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

November 18, 2013

EA-13-219

Ms. Karen Fili
Site Vice President
Monticello Nuclear Generating Plant
Northern States Power Company, Minnesota
2807 West County Road 75
Monticello, MN 55362-9637

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT - NRC INTEGRATED AND POWER UPRATE INSPECTION REPORT 05000263/2013004 AND EXERCISE OF ENFORCEMENT DISCRETION

Dear Ms. Fili:

On September 30, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Monticello Nuclear Generating Plant. The enclosed report documents the inspection findings, which were discussed on October 9, 2013, with you and other members of your staff.

One NRC-identified and three self-revealed findings of very low safety significance were identified during this inspection.

Three of these findings were determined to involve violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the Enforcement Policy.

If you contest these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, - Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Monticello Nuclear Generating Plant. In addition, if you disagree with a 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 Inspector at the Monticello Nuclear Generating Plant.

Additionally, a violation of Technical Specification 5.5.5, “Inservice Testing Program,” was identified. The NRC performed a risk evaluation of the issue and determined it to be of very low safety significance. Because the violation was identified during the discretion period described in Enforcement Guidance Memorandum 12-001, I have been authorized, after consultation with the Director, Office of Enforcement, and the Regional Administrator, to exercise enforcement discretion in accordance with Section 3.5, "Violations Involving Special Circumstances," of the NRC Enforcement Policy and, therefore, we are not issuing enforcement action for this violation.

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 by Julio Lara for/

Kenneth O'Brien, Acting Director
Division of Reactor Projects

Docket No. 50-263
License No. DPR-22

Enclosure: Inspection Report 05000263/2013004;
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-263
License No:	DPR-22
Report No:	05000263/2013004
Licensee:	Northern States Power Company, Minnesota
Facility:	Monticello Nuclear Generating Plant
Location:	Monticello, MN
Dates:	July 1 through September 30, 2013
Inspectors:	P. Zurawski, Senior Resident Inspector P. Voss, Resident Inspector K. Stoedter, Prairie Island Senior Resident Inspector T. Bilik, Senior Reactor Inspector D. Oliver, Reactor Inspector M. Ziolkowski, Reactor Engineer J. Corujo-Sandin, Reactor Engineer A. Dunlop, Senior Reactor Engineer S. Bell, Health Physicist C. Brown, Senior Reactor Engineer
Approved by:	K. Riemer, Branch Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000263/2013004; 07/01/2013 – 09/30/2013; Monticello Nuclear Generating Plant. Operability Determinations; Plant Modifications; Component Design Bases Inspection; Identification and Resolution of Problems; Radioactive Gaseous and Liquid Effluent Treatment; Other Activities

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. Three of the findings were considered non-cited violations (NCVs) 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 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 and non-cited violation of Technical Specification (TS) 5.4.1.a, "Procedures," occurred on June 3, 2013, due to the licensee's failure to implement procedures regarding maintenance or operations activities for draining and refilling the reactor vessel. Specifically, the licensee failed to follow Step 10 of Operations Manual B.02.02-05, "Reactor Water Cleanup System Operation," Section G.1, "Reactor Vessel Draining during Cold Shutdown Conditions," to adequately monitor water levels in the reactor during the reactor pressure vessel (RPV) partial draining process. While relying on a temporary installed level instrument, operators performed an RPV drain down which introduced pressure related inaccuracies into the temporary instrument and prevented operators from adequately monitoring vessel level. This resulted in a loss of positive configuration control of reactor coolant system (RCS) level during an infrequently conducted risk-significant evolution, and for four days thereafter. Corrective actions included transferring from the temporary level instrument to the flood up level instrument and enhancing RPV reassembly and temporary vessel installation procedures.

  This issue is more than minor because it is associated with the configuration control "shutdown equipment lineup" attribute of the Initiating Events Cornerstone and impacted the cornerstone objective to limit the likelihood of those events that challenge critical safety functions during shutdown operations. In addition, if left uncorrected, the reliance on inaccurate RPV level instrumentation could lead to a more significant safety issue because it constitutes a loss of positive control of reactor vessel level during a risk significant RCS drain down. Using IMC 0609, Appendix G, for shutdown operations, the inspectors determined that the finding had very low safety significance because it did not represent an inadvertent loss of two feet of RCS inventory or inadvertent RCS pressurization, and it did not adversely affect core heat removal, inventory control, power availability, containment control, or reactivity guidelines. The inspectors determined that this finding was cross-cutting in the Human Performance, decision making area, and involved aspects associated with using conservative assumptions in decision making and adopting a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate that it is unsafe [H.1(b)]. (Section 4OA2)

- Green. A self-revealed finding of very low safety significance occurred on August 27, 2013, due to the licensee's failure to adequately review and control modification work. Specifically, the licensee failed to follow FP-E-MOD-07, "Design Verification and Technical Review," when the review process did not ensure that a 13.8 kV switchgear modification was adequate and maintained all functions of the recirculation system. This led to the failure of plant personnel to land wires necessary to transmit breaker position signals to the recirculation speed control system and, as a result, the site failed to maintain the recirculation function to initiate runbacks in response to a condensate or feedwater pump trip. In addition, the inadequate modification left both recirculation pumps susceptible to spurious runbacks, and resulted in two inadvertent runbacks when operators were lowering flow on each pump. The licensee took action to lock the recirculation scoop tubes to terminate the inadvertent runbacks, initiated complex trouble-shooting and a root cause evaluation, and implemented a new modification to restore the recirculation system runback functions that were lost.

  The finding was more than minor because it was associated with the Initiating Events Cornerstone attribute of design control and 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. Specifically, the inadequate modification disabled the recirculation function to initiate runbacks after feed or condensate pump trips, and left both recirculation pumps susceptible to inadvertent runbacks. The inspectors utilized IMC 0609, Appendix A, and determined a detailed risk assessment was required because the finding involved the partial loss of a support system that contributes to the likelihood of, or causes, an initiating event AND affected mitigation equipment. Based on the Detailed Risk Evaluation, the senior reactor analysts determined that the finding was of very low safety significance. The inspectors concluded that this issue was cross-cutting in the Human Performance, resources area, because the modification development and review process failed to utilize complete, accurate, and up-to-date design documentation, procedures, and work packages [H.2(c)]. (Section 1R18)

Cornerstone: Mitigating Systems

- Green. A self-revealed finding of very low safety significance and an associated non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," occurred on June 13, 2013, due to the licensee's failure to accomplish activities affecting quality in accordance with instructions, procedures, or drawings of a type appropriate to the circumstances. Specifically, operators failed to utilize B.09.08-05.E.1/2, "Emergency Diesel Generators [EDGs]—System Operation, 11/12 Emergency Diesel Generator Operation," when verifying proper operation of both EDGs following their auto-start during a loss of normal offsite power event. This resulted in an inappropriate emergency shutdown of both EDGs when circumstances did not warrant the action, making them inoperable during an event that could have resulted in the necessity of their use. In addition, this action unnecessarily challenged future reliability of the EDGs due to the bypassing of the normal engine cool-down period. The licensee took immediate action to restore the EDGs to operable status once the inappropriate action was identified, performed a site clock reset, and improved training and associated procedures.

The finding was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of human performance and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). In addition, if left uncorrected, the performance deficiency could lead to a more significant safety concern. Specifically, failing to utilize necessary procedures when verifying proper operation of important safety-related equipment during an event, could lead to unnecessary unavailability or inoperability of additional systems. The inspectors utilized IMC 0609, Appendix G, and determined the finding had very low safety significance because it did not adversely affect core heat removal, inventory control, power availability, containment control, or reactivity guidelines. The inspectors concluded that this issue was cross-cutting in the Human Performance, resources area, because the licensee failed to make available complete, accurate, and up-to-date response procedures [H.2(c)]. (Section 4OA3)

Cornerstone: Public Radiation

- Green. A NRC-identified finding of very low safety significance and an associated non-cited violation of Technical Specification (TS) 5.5.1.a for the failure to perform an adequate technical review which led to the Offsite Dose Calculation Manual (ODCM) not being kept current. This issue was entered into the licensee's corrective action program as AR 01397500. The licensee is currently evaluating changes to the ODCM.

  The performance deficiency was determined to be of more than minor safety significance in accordance with IMC 0612, Appendix B, "Issue Screening," because it was associated with the program and process attribute of the Public Radiation Safety Cornerstone and the performance deficiency adversely affected the cornerstone objective to ensure adequate protection of public health and safety from exposure to radioactive materials released into the public domain as a result of routine civilian nuclear reactor operation. Specifically, the failure to maintain the ODCM current adversely impacted the licensee's ability to precisely determine offsite radiation dose under certain conditions. In accordance with IMC 0609, Appendix D, "Public Radiation Safety Significance Determination Process," the inspectors determined that the finding had a very low safety significance (Green) because the finding was related to the Effluent Release Program but did not involve: (1) a failure to implement an effluent program; or (2) result in public dose exceeding a limit in 10 CFR 50 Appendix I or 10 CFR 20.1301(e). The inspectors identified that the primary cause of this finding was related to the cross-cutting aspect of human performance with the component of resources. Specifically, the licensee did not ensure the ODCM (a procedure required by TSs) was up to date [H.2(c)] (Section 2RS6.1)

REPORT DETAILS

Summary of Plant Status

Monticello was shut down for Refueling Outage (RFO) 26 at the beginning of the inspection period. Power ascension began July 16, 2013, and the unit returned to 100 percent power on August 3, 2013, following post-outage testing activities. On August 24, 2013, power reduced to approximately 83 percent as a result of an unexpected runback of the 12 recirculation pump. The unit was restored to full power the same day. On August 27, 2013, power reduced to approximately 87 percent as a result of an unexpected runback of the 11 recirculation pump. Power was returned to 100 percent on August 30, 2013. Monticello operated at or near full power for the remainder of the inspection period with the exception of brief reductions in power to support the performance of planned surveillances or control rod adjustments.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- High pressure coolant injection (HPCI);
- Reactor core isolation cooling (RCIC); and
- 13 battery (250 Vdc).

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

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 32-A; emergency filtration train (EFT) 2nd Floor—Division I;
- Fire Zone 32-B; EFT 2nd Floor—Division II;
- Fire Zone 33; EFT 3rd Floor; and
- Fire Zone 37; transformers.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.
The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. 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 four quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Underground Vaults

a. Inspection Scope

The inspectors selected underground bunkers/manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors determined that the cables were not submerged, that splices were intact, and that appropriate cable support structures were in place. In those areas where dewatering devices were used, such as a sump pump, the device was operable and level alarm circuits were set appropriately to ensure that the cables would not be submerged. In those areas without dewatering devices, the inspectors verified that drainage of the area was available, or that the cables were qualified for submergence conditions. The inspectors also reviewed the licensee's corrective action documents with respect to past submerged cable issues identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following underground bunkers/manholes subject to flooding:

- ISFSI manhole vaults (NMH331 through NMH336);
- Manhole east of 1AR transformer (NMH337);
- Manhole west of main transformer (NMH313);
- Manhole southwest of reactor building nitrogen tank (2MH01);
- Manhole southwest of radwaste building (2MH02); and
- Manhole south of radwaste (CP102).

Specific documents reviewed during this inspection are listed in the Attachment to this report. This inspection constituted one underground vaults sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07)

.1 Triennial Review of Heat Sink Performance (71111.07T)

a. Inspection Scope

The inspectors reviewed operability determinations; completed surveillances; vendor manual information; associated calculations; performance test results and cooler inspection results associated with the 11 emergency diesel generators (EDGs) jacket cooler's heat exchanger and the 12 core spray pump (CSP) motor cooler. These heat exchangers/coolers were chosen based on their risk significance in the licensee's probabilistic safety analysis; their important safety-related mitigating system support functions; their operating history; and their relatively low margin.

For the 11 EDG jacket cooler's heat exchanger and the 12 CSP motor cooler, the inspectors verified that testing, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs were adequate to ensure proper heat transfer. This was accomplished by verifying: (1) the test method used was consistent with accepted industry practices, or equivalent; (2) the test conditions were consistent with the selected methodology; (3) the test acceptance criteria were consistent with the design basis values; and (4) the results of heat exchanger performance testing. The inspectors also verified the test results appropriately considered differences between testing conditions and design conditions, the frequency of testing based on trending of test results was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values and test results considered test instrument inaccuracies and differences.

For the 12 CSP motor cooler, the inspectors reviewed the methods and results of heat exchanger performance inspections. The inspectors verified the methods used to inspect and clean heat exchangers were consistent with as-found conditions identified and expected degradation trends and industry standards; the licensee's inspection and cleaning activities had established acceptance criteria consistent with industry standards; and the as-found results were recorded, evaluated, and appropriately dispositioned such that the as-left condition was acceptable.

In addition, the inspectors verified the condition and operation of the 11 EDG jacket cooler's heat exchanger and the 12 CSP motor cooler was consistent with design assumptions in heat transfer calculations and as described in the Final Safety Analysis Report (FSAR). This included verification that the number of plugged tubes was within pre-established limits based on capacity and heat transfer assumptions. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger.

The inspectors verified the performance of ultimate heat sinks (UHS) and safety-related service water systems and their subcomponents such as piping; intake screens; pumps, valves; etc., by tests or other equivalent methods to ensure availability and accessibility to the in-plant cooling water systems.

The inspectors reviewed the results of the licensee's inspection of the UHS weirs or excavations. The inspectors verified identified settlement or movement indicating loss of structural integrity and/or capacity was appropriately evaluated and dispositioned by the licensee. In addition, the inspectors verified the licensee ensured the UHS would remain available based on adequate river flow and level; and removing debris or sediment buildup in the intake structure.

The inspectors reviewed the licensee's performance testing of the safety-related essential diesel generator service water and EFT essential service water systems. This included the review of the licensee's performance test results for key components and service water flow balance test results. In addition, the inspectors compared the flow balance results to system configuration and flow assumptions during design basis accident conditions. The inspectors also verified the licensee ensured adequate isolation during design basis events, consistency between testing methodologies and design basis leakage rate assumptions, and proper performance of risk significant nonsafety-related functions. Finally, the inspectors reviewed maintenance tasks to ensure the intake structure and UHS remained capable to supply water to the safety-related service water pumps under design conditions.

In addition, the inspectors reviewed condition reports related to the heat exchangers/coolers and heat sink performance issues to verify the licensee had an appropriate threshold for identifying issues and to evaluate the effectiveness of the corrective actions. The documents that were reviewed are included in the Attachment to this report.

These inspection activities constituted three heat sink inspection samples as defined in IP 71111.07-05T.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

On September 16, 2013, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate; evaluators were identifying and documenting crew performance problems; and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

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

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

b. Findings

No findings were identified.

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

a. Inspection Scope

On July 16, 2013, the inspectors observed licensed operators performing RFO 26 plant startup evolutions in the control room. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;

- correct use and implementation of procedures;
- control board manipulations; and
- oversight and direction from supervisors.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Reactor recirculation system; and
- Primary containment structure.

The inspectors reviewed events, such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems, and independently verified the licensee's actions to address system performance 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.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Yellow risk condition for power ascension;
- Feedwater system oscillations;
- Condensate minimum flow valve bolts broke due to vibrations;
- Yellow risk condition for RCIC testing;
- Manual recirculation speed increase following scoop tube lock; and
- Emergent HPCI steam leak.

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

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Furmanite injection into turbine control valve BV-1;
- Missed inservice test (IST) shutdown testing requirements;
- EDG fuel oil service pump;

- External flooding; and
- HPCI steam leak.

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.

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

b. Findings

Inappropriate Invoking of Surveillance Requirement 3.0.3 Due to Missed In-service Tests

Introduction

The inspectors identified a violation of TS 5.5.5, "In-service Testing Program," due to the licensee's inappropriate invoking of Surveillance Requirement (SR) 3.0.3 on July 10, 2013, after operators identified several missed IST valve tests. Specifically, the licensee inappropriately invoked SR 3.0.3 after they failed to test residual heat removal (RHR)/ low pressure coolant injection (LPCI) valves in accordance with the American Society of Mechanical Engineers (ASME) Operation and Maintenance (O&M) Code and TS 5.5.5, "In-service Testing Program," which require cold shutdown IST tests to be performed every three months while shutdown, or within three months of the system becoming operable. The inspectors determined this issue met the criteria for granting enforcement discretion, as described in Enforcement Guidance Memorandum (EGM) 12-001.

Description

On July 10, 2013, the licensee identified that several IST cold shutdown tests were not scheduled properly, which had resulted in several missed testing requirements. Specifically, the ASME O&M Code and TS 5.5.5, "Inservice Testing Program," require cold shutdown IST tests to be performed every three months while shutdown, or within three months of the system becoming operable. Affected valves included:

- AO-10-46A, RHR Division I LPCI testable check valve;
- AO-10-46B, RHR Division II LPCI testable check valve;
- RHR-81; RHR shutdown cooling suction pressure equalizing check valve;
- MO-2-53A;11 recirculation pump discharge;
- MO-2-53B;12 recirculation pump discharge;

- MO-2030; RHR shutdown cooling outboard;
- MO-2029; RHR shutdown cooling suction inboard isolation; and
- Additional valves in the reactor water cleanup (RWCU), HPCI, RCIC, and condensate and feed water systems.

Following additional investigation, the licensee determined that in accordance with the testing requirements, only AO-10-46A, AO-10-46B, and RHR-81, required testing at the time of discovery of the missed IST tests. At the time of discovery, the licensee decided to invoke SR 3.0.3. This SR provides an exception to the requirements contained in SR 3.0.1, and allows the licensee to delay entry into the applicable TS Limiting Conditions for Operation (LCO), and delay testing of the component provided a risk evaluation is performed.

Specifically, TS SR 3.0.1 states, in part, “Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3.” Technical Specification SR 3.0.3 states, “if it is discovered that a Surveillance was not performed within its specified frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified frequency, whichever is greater. A risk evaluation shall be performed for any surveillance delayed greater than 24 hours and the risk impact shall be managed.”

The licensee believed this was an allowable path, because TS 5.5.5, “Inservice Testing Program,” Section C, states, “The provisions of SR 3.0.3 are applicable to inservice testing activities.” However, the licensee failed recognize that on February 24, 2012, the NRC issued EGM 12-001, "Dispositioning Noncompliance with Administrative Controls Technical Specifications Programmatic Requirements that Extend Test Frequencies and Allow Performance of Missed Tests," which concluded that such a use of SR 3.0.3 was inappropriate. In addition, on August 23, 2012, NRC Regulatory Issue Summary (RIS) 2012-10, “NRC Staff Position on Applying Surveillance Requirements 3.0.2 and 3.0.3 to Administrative Controls Program Tests,” was issued. Both of these documents provided licensees with the guidance that it was inappropriate to invoke SR 3.0.3 for tests that do not qualify as surveillance tests. Specifically, in the case of the IST program tests that the licensee failed to perform, there was no specific surveillance requirement associated with the IST tests and, as a result, invoking SR 3.0.3 to delay the tests represented a violation of TS Requirements. Instead, the licensee was required to enter each case of missed testing requirements into the CAP and assess each applicable component for operability, in accordance with Technical Guidance, Part 9900.

On July 11, 2013, the inspectors challenged the licensee’s usage of SR 3.0.3, and provided the information contained in RIS 2012-10 and EGM 12-001. Following licensee review of the guidance, operations staff exited the SR 3.0.3 risk evaluation and test delaying process and entered the applicable components into the Part 9900 operability determination process. The components were determined to be operable, but nonconforming with the test requirements, and actions to test the affected valves were initiated. The inspectors concluded that contrary to these requirements of TS 5.5.5 and SR 3.0.3, the licensee failed to test several LPCI and RHR valves in accordance with the three month test interval, and improperly applied TS allowances to delay the missed tests. This represented an NRC-identified violation of TS 5.5.5 by the licensee's inappropriate application of SR 3.0.3.

Analysis

The inspectors determined that the licensee's inappropriate invoking of SR 3.0.3 was a performance deficiency because it resulted in the failure to meet the requirements of TS 5.5.5; the cause was reasonably within the licensee's ability to foresee and correct; and should have been prevented. The inspectors screened the performance deficiency per IMC 0612, Appendix B, and determined the issue was more than minor because, if left uncorrected, the inappropriate invoking of SR 3.0.3 could lead to a more significant safety concern, because it could result in an unnecessary and inappropriate delaying of IST tests by up to several years. In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 2, the inspectors determined the performance deficiency affected the Mitigating Systems Cornerstone. In addition, the plant was shutdown at the time of the performance deficiency and, as a result, the inspectors determined the issue could be evaluated using Appendix G, "Shutdown Operations Significance Determination Process." The inspectors utilized IMC 0609, Appendix G, Attachment 1, Checklist 8, for boiling water reactors (BWRs), because the plant was in cold shutdown with more than two hours of time to boil and less than 23 feet of water above the reactor flange. The inspectors determined the performance deficiency had very low safety significance because it did not adversely affect core heat removal; inventory control; power availability; containment control; or reactivity guidelines (Green). Because the licensee is receiving enforcement discretion for this violation, no cross-cutting aspect was assigned.

Enforcement

A violation of TS 5.5.5, "In-service Testing Program," was identified. Specifically, the ASME O&M Code and TS 5.5.5, "In-service Testing Program," require cold shutdown IST tests to be performed every three months while shutdown, or within three months of the system becoming operable. Contrary to these requirements, the licensee failed to perform required testing for several RHR/LPCI valves and inappropriately invoked SR 3.0.3 to delay testing. Because the violation was identified during the discretion period described in EGM 12-001, the NRC is exercising enforcement discretion in accordance with Section 3.5, "Violations Involving Special Circumstances," of the NRC Enforcement Policy and is, therefore, not issuing enforcement action for this violation. Specifically, EGM 12-001 states, "The staff has determined that the enforcement discretion described in this EGM is appropriate because the restructuring of TS chapters during the development of improved Standard Technical Specifications (STS) resulted in unintended consequences when Section 3.0, "Surveillance Requirement Applicability," provisions were made applicable to Section 5.0 TSs. Specifically, applying STS rules of usage would prohibit licensees from using the SR 3.0.2 and 3.0.3 allowances contained in Section 5.0 TSs. The inspectors also noted that the issue met the Enforcement Policy discretion criteria in that there was a lack of clarity in the requirement, and the issue was of very low safety significance. Specifically, the allowance contained in TS 5.5.5, Section C, was misleading, in that it stated that the provisions of SR 3.0.3 were applicable to IST activities. The licensee initiated action to test the affected valves in accordance with the IST program, changed plant procedures to include EGM 12-001 and RIS 12-10 guidance, and developed an Operations Memo to alert operators to the guidance (EA-13-219).

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modifications:

- Recirculation system speed control 13.8 kV modification (EC-11445); and
- Recirculation system (various ECs).

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

This inspection constituted two permanent plant modification samples as defined in IP 71111.18-05.

b. Findings

Recirculation System Vulnerabilities Due To Inadequate Modification Review

Introduction

A finding of very low safety significance was self-revealed on August 27, 2013, due to the licensee's failure to adequately review and control modification work. Specifically, the licensee failed to follow FP-E-MOD-07, "Design Verification and Technical Review," when the review process did not ensure that a 13.8 kV switchgear modification maintained all functions of the recirculation system. This led to the failure of plant staff to land wires necessary to transmit breaker position signals to the recirculation speed control system and, as a result, the site failed to maintain the recirculation function to initiate runbacks in response to a condensate or feed water pump trip. In addition, the inadequate modification left both recirculation pumps susceptible to spurious runbacks, and resulted in two inadvertent runbacks when operators were lowering power on each pump.

Description

On August 27, and September 1, 2013, the licensee experienced inadvertent recirculation system runbacks on each of the site's two recirculation pumps. As a result, reactor power reduced from 100 percent to 94 percent during the first event and from 100 percent to 98 percent during the second event. Both events occurred while operations staff was reducing speed on each of the recirculation pumps. Operators took action to lock the recirculation speed control scoop tubes to limit the impact of the two runbacks, and to prevent additional inadvertent runbacks. Troubleshooting activities revealed that during modification work to install a 13.8 kV electrical system during the recent RFO, plant personnel had failed to land wires necessary to transmit condensate and feed pump breaker positions to the recirculation speed control system. Specifically, when the 13.8 kV electrical system was connected to the plant computer, workers unknowingly eliminated wiring associated with the 4 kV system that interfaced between the plant computer and speed control system. The workers then failed to install new wiring associated with the 13.8 kV system to maintain interties between the plant computer and recirculation speed control system. As a result, the modification unintentionally altered inputs to the recirculation runback circuitry, and disabled the system function to initiate runbacks in response to a condensate or feed pump trip.

At the time of the inspection, the licensee was planning a root cause evaluation to examine the circumstances surrounding these events. The inspectors interviewed plant personnel to evaluate process breakdowns. The inspectors concluded that the modification deficiency was the result of design work associated with the 13.8 kV modification developed and installed during the previous outage. The inspectors determined that the design drawings utilized during the design development and review processes did not contain necessary information detailing the interface between the plant computer and the recirculation speed control system. Specifically, these drawings did not provide indication that the computer points being modified served as inputs into the recirculation speed control system. Inspectors concluded that the use of these incomplete design drawings contributed to the inadequate modification. In addition, other drawings associated with the recirculation speed control system which contained this information did not appear to have been consulted during modification development and review.

The inspectors concluded that a deficiency existed in the licensee's modification review process for the 13.8 kV modification work. Specifically, as part of the modification review process, EC-11445, "EPU [extended power uprate] - New 13.8 kV Bus 11 and 12 Switchgear Upgrades," was classified as an Augmented Quality modification and underwent a design verification. Engineering Change EC-11445 also established that procedures in the fleet modification series, the FP-E-MOD series, were applicable to the 13.8 kV modification EC package. Specifically, EC-11445 states that the contract companies that performed design work for the 13.8 kV modification "have the responsibility of this EC package in accordance with the applicable Xcel Energy fleet modification process and Monticello implementing procedures."

As stated in FP-E-MOD-02, "Engineering Change Control," for Augmented Quality modifications, "these modifications should include nearly all of the same controls as a Safety Related modification." These controls included performance of a design verification review. Per FP-E-MOD-07, "Design Verification and Technical Review," design verification is a process for reviewing, confirming, or substantiating that a design or change to a design is technically correct, accurate, and adequate, and that the design is in conformance with all specified design inputs, design bases, design criteria, and design requirements. Fleet Procedure FP-E-MOD-07, Section 5.3, "Verification Process," Step 5.3.2.6, states, "the Verifier SHALL evaluate the adequacy of design output documents." Contrary to this standard, the site review process failed to ensure that the new 13.8 kV switchgear modification design was adequate and maintained all functions of the recirculation system.

Analysis

The inspectors determined that the licensee's failure to adequately review and control modification work was a performance deficiency, because it was the result of the failure to meet the standards of FP-E-MOD-07; the cause was reasonably within the licensee's ability to foresee and correct; and should have been prevented. The inspectors concluded that this issue was cross-cutting in the Human Performance, resources area, because the modification development and review process failed to utilize complete, accurate, and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, the design drawings utilized during the design development and review processes did not contain necessary information detailing the interface between the plant computer and the recirculation speed control system. In addition, alternative drawings which contained this information were not appropriately consulted during modification development and review.

The inspectors screened the performance deficiency per IMC 0612, "Power Reactor Inspection Reports," Appendix B, and determined that the issue was more than minor because it was associated with the Initiating Events Cornerstone attribute of design control and 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. Specifically, the inadequate modification disabled the recirculation function to initiate runbacks after feed or condensate pump trips, and left both recirculation pumps susceptible to inadvertent runbacks.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 2, the inspectors determined the finding affected the Initiating Events Cornerstone. As a result, the inspectors determined the finding could be evaluated using Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 1, for the Initiating Events Cornerstone. The inspectors determined a detailed risk assessment was required because the finding involved the partial loss of a support system that contributes to the likelihood of, or causes, an initiating event AND affected mitigation equipment, and determined a Detailed Risk Evaluation was required.

The senior reactor analysts (SRAs) performed a Detailed Risk Evaluation as detailed below. Per the TS 3.4.1 Bases, the loss-of-coolant-accident (LOCA) analyses assume that both reactor recirculation loops (RRLs) are operating at the same flow prior to the accident. Thus, to provide an upper bound to the delta core damage frequency (ΔCDF) associated with the finding, it was assumed that any time spent outside the jet pump flow mismatch requirements (per SR 3.4.1.1) would result in a core damage event, if a LOCA occurred while the flow mismatch was present.

The SRAs determined the frequency of LOCA events using the Monticello Standardized Plant Analysis Risk (SPAR) model version 8.20. The following LOCA frequencies were obtained from the Monticello SPAR model:

Small LOCA (SLOCA)	7.43E-4/yr
Medium LOCA (MLOCA)	1.00E-4/yr
Large LOCA (LLOCA)	1.00E-5/yr

The total LOCA frequency is obtained by summing the three LOCA frequencies identified above or 8.53E-4/yr.

Since the completion of the Monticello RFO in June 2013, there have been two events in which a RRL flow mismatch has been present due to the performance deficiency. On August 27, 2013, following a runback on the 'B' recirculation pump, there was a loop flow mismatch for a time period of 3 hours and 29 minutes. On September 1, 2013, following a runback on the 'A' recirculation pump, there was a loop flow mismatch for a time period of 5 hours and 13 minutes. Thus, the total time period for a RRL flow mismatch due to the performance deficiency is 8 hours and 42 minutes or 8.7 hours.

Conservatively assuming that a core damage event would occur if a LOCA had occurred during these 8.7 hours of loop flow mismatch results in a ΔCDF of:

ΔCDF = [8.53E-4/yr] x [8.7 hours] ÷ [8760 hours]
= 8.5E-7/yr

Since the total estimated change in CDF was greater than 1.0E-7/yr, external events and large-early release-frequency (LERF) were evaluated for risk significance.

External events (i.e., fire, seismic, and flooding induced events) were judged insignificant relative to internal event risk and, therefore, did not contribute to the risk of this finding. Thus, the total ΔCDF is 8.5E-7/yr.

Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," was used to determine the potential risk contribution due to LERF. Monticello is a BWR with a Mark I containment. Table 5.2 from Appendix H (Phase 2 Assessment Factors) listed a LERF factor of 0.6 for core damage sequences ending with a flooded drywell and high reactor coolant system (RCS) pressure (high pressure defined as greater than 250 psi at the time of reactor vessel breach) and a LERF factor of less than 0.1 for core damage sequences ending with a flooded drywell and low RCS pressure. Note 2 in Table 5.2 identifies that SLOCAs will usually result in pressures in the RCS greater than 250 psi at the time of reactor vessel melt-through in the absence of manual depressurization.

The Human Error Probability (HEP) was evaluated that the operators would not follow the actions in the emergency operating procedures (EOPs) and cooldown and depressurize the RCS following a SLOCA. The HEP was determined using the SPAR-H human reliability analysis method (per NUREG/CR-6883). Using SPAR-H, only the "Action" part of the evolution following a SLOCA was determined to be applicable. For Action, the performance shaping factor (PSF) for "Stress" was determined to be "High," the PSF for "Complexity" was determined to be "Highly Complex," with the other

PSFs at a nominal value. This resulted in an HEP that the operators would not follow the actions in the EOPs and cooldown and depressurize the RCS following a SLOCA of 1E-2.

Using this HEP, a weighted average LERF factor for this finding was obtained by performing the following:

(LERF factor)(8.53E-4) = (0.6)(7.43E-4 + 1E-4)(1E-2) + (0.1)(7.43E-4 + 1E-4)(1 – E-2) + (0.1)(1E-5)

The weighted average LERF factor is thus calculated to be 1.05E-1.

The delta LERF (ΔLERF) for the finding is thus obtained as:
ΔLERF = [8.5E-7/yr] x [1.05E-1]
= 8.9E-8/yr

Based on the Detailed Risk Evaluation, the SRAs determined that the finding was of very low safety significance (Green).

Enforcement

No violation of NRC requirements was identified during this inspection due to the recirculation speed control system being nonsafety-related. Corrective actions for this issue included locking of the recirculation pump scoop tubes; initiation of complex trouble-shooting; planned performance of a root cause evaluation; and implementation of a new modification to restore the recirculation system runback functions that were lost. (**FIN 05000263/2013004-01; Recirculation System Vulnerabilities due to Inadequate Modification Review**)

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 2R lockout following breaker cubicle restoration from arc flash;
- RCIC PM flow testing after speed controller replacement;
- Containment closeout/containment systems walkdown; and
- Turbine overspeed testing following outage work.

These activities were selected based upon the SSCs 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 PM tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted four PM testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors continued to review activities associated with RFO 26, which began during the first quarter 2013. During third quarter RFO activities, the inspectors monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the Outage Safety Plan for key safety functions and compliance with the applicable TS when taking equipment out of service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and Outage Safety Plan requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system (ECCS) suction strainers, and reactor physics testing; and

- licensee identification and resolution of problems related to RFO activities.

Documents reviewed are listed in the Attachment to this report.

Inspection activities this quarter did not constitute a RFO sample, as defined in IP 71111.20-05, since the sample had been accounted for as part of NRC Inspection Report 05000263/2013002.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- 0114; RCIC pump flow testing (routine);
- 0108; HPCI pump flow and valve tests w/pressure <165 psi (IST);
- 1057; HPCI overspeed trip; 0114; RCIC pump flow testing (routine); and
- 0301; Safeguard bus voltage protection relay unit functional test (routine).

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for IST activities, testing was performed in accordance with the applicable version of Section XI, ASME Code, and reference values were consistent with the system design basis;

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

Documents reviewed are listed in the Attachment to this report.

This inspection constituted three routine surveillance testing samples and one IST sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Occupational and Public Radiation Safety

2RS2 Occupational As-Low-As-Reasonably-Achievable Planning and Controls (71124.02)

The inspection activities supplement those documented in NRC Inspection Reports 05000263/2012004, 05000263/2012005, and 05000263/2013002, and constitute a partial sample as defined in IP 71124.02-05.

.1 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected the following work activities of the highest exposure significance:

- Refueling activities;
- Inservice inspections; and
- Snubber evaluations.

The inspectors determined whether post-job reviews were conducted and if identified problems were entered into the licensee’s CAP.

b. Findings

No findings were identified.

.2 Verification of Dose Estimates and Exposure Tracking Systems (02.03)

a. Inspection Scope

The inspectors evaluated whether the licensee established measures to track, trend, and if necessary, to reduce occupational doses for ongoing work activities. The inspectors assessed whether trigger points or criteria were established to prompt additional reviews and/or additional as-low-as-reasonably-achievable (ALARA) planning and controls.

b. Findings

No findings were identified.

.3 Source Term Reduction and Control (02.04)

a. Inspection Scope

The inspectors used licensee records to determine the historical trends and current status of significant tracked plant source terms known to contribute to elevated facility aggregate exposure. The inspectors assessed whether the licensee made allowances or developed contingency plans for expected changes in the source term as the result of changes in plant fuel performance issues or changes in plant primary chemistry.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

This inspection constituted one complete sample as defined in IP 71124.06-05.

.1 Inspection Planning and Program Reviews (02.01)

Event Report and Effluent Report Reviews

a. Inspection Scope

The inspectors reviewed the radiological effluent release reports issued since the last inspection to determine if the reports were submitted as required by the Offsite Dose Calculation Manual (ODCM)/TSs. The inspectors reviewed anomalous results, unexpected trends, or abnormal releases identified by the licensee for further inspection to determine if they were evaluated, were entered in the CAP, and were adequately resolved.

The inspectors selected radioactive effluent monitor operability issues reported by the licensee as provided in effluent release reports, to review these issues during the onsite inspection, as warranted, given their relative significance and determine if the issues were entered into the CAP and adequately resolved.

b. Findings

No findings were identified.

Offsite Dose Calculation Manual and Final Safety Analysis Report Review

a. Inspection Scope

The inspectors reviewed FSAR descriptions of the radioactive effluent monitoring systems, treatment systems, and effluent flow paths so they could be evaluated during inspection walkdowns.

The inspectors reviewed changes to the ODCM made by the licensee since the last inspection against the guidance in NUREG-1301, 1302, and 0133, and Regulatory Guides 1.109, 1.21, and 4.1. When differences were identified, the inspectors reviewed the technical basis or evaluations of the change during the onsite inspection to determine whether they were technically justified and maintain effluent releases ALARA.

The inspectors reviewed licensee documentation to determine if the licensee has identified any non-radioactive systems that have become contaminated as disclosed either through an event report or the ODCM since the last inspection. This review provided an intelligent sample list for the onsite inspection of any 10 CFR 50.59 evaluations and allowed a determination if any newly contaminated systems have an unmonitored effluent discharge path to the environment, whether any required ODCM revisions were made to incorporate these new pathways and whether the associated effluents were reported in accordance with Regulatory Guide 1.21.

b. Findings

Failure To Maintain The Offsite Dose Calculation Manual

Introduction

The inspectors identified a finding of very low safety significance (Green) and associated NCV of TS 5.5.1.a for the failure to perform an adequate technical review which led to the ODCM not being kept current.

Description

Appendix A of the ODCM, Revision 1, provides the atmospheric dispersion (X/Q) and deposition (D/Q) parameters. These parameters are utilized to determine radiation dose to members of the public. Appendix A X/Q and D/Q parameters were previously derived using the average meteorological data from September 1, 1976, through August 30, 1978. The licensee performed a periodic review which determined that the meteorological data from 2011 – 2012 was consistent with the period of 2006 – 2010. The inspectors requested a comparison of recent meteorological data to the data currently contained within the ODCM. The licensee determined that the 1976-1978 meteorological data was no longer representative of the current conditions. Specifically, the 10-meter elevation wind speed currently observed is approximately 24 percent, on average, lower than from the historical period (1976 – 1978) contained within the ODCM. Lower wind speed values would result in higher radiation concentrations near the site and yield a higher radiation dose at defined locations.

Analysis

The inspectors determined that the failure to provide an adequate review and subsequently not maintaining the ODCM current was a performance deficiency, the cause of which was reasonably within the licensee's ability to foresee and correct, and should have been prevented. This finding was not subject to traditional enforcement since the incident did not result in a significant safety consequence, did not impact the NRC's ability to perform its regulatory function, and was not willful.

The performance deficiency was determined to be of more than minor safety significance in accordance with IMC 0612, Appendix B, "Issue Screening," because it was associated with the program and process attribute of the Public Radiation Safety Cornerstone and the performance deficiency adversely affect the cornerstone objective to ensure adequate protection of public health and safety from exposure to radioactive materials released into the public domain as a result of routine civilian nuclear reactor operation. Specifically, the failure to maintain the ODCM current adversely impacted the licensee's ability to precisely determine offsite radiation dose under certain conditions. The inspectors also reviewed the guidance in IMC 0612, Appendix E, "Examples of Minor Issues," and did not find any similar examples.

In accordance with IMC 0609, Appendix D, "Public Radiation Safety Significance Determination Process," the inspectors determined that the finding had a very low safety significance (Green) because the finding was related to the Effluent Release Program but did not involve: (1) a failure to implement an effluent program; or (2) result in public dose exceeding a limit in 10 CFR 50, Appendix I, or 10 CFR 20.1301(e).

The inspectors identified that the primary cause of this finding was related to the cross-cutting aspect of human performance with the component of resources. Specifically, the licensee did not ensure the ODCM (a procedure required by TSs) was up-to-date [H.2(c)].

Enforcement

Technical Specification 5.5.1.a states in part, that the ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents.

ODCM Appendix A, Revision 1, states in part, that on-site meteorological data for the period September 1, 1976, through August 31, 1978, (as presented in Appendix B) were used as input to XOQDOQ (computer program for calculating undepleted, undecayed dispersion parameters.)

Contrary to the above, as of [date of your inspection] the ODCM did not contain the methodology and parameters used in the calculation of offsite doses as the meteorological data in the ODCM was not representative of current conditions.

Since the violation of TS 5.5.1.a was of very low safety significance and has been entered into the licensee's CAP (as AR 01397500), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000263/2013004-02; Failure to Maintain the ODCM)

Groundwater Protection Initiative Program

a. Inspection Scope

The inspectors reviewed reported groundwater monitoring results and changes to the licensee's written program for identifying and controlling contaminated spills/leaks to groundwater.

b. Findings

No findings were identified.

Procedures, Special Reports, and Other Documents

a. Inspection Scope

The inspectors reviewed Licensee Event Reports (LERs), event reports and/or special reports related to the effluent program issued since the previous inspection to identify any additional focus areas for the inspection based on the scope/breadth of problems described in these reports.

The inspectors reviewed effluent program implementing procedures, particularly those associated with effluent sampling, effluent monitor set-point determinations, and dose calculations.

The inspectors reviewed copies of licensee and third party (independent) evaluation reports of the Effluent Monitoring Program since the last inspection to gather insights into the licensee's program and aid in selecting areas for inspection review (smart sampling).

b. Findings

No findings were identified.

.2 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down selected components of the gaseous and liquid discharge systems to evaluate whether equipment configuration and flow paths align with the documents reviewed in 02.01 above and to assess equipment material condition. Special attention was made to identify potential unmonitored release points (such as open roof vents, temporary structures butted against turbine, auxiliary or containment buildings), building alterations which could impact airborne, or liquid effluent controls, and ventilation system leakage that communicates directly with the environment.

For equipment or areas associated with the systems selected for review that were not readily accessible due to radiological conditions, the inspectors reviewed the licensee's material condition surveillance records, as applicable.

The inspectors walked down filtered ventilation systems to assess for conditions such as degraded high-efficiency particulate air/charcoal banks, improper alignment, or system installation issues that would impact the performance or the effluent monitoring capability of the effluent system.

As available, the inspectors observed selected portions of the routine processing and discharge of radioactive gaseous effluent (including sample collection and analysis) to evaluate whether appropriate treatment equipment was used and the processing activities align with discharge permits.

The inspectors determined if the licensee has made significant changes to their effluent release points (e.g., changes subject to a 10 CFR 50.59 review or that require NRC approval of alternate discharge points).

As available, the inspectors observed selected portions of the routine processing and discharging of liquid waste (including sample collection and analysis) to determine if appropriate effluent treatment equipment is being used and that radioactive liquid waste is being processed and discharged in accordance with procedure requirements and aligns with discharge permits.

b. Findings

No findings were identified.

.3 Sampling and Analyses (02.03)

a. Inspection Scope

The inspectors selected effluent sampling activities, consistent with smart sampling, and assessed whether adequate controls have been implemented to ensure representative samples were obtained (e.g., provisions for sample line flushing, vessel recirculation, composite samplers, etc.).

The inspectors selected effluent discharges made with inoperable (declared out-of-service) effluent radiation monitors to assess whether controls were in place to ensure compensatory sampling was performed consistent with the radiological effluent TSs (RETS)/ODCM and that those controls were adequate to prevent the release of unmonitored liquid and gaseous effluents.

The inspectors determined whether the facility was routinely relying on the use of compensatory sampling in lieu of adequate system maintenance based on the frequency of compensatory sampling since the last inspection.

The inspectors reviewed the results of the Inter-Laboratory Comparison Program to evaluate the quality of the radioactive effluent sample analyses and assessed whether the Inter-Laboratory Comparison Program includes hard-to-detect isotopes as appropriate.

b. Findings

No findings were identified.

.4 Instrumentation and Equipment (02.04)

Effluent Flow Measuring Instruments

a. Inspection Scope

The inspectors reviewed the methodology the licensee uses to determine the effluent stack and vent flow rates to determine if the flow rates were consistent with RETS/ODCM or FSAR values, and that differences between assumed and actual stack and vent flow rates did not affect the results of the projected public doses.

b. Findings

No findings were identified.

Air Cleaning Systems

a. Inspection Scope

The inspectors assessed whether surveillance test results since the previous inspection for TS required ventilation effluent discharge systems (high-efficiency particulate air and charcoal filtration), such as the standby gas treatment system and the containment/auxiliary building ventilation system met TS acceptance criteria.

b. Findings

No findings were identified.

.5 Dose Calculations (02.05)

a. Inspection Scope

The inspectors reviewed all significant changes in reported dose values compared to the previous radiological effluent release report (e.g., a factor of five, or increases that approach Appendix I criteria) to evaluate the factors which may have resulted in the change.

The inspectors reviewed radioactive liquid and gaseous waste discharge permits to assess whether the projected doses to members of the public were accurate and based on representative samples of the discharge path.

The inspectors evaluated the methods used to determine the isotopes that are included in the source term to ensure all applicable radionuclides are included within detectability standards. The review included the current 10 CFR, Part 61, analyses to ensure hard-to-detect radionuclides are included in the source term.

The inspectors reviewed changes in the licensee’s offsite dose calculations since the last inspection to evaluate whether changes were consistent with the ODCM and Regulatory Guide 1.109. The inspectors reviewed meteorological dispersion and deposition factors used in the ODCM and effluent dose calculations to evaluate whether appropriate factors were being used for public dose calculations.

The inspectors reviewed the latest Land Use Census to assess whether changes (e.g., significant increases or decreases to population in the plant environs, changes in critical exposure pathways, the location of the nearest member of the public, or critical receptor, etc.) have been factored into the dose calculations.

For the releases reviewed above, the inspectors evaluated whether the calculated doses (i.e., monthly, quarterly, and annual dose) are within the 10 CFR, Part 50, Appendix I, and TS dose criteria.

The inspectors reviewed, as available, records of any abnormal gaseous or liquid tank discharges (e.g., discharges resulting from misaligned valves, valve leak-by, etc.) to ensure the abnormal discharge was monitored by the discharge point effluent monitor. Discharges made with inoperable effluent radiation monitors, or unmonitored leakages were reviewed to ensure that an evaluation was made of the discharge to satisfy 10 CFR 20.1501 so as to account for the source term and projected doses to the public.

b. Findings

No findings were identified.

.6 Groundwater Protection Initiative Implementation (02.06)

a. Inspection Scope

The inspectors reviewed monitoring results of the Groundwater Protection Initiative to determine if the licensee implemented its program as intended and to identify any anomalous results. For anomalous results or missed samples, the inspectors assessed whether the licensee identified and addressed deficiencies through its CAP.

The inspectors reviewed identified leakage or spill events and entries made into 10 CFR 50.75 (g) records. The inspectors reviewed evaluations of leaks or spills and reviewed any remediation actions taken for effectiveness. The inspectors reviewed onsite contamination events involving contamination of ground water and assessed whether the source of the leak or spill was identified and mitigated.

For unmonitored spills, leaks, or unexpected liquid or gaseous discharges, the inspectors assessed whether an evaluation was performed to determine the type and amount of radioactive material that was discharged by:

Assessing whether sufficient radiological surveys were performed to evaluate the extent of the contamination and the radiological source term and assessing whether a survey/evaluation had been performed to include consideration of hard-to-detect radionuclides.

Determining whether the licensee completed offsite notifications as provided in its Groundwater Protection Initiative implementing procedures.

The inspectors reviewed the evaluation of discharges from onsite surface water bodies that contain or potentially contain radioactivity, and the potential for ground water leakage from these onsite surface water bodies. The inspectors assessed whether the licensee was properly accounting for discharges from these surface water bodies as part of their effluent release reports.

The inspectors assessed whether onsite ground water sample results and a description of any significant onsite leaks/spills into ground water for each calendar year were documented in the Annual Radiological Environmental Operating Report for the Radiological Environmental Monitoring Program (REMP) or the Annual Radiological Effluent Release Report for the RETS.

For significant, new effluent discharge points, (such as significant or continuing leakage to ground water that continues to impact the environment if not remediated) the inspectors evaluated whether the ODCM was updated to include the new release point.

b. Findings

No findings were identified.

.7 Problem Identification and Resolution (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with the Effluent Monitoring and Control Program were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. In addition, they evaluated the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving radiation monitoring and exposure controls.

b. Findings

No findings were identified.

2RS7 Radiological Environmental Monitoring Program (71124.07)

This inspection constituted one complete sample as defined in IP 71124.07-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the annual radiological environmental operating reports and the results of any licensee assessments since the last inspection to assess whether the REMP was implemented in accordance with the TSs and ODCM. This review included reported changes to the ODCM with respect to environmental monitoring, commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, Inter-Laboratory Comparison Program, and analysis of data.

The inspectors reviewed the ODCM to identify locations of environmental monitoring stations.

The inspectors reviewed the FSAR for information regarding the Environmental Monitoring Program and meteorological monitoring instrumentation.

The inspectors reviewed quality assurance audit results of the program to assist in choosing inspection "smart samples." The inspectors also reviewed audits and technical evaluations performed on the vendor laboratory if used.

The inspectors reviewed the annual effluent release report and the 10 CFR Part 61, “Licensing Requirements for Land Disposal of Radioactive Waste,” report, to determine if the licensee was sampling, as appropriate, for the predominant and dose-causing radionuclides likely to be released in effluents.

b. Findings

No findings were identified.

.2 Site Inspection (02.02)

a. Inspection Scope

The inspectors walked down select air sampling stations and thermoluminescent dosimeter monitoring stations to determine whether they were located as described in the ODCM and to determine the equipment material condition. Consistent with smart sampling, the air sampling stations were selected based on the locations with the highest X/Q, D/Q wind sectors, and thermoluminescent dosimeters were selected based on the most risk-significant locations (e.g., those that have the highest potential for public dose impact).

For the air samplers and thermoluminescent dosimeters selected, the inspectors reviewed the calibration and maintenance records to evaluate whether they demonstrated adequate operability of these components. Additionally, the review included the calibration and maintenance records of select composite water samplers.

The inspectors assessed whether the licensee initiated sampling of other appropriate media upon loss of a required sampling station.

The inspectors observed the collection and preparation of environmental samples from different environmental media (e.g., ground and surface water, milk, vegetation, sediment, and soil), as available, to determine if environmental sampling was representative of the release pathways as specified in the ODCM and if sampling techniques were in accordance with procedures.

Based on direct observation and review of records, the inspectors assessed whether the meteorological instruments were operable, calibrated, and maintained in accordance with guidance contained in the FSAR, NRC Regulatory Guide 1.23, “Meteorological Monitoring Programs for Nuclear Power Plants,” and licensee procedures. The inspectors assessed whether the meteorological data readout and recording instruments in the control room and, if applicable, at the tower were operable.

The inspectors evaluated whether missed and/or anomalous environmental samples were identified and reported in the Annual Environmental Monitoring Report. The inspectors selected events that involved a missed sample, inoperable sampler, lost thermoluminescent dosimeter, or anomalous measurement to determine if the licensee identified the cause and implemented corrective actions. The inspectors reviewed the licensee’s assessment of any positive sample results (i.e., licensed radioactive material detected above the lower limits of detection) and reviewed the associated radioactive effluent release data that was the source of the released material.

The inspectors selected SSCs that involve or could reasonably involve licensed material for which there is a credible mechanism for licensed material to reach ground water and assessed whether the licensee implemented a Sampling and Monitoring Program sufficient to detect leakage of these SSCs to ground water.

The inspectors evaluated whether records, as required by 10 CFR 50.75(g), of leaks, spills, and remediation since the previous inspection were retained in a retrievable manner.

The inspectors reviewed any significant changes made by the licensee to the ODCM as the result of changes to the land census, long-term meteorological conditions (3-year average), or modifications to the sampler stations since the last inspection. They reviewed technical justifications for any changed sampling locations to evaluate whether the licensee performed the reviews required to ensure that the changes did not affect its ability to monitor the impacts of radioactive effluent releases on the environment.

The inspectors assessed whether the appropriate detection sensitivities with respect to TS/ODCM where used for counting samples (i.e., the samples meet the TS/ODCM required lower limits of detection). The inspectors reviewed quality control charts for maintaining radiation measurement instrument status and actions taken for degrading detector performance as applicable. The licensee uses a vendor laboratory to analyze the REMP samples; therefore the inspectors reviewed the results of the vendor's Quality Control Program, including the inter-laboratory comparison, to assess the adequacy of the vendor's program.

The inspectors reviewed the results of the licensee's Inter-Laboratory Comparison Program to evaluate the adequacy of environmental sample analyses performed by the licensee. The inspectors assessed whether the inter-laboratory comparison test included the media/nuclide mix appropriate for the facility. The inspectors reviewed the licensee's determination of any bias to the data and the overall effect on the REMP.

b. Findings

No findings were identified.

.3 Identification and Resolution of Problems (02.03)

a. Inspection Scope

The inspectors assessed whether problems associated with the REMP were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. Additionally, they assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involved the REMP.

b. Findings

No findings were identified.

OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) Emergency Alternating Current (AC) Power System performance indicator (PI) for the period from the fourth quarter 2012 through the third 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, MSPI derivation reports, issue reports, event reports and NRC Integrated Inspection Reports for the period of October 2012 through September 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.

This inspection constituted one MSPI emergency AC power system sample as defined in IP 71151 05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI High Pressure Injection Systems PI for the period from the fourth quarter 2012 through the third 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 Inspection Reports for the period of October 2012 through September 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.

This inspection constituted one MSPI high pressure injection system sample as defined in IP 71151 05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI Heat Removal System PI for the period from the fourth quarter 2012 through the third 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, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of October 2012 through September 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.

This inspection constituted one MSPI heat removal system sample as defined in IP 71151 05.

b. Findings

No findings were identified.

.4 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Specific Activity PI for the Monticello Nuclear Generating Plant for the period from the third quarter 2012 through the second quarter 2013. The inspectors used PI definitions and guidance contained in the NEI Document 99 02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's RCS chemistry samples, TS requirements, issue reports, event reports and NRC Integrated Inspection Reports to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems were identified with the PI data collected or transmitted for this indicator. The inspectors reviewed recent RCS sample analysis. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one RCS specific activity sample as defined in IP 71151 05.

b. Findings

No findings were identified.

.5 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences PI for the period from the third quarter 2012 through the second quarter 2013. The inspectors used PI definitions and guidance contained in the NEI Document 99 02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee’s PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarms and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational exposure control effectiveness sample as defined in IP 71151 05.

b. Findings

No findings were identified.

.6 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the RETS/ODCM radiological effluent occurrences PI for the period from the third quarter 2012 through the second quarter 2013. The inspectors used PI definitions and guidance contained in the NEI Document 99 02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s issue report database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee’s methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one RETS/ODCM radiological effluent occurrences sample as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

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

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold; that adequate attention was being given to timely corrective actions; and that adverse trends were identified and addressed. Attributes reviewed included: 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 Selected Issue Follow-Up Inspection: Review of Corrective Actions to Address Loss of Temporary Level Indication During the Refueling Outage

a. Inspection Scope

The inspectors reviewed the circumstances surrounding an event involving a self-revealed level instrument issue following a partial drain-down of the RCS to support ECCS testing. The issue was documented in CAP 1385754. Inspectors reviewed the Apparent Cause Evaluation performed for the equipment deficiency, and verified corrective actions associated with the deficiency were appropriate. Inspectors also verified the licensee recognized operational decision making aspects that led to the event, and confirmed the licensee commissioned a separate Apparent Cause Evaluation focused on identifying the deficiencies in the decision making process that led to this event.

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

b. Findings

Loss Of Accurate Level Indication During Partial Reactor Coolant System Drain Down

Introduction

A self-revealed finding of very low safety significance and NCV of TS 5.4.1.a, "Procedures," occurred on June 3, 2013, due to the licensee's failure to implement procedures regarding maintenance or operations activities for draining and refilling the reactor vessel. Specifically, the licensee failed to follow Step 10 of Operations Manual B.02.02-05, "Reactor Water Cleanup System Operation," Section G.1, "Reactor Vessel Draining during Cold Shutdown Conditions," to adequately monitor water levels in the reactor during the reactor pressure vessel (RPV) partial draining process. While relying on a temporary installed level instrument, operators performed an RPV drain down which introduced pressure related inaccuracies into the temporary instrument and prevented operators from adequately monitoring vessel level. This resulted in a loss of positive configuration control of RCS level during an infrequently conducted risk-significant evolution, and for four days thereafter.

Description

On May 26, 2013, the site was making preparations to start the plant up from a RFO, when they installed the reactor head onto the RPV. By May 29, the head had been fully tensioned, and in accordance with Procedure 9212, "Master RPV Reassembly Procedure," the head vent line installed, with a vent path established between the RPV and the drywell sump. Specifically, Step 30 of Procedure 9212 states, "Perform Procedure 9269 (installation of RPV head insulation)," and contains two bullets, one of which says, "RPV vent path established (XDV-2 and XDV-3 OPEN)." The inspectors noted that this path, involving XDV-2 and XDV-3, and the parallel head vent path utilizing CV-2371 and CV-2372, are referred to in Procedure C.3, "Operations Manual—Shutdown Procedure," as vent paths that are directed to the closed radwaste drywell sump, and are not necessarily open to the atmosphere.

On May 31, in accordance with Procedure 9212, the licensee performed backfilling of the reference leg for the installed flood up level instrument. This process was intended to flush out air bubbles from the flood up level instrument line that could prevent the instrument from accurately indicating reactor water level. Step 33 states, "Fill level transmitter LT-2-3-61 instrument lines by completing the following at instrument Rack C-55," and provides directions on how to backflush the instrument line. This step also contains a substep to "Independently verify LT-2-3-61 is valved into service." Step 33 was labeled as a step that "SHALL be satisfactorily completed to meet NRC Commitment M92115A requirements."

Following this effort, operators performed Step 34 of Procedure 9212, which directed them to verify the accuracy of the flood up level instrument's level readings. Specifically, Step 34 states, "Verify vessel level indication LI-2-3-86 and RPV 112, is in agreement with other level indication available." In this case, the only other RPV level instrument that was on scale and available was the temporary level instrument. In accordance with Procedure 9212, immediately prior to installing the RPV head, plant personnel had visually validated that the temporary instrument readings were consistent with where the water level was in reference to the RPV flange. When operators compared the two indications, they recognized that the installed flood up level indicator was reading 40 inches lower than the temporary instrument. Rather than perform additional backfilling of the instrument at the time of the discrepancy, or to prioritize investigation of the inaccuracy, plant personnel chose to continue to rely on the temporary level instrument for several days as they progressed toward drain down. On June 1, a CAP and a work request were written directing the instrument line to be flushed. The next step in Procedure 9212 directs plant staff to remove the temporary vessel level instrument per Procedure 9040, "Temporary Vessel Level Instrumentation Installation and Restoration." However, because plant personnel could not successfully complete the previous step, Step 34, they chose not to perform this step until the flood up level instrument could be fixed to display an accurate level reading.

On June 3, plant personnel proceeded with Procedure 9212, Step 38, which directs restoration of water level to normal, and draining to below the main steam lines. The draining activity was performed in accordance with Operations Manual B.02.02-05, "Reactor Water Cleanup System Operation," Section G.1, which provides instructions for "Reactor Vessel Draining during Cold Shutdown Conditions." The drain-down was performed in preparation for ECCS testing per Procedure OSP-ECC-0566, "Low Pressure ECCS Automatic Initiation and Loss of Auxiliary Power Test." Specifically, the OSP-ECC-0566 prerequisites included, "Reactor level maintained at least 28 inches below the steam lines (Reference C.3 (Shutdown Procedure) shutdown and refueling mode requirements RHR shutdown cooling operations))." Unbeknownst to the operators, the drain-down process resulted in the drawing of a vacuum in the RPV. As a result, pressure induced inaccuracies were introduced into the temporary instrument, and from the beginning of the drain-down until four days later, plant staff controlled level while relying on this inaccurate instrumentation.

On June 4, the flood up instrument was backfilled to flush out the previously accumulated air bubbles. As a result, the instrument reading increased from 120 inches to 155 inches. At this time, the temporary level instrument was indicating a nominal 84 inches, and because of the discrepancy, plant staff continued to rely on the temporary instrument. Staff would later learn that at that point, the flood up instrument was reading accurately, and was displaying actual water level. On June 7, as part of the effort to investigate the level discrepancy, valves in a parallel vent path (CV-2371 and CV-2372) were cycled. As a result, the vacuum was relieved and temporary level indication quickly increased from 98 inches to 113 inches. Over the course of the previous few days, actual level as displayed on the flood up instrument had slowly trended down from 155 inches to 115 inches. At this point, both level instruments matched, and operators recognized what had occurred.

In evaluating the equipment deficiencies, the licensee found that by design, the head vent lines were not vented to atmosphere and should never have been assumed to maintain constant atmospheric pressure in the RPV for the purposes of temporary level instrument accuracy. In this case, the licensee concluded that during the RPV draining process, the head vent line had pulled a column of water from the drywell sump into the vent line discharge piping. As a result, after the draining, a vacuum was maintained in the RPV. The licensee noted that a vacuum breaker was located on the head vent line, but it was only designed to relieve at 1 psig of vacuum, which would have allowed up to a 28 inch level error to be introduced into the temporary instrument. Exacerbating the situation was the fact that this vacuum breaker was degraded to the point that it could no longer operate to relieve a vacuum as designed. The licensee concluded that the temporary instrument, which is susceptible to pressure-induced error, should not be relied upon when the reactor vessel is pipe tight.

In order to examine plant staff's performance of the level instrument and RPV draining procedural steps out of the prescribed sequence, the inspectors reviewed Procedure 9212, "Master RPV Reassembly Procedure." The inspectors noted that Procedure 9212 contains a general note, which states, "Flexibility in the sequence of steps is permissible provided all of the following are satisfied:

a. Steps are NOT omitted.
b. Steps are performed in the manner described.
c. Steps that are called for at or prior to reaching specific conditions are performed before passing on these conditions."

Inspectors also noted that immediately following Step 33 directing backfilling of the installed flood up instrument, and just prior to Step 34, Procedure 9212, contains a note which states, "NOTE: Ability to compare levels can be affected by plant operating conditions such as recirculation pump operation or level off scale high. Judgment is to be used based on known plant conditions." Considering these two apparent allowances, the inspectors concluded that the procedure did not clearly specify that operators were prohibited from performing the draining sequence prior to transferring level indication from the temporary indicator to the installed indicator. The inspectors determined that these implied allowances represented a procedural weakness, in that they relied on user discretion to determine whether or not it is appropriate to perform steps out of sequence.

When evaluating the decision-making process, the inspectors noted that the temporary level instrument was widely known to be susceptible to pressure induced inaccuracies, and the inspectors concluded that this fact should have been heavily factored into the decision-making process when the initial backfill of the installed flood up instrument was not successful on May 31, 2013. Specifically, the inspectors reviewed Procedure 9040, “Temporary Vessel Level Instrumentation Installation and Restoration,” which provided instructions to plant personnel on installation and removal of the temporary instrumentation. The inspectors noted that the Bases section of the procedure stated, “Any activity which changes the reactor pressure can affect the level instrumentation. For example, removal of the vent piping and the reactor head itself will result in level changes. A vent path to the reactor should be maintained during head removal operations. Not doing so could result in inaccurate level indications on the temporary level instrumentation, since the instrumentation assumes an open tank variable leg and an atmospheric reference leg. Any obstruction such as solid foreign material exclusion protection covers over the vessel head components could affect level indication.”

The inspectors noted that the decision-making process relied on an incomplete understanding of the design and operation of the head vent paths. Specifically, as previously noted, the head vent system was designed such that its vent paths (the only two vent paths that were available based on plant configuration) had the potential to allow up to 1 psig vacuum to be drawn in the RPV. This amount of pressure would introduce an approximate 28 inch level deviation between actual level and level indicated on the temporary instrument. This information should have been weighed in the decision to perform the procedure steps out of sequence. Ultimately, the inspectors concluded that plant personnel chose to keep the pressure-sensitive temporary instrument in service without fully understanding that the head vent path did not vent to atmosphere and could not be guaranteed to maintain atmospheric pressure in the vessel.

The inspectors noted that while performance of the level instrument and RPV draining procedure steps out of sequence was not explicitly prohibited, an evaluation of the draining process and the potential vulnerabilities associated with the temporary level instrument should have revealed that performing these steps out of sequence meant that they were not meeting the requirement that, “Steps are performed in the manner described.” Therefore, inspectors concluded that the general note allowance was inappropriately applied. Furthermore, inspectors concluded that the licensee had inappropriately applied the procedural note which stated, “Ability to compare levels can be affected by plant operating conditions such as recirculation pump operation or level off scale high. Judgment is to be used based on known plant conditions.” Specifically, skipping the flood up instrument backfilling step because it could not be successfully performed due to air bubbles in the instrument line did not appear to be consistent with the intent of the note.

The inspectors noted that the bottoms of the main steam lines are located at 109 inches. Throughout the course of the time period where the temporary level instrument was inaccurate, actual water level gradually declined from approximately 155 inches to 115 inches. Inspectors noted that the operational staff was not aware at this time that actual reactor level was lowering. In addition, the staff was not aware that water level was at or above the main steam lines during this period. This meant that the site had failed to establish level in the prerequisite band required for ECCS testing. This issue was reviewed by the licensee and determined not to have negatively impacted the test or natural circulation capability. The inspectors also noted that if an event were to occur during the period where plant personnel were relying on inaccurate level indication, it may result in complicating control room staff response. Inspectors noted that there were several other level instruments that would become available and would come on scale if level had decreased substantially. The inspectors noted that this fact and the availability of automatically responding equipment limited the significance of this deficiency. This performance deficiency resulted in a loss of positive control over RCS level during and after a risk significant evolution.

The inspectors concluded that the licensee inappropriately applied procedural allowances contained in Procedure 9212, "Master RPV Reassembly Procedure," to perform a partial RCS drain down prior to completing steps necessary to transfer from the temporary level instrument to the installed flood up level instrument. As a result, the site failed to adequately monitor reactor vessel level during the drain down process, as required by Operations Manual B.02.02-05. Specifically, B.02.02-05, "Reactor Water Cleanup System Operation," Section G.1, "Reactor Vessel Draining during Cold Shutdown Conditions," provides instructions on actions required to drain the vessel during cold shutdown. Specifically, following actions to establish a vessel drain path, Step 10, states, "Monitor water levels in the reactor." Due to the operators' reliance on the inaccurate temporary vessel level indication, the site failed to adequately perform this action.

Analysis

The inspectors determined that the licensee's failure to adequately monitor RCS level during a risk-significant RCS draining evolution was a performance deficiency, because it was the result of the failure to meet the requirements of TS 5.4.1.a, "Procedures," the cause was reasonably within the licensee's ability to foresee and correct, and should have been prevented. The inspectors determined that this finding was cross-cutting in the Human Performance, decision making area, and involved aspects associated with using conservative assumptions in decision making and adopting a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate that it is unsafe in order to disapprove the action [H.1(b)]. Specifically, the licensee failed to adequately monitor level due to plant personnel's performance of the 9212 procedure steps out of the prescribed order, because the procedure did not explicitly prohibit it. Plant personnel relied on non-conservative assumptions about the head vent system design, despite a known risk of pressure-induced level monitoring impacts, and failed to take action to demonstrate the proposed action was safe.

The inspectors screened the performance deficiency per IMC 0612, "Power Reactor Inspection Reports," Appendix B, dated September 7, 2012, and determined that the issue was more than minor because it was associated with the configuration control "shutdown equipment lineup" attribute of the Initiating Events Cornerstone and impacted the cornerstone objective to limit the likelihood of those events that challenge critical safety functions during shutdown operations. Specifically, RCS level indication did not accurately reflect the level in the reactor vessel, and availability of RPV level indication impacts the core heat removal and inventory control critical safety functions. In addition, if left uncorrected, the reliance on inaccurate RPV level instrumentation could lead to a more significant safety issue because it constitutes a loss of positive control of reactor vessel level during a risk significant RCS drain down. Using IMC 0609, Appendix G, for shutdown operations, the inspectors used Checklist 8 and determined that the finding had very low safety significance because it did not adversely affect core heat removal; inventory control; power availability; containment control; or reactivity guidelines. Specifically, the temporary level instrument being used by operators indicated lower level than actual; and other sources of vessel level indication would have become available and would have been noticed by the operators if the vessel level had lowered to the point where normal level instrumentation came on scale. In addition in accordance with Table 1 of IMC 0609, Appendix G, it did not represent an inadvertent loss of two feet of RCS inventory or inadvertent RCS pressurization.

Enforcement

Technical Specification 5.4.1 states, "Written procedures shall be established, implemented, and maintained covering the following activities: (a) The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978." NRC Regulatory Guide 1.33, Appendix A, Section 9.d.4, requires maintenance or operational procedures for "Draining and Refilling the Reactor Vessel."

Contrary to the above, on June 3, 2013, the licensee failed to implement procedures regarding maintenance or operations activities for draining and refilling the reactor vessel. Specifically, the licensee failed to follow Operations Manual B.02.02-05, "Reactor Water Cleanup System Operation," Section G.1, "Reactor Vessel Draining during Cold Shutdown Conditions," when they failed to adequately monitor water levels in the reactor during the RPV partial draining process. While relying on a temporary installed level instrument, the site performed an RPV drain-down which introduced pressure related inaccuracies into the temporary instrument and prevented operators from adequately monitoring vessel level. This resulted in a loss of positive configuration control of RCS level during an infrequently conducted risk-significant evolution, and for four days thereafter.

The licensee entered the issue into the corrective action program as CAP 1385754. Corrective actions included transferring from the temporary level instrument to the flood up level instrument and enhancing RPV reassembly and temporary vessel installation procedures. Because the violation was of very low safety significance and was entered into the licensee's corrective action program, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(**NCV 05000263/2013004-03; Loss of Accurate Level Indication during Partial RCS Drain Down**)

.4 Selected Issue Follow-Up Inspection: Review of Corrective Actions Taken to Address Previously Identified Maintenance Rule Deficiencies

a. Inspection Scope

During the first half of 2012, the inspectors identified several findings of very low safety significance and associated NCVs of 10 CFR 50.65. This regulation, commonly referred to as the Maintenance Rule, requires licensees to monitor the performance and/or condition of various SSCs to ensure that the SSCs remain capable of performing their intended function(s).

During the current inspection period, the inspectors reviewed the CAPs associated with each previously identified violation to ensure that the corrective actions addressed the violations and were implemented in a timely manner. The inspectors also discussed the status of current Maintenance Rule performance improvement activities with the engineering department to verify that the licensee's current program complied with 10 CFR 50.65 requirements and to ensure that progress was being made in addressing areas needing improvement.

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

b. Findings

The inspectors determined that the violations identified in 2012 were appropriately resolved. Based upon discussions with the engineering department, the inspectors concluded that progress was being made in addressing Maintenance Rule improvement items. The licensee had placed significant emphasis on ensuring that the Maintenance Rule expert panel continued to meet during the extended RFO. Specifically, 13 of 18 meetings were held as scheduled. However, continued emphasis was needed to make sure that the number of Maintenance Rule evaluations needing expert panel approval was reduced to pre-RFO levels in a timely manner.

No findings were identified.

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

.1 (Closed) Licensee Event Report (LER) 05000263/2013-004-00: Loss of Normal Off-site Power as a Result of Switchgear Fault

This event, which occurred on June 13, 2013, involved a 2R lockout and an inappropriate emergency shutdown of both EDGs. During a RFO with plant power provided by the 2R transformer, the licensee was performing testing activities associated plant modifications that had been installed in preparation for an EPU. During bump testing of the 12 condensate pump, the site experienced indications of a loss of normal offsite power. Specifically, the site lost power to nonsafety-related loads, and safety-related buses experienced an automatic transfer to the 1AR offsite power transformer. At the time of the event, the other normal offsite power transformer, 1R, was out of service for EPU-related modification work. As designed, both EDGs automatically started, but were not needed. In addition, due to the loss of normal offsite power, RHR shutdown cooling and spent fuel pool cooling were automatically isolated and removed from service. During the event, reports from the field indicated that the 13.8 kV breaker for the 2R to 11 bus feed had experienced an arc flash, which had caused a lockout of the 2R transformer.

After complex troubleshooting and a root cause evaluation, the licensee concluded that the root cause of the event was a combination of three factors. Specifically, they concluded that the arc flash was caused by foreign material in the breaker cubicle; an improperly secured insulating boot within the cubicle; and a voltage spike which came as the result of the 12 condensate pump bump test, where operators tripped the pump during its start sequence, with no other loads on the bus to absorb the impact. In addition, the licensee determined that there was a contributing cause which resulted in the event having a larger impact to the plant. This contributing cause was determined to be that there was a lack of a formal documented test plan for complex changes with multiple integrated design changes that assess risk at various phases of the plan. The inspectors review the licensee's corrective actions and did not identify any findings. The inspectors identified one NCV related to the emergency shutdown of the EDGs, which is discussed in the next section. Documents reviewed are listed in the Attachment to this report. This LER is closed.

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

Findings

Inappropriate Emergency Shutdown of Both Emergency Diesel Generators During a Loss of Normal Offsite Power Event

Introduction

A self-revealed finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," occurred on June 13, 2013, due to the licensee's failure to accomplish activities affecting quality in accordance with instructions, procedures, or drawings of a type appropriate to the circumstances. Specifically, operators failed to utilize B.09.08-05.E.1/2, "Emergency Diesel Generators—System Operation, 11/12 Emergency Diesel Generator Operation," when verifying proper operation of both EDGs following their auto-start during a loss of normal offsite power event. This resulted in an inappropriate emergency shutdown of both EDGs when circumstances did not warrant the action, making them inoperable during an event that could have resulted in the necessity of their use. In addition, as noted in procedural cautions, this action unnecessarily challenged future reliability of the EDGs due to the bypassing of the normal engine cool-down period.

Description

On June 13, 2013, during bump testing of the 12 condensate pump, the site experienced a loss of normal offsite power. As designed, both EDGs automatically started. Following the auto initiation of the EDGs, non-licensed operators were dispatched in response to an EDG annunciator for low turbo oil pressure, and to verify proper operation of the diesels. During the in-field assessment to determine the status of the EDGs, operators determined that the indications of low turbo oil pressure were abnormal, and could result in damage to both EDGs. As a result, after consultation with the control room operating crew, the control room supervisor gave the order for operators to perform an emergency shut-down of both EDGs. As a result, during a period of orange shutdown risk due to unavailability of power sources, both EDGs were emergency-shutdown and made inoperable. Within an hour of these actions, operators obtained additional information which identified that the low turbo oil pressure alarms and local indications they had relied on to make their original assessment were in fact expected conditions during the auto start of an EDG after a loss of normal offsite power (LONOP). As a result, operators realigned both EDGs to a standby condition, and restored them operable status.

The licensee's causal evaluation revealed that an inaccurate note in Annunciator Response Procedure (ARP) 93-A-26, "Low Turbo Oil Pressure," misled operators in that it stated that the alarms only actuate when the engine is shutdown. In addition, the licensee concluded that in accordance with Procedure C.4-B.09.02.B, "Loss of Normal Offsite Power," the operations crew should have utilized a procedure to confirm the operational status of the EDGs after an auto start. Specifically, Step 5 of C.4-B.09.02.B states, "If 11 EDG is running loaded onto Bus 15, the Dispatch operator to verify proper operation of 11 EDG. Refer to B.09.08-05 (Emergency Diesel Generators—System Operation)." While in this case, the EDGs were not loaded onto the bus, this step was marked complete by operators because this step is performed in practice to ensure availability of both diesels during events, even when they are not needed.

Procedure B.09.08-05, "Emergency Diesel Generators—System Operation," provides information on why the low turbo oil pressure annunciators are expected following an auto start of an EDG. Section E.1 (or E.2 for the 12 EDG), "11 Emergency Diesel Generator Operation," states the purpose of the procedure is to "provide instructions for items to be checked following an emergency start signal." Procedure E.1, under "Precautions and Limitations" states, "If the EDG is operating with the non-essential busses de-energized, alarms 93-A-27 (circulating oil pressure) and 93-A-26 (low turbo oil pressure) will be sounding." It continues on with instructions on how to tell if operating oil pressure is adequate. Inspectors concluded that if this procedure had been used after the EDG auto-start, it would have provided operators with the instructions to allow them to properly assess EDG condition. Section E.1 of the procedure provides additional parameters that need to be monitored following an auto start. The licensee's causal evaluation also found that the E.1 procedure was not readily available for use by operators. Specifically, the procedure was located in the turbine building operator office, and would have required responding field operators to travel to the EDG room to check the alarming local annunciators, and then return back to the office to obtain the applicable procedure. Considering the short time frame the operators believed they had before the condition caused damage to the EDG, this could have lengthened their response and, therefore, contributed to their failure to use the procedure.

In addition, during the operating crew's discussions while assessing the condition, operators failed to consult the B.09.08-05 procedure for general guidance to help inform their actions, because, as interviews revealed, they didn't think of it. The inspectors noted that ARP instructions were incomplete in that they should have prompted operators to use Operations Manual B.09.08-05 guidance. In addition, the ARP did not contain important cautions or notes, similar to cautions contained in B.09.08-05, that alerted operators to the expected status of these alarms. Specifically, in Section 4, "General Precautions," the procedure states, "When the EDG is operating as a result of an emergency demand, auxiliary equipment supplied from non-essential power supplies will NOT be available. The most significant of these loads are the Circulating oil pump and the Turbo circulating oil pump. Because these pumps are NOT operating on an emergency demand, alarms A-26 (low turbo oil pressure) and A-27 (circulating oil pressure) on Panel C-93 (11 EDG) or C-94 (12 EDG) will sound continuously while the engine is running."

The alarm response procedure provided inaccurate and incomplete information, and contributed to the operators' failure to consult Operations Manual B.09.08-05. As a result, the operators believed the low turbo lube oil pressure indications were abnormal, and took action to perform the emergency shutdown of the EDGs in accordance with B.09.08-05.H.2 and B.09.08-05.H.3, "Local Shutdown of 11(12) Diesel in Emergency Condition." The Precautions and Limitations Section of the procedure notes that "this procedure will bypass the normal shutdown sequence used to cool down the EDG following operation. This could have a significant negative effect on continuing EDG reliability. This procedure should only be used when circumstances require immediate action to shutdown the EDG." The inspectors concluded that operators performed an inappropriate emergency shutdown of both EDGs when circumstances did not warrant the action, making them inoperable during an event that could have resulted in the necessity of their use.

Analysis

The inspectors determined that the licensee's failure to utilize a procedure to verify proper operation of the EDGs was a performance deficiency, because it was the result of the failure to meet the requirements of 10 CFR 50, Appendix B; the cause was reasonably within the licensee's ability to foresee and correct; and should have been prevented. The inspectors concluded that this issue was cross-cutting in the Human Performance, resources area, because the licensee failed to make available complete, accurate and up-to-date response procedures [H.2(c)]. Specifically, the ARP contained a note which incorrectly stated that the annunciator would only alarm when the EDG was shutdown. This note led operators to erroneously believe that the presence of the low turbo oil pressure alarm, and the associated local indications were abnormal for the auto start condition, and resulted in the inappropriate emergency EDG shutdown. In addition, the Operations Manual E.1 Procedure for verifying proper EDG operation was not made readily available to the field operator responding to the diesel room.

The inspectors screened the performance deficiency per IMC 0612, "Power Reactor Inspection Reports," Appendix B, and determined that the finding was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of human performance and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the performance deficiency challenged the future reliability of the diesel generators, and made the diesel generators inoperable during an orange shutdown risk configuration due to limited availability of equipment supporting the electrical power critical safety function. In addition, if left uncorrected, the performance deficiency could lead to a more significant safety concern. Specifically, failing to utilize necessary procedures when verifying proper operation of important safety-related equipment during an event, could lead to unnecessary unavailability of additional systems. In this case, it could also have resulted in additional consequences if the EDGs had remained disabled and the equipment had become necessary. In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 2, the inspectors determined the finding affected the Mitigating Systems Cornerstone. In addition, the plant was shutdown at the time of the finding, and as a result, the inspectors determined the finding could be evaluated using Appendix G, "Shutdown Operations Significance Determination Process." The inspectors utilized IMC 0609, Appendix G, Attachment 1, Checklist 8, for

BWRs, because the plant was in cold shutdown with more than two hours of time to boil and less than 23 feet of water above the reactor flange. The inspectors determined the finding had very low safety significance because it did not adversely affect core heat removal, inventory control, power availability, containment control, or reactivity guidelines (Green).

Enforcement

Title 10 CFR Part 50, Appendix B, Criterion V, states, “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. Instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.”

Contrary to the above, on June 13, 2013, the licensee failed to accomplish activities affecting quality in accordance with instructions, procedures, or drawings of a type appropriate to the circumstances. Specifically, operators failed to utilize B.09.08-05.E.1/2, “Emergency Diesel Generators—System Operation, 11/12 Emergency Diesel Generator Operation,” when verifying proper operation of both EDGs following their auto start during a LONOP event.

The licensee entered the issue into their corrective action program as CAP 1385754. Corrective actions included immediate actions to restore the EDGs to operable status once the inappropriate action was identified, performance of a site clock reset, and improving training and associated procedures. Because the violation was of very low safety significance and was entered into the licensee’s corrective action program, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. (**NCV 05000263/2013004-04; Inappropriate Emergency Shutdown of Both EDGs during a LONOP Event**)

4OA5 Other Activities

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

a. Inspection Scope

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

From July 8 - 12, 2013, the inspectors conducted a review of records and procedures related to the licensee's program for buried pipe, underground pipe, and tanks in accordance with Phase II of TI-2515/182. This review was done to confirm that the licensee's program contained attributes consistent with Sections 3.3 A and 3.3 B of NEI 09-14 and to confirm that these attributes were scheduled and/or completed by the NEI 09-14, Revision 3, deadlines. The inspectors interviewed licensee staff responsible for the buried pipe program, to determine whether the program attribute was accomplished in a manner which reflected good or poor practices in program management,. Additionally, the inspectors performed a walkdown of rectifiers, anode beds and test points used for the operation and maintenance of the cathodic protection system.

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

b. Observations

The licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.a of the TI and it was confirmed that activities which correspond to completion dates specified in the program which have passed since the Phase I inspection was conducted, have been completed. Additionally, the licensee's Buried Piping and Underground Piping and Tanks Program was inspected in accordance with Paragraph 03.02.b of the TI and responses to specific questions, found at http://www.nrc.gov/reactors/operating/ops-experience/buried-pipe-ti-phase-2-insp-req-2011-11-16.pdf, were submitted to the NRC Headquarters staff.

c. Findings

No findings were identified.

This issue is described in Section 1R21 and was resolved to an NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

.2 Unit 1 Power Uprate Related Inspection Activities (71004)

During this inspection period, the inspectors observed several activities related to the power uprate amendment. As documented in Section 1R18 above, the inspectors reviewed selected power uprate related modification packages for the recirculation system.

4OA6 Management Meetings

.1 Exit Meeting Summary

On November 14, 2013, the inspectors met with Mr. Hate Haskell and other members of the licensee staff to discuss the status of Unresolved Items 05000263/2012008-01 and 05000263/2012008-02. The Licensee acknowledged the issues presented.

On October 9, 2013, the inspectors presented the inspection results to Ms. Karen Fili, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (TI-2515/182) with the Site Vice President, Mr. Mark Schimmel, and other members of the licensee staff on July 12, 2013.

- On August 2, 2013, the inspectors presented the Triennial Heat Sink Performance Inspection results to Mr. John Grubb, and other members of the licensee staff.

- The results of the inspectors URI inspection and closure were reviewed with Mr. Nate Haskell, and other members of the licensee staff on August 12, 2013.

- The inspection results for the areas of occupational ALARA planning and controls; radioactive gaseous and liquid effluent treatment; radiological environmental monitoring; and RCS specific activity, occupational exposure control effectiveness, and RETS/ODCM radiological effluent occurrences PI verification with Mr. John Grubb, Plant Manager, on September 27, 2013.

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

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

K. Fili, Site Vice President
J. Grubb, Plant Manager
P. Albares, Operations Manager
N. Haskell, Site Engineering Director
K. Jepson, Assistant Plant Manager
S. Mattson, Maintenance Manager
K. Petersen, Chemistry Manager
A. Zelie, Radiation Protection Manager
P. Kissinger, Regulatory Affairs Manager
S. O'Connor, Regulatory Affairs
G. Hernandez, Program Engineering Supervisor
C. Fosaaen, Regulatory Affairs
B. Goodnature, Chemist
T. Hedges, Radiation Protection General Supervisor

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000263/2013004-01	FIN	Recirculation System Vulnerabilities Due to Inadequate Modification Review (Section 1R18)
05000263/2013004-02	NCV	Failure to Maintain the ODCM (Section 2RS6.01)
05000263/2013004-03	NCV	Loss of Accurate Level Indication During Partial RCS Drain Down (Section 4OA2.3)
05000263/2013004-04	NCV	Inappropriate Emergency Shutdown of Both EDGs During a LONOP Event (Section 4OA3.1)

Closed

05000263/2013004-01	FIN	Recirculation System Vulnerabilities due to Inadequate Modification Review (Section 1R18)
05000263/2013004-02	NCV	Failure to Maintain the ODCM (Section 2RS6.01)
05000263/2013004-03	NCV	Loss of Accurate Level Indication During Partial RCS Drain Down (Section 4OA2.3)
05000263/2013004-04	NCV	Inappropriate Emergency Shutdown of Both EDGs During a LONOP Event (Section 4OA3.1)
05000263/2013-004-00	LER	Loss of Normal Off-site Power as a Result of Switchgear Fault (Section 4OA3.1)
2515/182	TI	Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (Section 4OA5.1)

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.

Section 1R04

2118; Plant Prestart Checklist HPCI System; Revision 16
2121; Plant Prestart Checklist RCIC System; Revision 15
2154-10; HPCI System Prestart Valve Checklist; Revision 32
2154-13; RCIC System Prestart Valve Checklist; Revision 27
B.09-.09-02; 250 Vdc System Description
CAP 1275004; HPCI FRP 25 Discovery Walkdown
CAP 1275916; HPCI-15 Failed IST Testing Requirements
CAP 1293796; HPCI Room Temp Low Operational and Design Margin (MRB-001)
CAP 1296987; 250 Vdc System Margin Issue; July 29, 2011
CAP 1317348; HPCI Vibration Point Entered Alert Range
CAP 134157; Found Bonnet Bolts on MO-2067 Loose
CAP 1368491; No. 13 Battery Cell Inter-connection Resistance Readings High
CAP 1379026; RCIC-9 Failed Inspection
CAP 1379914; RCIC Hi Frequency Null Voltage Reading Seems Noisier than Normal
CAP 1381696; MO-2076 Exceeded App J Admin Limit Post Maintenance
CAP 1382685; High Resistance on No. 13 Battery Inter-tier Connections
CAP 1382913; New Relay Found Broken in Electrical Storage Area
CAP 1389246; NRC Question on Alignment Data for HPCI and RCIC
NH-36249; P&ID (Steam side) HPCI System; Revision 79
NH-36250; P&ID (Water side) HPCI System; Revision 82
NH-36251; RCIC P&ID (Steam Side); Revision 78
NH-36252; RCIC P&ID (Water Side); Revision 78
Plant Restart Checklist 2126-02; Batteries and DC Power System 125 Vdc; Revision 19
Plant Restart Checklist 2126-03; 250 Vdc Batteries and DC Power System; Revision 18

Section 1R05

Strategy A.3-32-B; EFT Building Second floor (Div II); Revision 8
Strategy A.3-32-A; EFT Building Second floor (Div I); Revision 8
Strategy A.3-33; EFT Building Third Floor; Revision 6
Strategy A.3-37; Transformers; Revision 12
Strategy A.3-13B; RX Feedpump and Lube Oil Reservoir Room; Revision 12

Section 1R06

WO 461019-01; Inspection of Manholes for Water or Evidence of Water; Revision 4
NF-74413-6; Underground Services of Division II Cable Raceway System; Revision 78
NF-74413-4; Underground Services Electrical Power; Revision 90
NF-201636-01; ISFSI Temperature Monitoring System Electrical Layout and Details; Revision 2

NF-36763; Raceways, Grounding, and Direct Buried Cable Runs - South Turbine Generator Building; Revision 90
CAP 1391734; Underground Vaults May Not Have Been Inspected Properly

Section 1R07

4058-02-PM; RHR Pump 14 and CSP 12 Motor Cooler Chemical Cleaning; Revision 15
8898; Core Spray Motor Test Without Water Cooling; Revision 2
A.6; Acts of Nature; Revision 46
B.8.1.2; Maintenance Rule System Basis Document EDG-ESW System; Revision 1
CA-00-104; Intake Structure Minimum Water Level; Revision 0
CA- 96-020; HPCI Room SBA Transient Temperature; Revision 5
CA-03-111; EDG Jacket Cooler Maximum Allowed Tubes Plugged; Revision 10
CA-96-106; CSP Motor-Oil and Bearing Operation Temperatures Without Water Cooling; Revision 1
CA-03-017; Diesel Jacket Water Heat Exchanger Temperature Prediction; Revision A
CA-02-110; Diesel Jacket Water Heat Exchanger Temperature Prediction; Revision C
CAP 1275982; 12 EDG HX Requires Tube Plugging
CAP 0630233; Converted Issue No. 2007088; NRC Questioned EDG Mission Time
CAP 1348872; Could Not Reach Required Flow During 0255-03-IA-1-2
CAP 1233617; Div 2 Core Spray System Fails to Achieve Max Flow Values
CAP 1385756; Motor Cooling Flow Degraded for P-208B
CAP 1253835; Replaced Shear Pin
CAP 1390483; UHS Assessment - Needs Improvement: ECCS Motor Cooler Strategy
CAP 1390495; UHS Assessment - Needs Improved: Zebra Mussel Eradication Plan
CAP 1355457; Oct - Predicted EDG HX Outlet Shell Temp Exceeds Acceptance Criteria
CAP 1378077; 11 EDG Jacket Water Cooler Requires Tube Plugging
CAP 1356719; Inaccuracies in 11 EDG Thermal Performance Testing Inputs
CAP 1334248; Potential Margin Reduction from Degraded ECCS Pump Head
CAP 1379793; 11 CS Pump did not Regain Expected D/P after Rebuild
CAP 1307514; Multiple Unexpected Alarms Due to Changing River Conditions
CAP 1309393; Raw Water Alarm Received on No. 11 EDG
CAP 1335274; A Few Small Asiatic Clams Found in Dredging Spoils
CAP 1335419; Slight Worsening of Concrete Cracks in Intake Bay
CAP 1357002; Pump d/p Fell in Alert Range During 0187-02A
CAP 1384239; Buildup Rock/Debris Between Bar Rack and Deicing Line
CAP 1392232; NRC Questioned the Acceptability of Taking Both ESW Pumps to Pull-to-Lock
CAP 1325200; MR Action Plan Revision for CSP and RHR Motor Cooling Issue; Revision 2b
CAP 1255469; 12 EDG Coolant leak (Operability Determination)
CAP 1391499; Apparent Mismatch Requirements for CSP Motor Coolers (NRC Identified)
DBD B.08.01.02; DBD for EDG ESW System; Revision 4
DBD B.08.01.04; DBD for Emergency Service Water System; Revision 4
Design Change 03Q060; EDG ESW Heat Exchanger Tube Plugging; Revision 0
EWI-08.22.01; Generic Letter 89-013; Revision 8
EWI-08.22.02; Balance of Plant Heat Exchanger Program; Revision 8
FOI 91-0136; ECCS Motor Cooling Requirements Concern; April 19, 1991
GEN 02005134; Discrepancy in Maximum Expected Temperature in RHR Room; September 21, 2005
I.05.31; Operation of the Non-Oxidizing Biocide System; Revision 14
I.05.32; Sampling of the Non-Oxidizing Biocide Target Systems; Revision 5
I.05.45; Sampling Emergency Diesel Generator Coolant; Revision 7

Letter from MNGP to NRC in Response to Generic Letter 89-13; January 29, 1990
Letter from MNGP to NRC Follow-Up Response to Generic Letter 89-13; June 27, 1991
NH-36041; Service Water System; Revision 101
NF-36454: Intake Structure Plan at EL. 919', Revision 77
NF-36458; Intake Structure Sections and Detail; Revision A
NH-36489; Circulating Water System; Revision 82
NH-36664; RHR Service Water and Emergency Service Water Systems; Revision 85
NH-36665; Service Water System and Make-up Intake Structure; Revision 96
NH-36666; Screen Wash, Fire and Chlorination Systems Intake Structure; Revision 87
NH-458742; MNGP EDG-ESW Thermowell Locations; Revision A
Ops Man B.06.04-05, Section 4; Low River Level; Revision 61
Ops Man B.08.01.02-05; EDG Emergency Service Water; Revision 17
Ops Man B.08.01.02-01; EDG Emergency Service Water; Revision 8
Ops Man B.08.01.04-01; Emergency Service Water; Revision 5
Ops Man B.08.01.04-05; Emergency Service Water; Revision 26
Ops Man B.09.08-02; Emergency Diesel Generator; Revision 10
Ops Man C.4-B.08.01.01.A; Loss of Service Water; Revision 13
SRI 95-002; Core Spray Pump Motor without Cooling; Revision 1
Underwater Construction Corporation Intake Dredging and Inspection Report; May 8, 2013
WO 394436; PM 4125 East Service Water Bay
WO 394437; PM 4126 Inspect West Service Water Bay
WO 398732; Perform PMs of Traveling Screen
WO 399872; Dredge Intake Bays
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CAP 01386534; Insulating Boots for Fex Connectors at 1R Severely Damaged

Section 4OA5

CAP 1212245; NEI 09-53 Buried Piping Integrity Initiative Required Action; December 31, 2009
Procedure UPTI-PLAN Lacking Required Detail; July 3, 2013
CAP 1267747; NEI 09-14 Guideline for the Management of Buried Piping; January 25, 2011
CAP 1388889; UPTI-PLAN Has No Link to Fleet NDE Procedures; July 3, 2013
CAP 1389445; UPTI Coating Holiday Tester Had No Calibration Sticker; July 10, 2013
UPTI-PLAN; Underground Pipe and Tank Inspection Plan; Revision 0
Form 3856; Underground Pipe or Tank Inspection; Revision 0
BP-PLAN; MNGP Buried Pipe Inspection Plan; Revision 0
1404-01; EDG ESW Heat Exchanger Performance Test; Revision 15
M-112; P&ID RHR Service Water and Emergency Service Water Systems; Revision 85
1253; Underground Piping Inspection; Revision 5
Cathodic Protection Survey; MNGP; September 13, 2010
Cathodic Protection Survey; MNGP; August 17, 2011
Cathodic Protection Survey; MNGP; August 21, 2012
QF1306; Excavation Permit; Revision 10
NEI 09-14; Guideline for the Management of Underground Piping and Tank Integrity; Revision 3
FP-PE-PHS-01; Program Health Process; Revision 15
WO 460135; Cathodic Protection Rectifier Test; December 4, 2012
ESP-CAT-0597; Cathodic Protection Rectifier Test; Revision 4
FP-PE-NDE-425; Ultrasonic Thickness Examination-Localized Corrosion; Revision 1
EWI-08.25.01; Underground Piping and Tank Integrity Program; Revision 7
EWI-11.01.14; Buried Piping and Tanks Inspection; Revision 0
Report No. 1200191.401; Plant Site-Specific Risk-Analysis for Buried and Underground Piping and Tanks, MNGP; June 29, 2012
Report No. 1200191.402; APEC Survey, MNGP; October 16, 2012
Report No. 0800621.401.R0; G-Scan/B-Scan Assessment of Various Piping Systems; November 2, 2009
CD 5.39; Fleet Underground Piping and Tank Integrity Program Standard; Revision 2
NACE Std. RP0188-99; Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates; January 15 1999

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Reasonably-Achievable
ARP	Annunciator Response Procedure
ASME	American Society of Mechanical Engineers
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CSP	Core Spray Pump
ΔCDF	Delta Core Damage Frequency
ΔLERF	Delta Large-Early Release-Frequency
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EC	Engineering Change
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EFT	Emergency Filtration Train
EGM	Enforcement Guidance Memorandum
EOP	Emergency Operating Procedure
EPU	Extended Power Uprate
FIN	Finding
FP	Fleet Procedure
FSAR	Final Safety Analysis Report
HEP	Human Error Probability
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
IST	Inservice Test
kV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large-Early Release-Frequency
LLOCA	Large LOCA
LOCA	Loss of Coolant Accident
LONOP	Loss of Normal Offsite Power
LPCI	Low Pressure Coolant Injection
MLOCA	Medium LOCA
MNGP	Monticello Nuclear Generating Plant
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NUMARC	Nuclear Management and Resources Council
O&M	Operation and Maintenance
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records System

PI	Performance Indicator
PM	Post Maintenance
PSF	Performance Shaping Factor
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Programs
RETS	Radioactive Effluent Technical Specifications
RFO	Refueling Outage
RHR	Residual Heat Removal
RIS	Regulatory Issue Summary
ROP	Reactor Oversight Process
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RRL	Reactor Recirculation Loop
RWCU	Reactor Water Cleanup
SDP	Significance Determination Process
SLOCA	Small LOCA
SPAR	Standardized Plant Analysis Risk
SR	Surveillance Requirement
SRA	Senior Reactor Analyst
SSC	Structure, System and Component
STS	Standard Technical Specifications
TI	Temporary Instruction
TS	Technical Specification
UHS	Ultimate Heat Sink
URI	Unresolved Item
USAR	Updated Safety Analysis Report
Vdc	Volts Direct Current
WO	Work Order

discretion in accordance with Section 3.5, "Violations Involving Special Circumstances," of the NRC Enforcement Policy and, therefore, we are not issuing enforcement action for this violation.

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Sincerely,

/RA by Julio Lara for/

Kenneth O'Brien, Acting Director
Division of Reactor Projects

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Letter to Karen Fili from Kenneth O'Brien dated November 18, 2013

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT - NRC INTEGRATED AND POWER UPRATE INSPECTION REPORT 05000263/2013004 AND EXERCISE OF ENFORCEMENT DISCRETION

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