that caused all control room annunciator indications to be in alarm status on May 26, 2014. This condition resulted in a loss of normal audible and visual plant condition assessment capabilities and was assessed as being a significant loss of assessment capabilities by the licensee. Backup assessment capability was maintained by functionality of the control room alarm printer.

The inspectors reviewed the licensee's response to the event, including but not limited to:

- Status of plant equipment and plant condition backup assessment capability;
- Non-emergency notifications made to state and local government agencies as required by 10 CFR 50.72; and
- Development and implementation of licensee repair plans.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

Repair Work Priority Did Not Support Timely Corrective Action

Introduction

An NRC-identified finding of very low safety significance (Green) was identified following the inspectors' review of licensee corrective actions for a previous occurrence of the reportable condition that took place on May 26, 2014. Specifically, on November 17, 2013, the licensee's control room overhead annunciator system suffered a similar malfunction. That event was reported to the NRC as required (Event Notification 49546) and the licensee developed applicable corrective actions within their CAP. Several of corrective actions, however, were assigned the lowest possible priority within the licensee's work prioritization system, contrary to the licensee's established procedure guidance. No violation of NRC requirements was identified.

Description

On May 26, 2014, at 2:52 a.m., the control room overhead annunciators malfunctioned during the performance of an alarm check. The control room overhead annunciators were unable to be acknowledged and new alarms were unable to the received. After several attempts to clear the malfunction using an infrequently performed procedure section for locally resetting the control room overhead alarms using a jumper within the applicable instrumentation cabinet, control room personnel were successful at clearing the condition. A successful functional check of the overhead alarm system allowed the event to be terminated at 5:16 a.m.

Licensee personnel determined the event to be reportable in accordance with 10 CFR 50.72(b)(3)(xiii), as an event that had resulted in a major loss of emergency assessment capability. The licensee completed the required event notification to the NRC at 10:39 a.m., within the 8 hour time required by the regulations. During the period that the control room overhead annunciator system was disabled, backup assessment capability was determined to have been functional and provided by the control room alarm printer, as described in the licensee's procedures.

The licensee entered the event that occurred on May 26, 2014, into their CAP as CR 2014–09494. As part of their CAP requirements, the licensee performed a maintenance rule failure review of the issue. This review determined that the issue was caused by an intermittent connection in an electrical disconnect/fuse block associated with the overhead alarm circuitry located in cabinet C5457F. The maintenance rule failure review further discussed that the issue did constitute a functional failure of the control room overhead annunciator system; but that it was sufficiently similar to an earlier overhead annunciator alarm failure that took place on November 17, 2013, and for which the corrective action WO 200583393 had yet to have been performed, that it did not have to be considered as an independent/additional functional failure.

As part of their follow-up to this event, the inspectors reviewed CR 2014–09494, as well as CR 2013–18434, which the licensee had entered into their CAP for the similar event that had occurred on November 17, 2013. The inspectors noted that several WOs created by the licensee as elements of their corrective action plan in CR 2013–18434 for the event on November 17, 2013, had been assigned the lowest possible priorities within

the licensee's work control system and were listed as unscheduled work. This included WO 200583393, which the licensee credited in their maintenance rule failure review for CR 2014–09494 as the corrective action for the intermittent connection in the electrical disconnect/fuse block associated with the overhead alarm circuitry located in cabinet C5457F.

The inspectors reviewed the licensee's work categorization and prioritization guidance contained in NOP–WM–1003, “Nuclear Maintenance Notification Initiation, Screening, and Minor Deficiency Monitoring Processes.” Section 3.14 of this document states that priority 300, or "expedited" priority, work includes: "Emergent activities that are required to be completed to maintain plant reliability and reportability. This includes work that, if not completed, may result in additional reporting requirements to regulatory agencies." Section 3.14 further states that: "Work is expected to be completed in less than 21 calendar days."

Analysis

The inspectors reviewed this finding using the guidance contained in Appendix B, “Issue Screening,” of IMC 0612, “Power Reactor Inspection Reports.” The low priority assigned to the work that could have corrected the underlying issues involved with this event, contrary to the licensee's own work control guidance, constituted a performance deficiency that was reasonably within the licensee’s ability to foresee and correct and that should have been prevented. This finding was associated with the Mitigating Systems Cornerstone of reactor safety and was of more than minor significance because it directly impacted the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, as a result of the low priority assigned to WO 200583393, the work wasn't scheduled or performed, and additional significant malfunctions of the control room overhead annunciator system were incurred.

The inspectors evaluated the finding using IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power.” Using Exhibit 2, which contains the screening questions for the Mitigating Systems Cornerstone of Reactor Safety, the inspectors determined that the finding screened as very low safety significance (Green) because:

- It was not a deficiency affecting the design or qualification of the control room overhead annunciator alarm system;
- Since the backup alarm functions provided by the control room alarm printer and plant computer system were unaffected and remained intact, the deficiency did not represent a loss of system or function;
- It did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time; and
- It did not represent an actual loss of function of any non-TS trains of equipment designated as high safety significant in accordance with the licensee’s maintenance rule program.

This finding has a cross-cutting aspect in the area of problem identification and resolution, resolution aspect, because the licensee failed to take effective corrective actions to address issues in a timely manner commensurate with their safety significance. (P.3)

Enforcement

The inspectors concluded that the licensee did not adhere to the work prioritization guidance in procedure NOP–WM–1003, "Nuclear Maintenance Notification Initiation, Screening, and Minor Deficiency Monitoring Processes." This finding, however, did not involve a corresponding violation of NRC requirements. Specifically, the inspectors determined that control room overhead alarm and annunciator system, as well as the plant procedures governing and controlling the maintenance work activity performed on the system, are not covered under the quality assurance requirements set forth in 10 CFR Part 50, Appendix B. Additionally, the inspectors also determined that the plant procedures governing and controlling the maintenance work activity performed on the system are not covered under TS 5.4.1(a), which requires the licensee to establish, implement, and maintain applicable written procedures for the safety-related systems and activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A. **(FIN 05000346/2014003–05, "Repair Work Priority Did Not Support Timely Corrective Action")**

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 2, 2014, the inspectors presented the inspection results to Mr. T. Summers, the Director of Site Operations, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection period was returned to the licensee.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of the periodic refueling interval inservice inspection with the Site Regulatory Compliance Manager, Mr. P. McCloskey, and other members of the licensee's staff on June 6, 2014; and
- The inspection results for the triennial heat sink inspection with the Site Vice President, Mr. R. Lieb, and other members of the licensee's staff on June 27, 2014.

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

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Lieb, Site Vice President
B. Boles, Director, Site Operations (outgoing)
K. Byrd, Director, Site Engineering
G. Cramer, Manager, Site Protection
J. Cuff, Manager, Training
J. Cunnings, Manager, Site Maintenance
A. Dawson, Manager, Chemistry
D. Hartnett, Superintendent, Operations Training
J. Hook, Manager, Design Engineering
D. Imlay, Director, Site Performance Improvement
G. Kendrick, Manager, Site Outage Management
B. Kremer, Manager, Site Operations
G. Laird, Manager, Technical Services Engineering
B. Matty, Manager, Plant Engineering
P. McCloskey, Manager, Site Regulatory Compliance
D. Munson, Site NDE Level III
D. Noble, Manager, Radiation Protection
W. O'Malley, Manager, Nuclear Oversight
R. Oesterle, Superintendent, Nuclear Operations
R. Patrick, Manager, Site Work Management
D. Petro, Manager, Steam Generator Replacement Project
T. Summers, Director, Site Operations (incoming)
M. Roelant, Manager, Site Projects
L. Rushing, Director, Special Projects
D. Saltz, Director, Site Maintenance
J. Sturdavant, Regulatory Compliance
L. Thomas, Manager, Nuclear Supply Chain
M. Travis, Superintendent, Radiation Protection
J. Vetter, Manager, Emergency Response
V. Wadsworth, Regulatory Assurance
G. Wolf, Supervisor, Regulatory Compliance
K. Zellers, Supervisor, Reactor Engineering

Nuclear Regulatory Commission

J. Cameron, Chief, Branch 4, Division of Reactor Projects
A. Stone, Chief, Engineering Branch 2, Division of Reactor Safety

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000346/2014003–01	NCV	Failure to Properly Perform Required Fire Watch (Section 1R05.1)
05000346/2014003–02	NCV	Failure to Maintain an Approved Hot Work Permit for Containment (Section 1R05.1)
05000346/2014003–03	NCV	Failure to Ensure Auxiliary Feedwater Design Bases Were Correctly Translated into Design Documents and Procedures (Section 1R07.1)
05000346/2014003–04	NCV	Acceptance Criteria for Emergency Core Cooling System Room Cooler Inspection Was Not Specified in Inspection Procedure (Section 1R07.1)
05000346/2014003–05	FIN	Repair Work Priority Did Not Support Timely Corrective Action (Section 4OA3.3)

Closed

05000346/2014003–01	NCV	Failure to Properly Perform Required Fire Watch (Section 1R05.1)
05000346/2014003–02	NCV	Failure to Maintain an Approved Hot Work Permit for Containment (Section 1R05.1)
05000346/2014003–03	NCV	Failure to Ensure Auxiliary Feedwater Design Bases Were Correctly Translated into Design Documents and Procedures (Section 1R07.1)
05000346/2014003–04	NCV	Acceptance Criteria for Emergency Core Cooling System Room Cooler Inspection Was Not Specified in Inspection Procedure (Section 1R07.1)
05000346/2014003–05	FIN	Repair Work Priority Did Not Support Timely Corrective Action (Section 4OA3.3)

Discussed

None

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 inspectors 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

Condition Reports:
- 2014-05322; Hayes Line & 81-B-65 Project - ACB34562 Failure to Close
- 2014-09059; ABS34625 Closed indicating light failed

Drawings:
- OS-056; 345 KV System; Revision 16

Procedures:
- DB-ME-09150; 345 KV Switchyard Maintenance; Revision 3
- DB-OP-01300; Switchyard Management; Revision 10
- DB-OP-02025; Davis-Besse 345 KV Switchyard Alarm Panel 25 Annunciators; Revision 12
- DB-OP-02521; Loss of AC Bus Power Sources; Revision 23
- DB-OP-02546; Degraded Grid; Revision 3
- DB-OP-06311; 345 KV Switchyard No. 1 (Main) Transformer, No. 11 (Auxiliary) Transformer, and Startup Transformers (01 and 02); Revision 27
- DB-SC-03023; Off-Site AC Sources Lined up and Available; Revision 31
- NOP-OP-1003; Grid Reliability Protocol; Revision 6
- NOP-OP-1007; Risk Management; Revision 18

1R04 Equipment Alignment

Condition Reports:
- 2012-10080; Corrective Actions required due date extension to correct parts not ordered in time to support Work Orders
- 2012-10252; BACC Packing leak was found on HP2B
- 2012-11867; Boric Acid Corrosion Control (BACC) – An Inboard Seal Leak was found on P58-1, HPI Pump 1-1
- 2014-00347; BACC boric acid packing leak identified on HP21 (HPI Pump #2 discharge flush connection)
- 2014-04090; HP2B closed torque switch bypass may be set wrong
- 2014-03188; Loose terminal block in HP2B
- 2014-08079; Leakage indicated on HP57/HP58 back to back check valve test, DB-PF-03969
- 2014-09420; NRC Identified housekeeping issues in ECCS Room 1 and MPR 1
- 2014-09421; 19C BACC: A Packing Leak was found on HP2B
- 2014-10897; Question Regarding Chain Lock Position of FW6325

Procedures:
- DB-MM-09173; High Pressure Injection Pump Maintenance; Revision 14
- DB-OP-06011; High Pressure Injection System; Revision 29
- DB-OP-06012; Decay Heat and Low Pressure Injection System Operating Procedure; Revision 61

- DB-OP-06223; Main Feedwater System; Revision 16
- DB-OP-06225; MDFP Operating Procedure; Revision 21
- DB-OP-06233; Auxiliary Feedwater System; Revision 37
- DB-OP-06316; Diesel Generator Operating Procedure; Revision 56
- DB-OP-06334; Station Blackout Diesel Generator Operating Procedure; Revision 22
- DB-OP-06610; Station Fire Suppression Water System; Revision 32

Drawings and Prints:
- ISID2-033A; Inservice Inspection Diagram High Pressure Injection; Revision 12
- OS-0003; High Pressure Injection System; Revision 36
- OS-0004; Decay Heat Removal / Low Pressure Injection System; Revision 52
- OS-0012A, Sheet 1; Main Feedwater System; Revision 26
- OS-0012A, Sheet 2; Main Feedwater System; Revision 32
- OS-0017A, Sheet 1; Auxiliary Feedwater System; Revision 31
- OS-0017A, Sheet 2; Auxiliary Feedwater System; Revision 5
- OS-0041A; Emergency Diesel Generator Systems; Revision 32
- OS-0041B; Emergency Diesel Generator Air Start / Engine Air System; Revision 52
- OS-0041C; Emergency Diesel Generator Diesel Oil System; Revision 16
- OS-0041D; Station Blackout Diesel Lube Oil and Jacket Water; Revision 14
- OS-0041E; Station Blackout Diesel Air Start / Engine Air System; Revision 15
- OS-0041F; Station Blackout Diesel Electrical Control and Fuel Oil Systems; Revision 5
- M-016A; Station Fire Protection System; Revision 54
- M-016B; Station Fire Protection System; Revision 52
- M-017A; Diesel Generators; Revision 19
- M-017B; Diesel Generators Air Start; Revision 47
- M-033A; High Pressure Injection; Revision 44
- M-033B; Decay Heat Train 1; Revision 56
- M-036B; Component Cooling Water System; Revision 39

Work Orders / Notifications:
- 600635699; HP2B Post 16RFO Bonnet Issues; August 30, 2010
- 200429182; HP2B Replace Valve Bonnet

<u>1R05 Fire Protection</u>

Condition Reports:
- 2014-06825; Control of Ignition Sources during Post Weld Heat Treatment
- 2014-06832; SG 1-1 North Cold Leg Post Weld Heat Treat Performed Without Fire Watch
- 2014-06830; Bechtel Hot Work Performed Without an Approved Hot Work Permit

Procedures:
- DB-FP-00007; Control of Transient Combustibles; Revision 13
- DB-FP-00009; Fire Protection Impairment and Fire Watch; Revision 20
- DB-FP-00018; Control of Ignition Sources; Revision 12

Pre-Fire Plans:
- PFP-CB-216; Steam Generator West D Ring Area, Room 216, Fire Area D; Revision 5
- PFP-CB-218; Steam Generator East D Ring Area, Room 218, Fire Area D; Revision 5

Drawings:
- A-222F; Fire Protection General Floor Plan Elevation 565’-0”; Revision 17

- A-225F; Fire Protection General Floor Plan Elevation 623'-0"; Revision 12

Other:
- Fire Hazard Analysis Report

1R07 Heat Sink Performance

Condition Reports:
- 2002-06767; LIR-AFW-JCO Inputs Not Bounding
- 2002-06777; LIR-AFW-CR 1999-1497 Deficiency
- 2009-67479; CDBI 2009: Question #185: ECCS Room Temperature Calculation Questions
- 2009-68031; CDBI 2009: Incorrect Thermal Performance Model
- 2011-00422; Intake Canal Dike Does Not Meet Design Configuration Requirements
- 2014-06833; Aux Feed Pump 1 Governor Cooler Leak
- 2014-10993; 2014 UHS Inspection: Cracked/Missing Grout Identified on SW Strainer 3 pad
- 2014-10995; 2014 UHS Inspection: Surface Rust identified on SW Strainer 3 gearbox collar and packing pusher
- 2014-10995; 2014 UHS Inspection: Non-Conformance With NOP-ER-2006
- 2014-10917; 2014 NRC UHS Triennial Inspection: AFW System Description SD-015 Figure 1.1-1 Does Not Reflect Strainer S-503 or S-504
- 2014-11017; NRC 2014 UHS Triennial Inspection – Minimum AFW Bearing and Governor Cooling Water Flow Requirements
- 2014-11018; 2014 NRC Triennial UHS Inspection: AFW Pump 1 Oil Cooler Cooling Water Flow Balancing; June 26, 2014
- 2014-11131; 2014 NRC Triennial Heat Sink Inspection: Vulnerability for Initial CST Temperature

Procedures:
- DB-CH-06013; Station Chlorination System; Revision 40
- DB-MM-09150; AFPT Maintenance; Revision 13
- DB-OP-02000; RPS, SFAS, SFRCS Trip, or SG Tube Rupture; Revision 27
- DB-OP-06233; Auxiliary Feedwater System; Revision 37
- DB-SP-03151; AFP 1 Quarterly Test; Revision 24
- DB-OP-06233; Auxiliary Feedwater System; Revision 37
- DB-OP-02011; Heat Sink Alarm Panel 11 Annunciators; Revision 13
- NOP-ER-2006; Service Water Reliability Management Program; Revisions 1 and 2

Manuals, Drawings, and Prints:
- M-036-00020-08; Auxiliary Feed Pump Installation and Operation Instructions; Revision 8
- M-036-00021; Terry Turbine Instruction Manual; Revision 18
- M-036AQ-00004; Governor Oil Cooler Drawing; Revision B
- OS-17A, Sheets 1 and 2; Operational Schematic Auxiliary Feedwater System; Revision 31
- OS-17B, Sheets 1 and 2; Operational Schematic Auxiliary Feedwater Pumps and Turbines; Revision 25

Calculations:
- Calculation No. 069.002; Auxiliary Feedwater System; Revision 2
- C-NSA-50.03-026; Condensate Heating With Auxiliary Feed; Revision 0
- C-NSA-032.02-006; ECCS Pump Room Heatup During Post LOCA; Revision 3

Work Orders / Notifications:
- 200514141; SW Strainer 1-1 Leak Repair; August 24, 2012
- 200519124; SW Strainer 1-1 Leak Repair; October 23, 2012
- 200498516; Traveling Water Screen 1-1 Lube/Inspect; May 16, 2014
- 200480142; Traveling Water Screen 1-1 Lube/Inspect; October 25, 2013
- 200357139; SW Strainer 1-3 Disassembly/Inspection; August 9, 2011
- 200224408; SW Strainer 1-3 Disassembly/Inspection; March 4, 2008
- 200376396; LT 902 Forebay Level 18-Month Calibration; February 22, 2012
- 200449237; LT 902 Forebay Level PM 3047 18-Month Calibration; October 31, 2013
- 200449215; PM 5492 Trash Racks Annual Inspection; October 11, 2013
- 200429366; PM 4597 Inspect Intake Bay 3; November 25,2013
- 200142404; AFW Piping Inspection PM; January 26, 2006
- 200542642; ECCS Room Cooler 1 Inspection; January 18, 2013
- 200142404; AFW Piping Inspection PM; March 11, 2007
- 200542642; ECCS Room Cooler 1 Inspection; January 20, 2013

Other Items:
- NRC Generic Letter 89-13 Service Water Reliability Program Manual; Revision 0
- RFA 00-0464; Maximum Allowable Bearing Cooling Water Temperature; December 29, 2000
- SD-015; System Description for Auxiliary Feedwater System; Revision 4

1R08 Inservice Inspection Activities

Condition Reports:
- 2013-02675; Discrepancy Identified Between Cold Leg Drain 1-2 Weld Overlay Preservice and Inservice Coverage Calculations
- 2014-01681; Main Feedwater Weld SW-57B Rejected by Radiographic Examination
- 2014-01783; EPRI NDE Alert # NDE 2013-09 - Appendix VIII Bolting Noncompliance
- 2014-01964; Staining/Corrosion Noted on Reactor Vessel Closure Head Flange

NDE Reports:

- NDE Report No. BOP-VT-14-068; System Leakage Test (VT-2) of Containment Vessel Opening Restoration Weld; April 27, 2014
- NDE Report No. 18-MT-088; Magnetic Particle Examination of SG-2 36 inch Hot Leg Pipe to SG Inlet Nozzle Weld; April 18, 2014
- NDE Report No. 18-UT-131; Ultrasonic Examination of SG-2 36 inch Hot Leg Pipe to SG Inlet Nozzle Weld; April 18, 2014
- NDE Report No. 18-MT-086; Magnetic Particle Examination of SG-2 36 inch Hot Leg Pipe to Pipe Weld; April 9, 2014
- NDE Report No. 18-UT-115; Ultrasonic Examination of SG-2 36 inch Hot Leg Pipe to Pipe Weld; April 10, 2014
- NDE Report No. 18-MT-089; Magnetic Particle Examination of SG-1 36 inch Hot Leg Pipe to SG Inlet Nozzle Weld; April 17, 2014
- NDE Report No. 18-UT-130; Ultrasonic Examination of SG-1 36 inch Hot Leg Pipe to SG Inlet Nozzle Weld; April 17, 2014
- NDE Report No. 18-MT-079; Magnetic Particle Examination of SG-1 36 inch Hot Leg Pipe to Pipe Weld; April 18, 2014
- NDE Report No. 18-UT-114; Ultrasonic Examination of SG-1 36 inch Hot Leg Pipe to Pipe Weld; April 18, 2014

- NDE Report No. 18-MT-083; Magnetic Particle Examination of SG-2 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 9, 2104
- NDE Report No. 18-UT-117; Ultrasonic Examination of SG-2 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 10, 2104
- NDE Report No. 18-MT-084; Magnetic Particle Examination of SG-2 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 9, 2104
- NDE Report No. 18-UT-118; Ultrasonic Examination of SG-2 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 10, 2104
- NDE Report No. 18-VENDOR-273; Magnetic Particle Examination of SG-1 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 14, 2104
- NDE Report No. 18-UT-119; Ultrasonic Examination of SG-1 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 10, 2104
- NDE Report No. 18-MT-087; Magnetic Particle Examination of SG-1 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 10, 2104
- NDE Report No. 18-UT-116; Ultrasonic Examination of SG-1 28 inch Cold Leg Outlet Safe End to Elbow Weld; April 10, 2104
- NDE Report No. RT-REPORT-307; Radiographic Examination of SG-1 36 inch Hot Leg Pipe to Pipe Weld; April 4, 2014
- NDE Report No. RT-REPORT-329; Radiographic Examination of SG-1 36 inch Hot Leg Pipe to SG Inlet Nozzle Weld; April 4, 2014
- NDE Report No. RT-REPORT-317; Radiographic Examination of Containment Vessel Opening Weld; April 10, 2014

Other:
- Document No. B&W-TR-2013-0010; Pre-service Eddy Current Tubing Inspection Report for Davis-Besse Replacement Once Through Steam Generators; September 9, 2013
- Document No. 25539-000-GMX-GCE-00001; Bechtel Special Processes Manual for Davis Besse Steam Generator Replacement Project; Revision 3
- AREVA Document No. 51- 9218773 - 000; Reactor Vessel Upper and Lower Head Bare Metal Visual Examination Final Report for First Energy's Davis Besse Unit; May 12, 2014

1R11 Licensed Operator Requalification Program and Licensed Operator Performance

Condition Reports:
- 2014-07009; Out of Date Posted Operator Aids Discovered in the Field
- 2014-09230; Crew Performance Critique for CR 2014-08555: Late Reporting of Manual Reactor Trip Per 10 CFR 50.72

Procedures:
- DB-OP-06005; RC Pump Operation; Revision 30
- DB-OP-06402; CRD Operating Procedure; Revision 23
- DB-OP-06902; Power Operations; Revision 45
- DB-OP-06904; Shutdown Operations; Revision 45
- DB-NE-03212; Zero Power Physics Testing; Revision 10
- DB-NE-06202; Reactivity Balance Calculations; Revision 8
- DB-SC-03270; Control Rod Assembly Insertion Time Test; Revision 12
- NOP-OP-1002; Conduct of Operations; Revision 9
- NOP-OP-1015; Event Notifications; Revision 0
- NT-OT-7001; Training and Qualification of Operations Personnel; Revision 13
- NOP-TR-1001; Conduct of Training; Revision 16
- NOP-TR-1008; FENOC Simulator Configuration Management; Revision 0

- NOP-TR-1010; Licensed Operator Requalification Exam Development; Revision 2
- NOP-OP-1013; Control of Time Critical Operator Actions; Revision 1

FENOC Business Practices:
- DBBP-TRAN-0014; License Requirements for Licensed Operators; Revision 9
- DBBP-TRAN-0021; Simulator Configuration Control; Revision 3
- DBBP-TRAN-0502; Development of Continuing Training Simulator Evaluation; Revision 11
- NOBP-TR-1112; FENOC Conduct of Simulator Training and Evaluation; Revision 2
- DBBP-OPS-1013; Control of Time Critical Actions; Revision 2
- NOBP-OP-0007; Conduct of Infrequently Performed Tests or Evolutions; Revision 5

Simulator Guides:
- OTLC-JIT-DB-1402; 18 RFO Startup JITT; Revision 0
- OTL-IPO-S104; Preparation for Plant Heatup; Revision 0
- OTL-IPO-S105; Plant Heatup Mode 5 to Mode 3; Revision 0
- OTL-IPO-S106; Reactor Startup to 18% Power; Revision 0
- OTL-IPO-S107; Power Operations; Revision 0

1R12 Maintenance Effectiveness

Condition Reports:
- 2011-92303; Annunciator 7-5-A Repeatedly Alarmed and Cleared With and Without Computer Point
- 2012-05516; Issues Found with ECP 11-0512 Alternate Power Supply to Transfer Switch YSW1
- 2013-14023; Control Room Annunciator Malfunction During Modification Process
- 2013-15832; Annunciator System Trouble, 7-5-A Annun Sys Trbl, Unexpected Annunciator
- 2013-18434; Control Room Annunciator Alarms Unable To Be Reset
- 2013-18797; Annunciator System Components Appear Incorrectly classified per AP-913
- 2014-04360; Control Room Annunciators Continuously Flashing
- 2014-05381; PA-DB-12-01: the 50.59 RAD and Screen for ECP 12-0758, Installation of Flexible Hoses on RCP Seal Lines, does not address the appropriate ECP supplemental packages
- 2014-03233; Wiring discrepancies found in the CTRM annunciator horn circuit in C5754F
- 2014-06522; Indications on flanges for RCP 1-1-1 and 1-1-2 flex hose connections
- 2014-06677; FENOC Replicate CR for Bechtel NCR 00089 - MT Indication Found Cold Leg Piping Adjacent to FW (1-2)
- 2014-09134; 7-5-A (Annun Sys Trbl) Spuriously Alarming
- 2014-09280; Backup Annunciator Power Supply Did Not Work
- 2014-09494; Control Room Annunciators Fast Flash and Can't Be Acknowledged when Alarm Received
- 2014-09498; Slow Duty Team Response to a Potential Reportable Event

Drawings:
- 152055 E; Reactor Coolant Pipe Assembly Plan View; Revision 12
- 302-286-719800-2E, Sheet 1; Assembly & Wiring Model 719 Annunciator; September 15, 2005
- 302-286-719800-2E, Sheet 3; Annunciator for K1R001 & K1K002, Assembly & Wiring Model 719 Annunciator; September 15, 2005
- 302-286-719800-2E, Sheets 4 and 4A; Annunciator for K21N04 & K20003, Assembly & Wiring Model 719 Annunciator; August 15, 1973

- 302-286-719800-2E, Sheet 12; Assembly & Wiring Model 719 Annunciator; August 15, 1973
- E-7; 250/125V DC and Instrumentation AC One Line Diagram; Revision 48
- FSK-M-CCB-7-1; Reactor Coolant Pumps Seal Injection Piping From Reactor Coolant Pumps to HV-MU 59-C; Revision 11
- FSK-M-CCB-8-1-H; Seal Injection Piping from Stop Check Valves to RC Pumps; Revision 6
- ISID2-030A; Reactor Coolant System; Revision 11
- ISID2-040D; Reactor Coolant Pump and Motor; Revision 5
- M-030A; Reactor Coolant System; Revision 68
- M-040C; Reactor Coolant Pump and Motor; Revision 17
- M-050D; Reactor Coolant Pump and Motor; Revision 18
- M06773-1; ¾" Flexible Hose Assembly For RCP Seal Vent Piping; Revision 3
- OS-001A; Reactor Coolant System; Revision 44
- OS-001B; Reactor Coolant Pumps and Motors; Revision 25

Engineering Change Packages:
- 12-0270; Rework Annunciator Horn Circuits, Revision 1
- 12-0785; Install Flexible Hoses in RCP Seal Vent Lines; Revision 0
- 14-0261; RCP 1-1-1 Seal Vent Like Blank Assembly Temporary Modification; Revision 0
- 14-0395; TM ECP for C5754F Disconnect Switch; Revision 0

Procedures:
- DB-OP-01006; Guidelines for Loss of Plant Annunciator(s); Revision 0
- DB-OP-06411; Station Annunciator Operating Procedure; Revision 20
- DB-OP-02007; Radwaste Alarm Panel 7 Annunciators; Revision 12
- NOP-LP-2001; Corrective Action Program; Revision 32

Other:
- E-023-00037-05; Panalarm Instruction Manual for Station Annunciators; Revision 5
- Davis-Besse System Health Report 2013 Second Half
- MRPM; Maintenance Rule Program Manual; Revision 33

<u>1R13 Maintenance Risk Assessments and Emergent Work Control</u>

Condition Reports:
- 2014-06371; FENOC Replicate CR for Bechtel CR 864 - SG 1-1 Hot Leg FOSAR
- 2014-06455; FENOC Replicate for Bechtel CR 871 SG 1-2 Hot Leg FOSAR
- 2014-06522; Indications on flanges for RCP 1-1-1 and 1-1-2 flex hose connections
- 2014-06677; FENOC Replicate CR for Bechtel NCR 00089 - MT Indication Found Cold Leg Piping Adjacent to FW (1-2)
- 2014-06884; Spill over from Reactor Vessel flange during Reactor Vessel Closure Head lift
- 2014-06956; Apparent corrosion products flushed into the reactor vessel during HPI system testing
- 2014-07019; High intercooler pressure observed on Station Air Compressor 1 when in standby
- 2014-07218; Station Air Compressor 1 AUTO started for no reason
- 2014-07887; Revision to ODMI for CR 2013-08434 (Station Air Compressor 2 discharge pressure degradation due to ambient conditions)
- 2014-07995; Failed Trip Confirm Check from CRD to DEHC During OP-06402; Attachment 9
- 2014-07996; Failure in CRD Electronic Trip D Circuit
- 2014-08010; SAC2 surging and auto start of SAC1

- 2014-08216; Issues Encountered when Attempting to Transfer Control Rods to the Auxiliary Power Supply
- 2014-08263; Unexpected Control Rod 4-9 Movement
- 2014-08265; RTB D Failed to Close During Restoration of the CRD System
- 2014-08278; Temporary Diesel Air Compressor Trip
- 2014-08292; Rod 7-4 0 Percent Zone Reference Light Not Lit with the Rod Fully Inserted Per API

Procedures:
- DB-OP-02528; Instrument Air System Malfunctions; Revision 20-21
- DB-OP-06000; Filling and Venting the Reactor Coolant System; Revision 28
- DB-OP-06281; Station and Instrument Air System Operating Procedure; Revision 38
- DB-OP-06402; CRD Operating Procedure; Revision 23
- DB-OP-06904; Shutdown Operations; Revision 45
- DB-MM-09156; Joy Reciprocating Air Compressor Maintenance; Revision 7
- DB-MM-09193; Assembly and Disassembly of the Reactor Vessel Head and Internals Handling Fixture (Pin Connected); Revision 0
- DB-MN-00006; Control of Lifting and Handling of Heavy Loads; Revision 17

FENOC Business Practices:
- NOBP-OP-0007; Conduct of Infrequently Performed Tests or Evolutions; Revision 5

Engineering Change Packages:
- 12-0785; Install Flexible Hoses in RCP Seal Vent Lines; Revision 0
- 14-0261; RCP 1-1-1 Seal Vent Like Blank Assembly Temporary Modification; Revision 0

Work Orders:
- 200598268; C101-1 Replace High Pressure Discharge Valve, lower right; April 20, 2014
- 200587282; SA120 Replace Check Valve; April 20, 2014
- 200601792; PI Tube Replacement N-12 (7-4); May 5, 2014

Other:
- Davis-Besse System Health Report 2013 Second Half

<u>1R15 Operability Determinations and Functionality Assessments</u>

Condition Reports:
- 2014-02189; 18RFO ISI Containment Vessel Interior Visual Examination Summary
- 2014-04450; Paint Peeling off East D-Ring Wall Plates
- 2014-05806; Revised Painting Procedure and Specification Still Have Unresolved Issues
- 2014-05950; Paint Peeling Off Outer West D-Ring Wall
- 2014-06239; Flow discrepancy noted on RE 4598AA and RE 4598BA
- 2014-07828; Areas of Paint Delaminating in Containment Normal Sump
- 2014-07843; Items That Could Not Be Removed During Containment Closeout
- 2014-07864; Additional Items That Could Not Be Removed During Containment Closeout Walkdowns
- 2014-07895; 18RFO: Flaking Coatings Noted In Containment
- 2014-08445; Pressurizer Spray Valve, RC2, Leaking After an Automatic Cycle
- 2014-08558; RC2, Pressurizer Spray Valve Failed Open
- 2014-08650; ODMI For Operational Guidance For Operation With RC2, Pressurizer Spray Valve, Not Fully Closing

- 2014-08664; Axial Power Shaping Rod (APSR) in Core Location D-10 Decoupled
- 2014-08679; CRD Breaker B Tripped Open Unexpectedly
- 2014-09018; Question Concerning APSR 8-2 Condition and Actions for Misaligned Control Rod
- 2014-09040; Crew Performance Critique for RC2 (Pressurizer Spray Valve) Failing to Close Completely After Cycling
- 2014-09287; ODMI: Operational Guidance with Axial Power Shaping Rod (APSR) 8-2 (Core Location D-10) Uncoupled

Procedures:
- DB-CH-06012; Accident Range Station Vent Monitor Operation; Revision 1
- DB-CN-03009; Station Vent Releases, Weekly Radiological Monitoring; Sampling and Analysis of RE4598BA; Revision 7
- DB-OP-02513; Pressurizer System Abnormal Operation; Revision 11
- DB-OP-03013; Containment Daily Inspection & Containment Closeout Inspection, Revision 10
- DB-OP-06402; CRD Operating Procedure; Revision 23
- DB-ME-03020; Reactor Trip Breaker Response Time Test; Revision 4
- DB-ME-09101; Reactor Trip Breaker Maintenance and Testing; Revision 3
- DB-ME-09109; G.E. AK-25 Reactor Trip Breaker Teardown and Reassembly; Revision 2
- DB-MI-03011; Channel Functional Test of Reactor Trip Breaker B, RPS Channel 1 Reactor Trip Module Logic, and ARTS Channel 1 Output Logic; Revision 30
- DB-MI-03413; Channel Calibration of RE4598AA and RE4598BA Station Vent Normal Range Radiation Monitors; Revision 26
- NOP-CC-1001; Configuration Management Program; Revision 1
- NOP-CC-2003; Engineering Changes; Revision 19
- NOP-ER-3001; Problem Solving and Decision Making Process; Revision 5
- NOP-OP-1010; Operational Decision-Making; Revision 4
- NOP-OP-1014; Plant Status Control; Revision 3

FENOC Business Practices:
- NOBP-CC-2004; Engineering Change Risk Analysis; Revision 0

Plant Notifications:
- 600886573; 18R SGRP Containment Coating Work
- 600893586; EER Evaluate Materials for CTMT Inventory

Calculations:
- Calculation C-CSS-100.05-001; Service Level 1 Non-DBA Qualified Protective Coating Application Inventory; Revision 5 and Addendum A01 and Addendum A05
- Calculation C-NSA-059.01-023; Davis Besse Containment Building LOCA Debris Generation; Revision 0

Drawings:
- J-905; Tubing Isometric RE 4598AA Station Vent; Revision 0

Other:
- ISTB1; Pump and Valve Basis Document, Volume I – Valve Basis; Revision 14

1R18 Plant Modifications

Condition Reports:
- 2011-97930; Unable to Maintain Requested MVAR Output Due to Limitations on the TPCW System

Drawings:
- M-0009A; Cooling Water System; Revisions 23-25

Engineering Change Packages (ECPs):
- 12-0584-004; Replace TPCW Heat Exchanger E8-2 Tube Bundle and Increase Associated Vent and Drain Valves to 2"; Revision 1
- 12-0584-007; Replace TPCW Heat Exchanger E8-3 Tube Bundle and Increase Associated Vent and Drain Valves to 2"; Revision 1
- 14-0357-000; TM to Disable Source Interruption Devices A and B 94 Relays; Revision 0
- 14-0357-001; TM for CRD RTB B 94 Relay Removal; Revision 0
- 14-0357-002; TM for CRD RTB B 94 Relay Re-Installation; Revision 0
- 14-0357-003; TM for CRD RTB A 94 Relay Removal; Revision 0
- 14-0357-004; TM for CRD RTB A 94 Relay Re-Installation; Revision 0

Procedures:
- NOP-CC-1001; Configuration Management Program; Revision 1
- NOP-CC-2003; Engineering Changes; Revision 19

FENOC Business Practices:
- NOBP-CC-2004; Engineering Change Risk Analysis; Revision 0

Work Orders:
- 200602591; RTB A 94 Relay Removal; May 21, 2014
- 200602427; RTB B 94 Relay Removal; May 21, 2014

1R19 Post-Maintenance Testing

Condition Reports:
- 2014-07670; PIRC2A6 Impact from CTMT Pressure Test
- 2014-07995; Failed Trip Confirm Check from CRD to DEHC During OP-06402; Attachment 9
- 2014-07996; Failure in CRD Electronic Trip D Circuit
- 2014-08099; 18R BACC- RC13-B Leak Found During Walkdown
- 2014-08100; Debris Identified During Mode 3 VT-2 Examination and Unable to Be Retrieved at This Time
- 2014-08105; 18R BACC - A Packing-Stem/Flange Leak Was Found On RC201A
- 2014-08118; 18R BACC - Active Leak on MU466A
- 2014-08120; 18R BACC – A Packing Leak Was Found On MU455A
- 2014-08189; Leak at Tubing Found During CTMT Walkdown Downstream of PT616 SG 1 Feedwater Nozzle Pressure Transmitter Source
- 2014-08216; Issues Encountered when Attempting to Transfer Control Rods to the Auxiliary Power Supply
- 2014-08263; Unexpected Control Rod 4-9 Movement
- 2014-08265; RTB D Failed to Close During Restoration of the CRD System
- 2014-08292; Rod 7-4 0 Percent Zone Reference Light Not Lit with the Rod Fully Inserted Per API

- 2014-08337; Control Rod Assembly Insertion Time Test – Plant Status Control Event
- 2014-08344; Manual Reactor Trip Due to High CRD Temperature >180 °F
- 2014-08371; Control Rods Retested During Performance of DB-SC-03270
- 2014-08516; Power System Stabilizer Circuit for Automatic Voltage Regulator Enabled Prior to Commissioning Testing
- 2014-08518; Auto Voltage Regulator (AVR) Offline Commissioning Test Procedure DB-TP-12406, Step 6.12, Cannot Be Performed as Written
- 2014-08543; Acceptance criteria for the Emergency-Main Turbine OSTT in DB-SS-04163 is Incorrect
- 2014-08583; Unexpected Swing in MVARs During the Performance of DB-TP-12407, AVR Online Commissioning Test
- 2014-09044; Containment Pressure Test Post Instrument Calibrations and Nonconformance Report

Procedures:
- DB-OP-03013; Containment Daily Inspection and Containment Closeout Inspection; Revision 10
- DB-OP-06005; RC Pump Operation; Revision 30
- DB-OP-06202; Turbine Operating Procedure; Revision 25
- DB-OP-06409; Digital EHC and TSI System Operating Procedure; Revision 0
- DB-PF-00205; Containment Leakage Test Program; Revision 6
- DB-PF-03008; Containment Local Leakage Rate Tests; Revision 18
- DB-PF-03009; Containment Vessel and Shield Building Visual Inspection; Revision 8
- DB-PF-03010; RCS Leakage Test; Revision 13
- DB-PF-05000; Motor Testing; Revision 4
- DB-PF-05031; Alteration to Penetration P17; Revision 7
- DB-PF-05032; Alteration to Penetration P59; Revision 7
- DB-PF-05033; Alteration to Emergency Air Lock Penetration P-80; Revision 8
- DB-PF-05064; Electrical Machine Testing Using PdMA Motor Tester; Revision 13
- DB-PF-10311; Primary Containment Vessel Post Modification Pressure / New Weld Leakage Inspection Test; Revision 02
- DB-SC-03270; Control Rod Assembly Insertion Time Test; Revision 12
- DB-SC-03273; CRD Independent SCR Functional Test; Revision 2
- DB-SP-03134; Containment Emergency Sump Visual Inspection; Revision 6
- DB-SS-03255; Emergency Ventilation System Train 2 Refueling Interval SFAS Drawdown Test; Revision 13
- DB-SS-04163; Main Turbine Overspeed Trip Test; Revision 7-9
- DB-TP-12405; EX2100E Prestart Commissioning Procedure; Revision 2
- DB-TP-12406; EX2100E Offline Commissioning Procedure; Revision 0
- DB-TP-12407; EX2100E Online Commissioning Procedure; Revision 0
- DB-TP-12408; EX2100E PSS Commissioning Procedure; Revision 0
- DB-TP-12411; Digital Electro Hydraulic Control and Automatic Voltage Regulator Power Ascension Testing; Revision 0
- NG-DB-00212; Containment Storage; Revision 4
- NOP-ER-2001; Boric Acid Corrosion Control Program; Revision 11

Work Orders:
- 200511847; Construction Opening Restoration; March 24, 2014
- 200512648; PF3010-003 DH14 RCS Class 1; May 2, 2014
- 200512649; PF3010-005 RC1 RCS Class 1; May 2, 2014
- 200512658; PF3010-001 CF9 RCS Class 1; May 2, 2014

- 200512659; PF3010-002 CF10 RCS Class 1; May 2, 2014
- 200512660; PF3010-004 DH16 RCS Class 1; May 2, 2014
- 200512824; Main Turbine Overspeed Trip; May 15, 2014
- 200512836; PF3010-011 DH15 RCS Class 1; May 2, 2014
- 200517193; SC3270-001 Rod Drop CRA Insertion; May 6, 2014
- 200534740; Primary Containment Vessel Post Modification Pressure / New Weld Leakage Inspection Test; April 27, 2014
- 200562962; Perform VT-2 and Leak Checks; May 2, 2014

Drawings:
- OS-001A; Reactor Coolant System; Revision 46
- OS-001B; Reactor Coolant Pumps and Motors; Revision 25
- OS-033B; Containment Purge System; Revision 30
- OS-033D; Emergency Ventilation System; Revision 15
- M-030A; P&ID Reactor Coolant System; Revision 69
- M-033B; P&ID Reactor Coolant System Instrumentation; Revision 26
- M-233B; Emergency Core Cooling System Pump Suction Piping; Revision 23
- C-0903; Emergency Sump Plan & Sections; Revision 0
- C-0906; Perforated Plate Details; Revision 0
- C-0907; Incore Tunnel Strainer Layout – Arrangement; Revision 0
- C-0908; Incore Tunnel Strainer At Support A; Revision 0
- C-0909; Incore Tunnel Strainer Perforated Pipe Details; Revision 1
- C-0910; Incore Tunnel Strainer Collector Box; Revision 1
- C-0919; Incore Tunnel Strainer Support 'E' Sections; Revision 1
- ISID2-0030A; Reactor Coolant System; Revision 11

Concrete Field and Lab Test Reports:
- Job 6472-11-0327; Mix ID: Davis-Besse 645-31; Set 20; Shield Building Opening Compression Test Results; April 14, 2014
- Job 6472-11-0327; Mix ID: Davis-Besse 645-31; Set 21; Shield Building Opening Compression Test Results; April 14, 2014

Other:
- Davis-Besse Unit 1, Cycle 19 Core Map
- Davis-Besse Cycle 19 Core Fuel Assembly ID Verification DVD
- Certificate of Conformance for All Work under Bechtel Subcontract No 25539-000-HC4-NEE0-00016 (Change Order 5); April 24, 2014

<u>1R20 Outage Activities</u>

Condition Reports:
- 2014-07864; Additional Items That Could Not Be Removed During Containment Closeout Walkdowns
- 2014-07897; Containment Inventory Items Identified During NRC Walkdowns
- 2014-07898; 18RFO: Debris Found in Various Areas of Containment
- 2014-07929; FW Valves FW780 and SP6B Leaking By
- 2014-07934; MS-C-14-03-12: Incorrect Procedure Attachment Used to Calculate Shutdown Margin Minimum Boron

Procedures:
- DB-OP-03013; Containment Daily Inspection & Containment Closeout Inspection; Revision 10

- DB-OP-06000; Filling and Venting the Reactor Coolant System; Revision 28
- DB-OP-06003; Pressurizer Operating Procedure; Revision 30
- DB-OP-06005; RC Pump Operation; Revision 30
- DB-OP-06202; Turbine Operating Procedure; Revision 25
- DB-OP-06402; CRD Operating Procedure; Revision 23
- DB-OP-06409; Digital EHC and TSI System Operating Procedure; Revision 0
- DB-OP-06900; Plant Heatup; Revision 61
- DB-OP-06901; Plant Startup; Revision 35
- DB-OP-06902; Power Operations; Revision 45
- DB-OP-06904; Shutdown Operations; Revision 45
- DB-OP-06911; Pre-Startup Checklist; Revision 24
- DB-OP-06912; Approach to Criticality; Revision 17
- DB-NE-06202; Reactivity Balance Calculations; Revision 8
- DB-PF-00205; Containment Leakage Test Program; Revision 6
- DB-SC-03270; Control Rod Assembly Insertion Time Test; Revision 12
- DB-NE-03212; Zero Power Physics Testing; Revision 10
- NOP-OP-1005; Shutdown Defense in Depth; Revision13

FENOC Business Practices:
- NOBP-OP-0007; Conduct of Infrequently Performed Tests or Evolutions; Revision 5

Other:
- 18RFO Shutdown Defense in Depth Report; Revisions 0 and 1
- Davis-Besse Cycle 19 Core Operating Limits Report; Revision 0

1R22 Surveillance Testing

Condition Reports:
- 2014-00868; SW Pump 2 Motor Abnormal Surging Noise
- 2014-08099; 18R BACC- RC13-B Leak Found During Walkdown
- 2014-08100; Debris Identified during Mode 3 VT-2 Examination and Unable to Be Retrieved at This Time
- 2014-08105; 18R BACC - A Packing-Stem/Flange Leak Was Found on RC201A
- 2014-08118; 18R BACC - Active Leak on MU466A
- 2014-08120; 18R BACC – A Packing Leak was Found On MU455A
- 2014-08189; Leak at Tubing Found During CTMT Walkdown Downstream of PT616 SG 1 Feedwater Nozzle Pressure Transmitter Source
- 2014-08543; Acceptance criteria for the Emergency Main Turbine Overspeed Trip Test in DB-SS-04163 is Incorrect
- 2014-10339; Vibrations on Service Water Pump 2 May Be Out of Limits

Procedures:
- DB-MM-05003; Vibration Monitoring; Revision 11
- DB-OP-02250; SBODG Alarm Panel 250 Annunciators; Revision 4
- DB-OP-06202; Turbine Operating Procedure; Revision 25
- DB-OP-06261; Service Water System Operating Procedure; Revision 62
- DB-OP-06334; Station Blackout Diesel Generator Operating Procedure; Revision 22
- DB-OP-06409; Digital EHC and TSI System Operating Procedure; Revision 00
- DB-SC-03270; Control Rod Assembly Insertion Time Test; Revision 12
- DB-SC-04271; SBODG Monthly Test; Revision 23
- DB-PF-03010; RCS Leakage Test; Revision 13

- DB-PF-03023; Service Water Pump 2 Testing; Revision 22
- DB-PF-06703; Miscellaneous Operations Curves; Revisions 20 – 21
- DB-PF-06704; Pump Performance Curves; Revision 33
- DB-PF-06705; Tank Level Calibration Curves; Revision 9
- DB-SS-03255; Emergency Ventilation System Train 2 Refueling Interval SFAS Drawdown Test; Revision 13
- DB-SS-04163; Main Turbine Overspeed Trip Test; Revision 7-9
- DB-NE-03212; Zero Power Physics Testing; Revision 10
- NOP-ER-2001; Boric Acid Corrosion Control Program; Revision 11

Work Orders:
- 200500359; Station Blackout Diesel Generator Monthly Test – DA 215 Side; April 16, 2014
- 200500381; SBO Quarterly Vibrations; April 16, 2014
- 200502601; Service Water Pump 2 Quarterly Test; May 16, 2014
- 200512648; PF3010-003 DH14 RCS Class 1; May 2, 2014
- 200512649; PF3010-005 RC1 RCS Class 1; May 2, 2014
- 200512658; PF3010-001 CF9 RCS Class 1; May 2, 2014
- 200512659; PF3010-002 CF10 RCS Class 1; May 2, 2014
- 200512660; PF3010-004 DH16 RCS Class 1 May 2, 2014
- 200512836; PF3010-011 DH15 RCS Class 1; May 2, 2014
- 200562962; Perform VT-2 and Leak Checks; May 2, 2014

Drawings and Prints:
- M-030A; P&ID Reactor Coolant System; Revision 69
- M-033B; P&ID Reactor Coolant System Instrumentation; Revision 26
- ISID2-0030A; Reactor Coolant System; Revision 11
- OS-0001A; Reactor Coolant System; Revision 46
- OS-020; Service Water System; Revision 93
- OS-033B; Containment Purge System; Revision 30
- OS-033D: Emergency Ventilation System; Revision 15
- OS-0041D; Station Blackout Diesel Lube Oil and Jacket Water; Revision 14
- OS-0041E; Station Blackout Diesel Air Start / Engine Air System; Revision 15
- OS-0041F; Station Blackout Diesel Electrical Control and Fuel Oil Systems; Revision 5

<u>4OA1 Performance Indicator Verification</u>

Forms:
- NOBP-LP-4012-45; Safety System Functional Failures; Revision 0; Completed Forms for April 2013 through March 2014
- NOBP-LP-4012-46; MSPI Emergency AC Power System; Revision 1; Completed Forms for April 2013 through March 2014
- NOBP-LP-4012-47; MSPI High Pressure Injection System; Revision 1; Completed Forms for April 2013 through March 2014

Procedures:
- NOBP-LP-4012; NRC Performance Indicators; Revision 4

Other:
- Select Operator Logs covering the period of April 2013 through March 2014

4OA2 Problem Identification and Resolution

Condition Reports:
- 2013-14023; Control Room Annunciator Malfunction During Modification Process
- 2013-18434; Control Room Annunciator Alarms Unable To Be Reset
- 2014-04360; Control Room Annunciators Continuously Flashing
- 2014-08344; Manual Reactor Trip Due to High CRD Temperature >180 °F
- 2014-08555; Late Reporting of Manual Reactor Trip Per 10 CFR 50.72
- 2014-09230; Crew Performance Critique for CR 2014-08555: Late Reporting of Manual Reactor Trip Per 10 CFR 50.72
- 2014-09280; Backup Annunciator Power Supply Did Not Work
- 2014-09494; Control Room Annunciators Fast Flash and Can't Be Acknowledged when Alarm Received
- 2014-09498; Slow Duty Team Response to a Potential Reportable Event
- 2014-11234; Missed Report of Annunciator Malfunction

Procedures:
- NOP-LP-2001; Corrective Action Program; Revision 32

Work Orders:
- 200583393; Replace Annunciator Disconnect Switch 2; TBD/Unscheduled
- 200601792; PI Tube Replacement N-12 (7-4); May 5, 2014

Other:
- Select Operator Logs covering the period of January 2014 through June 2014

4OA3 Followup of Events and Notices of Enforcement Discretion

Condition Reports:
- 2013-14023; Control Room Annunciator Malfunction During Modification Process
- 2013-18434; Control Room Annunciator Alarms Unable To Be Reset
- 2014-04360; Control Room Annunciators Continuously Flashing
- 2014-08344; Manual Reactor Trip Due to High CRD Temperature >180 °F
- 2014-08555; Late Reporting of Manual Reactor Trip Per 10 CFR 50.72
- 2014-09230; Crew Performance Critique for CR 2014-08555: Late Reporting of Manual Reactor Trip Per 10 CFR 50.72
- 2014-09280; Backup Annunciator Power Supply Did Not Work
- 2014-09494; Control Room Annunciators Fast Flash and Can't Be Acknowledged when Alarm Received
- 2014-09498; Slow Duty Team Response to a Potential Reportable Event

Work Orders:
- 200583393; Replace Annunciator Disconnect Switch 2; TBD/Unscheduled
- 200601792; PI Tube Replacement N-12 (7-4); May 5, 2014

Procedures:
- DB-OP-06402; CRD Operating Procedure; Revision 23
- DB-OP-06411; Station Annunciator Operating Procedure; Revision 21
- NOP-OP-1015; Event Notifications; Revision 0
- NOP-LP-5004; Equipment Important to Emergency Response; Revision 1

- NOP-WM-1003; Nuclear Maintenance Notification Initiation, Screening, and Minor Deficiency Monitoring Processes; Revision 6
- RA-EP-01500; Emergency Classification; Revision 15

FENOC Business Practices and Reference Manuals:
- NOBP-OP-1015; Event Notifications; Revision 00
- DBRM-EMER-1500A; Davis-Besse Emergency Action Level Basis Document; Revision 5
- DBRM-EMER-1500B; Hot and Cold EAL Wall Board; Revision 1
- DBRM-EMER-1500C; Davis-Besse Emergency Action Level Reference Manual; Revision 0
- DBRM-EMER-5003; Equipment Important to Emergency Response; Revision 11

NRC Event Notification System (ENS) Forms:
- 50086: Manual Reactor Scram with Rod Motion While Shutdown; May 5, 2014
- 50097: Manual Initiation of the Reactor Protection System While Shutdown; May 8, 2014
- 50143: Control Room Overhead Annunciator Malfunction; May 26, 2014

Other:
- Select Operator Logs covering the period of January 2014 through June 2014

LIST OF ACRONYMS USED

ºF	Degrees Fahrenheit
AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AFW	Auxiliary Feedwater
APSR	Axial Power Shaping Rod
ASME	American Society of Mechanical Engineers
BA	Boric Acid
BACC	Boric Acid Corrosion Control
BMV	Bare Metal Visual
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CIV	Containment Isolation Valve
CR	Condition Report
CRD	Control Rod Drive
CST	Condensate Storage Tank
DH	Decay Heat
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
ECP	Engineering Change Package
EDG	Emergency Diesel Generator
EP	Emergency Plan
EPRI	Electric Power Research Institute
ET	Eddy Current Testing
FW	Feedwater
GL	Generic Letter
gpm	Gallons Per Minute
HPI	High Pressure Injection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
ISI	Inservice Inspection
IST	Inservice Testing
KV	Kilovolt
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOFW	Loss of Feedwater
MDFP	Motor-Driven Feedwater Pump
MSPI	Mitigating Systems Performance Index
MT	Magnetic Particle
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
PI	Performance Indicator
PM	Preventative Maintenance
PMT	Post-Maintenance Testing
PWHT	Post Weld Heat Treatment
RCS	Reactor Coolant System

RFO	Refueling Outage
RPS	Reactor Protection System
RTB	Reactor Trip Breaker
SBODG	Station Blackout Diesel Generator
SDP	Significance Determination Process
SG	Steam Generator
SSC	Systems, Structures, and Components
SW	Service Water
TS	Technical Specification
TSO	Transmission System Operator
UHS	Ultimate Heat Sink
USAR	Updated Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic
Vdc	Volts Direct Current
WBC	Whole Body Count
WO	Work Order

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Sincerely,

/RA Bruce Bartlett Acting for/

Jamnes L. Cameron, Chief
Branch 4
Division of Reactor Projects

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