UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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November 1, 2013

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

SUBJECT: DAVIS-BESSE NUCLEAR POWER STATION – NRC INTEGRATED INSPECTION REPORT 05000346/2013004

Dear Mr. Lieb:

On September 30, 2013, 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 October 15, 2013, with you and other members of your staff.

Based on the results of this inspection, two NRC-identified and two self-revealed findings of very low safety significance were identified. Two of the four findings also involved violations of NRC requirements. Additionally, a licensee-identified violation is described in Section 4OA7 of this report. 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 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 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and 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), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Patricia J. Pelke, Acting Chief
Branch 6
Division of Reactor Projects

Docket No. 50-346
License No. NPF-3

Enclosure: Inspection Report 05000346/2013004
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:	05000346/2013004
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Davis-Besse Nuclear Power Station
Location:	Oak Harbor, OH
Dates:	July 1, 2013, through September 30, 2013
Inspectors:	D. Kimble, Senior Resident Inspector T. Briley, Resident Inspector A. Dunlop, Senior Engineering Inspector J. Neurauter, Senior Engineering Inspector J. Steffes, Reactor Engineer
Approved by:	Patricia J. Pelke, Acting Chief Branch 6 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000346/2013004; 7/1/2013-9/30/2013; Davis-Besse Nuclear Power Station; Licensed Operator Requalification Program; Component Design Bases Inspection; and Follow Up of Events and Notices of Enforcement Discretion.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Four Green findings were identified by the inspectors. Two of the four findings were considered non-cited violations (NCV) 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" dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A self-revealed finding of very low safety significance was identified for the licensee's failure to procure and install appropriate replacement parts for repair of the Reactor Coolant Pump (RCP) 1-2 motor during the 2010 refueling outage. Specifically, a degraded terminal strip in the motor's current transformer (CT) circuit was replaced with a new terminal strip that had substandard fasteners. The licensee's procurement process did not have any provisions in place to ensure the fasteners (screws) were of the appropriate quality for the application, and some of the screws ultimately failed due to vibration induced fatigue causing a reactor trip when the RCP tripped due to an electrical fault. No corresponding violation of NRC requirements was identified.

  The finding was determined to be of more than minor significance because it was associated with cornerstone attribute of design control and adversely affected the cornerstone objective: "To limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations." The finding was determined to be of very low safety significance (Green) because it resulted in a reactor trip without any corresponding loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition, and there were no other abnormal events such as fire, flooding, or high energy line breaks (HELBs). The finding had a cross-cutting aspect in the area of human performance, resources component, because the licensee had failed to ensure that the replacement terminal strip, which ultimately was cause of the reactor trip, was adequate for its service environment. (H.2(d)) (Section 4OA3.1)

- Green. A self-revealed finding of very low safety significance and an associated non-cited violation of TS 3.4.13, "Reactor Coolant System (RCS) Operational Leakage," were identified for the licensee's failure to fully evaluate a previously identified degraded condition on the first stage seal cavity vent line for RCP 1-2. Specifically, a known high vibration condition associated with this line had caused a pinhole leak on a socket weld on the line that was repaired in June of 2012. However, the licensee's root cause evaluation and subsequent repair efforts for that leak failed to adequately address other welds on that vent line that were also subjected to the same high vibration levels, such that following an unplanned reactor trip another small RCS pressure boundary leak was discovered on a different socket weld on the same line on July 1, 2013.

This finding was determined to be of more than minor significance because it was associated with cornerstone attribute of equipment performance and adversely affected the cornerstone objective: "To limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations." Since the finding was not related to pressurized thermal shock and only involved an RCS barrier (leakage) issue, it was evaluated under the Initiating Events Cornerstone and determined it to be of very low safety significance because:

- After a reasonable assessment of degradation, the inspectors determined that due to the small size of the RCP 1-2 first stage seal cavity vent line that the finding could not result in exceeding the RCS leak rate for a small loss of coolant accident (LOCA); and
- After a reasonable assessment of degradation, the inspectors determined that the finding could not have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA, etc.).

The finding had a cross-cutting aspect in the area of problem identification and resolution (PI&R), corrective action program (CAP) component, because the licensee had failed to thoroughly evaluate the event in June of 2012 such that the resolution addressed causes and extent of conditions. (P.1(c)) (Section 4OA3.2)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance for the licensee's failure to perform an accurate and detailed shift turnover to ensure oncoming plant operators were aware of plant status. Specifically, cracks identified in two control power fuses associated with High Pressure Injection (HPI) Pump No. 2 were not communicated in the unit log or during shift turnover to the oncoming operations crew. As a result, the oncoming operating crew was unaware of the status of the cracked close control power fuses until after being questioned by the inspectors on the status of the fuses several hours into their shift. The HPI pump was subsequently declared inoperable to facilitate replacement of the control power fuses. No corresponding violation of NRC requirements was identified.

  The finding was determined to be of more than minor significance because it was associated with the Mitigating Systems Cornerstone and 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 inadequate shift crew turnover, HPI Pump No. 2 was rendered inoperable for an additional period of time to facilitate replacement of control power fuses. 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 HPI Pump No. 2; it did not represent a loss of system or function; it did not represent the loss of function for any technical specification (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 human performance, decision making component, because the licensee failed to communicate decisions and the basis for decisions to personnel who have a need to know the information in order to perform work safely, in a timely manner. Specifically, the night shift crew made an operability decision on the impacts of the cracked close control power fuses on HPI Train 2 without documenting or informing the oncoming crew the basis of that decision. (H.1(c)) (Section 1R11.2)

- Green. The inspectors identified a finding of very low safety significance and associated non-citied violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to ensure design features to protect the low and high voltage switchgear rooms, including the battery rooms, from the temperature and humidity effects of a HELB in the turbine building. Specifically, the licensee relied on non-safety-related equipment that was not verified to function under a HELB scenario. The licensee entered the issue into their CAP, isolated the ventilation system from the turbine building, and performed an analysis that concluded the safety-related switchgear rooms would have remained within their environmental qualification limits whether or not the non-safety-related equipment functioned as designed.

  The performance deficiency was determined to be more than minor because it affected the Mitigating Systems Cornerstone attribute of Design Control and adversely affected the cornerstone objective of ensuring the reliability, availability and capability of systems that respond to initiating events to prevent undesirable consequences, in that the licensee did not have adequate measures in place to ensure that qualified components were available to mitigate the consequences of a HELB in the turbine building. The finding screened as of very low safety significance (Green) because the finding involved a design or qualification deficiency that did not result in a loss of operability. The inspectors identified a cross-cutting aspect associated with this finding in the area of PI&R because the licensee did not thoroughly evaluate the reliance on non-safety-related components for protecting safety-related equipment. Specifically, the 2010 evaluation did not thoroughly evaluate the capability of non-safety-related equipment to mitigate the consequences of a HELB in the turbine building and the possible effects of the HELB on safety-related components located in the plant's switchgear rooms. (P.1(c)) (Section 1R21.1)

B. Licensee-Identified Violations

A violation of very low safety significance that was identified by the licensee has been reviewed by the NRC. Corrective actions taken or planned by the licensee have been entered into the licensee's CAP. This violation and CAP tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The unit began the inspection period shut down for a forced maintenance outage that had begun on June 29, 2013, when the reactor automatically tripped while operating at full power (see Section 4OA3 for additional details). The cause of the reactor trip, an electrical fault on Reactor Coolant Pump (RCP) 1-2, was corrected and other repairs were made to the plant (see Section 1R20 for additional details). The reactor was restarted on July 12, 2013, and the unit returned to operation at full power on July 14, 2013. With the exception of small power maneuvers (e.g., reductions in power of about 10 percent or less) to facilitate planned testing evolutions, the unit remained operating at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate AC 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 communication protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

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

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

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- The compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;

- A re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- The communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment 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.

The inspectors' reviews of the availability of offsite and alternate AC power systems constituted a single inspection sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

.2 External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the Updated Safety Analysis Report (USAR) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area of the station to identify any modifications to the site which would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also reviewed the station's abnormal operating procedure for mitigating the design basis flood to ensure it could be implemented as written. Specific documents reviewed during this inspection are listed in the Attachment to this report.

This inspection constituted one external flooding sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

.3 Readiness for Impending Adverse Weather Condition – Tornado Warning

a. Inspection Scope

On July 10, 2013, while the site was in a forced outage and relying upon off-site power, a tornado warning was issued for the Northwest Ohio area near the station. The inspectors reviewed the licensee’s overall preparations/protection for the impending severe weather conditions.

Just prior to the onset of the inclement weather conditions, the inspectors walked down the areas in and around the switchyard, under the site's high voltage lines and near transformers, and the licensee’s emergency AC power systems, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee’s preparations against the site’s procedures to determine whether or not the actions performed were adequate. The inspectors focused on plant-specific design features and the licensee’s procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant.

The inspectors also reviewed a sample of CAP items to verify that the licensee had identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report.

These reviews conducted by the inspectors in response to the July 10, 2013, tornado warning constituted a single readiness for impending adverse weather inspection sample as defined in 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 alignment verifications of the following risk-significant systems:

- Decay Heat (DH) Train 1 when the reactor was in the cold shutdown condition (Mode 5) and both trains of DH were required to be operable under the plant's Technical Specifications (TS) during the week ending July 6, 2013;
- The station's Motor-Driven Feed Pump with Auxiliary Feedwater Train 1 out-of-service for planned maintenance during the week ending August 3, 2013;
- Station Air Compressor (SAC) 1 and SAC 2 with the station's Emergency Instrument Air Compressor out-of-service for planned maintenance during the week ending August 17, 2013; and
- The Station Blackout Diesel Generator (SBODG) and its auxiliaries with Emergency Diesel Generator (EDG) 2 out-of-service for planned surveillance testing during the week ending August 17, 2013.

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 functions of the systems and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the station's USAR, 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 that 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 constituted four quarterly partial system alignment verification inspection samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown and Alignment Verification

a. Inspection Scope

During the week ending September 14, 2013, the inspectors performed a complete system alignment inspection of the DH/Low Pressure Injection System to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors walked down the system 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 station'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 complete system walkdown and alignment verification inspection sample as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Protection Zone Inspections

a. Inspection Scope

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

- Cable Spread Room (Rooms 422A and 422B; Fire Areas DD and CC); and
- Exterior construction areas adjacent to the Auxiliary Building and Shield Building, 585′ Elevation.

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 (IPEEE) 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. The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

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

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 September 17, 2013, the inspectors observed a crew of licensed operators in the plant's simulator during a periodic graded simulator scenario. The inspectors verified that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and that training was being conducted in accordance with licensee procedures. In addition, the inspectors verified that the licensee's personnel were observing NRC examination security protocols to ensure that the integrity of the graded scenario was being protected from being compromised. 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 senior reactor operators (SROs); and
- The ability of the crew to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

- Reactor and plant cooldown activities during the week ending July 5, 2013;
- Emergent plant cooldown activities to support repairs to the RCP 1-2 seal cavity vent line during the week ending July 5, 2013; and
- Reactor and plant startup activities during the week ending July 13, 2013.

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. 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

Inadequate Operations Crew Turnover

Introduction

An NRC-identified finding of very low safety significance (Green) was identified when the licensee failed to perform an accurate and detailed shift turnover to ensure oncoming plant operators were aware of plant status. Specifically, cracks identified in two control power fuses associated with High Pressure Injection (HPI) Pump No. 2 were not communicated in the unit log or during shift turnover to the oncoming operations crew. As a result, the oncoming operating crew was unaware of the status of the cracked close control power fuses until after being questioned by the inspectors on the status of the fuses several hours into their shift. The HPI pump was subsequently declared inoperable to facilitate replacement of the control power fuses. No violation of NRC requirements was identified.

Description

On August 14, 2013, during the night shift, the licensee was performing a quarterly HPI Train 2 pump and valve test. As part of this routine testing, the close control power fuses are removed from 4160 Vac breaker AD111 for the HPI Pump No. 2. After removal of the control power fuses, it was identified that fuses FU04 and FU07 had indications on the fuse ferrules that resembled cracks. Consulting with electrical maintenance personnel, the night operations crew determined that the fuses were still functional. The indications on the fuse ferrules were determined to be artifacts associated with the fuse manufacturing process and the fuses were reinstalled. All HPI Train 2 testing was completed and the pump was restored to an operable condition. The night operations crew generated CR 2013-12511 to document the condition with the fuses, with the understanding that electrical maintenance personnel had been notified and the fuses were to be replaced as a conservative measure prior to the end of the shift. The night operations crew did not verify, however, that the fuses had been replaced prior to being relieved.

The NRC inspectors, in the normal course of their daily CR reviews, identified CR 2013-12511 for follow-up the next morning. When the day operations crew was queried for additional details regarding the control power fuses and the basis for their reinstallation with identified cracks, they indicated that this was the first time that they had heard of the issue. The previous night operations crew had not informed their oncoming reliefs of the condition during turnover, nor had it been noted in any operations log. After calling up and reviewing CR 2013-12511, which at this point had not yet been formally reviewed by a SRO, the day operations crew conservatively decided to render HPI Pump No. 2 inoperable for several minutes to replace the control power fuses in question. The day operations crew subsequently investigated the issue further and determined, as the night operations crew independently had, that the indications on the fuse ferrules were artifacts associated with the fuse manufacturing process and not any condition impacting the function of the fuses.

The inspectors reviewed the licensee's standards and expectations contained in Section 4.13 of NOP-OP-1002, “Conduct of Operations,” for shift relief and turnover. The expectation states that operators: “perform accurate and detailed shift turnovers to ensure oncoming operators are aware of plant status.” The Conduct of Operations standards also state that: “the off-going shift personnel shall not leave their work area until they have been properly relieved, i.e., the relief is fully aware of existing conditions and the shift turnover checklist has been completed.” Contrary to these expectations and standards listed in NOP-OP-1002, the night operations crew failed to perform an accurate and detailed shift turnover to ensure oncoming plant operators were aware of the status of the control power fuses in 4160 Vac breaker cubicle AD111, and ultimately this led to additional HPI Train 2 inoperability to facilitate fuse replacement.

After the inspectors had discussed the potential for a finding related to the issue, the licensee entered the issue into their CAP as CR 2013-12633. Corrective actions included assigning operations crews a required reading discussing the condition and reinforcing the conduct of operations expectations for shift relief and turnover.

Analysis

The inspectors reviewed this finding using the guidance contained in Appendix B, “Issue Screening,” of Inspection Manual Chapter (IMC) 0612, “Power Reactor Inspection Reports.” The inspectors determined that the licensee’s failure to perform a proper shift turnover that was in accordance with their Conduct of Operations standards constituted 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 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 inadequate shift crew turnover, HPI Pump No. 2 was rendered inoperable for an additional period of time to facilitate replacement of control power fuses.

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 HPI Pump No. 2;
- It 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 human performance, decision making component, because the licensee failed to communicate decisions and the basis for decisions to personnel who have a need to know the information in order to perform work safely, in a timely manner. Specifically, the night shift crew made an operability decision on the impacts of the cracked close control power fuses on HPI Train 2 without documenting or informing the oncoming crew the basis of that decision. (H.1(c))

Enforcement

The inspectors concluded that the licensee did not comply with the standards and expectations for shift turnover contained in procedure NOP-OP-1002, "Conduct of Operations." This finding, however, did not involve a corresponding violation of NRC requirements. Specifically, the inspectors determined that the "Conduct of Operations" procedure is an administrative procedure, and not covered under the quality assurance (QA) requirements set forth in 10 CFR Part 50, Appendix B. Additionally, the inspectors also determined that the "Conduct of Operations" procedure is 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 05000346/2013004-01)

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- RCPs and Motors.

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 structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

The inspectors' reviews constituted a single quarterly maintenance effectiveness inspection sample as defined in IP 71111.12-05.

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Emergent work associated with repairs to a pinhole leak on the vent line for the RCP 1-2 mechanical seal cavity during the weeks ending July 6, 2013, and July 13, 2013;
- Emergent work associated with Post Accident Monitoring Panel Gammametrics Source Range Indication Channels 1 and 2 during the week ending July 13, 2013;
- Emergent work associated with repairs to the RCP 1-2 motor during the weeks ending July 6, 2013, and July 13, 2013; and
- Emergent work associated with troubleshooting and repairs to circuit breaker ACD2 for Component Cooling Water Pump No. 3. during the weeks ending August 31, 2013, through September 28, 2013.

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. Specific documents reviewed during this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Operability of the Main Steam Safety Valves following their actuation after the reactor trip on June 29, 2013, as documented in CR 2013-10044 and CR 2013-10048 during the week ending July 6, 2013;
- Validity of the existing operability determination on the pressurizer heater bundle (POD 2010-001) following the thermal cycle placed on the unit's pressurizer after the reactor trip on June 29, 2013, and the subsequent revision to that analysis documented in CR 2013-10266 during the week ending July 6, 2013;
- Operability of the HPI Systems following identification of above normal pressure in a normally isolated fill line for the core flood tanks, as documented in CR 2013-11638 during the week ending August 3, 2013; and
- Operability of the Control Room Emergency Air Temperature Control System, as documented in CR 2013-11895 during the weeks ending August 3, 2013, through September 14, 2013.

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. Documents reviewed are listed in the Attachment to this report.

The inspectors' reviews of these operability evaluations constituted four inspection samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the following permanent modification to the facility:

- Engineering Change Package (ECP) No. 13-0177: 345 kV Hayes Line and Breaker 65 Addition.

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 modifications 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 modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modifications with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modifications 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:

- PdMA de-energized motor testing and analysis following repairs to the RCP 1-2 motor during the week ending July 13, 2013;
- Energized motor tests of the RCP 1-2 motor following repairs during the week ending July 13, 2013;
- In situ pressure testing of the 1st stage seal cavity vent line for RCP 1-2 during the week ending July 13, 2013, following replacement of a section of that line that had developed a through wall pressure boundary leak;

- DH Cooler 1 Outlet Cooling Water Valve (CC1467) testing following repairs during the week ending September 7, 2013; and
- Containment Pressure to Safety Features Actuation System Channel 3 testing following transmitter replacement the week ending September 28, 2013.

These activities were selected based upon the system, structure 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. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 July 2013 Forced Maintenance Outage

a. Inspection Scope

The inspectors evaluated outage activities for a forced maintenance outage that began with an automatic reactor trip on June 29, 2013. At approximately 9:20 p.m., RCP 1-2 tripped due to an electrical fault. The ensuing rapid reduction in reactor coolant flow with the plant operating at full power resulted in a condition whereby reactor power was higher than the allowable value for the reactor coolant flow condition. This condition was sensed immediately by the Reactor Protection System (RPS), and an automatic reactor trip on flux/delta flux/flow was generated. Following completion of various plant repairs associated with the event, the reactor was restarted on July 12, 2013, and the unit returned to operation at full power on July 14, 2013.

The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule. The inspectors reviewed plant records associated with the reactor trip and observed the plant and cooldown. Outage equipment configuration, risk management, electrical lineups, selected clearances, control and monitoring of DH removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage were also reviewed and selectively observed by the inspectors.

These observations and reviews by the inspectors constituted a single other (i.e., non-refueling) outage inspection sample as defined in IP 71111.20-05.

b. Findings

No findings were identified.

1R21 Component Design Bases Inspection (71111.21)

.1 (Closed) Unresolved Item 05000346/2012008-01: Impact of a High Energy Line Break in the Turbine Building on Safety-Related Electrical Equipment Located in the Switchgear Rooms

a. Inspection Scope

The inspectors reviewed the analysis associated with the effects of a High Energy Line Break (HELB) in the turbine building on safety-related electrical equipment located in the switchgear rooms. This analysis was performed by the licensee in response to Unresolved Item (URI) 05000346/2012008-01, which was identified during the previous Component Design Bases Inspection. (Reference NRC IR 05000346/2012008; ADAMS Accession No. ML12339A169)

b. Findings

Impact of a High Energy Line Break in the Turbine Building on Safety-Related Electrical Equipment Located in the Switchgear Rooms

Introduction

The inspectors identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to ensure design features to protect the low and high voltage switchgear rooms, including the battery rooms, from the temperature and humidity effects of a HELB in the turbine building. Specifically, the licensee relied on non-safety-related equipment that was not verified to function under a HELB scenario.

Description

The non-safety-related non-radwaste area ventilation system provided ventilation for the low and high voltage switchgear rooms, as well as the battery rooms. The ventilation supply fan suction was from a mixing box that was supplied air from turbine building, recirculation flow from the switchgear rooms, and outside air sources, as required based on room temperature. A temperature controller modulated dampers on the three air supplies to ensure an appropriate mix of air in the mixing box.

The licensee credited the non-safety-related ventilation system in mitigating the consequences of the HELB event since commercial operation. In 2010 as documented in CR 2010-80802, the licensee identified that a turbine building HELB could close the fire damper associated with the safety-related ventilation system fan such that the ventilation system would not be able to exhaust into the turbine building to cool the switchgear room. In evaluating this issue, the licensee credited the proper operation of the non-safety ventilation system controls, as well as the non-safety fan and its modulating dampers even though the equipment was not designed or qualified to operate under a HELB scenario. The licensee reasoned that since the controls of the non-safety-related system were not exposed to a harsh environment, the system could be credited for mitigating the consequences of a turbine building HELB.

The inspectors disagreed with the licensee's assessment and were concerned that, a HELB in the turbine building may result in a hot, moist environment entering into the switchgear room through the two non-radwaste area ventilation system dampers (exhaust and supply) and the safety-related switchgear ventilation system damper located in the turbine building. The non-safety-related modulating damper located in the turbine building supply air duct, which the licensee relied upon for mitigation of a turbine building HELB were qualified for pressure rating of 6 inches of water while the plant's HELB analysis showed a peak pressure of 1.06 pounds per square inch gauge (psig) (about 30 inches of water). As such, the peak pressure may damage the modulating dampers and the isolation damper preventing their closure based on their lower design operating pressure. Furthermore, depending on the size and location of the break, the temperature of the HELB air entering the switchgear rooms may be lower than 135˚F setpoint to close the non-safety-related isolation damper on high temperatures and shut off the operating fan. As a result, these scenarios could prevent the isolation of the switchgear rooms from the turbine building HELB environment.

The licensee initiated CR 2012-12292 and performed a prompt operability determination. As documented in NRC IR 05000346/2012008, the inspectors had several concerns with the evaluation. Based on the inspectors' concerns with the reliance on equipment that may not function under a turbine building HELB scenario, the licensee implemented ECP 2012-0632 to modify the plant design by permanently closing exhaust damper CV5325B, supply damper CV5325C, and fire doors 519A and 520A. This design change would allow the non-safety-related non-radwaste area ventilation system to function by taking suction from outside air combined with recirculated air from the switchgear rooms. The change would also protect the switchgear rooms from the consequences of a HELB in the turbine building.

Prior to the isolation of the ventilation system, the inspectors were concerned with two different turbine building HELB scenarios that could affect the safety-related switchgear rooms. The first concern was a large HELB, such as a main steam line break, where the turbine building peak pressure would exceed the pressure ratings on the ventilation dampers such that the dampers may not function to isolate the HELB from the switchgear room. The second concern was a smaller HELB that would allow the non-radwaste ventilation system to function as designed, which during winter operation may continue to allow the hot/humid environment to enter the switchgear rooms in order to maintain the ventilation system set point temperature of 70˚F. The inspectors received additional information on the operation of the ventilation control equipment and concluded the ventilation system would operate in a manner to prevent the HELB environment in the turbine building from affecting the safety-related equipment in the switchgear rooms. Specifically, either the smoke detectors or temperature switches would isolate the ventilation system to the switchgear rooms from the HELB environment in the turbine building prior to exceeding any safety-related equipment qualifications.

Based on the inspectors' first concern, the licensee performed additional analysis to assess the following: 1) determined which turbine building pipe breaks could produce a peak pressure that would exceed the ratings of the non-safety ventilation system dampers; and 2) performed an analysis that determined the effects of a large turbine building HELB on the non-safety ventilation system and the resultant effects on the safety-related equipment in the switchgear rooms. This analysis was documented in FAI/120834, "Calculation to Analyze Heat-up and Condensation Potential in the Davis-Besse Turbine Building and Auxiliary Building Safety-Related Switchgear Rooms," and was developed to evaluate the effect of the turbine building HELB on the safety-related switchgear.

With respect to Item 1, the licensee concluded to perform the analysis under worst case conditions, a 36 inch main steam line pipe break with a failure of the main steam isolation valve to close. Although the analysis determined the peak pressure from a HELB in the turbine building would exceed the rating of the non-safety ventilation system dampers, the pressure losses in the ventilation system would reduce the pressure below the equipment rating (e.g., dampers). In addition, the peak pressure was determined to last for only a few seconds as the train bay door in the turbine building would fail at approximately 0.5 seconds. The ventilation dampers would not get a signal to close from either the temperature or smoke detectors until approximately eight seconds into the event such that the dampers would not have to close under a high differential pressure. Based on this analysis, the non-safety ventilation system dampers would not be damaged from the associated peak pressure in the turbine building due to the worst case HELB or any other potential HELBs that would result in a lower peak pressure.

The analysis for Item 2 consisted of six cases performed using the MAAP5 computer model that varied the response of the non-safety-related equipment associated with the non-safety-related non-radwaste area ventilation system as to whether the components would function as assumed or fail as-is. This included whether ventilation or fire dampers would close or remain open and whether the ventilation fans would continue to operate or shutdown. All of these cases were based on the worst case main steam line break. The results of the analyses concluded for all cases that the temperature and humidity in the switchgear rooms would not exceed the environmental qualifications of the safety-related equipment located within the rooms. Based on these results, the safety-related equipment in the switchgear rooms would be able to perform their functions as designed.

<u>Analysis</u>

The inspectors determined that the failure to ensure the safety-related electrical equipment located in the switchgear and battery rooms were protected with qualified equipment from the effects of a HELB in the turbine building was a performance deficiency. The performance deficiency was determined to be more than minor because it affected the Mitigating Systems Cornerstone attribute of Design Control and adversely affected the cornerstone objective of ensuring the reliability, availability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee did not have adequate measures in place to ensure that qualified components were available to mitigate the consequences of a HELB in the turbine building.

The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors used Exhibit 2 – "Mitigating Systems Screening Questions" for mitigating systems, structures, components and functionality. The finding screened as very low safety significance (Green) because the finding was a design deficiency that did not result in a loss of operability or functionality. Specifically, the licensee performed an analysis that concluded the environmental qualifications of the safety-related equipment in the switchgear rooms would not be exceeded by a HELB in the turbine building.

This finding has a cross-cutting aspect in the area of Problem Identification and Resolution (PI&R) because the licensee did not thoroughly evaluate the reliance on non-safety-related components that may not have been qualified to operate under a HELB scenario. Specifically, the 2010 evaluation did not thoroughly evaluate the capability of non-safety-related equipment to mitigate the consequences of a HELB in the turbine building and the possible effects of the HELB on safety-related components located in the plant's switchgear rooms. (P.1(c))

Enforcement

Criterion III of 10 CFR Part 50, Appendix B, "Design Control," requires in part, that "Measures shall be established to assure that applicable regulatory requirements and the design basis ... are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design documents… Measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components."

Contrary to the above, the licensee did not include provisions to assure that appropriate quality standards were included in design documents, nor did the licensee assure the suitability of application of equipment that are essential to the safety-related functions of systems and components. Specifically, the licensee did not assure that the non-safety dampers were suitable to function under HELB, for example the dampers' design pressure was lower than the pressure associated with a turbine building HELB. Because this violation was of very low safety significance and it was entered into the licensee's CAP as CR 2012-12992, which isolated the non-safety-related non-radwaste area ventilation system from the turbine building and performed an analysis that determined the safety-related equipment in the switchgear rooms would not have exceeded their environmental qualifications from the result of a HELB in the turbine building, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy. (NCV 05000346/2013004-02)

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- DB-OP-03013; " Containment Daily Inspection & Containment Closeout Inspection," during the week ending July 13, 2013 (routine);
- DB-SC-03070; " Emergency Diesel Generator 1 Monthly Test," during the week ending August 3, 2013 (routine);
- DB-SS-03710; "Functional Test for Control Room Emergency Ventilation System, Train 1," during the week ending August 24, 2013 (routine);
- EN-DP-01511; " Design Guidelines for Maintenance Rule Evaluation of Structures," during the week ending August 31, 2013 (routine); and
- DB-PF-03008; "Containment Local Leakage Rate Tests," for containment penetrations 33 and 34 during the week ending July 6, 2013 (containment isolation valve).

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 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;
- Measuring and test equipment calibration was current;
- Test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- Test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- Test data and results were accurate, complete, within limits, and valid;
- Test equipment was removed after testing;
- Where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- Where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- Prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- Equipment was returned to a position or status required to support the performance of its safety functions; and
- All problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

The inspectors' reviews of these activities constituted four routine surveillance testing inspection samples and one containment isolation valve inspection sample as defined in IP 71111.22, Sections 02 and 05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on September 10, 2013, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Control Room and Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

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

b. Findings

No findings 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 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Heat Removal System performance indicator (PI) for the period from the third quarter 2012 through the second quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated IRs for the period of July 2012 through

June 2013 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 constituted a single MSPI - Heat Removal System PI inspection sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Residual Heat Removal System PI for the period from the third quarter 2012 through the second quarter 2013. 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 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated IRs for the period of July 2012 through June 2013 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 constituted a single MSPI – Residual Heat Removal System PI inspection sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems performance for the period from the third quarter 2012 through the second quarter 2013. 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 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated IRs for the period of July 2012 through June 2013 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 constituted a single MSPI – Cooling Water Systems PI 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 that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment 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 condition report packages.

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

b. Findings

No findings were identified.

.3 Annual Follow-Up Sample for In-Depth Review: Storage of Sea-Land Containers on the Dry Fuel Storage Pad

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting the long-term issues associated with storage of radioactive materials in Sea-Land containers on the dry fuel storage pad. The inspectors reviewed CRs, causal evaluations, and self-assessments to verify compliance with station procedures and regulatory requirements. The inspectors also verified that the licensee has planned and/or implemented corrective actions commensurate with the significance of identified issues. Documents reviewed are listed in the Attachment to this report.

The review of this issue by the inspectors constituted a single annual follow-up inspection sample for in-depth review as defined in IP 71152-05.

b. Observations

Temporary storage of radioactive material on the dry fuel storage pad was originally approved in 2000 and extended each year through 2007 using 10 CFR 72.48 screening evaluations to evaluate the impacts of changes, tests or experiments associated with independent storage of spent nuclear fuel and determine whether or not prior NRC approval is required. The 10 CFR 72.48 screening evaluation performed in 2007, which justified the storage of Sea-Land containers on the dry fuel storage pad, expired in March 2008. This discrepancy was identified by the NRC in November 2010. A new regulatory applicability determination and 10 CFR 72.48 screening were subsequently prepared without a specified end date to justify continued storage of Sea-Land containers on the dry fuel storage pad.

In March 2011, it was identified that the 10 CFR 72.48 screen preparer who prepared the previous 10 CFR 72.48 screening for the storage of Sea-Land containers on the dry fuel storage pad was not adequately qualified to current station and industry standards to perform the screening evaluation. The 10 CFR 72.48 screening was invalidated and a new regulatory applicability determination was prepared. Further investigation revealed that no training program had been formally established for qualifying new personnel in accordance with current station and industry standards, nor had the ability to formally document those qualifications in order to meet procedural requirements to perform 10 CFR 72.48 evaluations for dry fuel storage changes. Corrective actions included developing and implementing a formal training program to adequately qualify new 10 CFR 72.48 screen preparers to current station and industry standards and the ability to verify those qualifications.

In March 2013, it was identified that the regulatory applicability determination prepared in 2011 failed to identify that a 10 CFR 72.48 screening was necessary and, as a result, no 10 CFR 72.48 screening was prepared. An apparent cause evaluation performed to determine why Sea-Land containers were stored on the dry fuel storage pad without a valid 10 CFR 72.48 screen determined that the transfer, handling, and storage of radioactive material procedure was revised and implemented without ensuring the new training requirements were available. Corrective actions included removing all Sea-Land containers from the dry fuel storage pad and removing the procedure attachments allowing storage of Sea-Land containers on the dry fuel storage pad until further evaluation could be performed to verify acceptability in accordance with approved procedures.

The inspectors reviewed the time periods where Sea-Land containers were stored on the dry fuel storage pad without a valid 10 CFR 72.48 screening evaluation and/or applicable regulatory applicability determination. The inspectors determined the failure to maintain a valid written evaluation documenting the basis for storing Sea-Land containers on the dry fuel storage pad in order to comply with 10 CFR 72.48 constituted a minor violation that is not subject to enforcement action in accordance with the NRC's Enforcement Policy. The regulatory applicability determinations and 10 CFR 72.48 screening evaluations developed previously had determined that neither prior NRC approval nor changes to the Dry Fuel Storage Facility Basis Manual were required. Thus, the issue is of minor significance. Corrective actions had been developed by the licensee and entered into their CAP.

c. Findings

No findings were identified.

.4 Annual Follow-Up Sample for In-Depth Review: Review of Licensee Periodic Core Bore Visual Examinations for Shield Building Concrete Cracking Follow-Up

a. Inspection Scope

During a mid-cycle outage to replace the reactor vessel closure head in late 2011, the licensee identified laminar cracking in the safety-related shield building of the containment system while performing hydrodemolition operations to create a shield building maintenance access opening. Based on an evaluation of the licensee's extent-of-condition and technical analysis of the shield building laminar cracking, the NRC staff concluded that the licensee had provided reasonable assurance that the shield building was capable of performing its safety functions. In order to provide continued long-term confidence, the licensee agreed to several follow-on actions. Chief amongst these follow-on actions was the licensee's commitment to perform an investigation into the root cause of the cracking.

The licensee submitted a root cause report (ADAMS Accession No. ML120600056) to the NRC on February 27, 2012. The licensee identified the direct cause as the integrated effect of moisture content, wind speed, temperature, and duration from a severe winter blizzard that occurred in 1978, and the root cause as the design specification for construction of the shield building not specifying application of an exterior sealant from moisture. The licensee also identified three contributing causes involving specific design features of the building. The root cause report also identified planned corrective actions as well as associated due dates, and acknowledged that the shield building, although operable, did not conform to the licensing basis in its current condition.

The NRC completed an inspection of the licensee's root cause efforts and planned corrective actions on May 9, 2012 (NRC IR 05000346/2012009; ADAMS Accession No. ML12173A023). The NRC inspection team concluded that the licensee had a sufficient basis for the causes of the shield building laminar cracking related to the environmental factors associated with the 1978 blizzard, the lack of an exterior moisture barrier, and the structural design elements of the shield building. The team did, however, identify minor weaknesses in the licensee's root cause report associated with the level of detail in the documentation provided. These weaknesses did not constitute performance deficiencies or findings, because they did not adversely affect the outcome of the root cause process. The licensee submitted a revised root cause report (ADAMS Accession No. ML12142A053) on May 16, 2012, with changes to address the minor weaknesses identified during the NRC inspection.

As part of the long term monitoring of the shield building laminar cracking condition, the licensee subjected a sample of existing shield building core bores to visual examination as prescribed by licensee procedure EN-DP-01511, "Design Guidelines for Maintenance Rule Evaluation of Structures." One purpose of the core bore visual examinations conducted under this procedure was to identify any crack growth or change in existing crack thickness to determine if the shield building laminar cracking is active (growing) or passive (not growing).

During the course of this in-depth review, the inspectors verified the status of the licensee's core bore visual examinations to date, as well as their evaluations and corrective action documents resulting from shield building laminar cracking not identified by previous visual examinations. In addition, the inspectors reviewed the licensee's plans for follow-on examinations and corrective actions that had been established to verify that the classification, prioritization, focus, and timeliness of these actions were commensurate with the safety significance of the issue. Documents reviewed are listed in the Attachment to this report.

The review of this issue by the inspectors constituted a single annual follow-up inspection sample for in-depth review as defined in IP 71152-05.

b. Observations

For the 2013 examinations, the licensee utilized a boroscope with higher definition that provided improved clarity and mobility over equipment used in previous visual examinations of shield building core borings. On August 26, 2013, the licensee identified a crack in Core Bore S4-650.0-016 that had not been identified by previous periodic visual examinations. The issue was entered into the licensee's CAP as CR 2013-13239 on August 27, 2013. As part of their extent-of-condition investigation, the licensee identified an additional crack in Core Bore S3-650.0-011, which had also not been identified by previous period visual examinations. The licensee documented this issue in their CAP under CR 2013-13458 on August 28, 2013. As a result of the additional core bore cracking identified by further expansion of the 2013 periodic visual examinations, the licensee expanded their extent-of-condition visual examinations during the 2013 campaign to include all existing shield building core borings that had not been refilled with concrete. This extended the sample size to a total of 80 core bore locations.

The inspectors examined shield building Core Bore S4-650.0-016 and Core Bore S3-650.0-011 using the examination boroscope utilized by the licensee during their 2012 visual examination campaign and the current examination boroscope that is being used for the licensee's 2013 campaign. The inspectors concluded that due to the lower clarity and mobility of the 2012 examination boroscope, some very tight existing cracks (approximately 0.005 inches thick) were likely not identified during the 2012 or earlier examinations.

The licensee justified categorizing a portion of the newly identified cracking as previously existing using shield building core bores and/or core bore documentation that show crack indications at corresponding core crack locations. The inspectors reviewed the cores and core indication documents for Core Bore S4-650.0-016 and Core Bore S3-650.0-011 and determined that the new cracking identified in these core bore locations aligned with corresponding known and documented core crack locations. Therefore, the inspectors determined that the recently identified cracking in these core bore locations was likely pre-existing and traceable back to 2011 when the core samples were originally taken.

The inspectors also reviewed the licensee’s justification for shield building operability and functionality that had considered the impact of the newly identified laminar cracking. The inspectors concluded that the licensee has, to date, provided reasonable assurance that the shield building has remained capable of performing all of its required design basis functions.

As of the conclusion of the inspection period on September 30, 2013, the licensee had visually examined 72 of the 80 shield building core bore locations using their higher definition boroscope. To date, the licensee has documented the following twelve new crack indications in their CAP:

- Six of the newly identified crack locations correspond to a previously existing known crack in one of the original removed core bore plugs, and are likely the result of the licensee's use of the new higher definition borocope;
- Four of the newly identified crack locations do not correspond to a previously existing known crack in one of the original removed core bore plugs, and require further analysis and explanation; and
- Two of the newly identified crack locations appear to have grown, and require further analysis and explanation.

The inspectors continue to monitor the licensee’s ongoing core bore visual examinations, their evaluation of any newly identified cracking, and any corrective actions resulting from this concern.

c. <u>Findings</u>

No findings were identified.

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

.1 (Closed) Licensee Event Report 05000346/2013-001-00: Reactor Trip Due to Reactor Coolant Pump 1-2 Motor Faulty Electrical Connection

a. Inspection Scope

On June 29, 2013, at approximately 9:22 p.m., RCP 1-2 tripped due to an electrical fault. The ensuing rapid reduction in reactor coolant flow with the plant operating at full power resulted in a condition whereby reactor power was higher than the allowable value for the reactor coolant flow condition. This condition was sensed immediately by the RPS, and an automatic reactor trip on flux/delta flux/flow was generated. NRC inspectors responded to the site immediately following the reactor trip and remained on station in the site's control room providing independent assessment of the event until it was determined that the trip was uncomplicated by any significant equipment or human performance issues. The inspectors observed and reviewed the licensee's response to the event, operator logs, computer and recorder data, and procedural requirements. Specific items associated with this event that were reviewed included, but were not limited to:

- Mitigating systems and fission product barriers performance and integrity;
- The realignment plant equipment in response to the trip;
- The performance of plant operators in the Control Room and in the field;
- Event notifications made pursuant to 10 CFR 50.72;
- The potential for any generic issues, including those potentially requiring reporting under 10 CFR Part 21;
- The licensee's termination from their trip response procedures and transition to normal shutdown plant operations;
- The licensee's completed root cause report associated with the event; and
- The accuracy of the information provided by the licensee in the Licensee Event Report (LER).

Documents reviewed as part of this inspection are listed in the Attachment. This LER is closed.

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

b. Findings

RCP Trip, RPS Actuation and Reactor Trip Results from the Installation of a RCP Motor Repair Part Not Suitable for the Application

Introduction

A self-revealed finding of very low safety significance (Green) was identified for the licensee's failure to procure and install appropriate replacement parts for repair of the RCP 1-2 motor during the 2010 refueling outage (RFO). Specifically, a degraded terminal strip in the motor's current transformer (CT) circuit was replaced with a new terminal strip that had substandard fasteners. The licensee's procurement process did not have any provisions in place to ensure the fasteners (screws) were of the appropriate quality for the application, and some of the screws ultimately failed due to vibration-induced fatigue.

Description

During the licensee's 16th RFO in March of 2010, the licensee identified degraded CT circuit electrical components in the electrical termination box on the RCP 1-2 motor. The inspection determined that some wires and terminal strip should be replaced. The original wiring and terminal strip had been installed by the RCP manufacturer and had been in service for over 30 years. The replacement components were considered to be like for like replacements.

With the reactor operating at full power, on June 29, 2013, at approximately 9:22 p.m., the RCP 1-2 motor tripped on actuation of the associated No. 87 differential relay. The trip of RCP 1-2 caused a trip of RPS Channels 2 and 4 on the flux/delta flux/flow parameter, which in turn tripped the reactor.

An investigation following the reactor trip revealed that the CT wiring and associated terminal strip in the electrical termination box on the RCP 1-2 motor were degraded. The wiring was broken and had cracked insulation, with other degradation noted being consistent with damage caused by corona and/or partial electrical discharge. The wiring appeared to have contacted the insulation of the high voltage components in the termination box. There were black burn marks on a high voltage bar that the licensee concluded were most probably the result of an electric arc which occurred when the CT circuit opened. The arc burned through the wiring causing another open circuit in the CT wiring. The terminal strip screws all showed signs of degradation. Two screw heads were found broken, and one screw and wiring had lifted from the terminal block causing the CT circuit to open. Another screw broke when plant electricians attempted to remove it.

The licensee collected the terminal strip screws, ring lugs and screw heads, and those that could be cleaned and radiologically released were sent to the licensee's off site lab facility for analysis and testing along with a new terminal strip from stock for comparison. This analysis and testing revealed that the terminal strip screws had likely failed from vibration-induced fatigue. Further, the licensee's investigation showed that the terminal strip screws were purchased as an integral component of the replacement terminal strip that was installed in 2010. Individual fasteners (i.e., screws, etc.) procured by the licensee through their commercial grade process would have been verified to have met applicable American National Standards Institute (ANSI) requirements for quality. However, because the screws on the replacement terminal strip were purchased as an integral component of the terminal strip, they were not verified to have met applicable ANSI requirements for quality. The licensee's analysis concluded that the screws on the replacement terminal strip were substandard and not appropriate for a high vibration service environment like that within the RCP 1-2 motor electrical termination box.

In response to the event, the licensee conducted a full root cause investigation. Corrective actions taken by the licensee included the replacement of the damaged electrical components within the RCP 1-2 motor electrical termination box with repair parts meeting applicable ANSI-quality requirements. Additionally, the RCP 1-2 motor was electrically tested prior to restart to ensure that the CT circuit fault had not resulted in any other damage. The licensee also verified via field inspections and review of maintenance records that the other three RCP motor CT circuits were not similarly degraded. The licensee had entered this event into their CAP as CR 2013-10038.

Analysis

The inspectors reviewed this finding using the guidance contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor IRs." The inspectors determined that the licensee's failure to procure and install a replacement terminal strip in the RCP 1-2 motor CT circuit that was of appropriate quality and properly rated for the service environment 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 determined to be of more than minor significance because it was associated with cornerstone attribute of design control and adversely affected the cornerstone objective: "To limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations."

The inspectors evaluated the finding using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." Using Exhibit 1 – "Initiating Events Screening Questions," the inspectors determined the finding to be of very low safety significance (Green) because it resulted in a reactor trip without any corresponding loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition, and there were no other abnormal events such as fire, flooding, or HELBs.

Using IMC 0310, "Components Within the Cross-Cutting Areas," the inspectors determined that the finding had a cross-cutting aspect in the area of human performance, resources component, because the licensee had failed to ensure that the replacement terminal strip, which ultimately was cause of the reactor trip, was adequate for its service environment. (H.2(d))

Enforcement

The quality of replacement parts intended for use in safety-related applications is regulated under Appendix B of 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Because the component in question, the replacement terminal strip for the CT circuit within the RCP 1-2 motor electrical termination box, was not intended for use or used for a safety-related application, the inspectors determined that the finding did not involve any corresponding violation of regulatory requirements. (FIN 05000346/2013004-03)

.2 (Closed) Licensee Event Report 05000346/2013-002-00: Leak From Reactor Coolant Pump Seal Piping Socket Weld Due to High Cycle Fatigue

a. Inspection Scope

The inspectors reviewed the subject Licensee Event Report (LER) and related documents. Specific items associated with this event that were reviewed included, but were not limited to:

- The accuracy of the information provided by the licensee in the LER;

- The appropriateness of corrective actions taken by the licensee in response to the event;
- The potential for any generic issues, including those potentially requiring reporting under 10 CFR Part 21; and
- The licensee's completed root cause report associated with the event.

Documents reviewed as part of this inspection are listed in the Attachment. This LER is closed.

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

b. Findings

Operation of the Plant at Power with Reactor Coolant System (RCS) Pressure Boundary Leakage

Introduction

A self-revealed finding of very low safety significance (Green) and an associated NCV of TS 3.4.13, "RCS Operational Leakage," were identified for the licensee's failure to fully evaluate a previously identified degraded condition on the first stage seal cavity vent line for RCP 1-2. Specifically, a known high-vibration condition associated with this line had caused a pinhole leak on a socket weld on the line that was repaired in June of 2012. However, the licensee's root cause evaluation and subsequent repair efforts for that leak failed to adequately address other welds on that vent line that were also subjected to the same high vibration levels, such that following an unplanned reactor trip another small RCS pressure boundary leak was discovered on a different socket weld on the same line on July 1, 2013.

Description

On June 6, 2012, the unit was offline and in a hot standby (Mode 3) condition with the RCS at normal operating pressure and temperature. Plant personnel were in the process of conducting scheduled visual inspections of RCS components for leakage as part of the regular sequence of events required to return the plant to operation following reactor refueling activities. During the course of these inspections, plant engineering personnel identified a small pinhole leak on a socket weld on the first stage seal cavity vent line (¾ inch diameter) for RCP 1-2. The leak was estimated to be approximately 0.1 gpm, and due to its location could not be isolated from the RCS.

In order to meet the requirements of TS 3.4.13 for RCS pressure boundary leakage, the licensee conducted a plant cooldown. The unit entered a cold shutdown (Mode 5) condition on June 7, 2012. Utilizing a freeze seal to isolate the pinhole leak from the RCS, the licensee affected repairs by grinding out the weld defect and then restoring the socket weld to its original design on June 11, 2012.

In response to this issue, the licensee conducted an evaluation into the root cause. While a definitive cause could not be established due to the fact that all forensic evidence related to the defect was eliminated by the nature of the repair technique (i.e., grinding out the weld defect and performing a re-weld, etc.), the licensee established that the most probable cause for the leak had been a high-cycle fatigue failure. The licensee postulated that the leak resulted from a combination of a less than adequate design for the RCP vibration conditions in combination with a discontinuity that was most probably induced during the initial weld's root pass. These conditions had existed since 1990, when the licensee modified their RCP seal cavity vent lines to accommodate a new style of RCP seal package.

In addition to the weld repairs made to the leak on the RCP 1-2 first stage seal cavity vent line, other corrective actions performed by the licensee included inspections of all similar RCP seal cavity vent lines for any signs of leakage. The licensee performed a detailed analysis of the vibration conditions being experienced by the RCP 1-2 first stage seal cavity vent line, and found that the peak vibration conditions were at a velocity of about 0.93 inches per second (ips). Further exacerbating the condition, the licensee found that this peak vibration level occurred at a natural harmonic frequency for RCP 1-2.

Because vibration induced high-cycle fatigue failure of socket welds has been a problem within the power plant industry, the Electric Power Research Institute (EPRI) has recommended that an improved 2 over 1 weld configuration be used for all socket welds in vibration-critical applications. Additionally, non-mandatory Part 3, Appendix D, of the ASME O/M Code, "Operation and Maintenance of Nuclear Power Plants," 1990 Edition, described a screening vibration velocity value that could be used to determine whether or not piping systems require supplementary analysis. Essentially, per this accepted industry guidance piping systems with peak velocities less than 0.5 ips are considered to be acceptable from a vibratory stress standpoint and require no further analysis. Piping systems with peak velocities greater than 0.5 ips are required to undergo further analysis to determine acceptability.

Ultimately, the licensee's corrective action plans called for the replacement of all of the RCP seal cavity vent lines with flex hose connections during the next RFO in 2014 to remove the vibration induced high-cycle socket weld-fatigue failure vulnerability. Despite the fact that the licensee measured the RCP 1-2 first stage seal cavity vent line at nearly double the 0.5 ips screening value and none of the existing socket welds on that line featured the EPRI recommended improved 2 over 1 weld configuration, the licensee concluded that no additional actions were required at that time and that the unit could be restarted and operate through the fuel cycle with the existing RCP 1-2 first stage seal cavity vent line to the next RFO in 2014.

On June 30, 2013, with the unit in Mode 3 following a reactor trip that had occurred the previous day, licensee personnel discovered an unusually large amount of boric acid residue covering essentially most of the mechanical seal package area surfaces, components, and pipes within the driver mount (pump bowl) of RCP 1-2. Extensive efforts were required to remove the boric acid residue, such that on July 1, 2013, a small RCS pressure boundary leak of about 8 to 9 drops per minute was identified on the ¾ inch, 1500 lb flange socket weld for the first stage seal cavity vent line. As with the previous leak in June of 2012, in order to meet the requirements of TS 3.4.13 for RCS pressure boundary leakage the licensee conducted a plant cooldown to Mode 5 to affect repairs.

In response to the event, the licensee conducted a full root cause investigation. Instead of performing a weld repair as had been done in June of 2012, corrective actions taken by the licensee included the replacement of the section of RCP 1-2 first stage seal cavity vent line that was closest to the RCP and most affected by the high vibration condition. This new section of vent line was fabricated from new materials and featured the EPRI recommended improved 2 over 1 weld configuration in all of its socket welds. Additionally, the licensee gathered more comprehensive vibration data for the first, second, and third stage seal cavity vent lines on all RCPs. Detailed analysis of this data revealed that the RCP 1-2 first stage seal cavity vent line was an outlier, and was experiencing significantly higher vibration levels than any other seal cavity vent line. The licensee had entered this event into their CAP as CRs 2013-10061 and 2013-10089, and still intends to replace all of the RCP seal cavity vent lines with flex hose connections during the next RFO in 2014 to remove the vibration induced high-cycle socket weld fatigue failure vulnerability.

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 fully evaluate the circumstances surrounding the June of 2012 RCS pressure boundary leak on the RCP 1-2 first stage seal cavity vent line and the impact of continued operation with the original vent line installed constituted 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 determined to be of more than minor significance because it was associated with cornerstone attribute of equipment performance and adversely affected the cornerstone objective: "To limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations."

The inspectors evaluated the finding using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." Since the finding was not related to pressurized thermal shock and only involved an RCS barrier (leakage) issue, the inspectors used Exhibit 1 – "Initiating Events Screening Questions" and determined it to be of very low safety significance (Green) because:

- After a reasonable assessment of degradation, the inspectors determined that due to the small size of the RCP 1-2 first stage seal cavity vent line that the finding could not result in exceeding the RCS leak rate for a small loss of coolant accident (LOCA); and
- After a reasonable assessment of degradation, the inspectors determined that the finding could not have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA, etc.).

Using IMC 0310, "Components Within the Cross-Cutting Areas," the inspectors determined that the finding had a cross-cutting aspect in the area of PI&R, CAP component, because the licensee had failed to thoroughly evaluate the event in June of 2012 such that the resolution addressed causes and extent of conditions. (P.1(c))

Enforcement

Based on the widespread and significant boric acid residue discovered within the pump bowl of RCP 1-2 on June 30, 2013, the inspectors concluded that the small RCS pressure boundary leak that was identified on July 1, 2013, had existed for several days, or perhaps even weeks, prior to the reactor trip on June 29, 2013. While operating in

Modes 1 through 4, TS 3.4.13, "RCS Operational Leakage," states that no RCS pressure boundary leakage is allowed. Thus, contrary to this requirement, the licensee operated the unit for a period of time contrary to the requirements of this TS.

Because this finding was of very low safety significance and had been entered into the licensee's CAP, the associated violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. Corrective actions taken and planned by the licensee and the applicable CAP CR numbers are discussed in detail in the Description Section above. (NCV 05000346/2013004-03)

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 15, 2013, the inspectors presented the inspection results to the Site Vice President, Mr. R. Lieb, and other members of the licensee staff. The licensee acknowledged the issues presented. Proprietary information reviewed by the inspectors was identified and were either returned to the licensee or verified as being controlled in accordance with applicable NRC policy and procedures regarding sensitive unclassified information.

.2 Interim Exit Meetings

An interim exit was conducted via telephone for:

- On September 25, 2013, the inspectors presented the preliminary inspection results regarding the closure of URI 05000346/2012008-01: Impact of a HELB in the Turbine Building on Safety-Related Electrical Equipment Located in the Switchgear Rooms, to Mr. K. Byrd, the Site Engineering Director, and other members of the licensee staff. The licensee acknowledged the issues presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Several documents reviewed by the inspectors were considered proprietary information and were either returned to the licensee or verified as being controlled in accordance with applicable NRC policy and procedures regarding sensitive unclassified information.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section 2.3.2 of the NRC Enforcement Policy for being dispositioned as an NCV.

.1 Additional High Pressure Injection Train 1 Inoperability and Unavailability Caused by Failure to Follow Procedure

Appendix B of 10 CFR Part 50, Criterion V, "Instructions, Procedures, Drawings" requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

Contrary to this requirement, on September 24, 2013, an equipment operator failed to adequately perform procedure DB-SP-03218, High Pressure Injection Train 1 Pump and Valve Test. Specifically, the licensee failed to verify step 4.3.10 of DB-SP-03218 was performed to request an instrument and controls technician to open high pressure drain valve HP4BA1 to place a test pressure gauge in service. The equipment operator was not able to contact the instrument and controls technician and signed off the procedure step as completed. The valve to the test pressure gauge was never opened and the test pressure gauge displayed, and was recorded multiple times as, zero for the duration of the test. Note 4.3.11 of DB-SP-03218 specifically indicated the expected pressure of the test gauge was approximately 25 psig. The procedure was then completed without noticing the test pressure gauge discrepancy and the acceptance criteria were incorrectly signed off as acceptable. The SRO reviewing the test acceptance criteria identified the error, and the test was re-performed satisfactorily on September 26, 2013.

The objective of the Mitigating Systems Cornerstone of Reactor Safety is to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). A key attribute of this objective is human performance, and specifically, configuration control. In accordance with NRC IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” the inspectors determined that the violation was of more than minor significance in that it had a direct impact on this cornerstone objective. The licensee’s failure to complete DB-SP-03218 as written resulted in additional inoperability and unavailability time for HPI train 2 during re-performance of the test procedure. The licensee had entered this issue into their CAP as CR 2013-14882. A full apparent cause evaluation was in progress at the end of the inspection period to determine appropriate corrective actions.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Lieb, Site Vice President
D. Blakely, Supervisor, Design Engineering
B. Boles, Director, Site Operations
K. Byrd, Director, Site Engineering
V. Capozziello, Chemistry Supervisor
G. Cramer, Manager, Site Protection
J. Cuff, Manager, Training
A. Dawson, Manager, Chemistry
J. Dominy, Director, Site Maintenance
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, Plant Engineering
P. McCloskey, Manager, Site Regulatory Compliance
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, Manager, Site Operations
M. Roelant, Manager, Site Projects
L. Rushing, Director, Special Projects
C. Sacha, Radiation Protection Supervisor
D. Saltz, Manager, Site Maintenance
J. Sturdavant, Regulatory Compliance
L. Thomas, Manager, Nuclear Supply Chain
M. Travis, Superintendent, Radiation Protection
J. Vetter, Manager, Emergency Response
V. Wadsworth, Sr. Nuclear Specialist, Regulatory Compliance
G. Wolf, Supervisor, Regulatory Compliance
K. Zellers, Supervisor, Reactor Engineering

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000346/2013004-01	FIN	Inadequate Operations Crew Turnover (Section 1R11.2)
05000346/2013004-02	NCV	Impact of a HELB in the Turbine Building on Safety-Related Electrical Equipment Located in the Switchgear Rooms (Section 1R21.1)
05000346/2013004-03	FIN	RCP Trip, RPS Actuation and Reactor Trip Results from the Installation of a RCP Motor Repair Part Not Suitable for the Application (Section 4OA3.1)
05000346/2013004-04	NCV	Operation of the Plant at Power with Reactor Coolant System Pressure Boundary Leakage (Section 4OA3.2)

Closed

05000346/2013004-01	FIN	Inadequate Operations Crew Turnover (Section 1R11.2)
05000346/2013004-02	NCV	Impact of a HELB in the Turbine Building on Safety-Related Electrical Equipment Located in the Switchgear Rooms (Section 1R21.1)
05000346/2012008-01	URI	Impact of a HELB in the Turbine Building on Safety-Related Electrical Equipment Located in the Switchgear Rooms (Section 1R21.1)
05000346/2013004-03	FIN	RCP Trip, RPS Actuation and Reactor Trip Results from the Installation of a RCP Motor Repair Part Not Suitable for the Application (Section 4OA3.1)
05000346/2013-001-00	LER	Reactor Trip Due to Reactor Coolant Pump 1-2 Motor Faulty Electrical Connection (Section 4OA3.1)
05000346/2013004-04	NCV	Operation of the Plant at Power with Reactor Coolant System Pressure Boundary Leakage (Section 4OA3.2)
05000346/2013-002-00	LER	Leak From Reactor Coolant Pump Seal Piping Socket Weld Due to High Cycle Fatigue (Section 4OA3.2)

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

1R01 Adverse Weather Protection

Condition Reports:
- 2013-10547; Actual ANS Siren Activation Due to Sever Weather
- 2013-10564; Emergency Operations Facility Lost Normal Power Due to Storm

Procedures:
- DBRM-EMER-1500A; Davis-Besse Emergency Action Level Basis Document; Revision 4
- DBRM-EMER-1500B; Davis-Besse EAL Wallboards; Revision 1
- DB-SC-03020; 13.8 KV System Bus A&B Transfer Test; Revision 16
- DB-SC-03022; Off-Site AC Sources Bus Transfer Test; Revision 13
- DB-ME-09150; 345 KV Switchyard Maintenance; Revision 3
- DB-OP-01300; Switchyard Work Management; Revision 8
- DB-OP-02025; Davis-Besse 345 KV Switchyard Alarm Panel 25 Annunciators; Revision 9
- DB-OP-02521; Loss of AC Bus Sources; Revision 21
- DB-OP-02546; Degraded Grid; Revision 2
- NG-DB-00204; Control of Vehicles and Heavy Equipment Near Vital Station Equipment; Revision 3
- NOP-OP-1003; Grid Reliability Protocol; Revision 5
- NOP-OP-1007; Risk Management; Revision 16
- NOP-OP-1012; Material Readiness and Housekeeping Inspection Program; Revision 7
- RA-EP-01500; Emergency Classification; Revision 15
- RA-EP-02810; Tornado or High Winds; Revision 11
- RA-EP-02830; Flooding; Revision 2
- RA-EP-02870; Station Isolation; Revision 5

Work Orders:
- 200567276; SC3023-003 05.300 Offsite AC Source Available

Other:
- Individual Plant Examination of External Events for the Davis-Besse Nuclear Power Station Section 5.3 and 5.4; High Winds and Tornadoes and Floods; December 1996

1R04 Equipment Alignment

Condition Reports:
- 2013-12645; SBODG Electrical Room Fan Found in Non-Normal Position

Procedures:
- DB-OP-06012; Decay Heat and Low Pressure Injection Operating Procedure; Revision 58
- DB-OP-06225; MDFP Operating Procedure; Revision 20
- DB-OP-06251; Station and Instrument Air System Operating Procedure; Revision 37
- DB-OP-06334; Station Blackout Diesel Generator Operating Procedure; Revision 20

Drawings:
- OS-004, Sheet 1; Decay Heat Removal / Low Pressure Injection System; Revision 51
- OS-004, Sheet 2; Decay Heat Removal; / Low Pressure Injection System; Revision 7
- OS-0012A, Sheet 1; Main Feedwater System; Revision 26
- OS-0017A, Sheet 1; Auxiliary Feedwater System; Revision 27
- M-0015A; Instrument Air System; Revision 60
- M-0015C; Station Air System; Revision 25
- M-0015D; Station Air System; Revision 23
- M-0017D; Station Blackout Diesel Generator; Revision 15
- M-033B; Decay Heat Train 1; Revision 55
- M-033C; Decay Heat Train 2; Revision 27

1R05 Fire Protection

Condition Reports:
- 2013-10151; MS-C-13-05031: Quarterly Fire Brigade Drill Frequency and Type Deficiency
- 2013-12007; Two creepers were found staged in the Cable Spread Room

Pre-Fire Plans:
- PFP-AB-422A; Cable Spreading Room, Room 422A, Fire Area DD; Revision 4

Other:
- Fire Hazard Analysis Report

1R11 Licensed Operator Requalification Program and Licensed Operator Performance

Condition Reports:
- 2013-10039; SP7B Did Not Respond Properly Following Reactor Trip
- 2013-10043; MFPT No. 2 Control Signal Anomalies During Reactor Trip Recovery
- 2013-10046; Reactor Trip From Automatic Reactor Protection System Actuation
- 2013-10315; Reactor Trip Transient Response Resulted In High Condenser Pressure
- 2013-10431; NI1 SR and NY NI1 SUR Momentarily Spiked
- 2013-10473; Gammametrics Channel 2 Source Range Inoperable
- 2013-12511; AD111 Close Power Fuses Cracked but Functioning
- 2013-12633; Operations Turnover Did Not Meet Expectations

Procedures:
- DB-OP-06002; RCS Draining and Nitrogen Blanketing; Revision 20
- DB-OP-06301; Generator and Exciter Operating Procedure; Revision 24
- DB-OP-06401; Integrated Control System Operating Procedure; Revision 21
- DB-OP-06900; Plant Heatup; Revision 55
- DB-OP-06901; Plant Startup; Revision 35
- DB-OP-06903; Plant Cooldown; Revisions 42-43
- DB-OP-06904; Shutdown Operations; Revisions 40-43
- DB-OP-06910; Trip Recovery; Revision 20
- DB-OP-06911; Pre-Startup Checklist; Revision 23
- DB-OP-06912; Approach to Criticality; Revision 16
- DB-NE-06201; Reactor Operator's Curve Book; Revision 13
- NOP-OP-1002; Conduct of Operations; Revision 8
- NOP-OP-1015; Event Notifications; Revision 0
- NT-OT-7001; Training and Qualification of Operations Personnel; Revision 13

- 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:
- NOBP-OP-0007; Conduct of Infrequently Performed Tests or Evolutions; Revision 5
- 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 10
- NOBP-TR-1112; FENOC Conduct of Simulator Training and Evaluation; Revision 2
- DBBP-OPS-1013; Control of Time Critical Actions; Revision 2

1R12 Maintenance Effectiveness

Condition Reports:
- 2012-09381; During DB-PF-03010 NOP/NOT: Active Leak on RCP 1-2 1st Seal Cavity Vent Line
- 2013-10038; RCP 1-2 Motor Trip
- 2013-10089; RCP 1-2 Seal Cavity Vent Line Active Leak
- 2013-10120; Damaged Current Transformer Wires Discovered on RCP 1-2
- 2013-10186; RCP 1-2 T1 Bus Bar Potentially Degraded Silver Plating
- 2013-10187; Motor Testing Equipment Unable to Test RCP Motors as in the Past
- 2013-10246; RCP 1-2 Final PdMA Polarization Index Testing Fails Acceptance Criteria
- 2013-10264; BACC: Category C Material Loss Identified Near the Driver Mount to Pump Cover Interface of RCP 1-2
- 2013-10349; RCP 2-2 Motor Enclosure Leaking Small Amounts of Water
- 2013-10354; CCW Leak in RCP 2-2 Motor Air Box

Work Orders:
- 200568447; RCP 1-2 1st Stage Seal Cavity Vent Repair; 07/05/2013

1R13 Maintenance Risk Assessments and Emergent Work Control

Condition Reports:
- 2013-10038; RCP 1-2 Motor Trip
- 2013-10089; RCP 1-2 Seal Cavity Vent Line Active Leak
- 2013-10120; Damaged Current Transformer Wires Discovered on RCP 1-2
- 2013-10186; RCP 1-2 T1 Bus Bar Potentially Degraded Silver Plating
- 2013-10187; Motor Testing Equipment Unable to Test RCP Motors as in the Past
- 2013-10246; RCP 1-2 Final PdMA Polarization Index Testing Fails Acceptance Criteria
- 2013-10289; PdMA Motor Tester M&TE No. MMT0003 Has a Questionable High Voltage Power Supply
- 2013-10335; Review of Period of Yellow Shutdown Defense in Depth
- 2013-10338; PA-DB-13-02: Entry Into Yellow Risk for Shutdown Safety Was Not Documented in the Narrative Log
- 2013-10473; Gammametrics Channel 2 Source Range Inoperable
- 2013-10686; Gammametrics Channel 1 Continuing Test Circuitry Issue
- 2013-10652; Condition Report generated for performance of DB-SC-03180 for Gammametrics Channel 1 NI5874C
- 2013-13238; ACD2, ACD2 Tie To Feeder Breaker AC108, Tripped OPEN

Procedures:
- DB-PF-05064; Electrical Machine Testing Using PdMA Motor Tester; Revision 12
- NOP-OP-1005; Shutdown Defense in Depth; Revision 13
- DB-SC-03180; Remote Shutdown, Post Accident Monitoring Instrumentation Monthly Channel Check; Revision 13

Work Orders:
- 200510408; De-Energized Motor Testing on RCP 1-2 Using DB-PF-05064; 07/05/2013
- 200568447; RCP 1-2 1st Stage Seal Cavity Vent Repair; 07/05/2013

1R15 Operability Determinations and Functionality Assessments

Condition Reports:
- 2013-10044; Metal Strips Found Outside Following Reactor Trip
- 2013-10048; Main Steam Line Safety Valve Anomalies Following Reactor Trip
- 2013-10266; POD 10-001 Review of Mode Change or Plant Operating Restrictions
- 2013-11638; High Pressure on PIHP-42, HPI-CFT Pressure
- 2013-11895; Overly Conservative Assumption in CREATCS Evaluation Methodology

Procedures:
- DB-SS-03710; Functional Test for Control Room Emergency Ventilation System Train 1; Revisions 11-12
- DB-SS-03711; Functional Test for Control Room Emergency Ventilation System Train 2; Revision 12

Work Orders:
- 200426812; Control Room Emergency Ventilation System Train 2 Functional Test; 9/6/2013
- 200529779; Control Room Emergency Ventilation System Train 2 Air Flow; 9/6/2013
- 200529199; Control Room Emergency Ventilation System Train 2 Positive Pressure Test; September 6, 2013

Drawings:
- M-031C; Make Up and Purification System; Revision 41
- M-033A; High Pressure Injection; Revision 44
- M-034; Emergency Core Cooling System, Containment Spray, and Core Flooding Systems; Revision 67

1R18 Plant Modifications

Condition Reports:
- 2013-13650; Hayes Line & 81-B-65 Project Requires a Temporary Low Bus Support Emergent Work Issue

Procedures:
- DBBP-OPS-0040; Switchyard Area Material Control; Revision 0
- DB-OP-01300; Switchyard Management; Revision 8
- NG-DB-00204; Control of Vehicles and Heavy Equipment Near Vital Station Equipment; Revision 3
- NOP-OP-1003; Grid Reliability Protocol; Revision 5
- NOP-WM-4007; Excavation & Trenching Controls; Revision 2

Work Orders:
- 200571212; ECP 13-0177-001 Above Grade Civil/Structural Activities; 8/26/2013

Drawings:
- 6E550-55; 345 kV Switchyard Raceway Layout Plan; Revision F
- 6E550-51-1; 345 kV Switchyard Electrical Equipment Plan View; Revision E
- 6E550-54; 345 kV Switchyard Ground Plan and Details; Revision E
- 6S550-1; 345 kV Switchyard Steel Key Plan SHT #1; Revision C
- T-550-14-03; Electrical Layout 345 kV Switchyard Sections and Elevations; Revision -
- T-550-14-01; Electrical Layout 345 kV Switchyard Sections and Elevations; Revision E

Other:
- ECP 13-0177-001; Above and Below Grade Civil/Structure Activities; Revision 0
- ECP 13-0177-002; Remove Bus Span between 34564 (F33) and K Bus; Revision 0
- ECP 13-0177-003; Demo Bay 3 Bus Foundations and Installation of Panels 2LA & 2LB; Revision 0

<u>1R19 Post Maintenance Testing</u>

Condition Reports:
- 2013-10038; RCP 1-2 Motor Trip
- 2013-10089; RCP 1-2 Seal Cavity Vent Line Active Leak
- 2013-10120; Damaged Current Transformer Wires Discovered on RCP 1-2
- 2013-10186; RCP 1-2 T1 Bus Bar Potentially Degraded Silver Plating
- 2013-10187; Motor Testing Equipment Unable to Test RCP Motors as in the Past
- 2013-10246; RCP 1-2 Final PdMA Polarization Index Testing Fails Acceptance Criteria
- 2013-10289; PdMA Motor Tester M&TE No. MMT0003 Has a Questionable High Voltage Power Supply
- 2013-13833; CC1467 Lower Regulator Leak

Procedures:
- DB-MI-03109; Functional Test/Calibration of PT-2002 Containment Pressure Transmitter to SFAS Channel 3; Revision 8
- DB-MI-03117; Response Time Test of 59A-ISP2002 Containment Pressure SFAS Channel 3; Revision 9
- DB-PF-03071; CCW Train 1 Valve Testing; Revision 14
- DB-PF-05064; Electrical Machine Testing Using PdMA Motor Tester; Revision 12
- DB-OP-06000; Miscellaneous Operation Curves; Revision 20
- DB-OP-06005; Reactor Coolant Pump Operation; Revision 30

Work Orders:
- 200423771; Energized Motor Testing on RCP 1-2 Using DB-PF-05064; 07/10/2013
- 200510408; De-Energized Motor Testing on RCP 1-2 Using DB-PF-05064; 07/05/2013
- 200510408; Energized Motor Testing on RCP 1-2 Using DB-PF-05064; 07/10/2013
- 200575121; CCW from Decay Heat Cooler 1 Solenoid; 9/7/2013
- 200568447; RCP 1-2 1st Stage Seal Cavity Vent Repair; 07/05/2013
- 200437633; Containment Pressure to SFAS Channel 3 Calibration; 9/26/2013
- 200471877; Containment Pressure to SFAS Channel 3 Bench Test; 9/26/2013

Drawings:
- E-52B, Sheet 46A; Reactor Coolant System Reactor Coolant Pump Motor MP0362 AC Circuit; Revision 10

1R20 Outage Activities

Condition Reports:
- 2013-10038; RCP 1-2 Motor Trip
- 2013-10039; SP7B did Not Respond Properly Following Reactor Trip
- 2013-10041; MS210 Excessive Noise Following Reactor Trip
- 2013-10043; MFPT No. 2 Control Signal Anomalies During Reactor Trip Recovery
- 2013-10044; Metal Strips Found Outside Following Reactor Trip
- 2013-10046; Reactor Trip From Automatic Reactor Protection System Actuation
- 2013-10048; Main Steam Line Safety Valve Anomalies Following Reactor Trip
- 2013-10060; Steam Leak on MS209 Actuator
- 2013-10061; BACC: Probable Seal Leak Was Found on P36-2 (RCP 1-1-2)
- 2013-10062; Containment Initial Entry After Reactor Trip June 2013
- 2013-10089; RCP 1-2 Seal Cavity Vent Line Active Leak
- 2013-10120; Damaged Current Transformer Wires Discovered on RCP 1-2
- 2013-10186; RCP 1-2 T1 Bus Bar Potentially Degraded Silver Plating
- 2013-10246; RCP 1-2 Final PdMA Polarization Index Testing Fails Acceptance Criteria
- 2013-10264; BACC: Category C Material Loss Identified Near the Driver Mount to Pump Cover Interface of RCP 1-2
- 2013-10301; BACC: Water Leaked from CRDM Vent Rig During Venting
- 2013-10315; Reactor Trip Transient Response Resulted In High Condenser Pressure
- 2013-10334; Documentation of Restart Readiness Review Meeting
- 2013-10335; Review of Period of Yellow Shutdown Defense in Depth
- 2013-10338; PA-DB-13-02: Entry Into Yellow Risk for Shutdown Safety Was Not Documented in the Narrative Log
- 2013-10349; RCP 2-2 Motor Enclosure Leaking Small Amounts of Water
- 2013-10354; CCW Leak in RCP 2-2 Motor Air Box
- 2013-10431; NI1 SR and NY NI1 SUR Momentarily Spiked
- 2013-10473; Gammametrics Channel 2 Source Range Inoperable
- 2013-11712; Reactor Coolant System Lithium Control Following RCP 1-2 Outage

Procedures:
- DB-OP-01200; Reactor Coolant System Leakage Management; Revision 12
- DB-OP-06000; Miscellaneous Operation Curves; Revision 20
- DB-OP-06002; RCS Draining and Nitrogen Blanketing; Revision 20
- DB-OP-06301; Generator and Exciter Operating Procedure; Revision 24
- DB-OP-06401; Integrated Control System Operating Procedure; Revision 21
- DB-OP-06900; Plant Heatup; Revision 55
- DB-OP-06901; Plant Startup; Revision 35
- DB-OP-06903; Plant Cooldown; Revision 43
- DB-OP-06904; Shutdown Operations; Revision 40
- DB-OP-06910; Trip Recovery; Revision 20
- DB-OP-06911; Pre-Startup Checklist; Revision 23
- DB-OP-06912; Approach to Criticality; Revision 16
- DB-NE-06201; Reactor Operator's Curve Book; Revision 13
- NOP-OP-1005; Shutdown Defense in Depth; Revision 13

FENOC Business Practices:
- NOBP-OP-0007; Conduct of Infrequently Performed Tests or Evolutions; Revision 5
- NOBP-OM-4010; Restart Readiness for Plant Outages; Revision 4

1R21 Component Design Basis Inspection

Procedures:
- DB-OP-06513; Auxiliary Building Nonradioactive Area Ventilation, Revision 21

Condition Reports:
- 2012-12292; Switchgear Room Ventilation during HELBs
- 2010-80802; Turbine Building HELB Design Analysis Concerns

Miscellaneous:
- BRK System Sensor Installation and Maintenance Instructions for Model DH1851AC and DH2851AC Air Duct Smoke Detectors
- System Sensor Installation and Maintenance Instructions Innovair DH100ACDCLP Air Duct Smoke Detector with Extended Air Speed Range
- Honeywell Limits Controls L4029E, F Manuals
- PRA-DB1-12-007-R00; Risk Assessment for HELB Impact on the Switchgear Rooms due to Operation of Aux Building Normal Ventilation; September 7, 2012

Drawings:
- OS-035; Auxiliary Building Non-Radioactive HVAC Systems; Revision 29

Calculation:
- FAI/120834; Calculation to Analyze Heat-up and Condensation Potential in the Davis-Besse Turbine Building and Auxiliary Building Safety-related Switchgear Rooms; Revision 0

1R22 Surveillance Testing

Condition Reports:
- 2013-10254; Different Acceptance Criteria in Surveillance Procedure DB-PF-03008 and the Maximum Allowable Leakage Rate (MALR) Basis Document
- 2013-11895; Overly Conservative Assumption in CREATCS Evaluation Methodology
- 2013-13458; Shield Building Core Bore S3-650.0-11 Findings
- 2013-13782; Shield Building Core Bore S5-666.0-10 Findings
- 2013-13854; Shield Building Core Bore S7-666.0-7 Findings
- 2013-13860; Shield Building Core Bore S7-666.0-9 Findings

Procedures:
- DB-SS-03710; Functional Test for Control Room Emergency Ventilation System Train 1; Revisions 11-12
- DB-OP-03013; Containment Daily Inspection & Containment Closeout Inspection; Revision 9
- DB-SC-03070; Emergency Diesel Generator 1 Monthly Test; Revision 31
- DB-PF-03008; Containment Local Leakage Rate Tests; Revision 17
- EN-DP-01511; Design Guidelines for Maintenance Rule Evaluation of Structures; Revision 1

Work Orders:
- 200425229; Performance of DB-SS-03710; 07/31/2013 and 08/21/2013
- 200471009; Performance of DB-SC-03070; 08/01/2013

- 200535377; CV5005 LLRT Using DB-PF-03008; 07/04/2013
- 200535384; CV5006 LLRT Using DB-PF-03008; 07/04/2013
- 200535385; CV5007 LLRT Using DB-PF-03008; 07/04/2013
- 200535386; CV5008 LLRT Using DB-PF-03008; 07/04/2013

Drawings:
- C-111A; Shield Building Exterior Developed Elevation; Revision 4
- C-111B; Shield Building Exterior Developed Elevation; Revision 0

1EP6 Drill Evaluation

Condition Reports:
- 2013-14249; EP DRILL - Operation Support Center (OSC) Team Performance Summary of the September 10, 2013 Integrated Drill
- 2013-14100; EP Drill - Sept 2013 Summary of Critiqued items from Simulator Control Room
- 2013-14351; EP Drill - September 2013 Summary of Critiqued Items from the Technical Support Center
- 2013-14223; EP Drill: Summary of Critiqued items from Emergency Operations Facility (EOF)

Drawings and Charts:
- DBRM-EMER-1500B; Hot EAL Wall Board, Revision 1
- DBRM-EMER-1500B; Cold EAL Wall Board, Revision 1

Other:
- Emergency Preparedness Integrated Drill Manual, September 10, 2013; Revision 0

4OA1 Performance Indicator Verification

Forms:
- NOBP-LP-4012-48; MSPI Heat Removal System (AFW); Completed Forms for July 2012 through June 2013
- NOBP-LP-4012-49; MSPI Residual Heat Removal System (LPI); Completed Forms for July 2012 through June 2013
- NOBP-LP-4012-50; MSPI Support Cooling System, Component Cooling Water; Completed Forms for July 2012 through June 2013
- NOBP-LP-4012-51; MSPI Support Cooling System, Service Water; Completed Forms for July 2012 through June 2013

Procedures:
- NOBP-LP-4012; NRC Performance Indicators; Revision 3

Other:
- NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 6
- Select Operator Logs covering the period of July 2012 through June 2013
- Maintenance Rule Unavailability Database covering the period of July 2012 through June 2013
- Mitigating System Performance Index Basis Document, Davis-Besse Nuclear Power Station; Revision 4

4OA2 Problem Identification and Resolution

Condition Reports:
- 2010-86104; NRC Minor Violation - 72.48 Evaluation Expired for Use of Dry Cask Storage Pad
- 2011-91477; MS-C-11-03-30: 10CFR72.48 Screen Preparer Not Qualified
- 2011-91587; MS-C-11-03-30: Dry Fuel Storage Basis Manual Deficiencies
- 2013-03613; MS-C-13-03-30 10 CFR 72.48 Screens Not Completed for Some Instruction

Changes:
- 2012-07131; No Training or Qualification Program for 10 CFR 72.48 Evaluations
- 2013-04596; MS-C-13-03-30 Finding: No Current Evaluation is in Place for Temporary Storage of Radioactive and Combustible Material on the Dry Fuel Storage Facility Pad
- 2013-13239; Shield Building Core Bore S4-650.0-16 Findings
- 2013-13458; Shield Building Core Bore S3-650.0-11 Findings
- 2013-13782; Shield Building Core Bore S5-666.0-10 Findings
- 2013-13854; Shield Building Core Bore S7-666.0-7 Findings
- 2013-13860; Shield Building Core Bore S7-666.0-9 Findings
- 2013-13988; Shield Building Core Bore S6-666.0-44 Findings
- 2013-14097; Shield Building laminar Crack Extends
- 2013-14623; Shield Building Core Bore S13-663.0-11 Findings
- 2013-14725; Shield Building Core Bore S10-780.0-19 Findings
- 2013-14961; Shield Building Core Bore S4-773-16 Findings
- 2013-15137; Shield Building Core Bore S2-798.5-4.5 Findings
- 2013-15359; Shield Building Core Bore S1-772.5-5 Findings

Procedures:
- NG-EN-00372; Dry Fuel Storage, Revision 5
- DB-HP-01702; Transfer, Handling, and Storage of Radioactive Material; Revision 21
- NOP-LP-2001; Corrective Action Program; Revision 31
- NOP-LP-4013; Evaluation of Changes, Tests, Experiments for Independent Spent Fuel Storage Installation; Revision 0
- EN-DP-01511; Design Guidelines for Maintenance Rule Evaluation of Structures; Revision 1

Drawings:
- C-111A; Shield Building Exterior Developed Elevation; Revision 4

Other:
- WO 200479708; Boroscope Examination Log: Core Bore S3-650.0-11; October 26, 2011
- WO 200479708; Boroscope Examination Log: Core Bore S4-650.0-16; October 26, 2011
- Boroscope Examination Log: Core Bore S4-650.0-16; August 30, 2012
- Boroscope Examination Log: Core Bore S4-650.0-16; August 26, 2013
- DFSBM; Dry Fuel Storage Basis Manual for the Standardized Nuhoms-24P; Revisions 0-1
- SN-SA-2012-0120; Independent Spent Fuel Storage Installation; October 24, 2012

4OA3 Followup of Events and Notices of Enforcement Discretion

Condition Reports:
- 2012-09381; During DB-PF-03010 NOP/NOT: Active Leak on RCP 1-2 1st Seal Cavity Vent Line
- 2013-10038; RCP 1-2 Motor Trip
- 2013-10039; SP7B Did Not Respond Properly Following Reactor Trip

- 2013-10046; Reactor Trip From Automatic Reactor Protection System Actuation
- 2013-10048; Main Steam Line Safety Valve Anomalies Following Reactor Trip
- 2013-10089; RCP 1-2 Seal Cavity Vent Line Active Leak
- 2013-10315; Reactor Trip Transient Response Resulted In High Condenser Pressure

Procedures:
- DB-OP-02000; RPS, SFAS, SFRCS Trip or SG Tube Rupture; Revision 26
- DB-OP-06910; Trip Recovery; Revision 20
- NOP-OP-1015; Event Notifications; Revision 0
- RA-EP-02110; Emergency Notification; Revision 12

4OA7 Licensee-Identified Violations

Condition Reports:
- 2013-14882; Invalid Acceptance Criteria Signed for During DB-SP-03218 HPI Train 1 Pump and Valve Test (Misposition)
- 2013-14915; Risk Change during Implementation Week – suspect readings for DB-SP-03218, HPI Train 1 Pump and Valve Test result in scheduling test to be performed again

Procedures:
- DB-SP-03218; High Pressure Injection Train 1 Pump and Valve Test; Revision 26

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CR	Condition Report
CT	Current Transformer
DH	Decay Heat
F	Degrees Fahrenheit
DRP	Division of Reactor Projects
ECP	Engineering Change Package
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPRI	Electric Power Research Institute
HELB	High Energy Line Break
HPI	High Pressure Injection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
ips	Inches Per Second
IR	Inspection Report
IST	Inservice Testing
kV	Kilovolt
lb	pound
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
LOCA	Loss of Coolant Accident
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PMT	Post-Maintenance Testing
psig	Pounds Per Square Inch Gauge
QA	Quality Assurance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RFO	Refueling Outage
RPS	Reactor Protection System
SAC	Station Air Compressor
SBODG	Station Blackout Diesel Generator
SDP	Significance Determination Process
SRO	Senior Reactor Operator
SSC	Structures, Systems, and Components
TS	Technical Specification
TSO	Transmission System Operator
USAR	Updated Safety Analysis Report

URI	Unresolved Item
Vac	Volts Alternating Current
WO	Work Order

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and 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), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Patricia J. Pelke, Acting Chief
Branch 6
Division of Reactor Projects

Docket No. 50-346
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