UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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February 1, 2012

Mr. Timothy J. O'Connor
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 INSPECTION REPORT 05000263/2011005

Dear Mr. O'Connor:

On December 31, 2011, 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 January 11, 2012, with you and other members of your staff.

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

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

Five of these findings were determined to involve violations of NRC requirements. Additionally, the NRC has determined that a traditional enforcement Severity Level IV violation occurred. This traditional enforcement violation was identified with an associated finding. Further, licensee-identified violations which were determined to be of very low safety significance are listed in this report. 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 Monticello Nuclear Generating Plant. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Monticello Nuclear Generating Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's Agencywide Document Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer, Branch Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000263/2011005
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-263
License No:	DPR-22
Report No:	05000263/2011005
Licensee:	Northern States Power Company, Minnesota
Facility:	Monticello Nuclear Generating Plant
Location:	Monticello, MN
Dates:	October 1 through December 31, 2011
Inspectors:	S. Thomas, Senior Resident Inspector P. Voss, Resident Inspector R. Walton, Inspector, DRS C. Zoia, Inspector, DRS M. Munir, Reactor Inspector K. Stoedter, Prairie Island Senior Resident Inspector P. Zurawski, Prairie Island Resident Inspector J. Beavers, Emergency Preparedness Inspector M. Phalen, Senior Health Physicist, DRS S. Bell, Health Physicist, DRS
Approved by:	K. Riemer, Branch Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000363/2011005; 10/01/2011 – 12/31/2011; Monticello Nuclear Generating Plant. Maintenance Risk Assessment and Emergent Work Control; Outage Activities; Follow-Up of Events and Notices of Enforcement Discretion; and Occupational Dose Assessment.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two Green findings were identified by the inspectors and three Green findings were self-revealed. These findings were considered non-cited violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance and non-cited violation (NCV) of Technical Specification (TS) 5.4.1, "Procedures," when the operators did not take conservative action to address a high differential pressure condition on an inservice condensate demineralizer vessel. Specifically, operators allowed the 'E' condensate demineralizer to exceed differential pressure operating limits prescribed in Alarm Response Procedure 80-DPAH-2215, "Vessel T-7E D/P High," and remain above those prescribed limits for approximately a shift before taking action to correct the abnormal condition. Specific corrective actions taken by the licensee to address this issue included updating the applicable alarm response procedures and operating procedures to reflect current system limitations; engineering management reinforcing the expectation that informal processes are not acceptable when communicating technical guidance to operations staff; and site management reinforcing the expectation that, once a degrading trend is recognized, actions must be taken in sufficient time to prevent crossing established operating limits.

  The inspectors determined that the licensee's failure to maintain the 'E' condensate demineralizer differential pressure within prescribed operational limits was a performance deficiency because it was the result of the failure to meet a requirement or a standard; 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, "Power Reactor Inspection Reports," Appendix B, and determined that the issue was more than minor because it impacted the Human Performance attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors applied IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," to this finding. The inspectors utilized Column 1 of the Table 4a worksheet to screen the finding. For transient initiators, the inspectors answered 'no' to the question, "Does the finding contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment of functions will not be available," and determined the finding to be of very low safety significance. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting area of Human Performance, having Work Control components, and involving aspects associated with the licensee planning and coordinating work activities, consistent with nuclear safety, specifically the need for planned contingencies, compensatory actions, and abort criteria [H.3(a)]. (Section 1R13)

- Green. A finding of very low safety significance and NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," was self-revealed following a reactor scram, which was the direct result of an electric plant realignment caused by a faulted feeder cable and lockout of the station's 2R transformer. Specifically, annual testing to monitor the performance of the 2R feeder cables, which was put in place as a corrective action to prevent recurrence to address issues identified subsequent to a similar event in 2008, had not been performed since the cables were placed back in service following that event. To address the identified material deficiencies, the licensee replaced and tested the electrical cables between 2RS and 2R in their entirety, employing a new route designed to avoid cable submergence. Additional corrective actions were put in place to strengthen the licensee's planned maintenance deferral process and their cable condition monitoring program.

  The inspectors determined that the licensee's failure to perform annual testing of the 2R transformer feeder cables, as required by the station's planned maintenance program, was a performance deficiency because it was the result of the failure to meet a requirement or a standard, the cause was reasonably within the licensee's ability to foresee and correct, and should have been prevented. The inspectors determined that the issue was more than minor because it impacted the Configuration Control attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors applied IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," to this finding. The inspectors utilized Column 1 of the Table 4a worksheet to screen the finding. Because the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions would not be available, the Region III Senior Reactor Analyst (SRA) performed a Phase 3 analysis, and screened the finding to be of very low safety significance. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting area of Human Performance, having decision-making components, and involving aspects associated with the licensees' making safety-significant or risk-significant decisions using a systematic process to ensure safety is maintained [H.1(a)]. (Section 1R20.1)

- Green. A finding of very low safety significance and NCV of TS 3.3.2.1, "Control Rod Block Instrumentation," was self-revealed to the operating crew, when normal startup testing could not be accomplished due to improperly configured equipment. Specifically, the operating crew transitioned from Mode 4 to Mode 2, with the rod worth minimizer (RWM) mode switch in the BYPASS position. With the RWM mode switch in the BYPASS position and the required actions of 3.3.2.1(c) not met, the requirements of TS 3.3.2.1, that the RWM be operable in Mode 1 and Mode 2 when thermal power is less than or equal to 10 percent rated thermal power, could not be met. Actions taken by the licensee in response to this event included declaring the event a reactivity management event; making an NRC notification under 50.72(b)(3)(v)(D); resetting their site event clock; providing additional training for the applicable operating crew; and revising procedures associated with this event to clarify the sequencing of key activities associated with the transition between Mode 4 and Mode 2.

The inspectors determined that the licensee's failure to properly control the configuration of the RWM prior to entering an operating mode that required its operability was a performance deficiency, because it was the result of the failure to meet a requirement or a standard; the cause was reasonably within the licensee's ability to foresee and correct; and should have been prevented. The inspectors determined that the issue was more than minor because it impacted the Configuration Control attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors applied IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," to this finding. The inspectors answered 'No' to the questions associated with transient initiators and screened the finding to be of very low safety significance. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting area of Human Performance, having work practices components, and involving aspects associated with personnel work practices that support human performance, specifically in the areas of pre-job briefing, self and peer checking, and proper documentation of activities [H.4(a)]. (Section 1R20.2)

Cornerstone: Mitigating Systems

- Severity Level IV. The inspectors identified a Severity Level IV NCV and associated finding of very low safety significance of 10 CFR 50.73(a)(2)(vii)(A-D), "Licensee Event Report System," for the failure to report an event to the NRC within 60 days, where a single cause or condition caused two independent trains to become inoperable in a single system designed to help maintain safe reactor shut down, remove residual heat, control radioactive releases, or mitigate accidents. Specifically, on September 29, 2011, the licensee identified that the surveillance test procedures being used to demonstrate load reject capabilities of both EDGs had never contained the correct load rejection testing requirements from the applicable design documents. As a result, the surveillances were considered never met, and both EDGs were declared inoperable. During their evaluation and subsequent reporting of the issue, the licensee failed to recognize that the inoperability of both diesel generators caused by a single common cause was reportable to the NRC within 60 days under the 50.73 common cause criterion. The licensee entered this issue into their corrective action program (CAP 1318116). Corrective actions for this issue included plans to revise their existing licensee event report (LER) and to perform an apparent cause evaluation to further evaluate the issue.

  The inspectors determined that the failure to report required plant events or conditions to the NRC in accordance with reporting requirements was a performance deficiency because it was the result of the failure to meet a requirement or a standard, the cause was reasonably within the licensee's ability to foresee and correct, and should have been prevented. In addition, it had the potential to impede or impact the regulatory process. As a result, the NRC dispositions violations of 10 CFR 50.73 using the traditional enforcement process instead of the SDP. However, if possible, the underlying technical issue is evaluated using the SDP. In this case, the inspectors determined that the licensee failed to develop and implement adequate Emergency Diesel Generator (EDG) testing procedures during their transition to the Improved Technical Specifications

in 2006, which resulted in both EDGs being declared TS inoperable, but available for use. The inspectors determined that the performance deficiency was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Human Performance and Procedure Quality and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Using IMC 0609, Attachment 4, “Phase 1 – Initial Screening and Characterization of Findings,” the inspectors determined that the finding had very low safety significance because they answered ‘No’ to all five questions contained in Column 2 of the Table 4a worksheet. As a result, the inspectors determined that the finding had very low safety significance (Green).
In accordance with Section 6.9.d.9 and 6.9.d.10 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because it was an example where the licensee failed to make a report required by 10 CFR 50.73; it represented a failure to identify all applicable reporting codes on an LER that may impact the completeness or accuracy of other information submitted to the NRC; and the underlying technical issue was evaluated by the SDP and determined to be of very low safety significance.
The inspectors determined that the contributing cause that provided the most insight into the performance deficiency affected the cross-cutting area of Problem Identification and Resolution, having corrective action program components, and involving aspects associated with properly classifying and evaluating for reportability conditions adverse to quality [P.1(c)]. (Section 4OA3.5)

Cornerstone: Public Radiation Safety

- Green. The inspectors reviewed a self-revealed finding of very low safety significance and an associated NCV of 10 CFR 71.5. Specifically, the licensee failed to appropriately block and brace a radioactively contaminated condensate demineralizer vessel within a transport package, such that, the package contents would not compromise and penetrate the transport package. The issue has been entered into the licensee’s corrective action program as CR [condition report] 01294652. Corrective actions were implemented to address supervision’s responsibilities during shipment preparation regarding appropriate blocking and bracing of package contents.

  The finding was more than minor because the performance deficiency could be reasonably viewed as a precursor to a significant event, in that, the penetration of the transportation package by its contents could lead to the inadvertent spread of radioactive contamination in the public domain. Using IMC 0609, Attachment D, for the Public Radiation Safety SDP, the inspectors determined the finding to be of very low safety significance. The inspectors also determined that this finding had a cross-cutting aspect in the area of problem identification and resolution (operating experience) [P.2(b)]. (Section 2RS8)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

During this inspection period, the Monticello plant experienced two plant scrams.

- October 21 (at 12:55): Plant scram resulting from an electric plant realignment caused by a faulted feeder cable to the 2R transformer.
- October 28 (at 05:22): Plant returned to power operation.
- November 19 (at 23:12): Plant scram during turbine control valve testing.
- November 27 (at 21:00): Reactor critical.
- November 28: Licensee attempted to place turbine online and was forced to secure the turbine due to excessive control oil fluctuations.
- November 29 (at 02:55): Reactor was shutdown to facilitate additional troubleshooting of turbine control oil issue.
- December 10 (at 02:55): Plant returned to power operation.

For the remainder of the inspection period, the plant operated at approximately 100 percent power, with the exception of brief reductions in power to support planned testing and rod pattern adjustments.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition – Extreme Cold Conditions

a. Inspection Scope

Since extreme cold conditions were forecast in the vicinity of the facility for December 2011, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On December 15 and 16, 2011, the inspectors walked down equipment discussed in the site's Winter Checklist (Procedure 1151, Revision 70) and equipment relied upon for supplemental heating in the reactor building and turbine building during a loss of the station's heating boiler. The inspectors observed insulation; heat trace circuits; space heater operation; and weatherized enclosures to ensure operability of affected systems. The inspectors reviewed licensee procedures and discussed potential compensatory measures with control room personnel. The inspectors focused on plant management's actions for implementing the station's procedures for ensuring adequate personnel for safe plant operation and emergency response would be available. Specific documents reviewed during this inspection are listed in the Attachment to this report.

This inspection constituted one readiness for impending adverse weather condition sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- reactor core isolation cooling (RCIC) during high pressure coolant injection (HPCI) planned maintenance; and
- Division I emergency filtration train (EFT)/control room ventilation (CRV) during Division II maintenance.

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), 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 two partial system walkdown samples as defined in 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 16 (corridor, turbine building east & west, elevations 911' and 931');
- Fire Zone 17 (turbine building north cable corridor 941');
- Fire Zone 29 (security diesel building);
- Fire Zone 8 (cable spreading room); and
- Fire Zone 33 (EFT building third floor).

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

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

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the USAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- east turbine building, 931' elevation.

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

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On November 7, 2011, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations 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 sample as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Biennial and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Biennial Written Examination, and the Annual Operating Test, administered by the licensee from August 29 through October 6, 2011, as required by 10 CFR 55.59(a). The results were compared to the thresholds established in Inspection Manual Chapter (IMC) 0609, Appendix I, "Licensed Operator Requalification SDP," to assess the overall adequacy of the licensee's Licensed Operator Requalification Training (LORT) program to meet the requirements of 10 CFR 55.59.

This inspection constitutes one annual licensed operator requalification inspection sample as defined in IP 71111.11A.

b. Findings

No findings were identified.

.3 Biennial Review (71111.11B)

a. Inspection Scope

The following inspection activities were conducted during the weeks of September 26 and October 3, 2011, to assess: 1) the effectiveness and adequacy of the facility licensee's implementation and maintenance of its systems approach to training (SAT) based LORT program, put into effect to satisfy the requirements of 10 CFR 55.59; 2) conformance with the requirements of 10 CFR 55.46 for use of a plant referenced simulator to conduct operator licensing examinations and for satisfying experience requirements; and, 3) conformance with the operator license conditions specified in 10 CFR 55.53. The documents reviewed are listed in the Attachment to this report.

- Facility Operating History and Licensee Training Feedback System (10 CFR 55.59(c); SAT element 5 as defined in 10 CFR 55.4): The inspectors evaluated the licensee's ability to assess the effectiveness of its LORT program and their ability to implement appropriate corrective actions to maintain its LORT Program up-to-date. The inspectors reviewed documents related to the plant's operating history and associated responses (e.g., plant issue matrix (PIM) and PPR [plant performance review] reports; recent examination and inspection reports (IRs); and LERs). The inspectors reviewed the use of feedback from operators, instructors, and supervisors as well as the use of feedback from plant events and industry experience information. The inspectors reviewed the licensee's quality assurance oversight activities, including licensee training department self-assessment reports.

- Licensee Requalification Examinations (10 CFR 55.59(c); SAT Element 4 as defined in 10 CFR 55.4): The inspectors reviewed the licensee's program for development and administration of the LORT biennial written examination and annual operating tests to assess the licensee's ability to develop and administer examinations that are acceptable for meeting the requirements of 10 CFR 55.59(a).

- The inspectors reviewed the methodology used to construct the examination including content, level of difficulty, and general quality of the examination/test materials. The inspectors also assessed the level of examination material duplication from week-to-week for both the operating tests conducted during the current year, as well as the written examinations administered on October 6, 2011. The inspectors reviewed a sample of the written examinations and associated answer keys to check for consistency and accuracy.

- The inspectors observed the administration of the annual operating test and biennial written examination to assess the licensee's effectiveness in conducting the examinations, including the conduct of pre-examination briefings, evaluations of individual operator and crew performance, and post examination analysis. The inspectors evaluated the performance of Crew 5 in parallel with the facility evaluators during two dynamic simulator scenarios, and evaluated various licensed crew members concurrently with facility evaluators during the administration of several job performance measures.

- The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the last requalification examinations and the training planned for the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans.

• <u>Conformance with Exam Integrity in 10 CFR 55.49</u>: The inspectors reviewed the licensee's processes related to examination physical security (e.g., access restrictions and simulator considerations) and integrity (e.g., predictability and bias) to verify compliance with 10 CFR 55.49, "Integrity of Examinations and Tests." The inspectors observed the licensee's implementation of examination security practices throughout the onsite inspection visit.

• <u>Conformance with Simulator Requirements Specified in 10 CFR 55.46</u>: The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements. The inspectors reviewed a sample of simulator performance test records (e.g., transient tests, malfunction tests, scenario based tests, post-event tests, steady state tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy corrective action process to ensure that simulator fidelity was being maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions as well as on nuclear and thermal hydraulic operating characteristics.

• <u>Conformance with Operator License Conditions (10 CFR 55.53)</u>: The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators, and which control room positions were granted watch standing credit for maintaining active operator licenses. Additionally, medical records for six licensed operators were reviewed for compliance with 10 CFR 55.53(I).

This inspection constitutes one biennial licensed operator requalification inspection sample as defined in IP 71111.11B.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- 11 recirc motor generator (MG) set oil cooler outlet valve (SW-125-1); and
- instrument air system.

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:

- single rod (30-19) scram while performing reactor scram functional test;
- high differential pressure on 'E' condensate demineralizer vessel;
- loss of configuration control associated with blocked deluge valves; and
- low turbine oil pressure relay actuation that caused a reactor scram.

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

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

b. Findings

Introduction

The inspectors identified a finding of very low safety significance and NCV of TS 5.4.1, "Procedures," for the operators failing to take conservative action to address a high differential pressure condition on an inservice condensate demineralizer vessel. Specifically, operators allowed the 'E' condensate demineralizer to exceed differential pressure operating limits prescribed in Alarm Response Procedure 80-DPAH-2215, "Vessel T-7E D/P High," and remain above those prescribed limits for approximately a shift before taking action to correct the abnormal condition.

Description

Full power operation of the condensate demineralizer system at Monticello Nuclear Generating Plant (MNGP) usually utilizes all five condensate demineralizer vessels, although full power operation can be maintained with only four vessels in service. On October 31, 2011, 'C' condensate demineralizer was taken out of service for maintenance. At approximately 20:00 on November 4, 2011, due, in part, to an extended maintenance period on 'C' condensate demineralizer, the vessel high differential pressure alarm setpoint (7.5 psid) was reached on 'E' condensate demineralizer. Alarm Response Procedure C.6-80-DPAH-2215, "Vessel T-7E D/P High," allows for the condensate demineralizer vessel to remain in service up to a maximum differential pressure of 12.5 psid. At approximately 20:00 on November 7, 2011, the 'E' condensate demineralizer vessel exceeded 12.5 psid. Even though several operating crews were aware of the increasing differential pressure trend, no action was taken to prevent it from exceeding 12.5 psid. Additionally, in the absence of an approved engineering evaluation or procedural guidance which allowed continued operation of the condensate demineralizer in excess of 12.5 psid, no action was taken for almost an entire shift (12 hours) to reduce the differential pressure on 'E' condensate demineralizer until after the inspectors questioned the duty Shift Manager on why he was not in compliance with his existing operating procedures. At approximately 08:00 on November 8, 2011, the on-coming crew reduced the differential pressure below 12.5 psid by changing the system's mode of operation from "Auto-Flow Balance" to "Auto-Setpoint." The licensee entered this issue into their corrective action program (CAP 01312079). Specific corrective actions taken by the licensee to address this issue included updating the applicable alarm response procedures and operating procedures to reflect current system limitations; engineering management reinforcing the expectation that informal processes are not acceptable when communicating technical guidance to operations staff; and site management reinforcing the expectation that, once a degrading trend is recognized, actions must be taken in sufficient time to prevent crossing established operating limits.

Analysis

The inspectors determined that the licensee's failure to maintain the 'E' condensate demineralizer differential pressure within prescribed operational limits was a performance deficiency because it was the result of the failure to meet a requirement or a standard, the cause was reasonably within the licensee's ability to foresee and correct, and should have been prevented. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting area of Human Performance, having Work Control components, and involving aspects associated with the licensee plans and coordinates work activities, consistent with nuclear safety, specifically the need for planned contingencies, compensatory actions, and abort criteria [H.3(a)].

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 impacted the Human Performance attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors applied IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," to this finding. The inspectors utilized Column 1 of the Table 4a worksheet to screen the finding. For Transient Initiators, the inspectors answered 'No' to the question, "Does the finding contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment of functions will not be available?" and determined the finding to be of very low safety significance (Green).

Enforcement

Licensee TS 5.4.1, “Procedures,” requires, in part, that written procedures shall be established, implemented, and maintained for activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Included as part of Regulatory Guide 1.33 recommendations are instructions for energizing, filling, venting, draining, startup, shutdown, and changing modes of operation for the condensate system (hotwell to feedwater pumps; including demineralizers and resin regeneration). Contrary to this requirement, on November 8, 2011, operators allowed the ‘E’ condensate demineralizer to exceed differential pressure operating limits prescribed in Alarm Response Procedure 80-DPAH-2215, “Vessel T-7E D/P High,” and remain above those prescribed limits for approximately a shift before taking action to correct the abnormal condition. Because the violation was of very low safety significance and was entered into the licensee’s corrective action program (CAP 01312079), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000263/2011005-01; ‘E’ Condensate Demineralizer Alarm Response Procedure Limits Exceeded)**

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- alternate shut down system (ASDS) vessel flood up level instrumentation inadequate surveillance procedure; and
- Excessive stem leakage – control rod drive (CRD) 111/50-31.

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 two samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

.2 <u>(Closed) Unresolved Item (URI) 5000263/2011004-01; Notice of Enforcement Discretion for Emergency Diesel Generator Load Rejection Surveillance Requirement 3.8.1.7</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the plant's response to a Notice of Enforcement Discretion (NOED) that was required for both emergency diesel generators (EDGs) becoming inoperable unexpectedly at the same time. On September 29, 2011, after discovering that they had not been adequately testing the load rejection capability of their EDGs, the licensee declared both the 11 and 12 EDGs inoperable and entered the applicable Limiting Condition for Operation (LCO) Action Statements. The Action Statements entered by the licensee required them to shut the plant down within 12 hours. Following risk assessments and evaluation of plant conditions, the licensee requested and was granted an NOED to extend the Action Completion Time for LCO 3.8.1.F from 12 hours to 5 days. The LCO time extension was requested to allow the site time to develop a new procedure that met the design requirements and perform the required EDG testing (NOED 11-3-001).

In accordance with the NRC's NOED process, the inspectors opened an Unresolved Item (URI) to facilitate prompt tracking, documentation, and closure of inspection, verification, and resolution activities, including enforcement action determinations, associated with the NOED.

The inspectors evaluated the underlying technical issues associated with the EDG inoperability to identify potential performance deficiencies associated with the inadequate surveillance procedure. The inspectors reexamined the site's actions to uncover the issue, their actions to address the issue once it was identified, and their compensatory actions associated with the receipt of the NOED. The inspectors also reviewed licensee documents to verify that information contained in the NOED request was accurate. Inspection activities included gathering additional information on why the procedure was inadequate; examining the site's decision-making process for the issue; reviewing the licensee's condition evaluation; observing the licensee's compensatory actions; and evaluating the licensee's operability determination for identification credit in order to determine how to appropriately disposition the issue.

To correct this issue and exit the NOED, the licensee created new test procedures for both diesel generators which included the appropriate test acceptance criteria and testing methodologies; satisfactorily tested both EDGs prior to the expiration of the NOED; and evaluated this issue under their CAP. The inspectors reviewed the new test procedures and observed the EDG testing to verify that the equipment could be restored to operable status within the required time frame. The inspectors concluded that once the issue was discovered, the licensee's efforts to identify and correct the condition were reasonable to restore operability of the EDGs and exit the NOED.

Documents reviewed in this inspection are listed in the Attachment to this report.
This URI is closed.

b. Findings

One licensee-identified violation associated with this issue is documented in Section 4OA7. The inspectors reviewed an LER associated with this event and the results of that review are discussed in Section 4OA3. The inspectors' review of the NOED and the subsequent licensee actions are also discussed separately in Section 4OA3.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modifications:

- EC 18663; connect demineralized water system to service condensate system for keep fill;
- EC 18936; furmanite leak seal for CV-6-13; and
- EC 18988; bypass interlock POS-2375 for 11 reactor feedwater pump.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the 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 in the course of this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

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:

- reactor pressure vessel (RPV) reactor flooding level instrument isolator;
- 1R transformer to No. 13 bus breaker replacement;
- EDG emergency service water (ESW) No. 11 pump replacement; and
- reactor low and low-low level Agastat relay replacement.

These activities were selected based upon the structures, systems, and components (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 Other Outage Activities (71111.20)

.1 October 21, 2011, Reactor Scram as a Result of the Lockout of 2R Transformer

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled outage that began on October 21, 2011, and continued through October 28, 2011. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown; outage equipment configuration and risk management; electrical lineups; selected clearances; control and monitoring of decay heat removal; control of containment activities; personnel fatigue management; startup and heatup activities; and identification and resolution of problems associated with the outage. The inspectors' primary focus during this forced outage was evaluating the licensee's actions associated with identifying the cause of the 2R transformer lockout and applicable extent of condition, and activities associated with correcting the equipment deficiency.

This inspection constituted one other outage sample as defined in IP 71111.20-05.

b. Findings

Introduction

A finding of very low safety significance and NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," was self-revealed following a reactor scram which was the direct result of an electric plant realignment caused by a faulted feeder cable and lockout of the station's 2R transformer. Specifically, annual testing to monitor the performance of the 2R feeder cables, which was put in place as a corrective action to prevent recurrence to address issues identified subsequent to a similar event in 2008, had not been performed since the cables were placed back in service following that event. As a result, the licensee was unable to monitor the performance of the cables prior the cable fault, which ultimately led to a reactor scram on October 21, 2011.

Description

On September 11, 2008, MNGP experienced an automatic reactor scram from 100 percent rated thermal power following an electrical lockout of the station's 2R transformer. Faults in the 34.5 KV underground cable feed from the 2RS transformer secondary to the 2R transformer primary led to the loss of the 2R transformer offsite power source. From September 15, 2008, through November 3, 2008, the Agency conducted a Special Inspection (IR 05000263/2008009) at the Monticello site to evaluate the facts and circumstances surrounding the loss of normal offsite power to the non-safety buses and resultant reactor scram, and other complications associated with the reactor scram. Two of the issues documented by the inspection team included the licensee's failure to scope the 34.5 KV cables into the maintenance rule monitoring program (NCV 05000263/2008009-03) and that the licensee's medium voltage cable testing program was inadequate (FIN 05000263/2008009-04). The licensee took several actions as a result of the event, which included performing a root cause evaluation to better understand the cause of the event, completing significant maintenance activities to address degraded or faulted equipment, and implementing multiple corrective actions to address indentified deficiencies. Specific corrective actions taken by the licensee to prevent recurrence (CAPR) of the event included identifying all underground cable access points and periodically monitoring the points for water intrusion; revising the cable monitoring program procedure to include tracking and monitoring cable splices; and to allocate and prioritize resources to carry out actions established in the cable monitoring program.

On September 28, 2008, the licensee initiated CAP 01152518, "4 KV System Maintenance Rule Allowed Unavailability Times Exceeded in September." The primary contributors to the maintenance rule unavailability times being exceeded were the loss of the 2R and loss of 1R transformers in September 2008. In addition to developing a Maintenance Rule a(1) action plan, the licensee implemented a CAPR (01152518-04) that put in place planned maintenance activities for the 34.5 KV cables between the 2R and 2RS transformers. The planned maintenance activities that were developed associated with the CAPR consisted of megger and tan delta testing of the cables on an annual basis, and partial discharge testing every four years.

On October 21, 2011, at 12:50, a lockout occurred due to a ground fault on the 'A' phase of the 2RS to 2R feeder cable, ultimately resulting in a reactor scram. During an evaluation of the event, it was determined that the annual testing put in place by

CAPR 01152518-04 had been deferred twice and had not been performed during the time between when the cables were put back in service following the September 2008 event and the more recent fault which resulted in the October 2011 2R transformer lockout.

On November 11, 2011, the licensee completed their root cause evaluation of the October 21, 2011, event. This evaluation concluded that the root cause of the event was the 'A' phase conductor supplying power from 2RS to 2R faulted to ground. The insulation at the location of the fault had degraded, such that it was unable to withstand either normal or transient conditions due to significant formation of water trees in the cable section subject to past wetting in combination with age-related degradation. The root cause evaluation also noted that the site's reliance on cable testing methods not well suited to predicting time to failure, and weaknesses in their planned maintenance deferral process were major contributing causes for the event. To address the identified material deficiencies, the licensee replaced and tested the electrical cables between 2RS and 2R in their entirety, employing a new route designed to avoid cable submergence. Additional corrective actions were put in place to strengthen the licensee's planned maintenance deferral process and their cable condition monitoring program.

<u>Analysis</u>

The inspectors determined that the licensee's failure to perform annual testing of the 2R transformer feeder cables, as required by the station's planned maintenance program, was a performance deficiency because it was the result of the failure to meet a requirement or a standard, the cause was reasonably within the licensee's ability to foresee and correct, and should have been prevented. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting area of Human Performance, having decision-making components, and involving aspects associated with the licensees' making safety-significant or risk-significant decisions using a systematic process to ensure safety is maintained. [H.1(a)]

The inspectors evaluated the finding using IMC 0609, "Significance Determination Process," Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," Table 4a, for the Initiating Events Cornerstone. The finding contributed to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions would not be available. Therefore, the finding required a Phase 2 evaluation using IMC 0609 Appendix A, "Determining the Significance of At-Power Reactor Inspection Findings."

The SRA used the Monticello Risk-Informed Inspection Notebook, Revision 2.1a, to perform the Phase 2 evaluation. The Transient Without Power Conversion Worksheet (Table 3.2) was solved assuming that the initiator occurred (i.e., initiating event likelihood (IEL) = 0 and recovery was possible. The result was a White finding. The dominant sequence was a transient without power conversion system (heat sink) followed by failures of the containment heat removal and late inventory safety functions.

The SRAs performed a Phase 3 initiating event risk evaluation to further refine the risk significance. The SRAs used SAPHIRE Version 8.0.7.17 and the Monticello Standardized Plant Analysis Risk (SPAR) model (Version 8.15). The SPAR model was modified to add transformer 2R and 4.16 kV Bus 13 as basic events. A "Loss of

Condenser Heat Sink" initiating event analysis was performed because the circulating water pumps tripped. Failures of transformer 2R, 4.16 kV Bus 13, reactor feed pump 11, and EDG-ESW Pump 11 were set to "TRUE" or "1.0" as necessary to represent their failure.

Recovery of the condenser as a heat sink was credited using a SPAR-H human reliability analysis. The turbine auxiliary oil pump, which allows for the use of the turbine bypass valves, tripped when the 4.16 kV Bus 15 transferred to reserve auxiliary transformer 1AR. Restoring power allowed use of these bypass valves required sending an operator in the field to reset the breaker for the pump. Also, restoring power to circulating water pump 12 required aligning power supplies to the discharge valve to allow for logic to be made up to enable the pump to be restarted. The performance shaping factors (PSFs) of stress and complexity were assumed to be performance drivers for both diagnosis and action. The estimated human error probability (HEP) for these combined manual actions to recover the condenser was evaluated as 0.044.

The result of the internal events Phase 3 analysis was an estimated delta core damage frequency of 2.8E-7. The dominant sequence was a loss of condenser heat sink initiating event followed by:

- successful scram;
- successful SRV over-pressure protection with no stuck open relief valve;
- successful feedwater injection;
- suppression pool cooling failure;
- successful depressurization (until containment overpressure);
- shutdown cooling failure;
- containment spray failure;
- power conversion recovery failure; and
- late injection failure.

This risk evaluation was an internal events initiating event analysis so there was no contribution from external events (e.g., fire, flooding, seismic).

The SRAs evaluated the potential risk contribution for this finding from a large early release frequency (LERF). The licensee provided its perspective that the dominant accident sequence listed above was conservative with respect to LERF and, in addition, provided a timing argument concluding that implementation of protective actions for the public would occur prior to containment failure. Considerations that the LERF impact was conservative included that containment failure should not impact availability of high pressure injection sources, such as feedwater and CRD system pumps.
The SRAs discussed this with Idaho National Laboratory and the SRAs agreed that the LERF impact was conservative in this regard.

Regarding the timing argument, the SRAs used the licensee's timing sequences from a report titled, "Evacuation time Estimates for the Plume Exposure Pathway Emergency Planning Zone," dated November 2008, for Monticello and estimated the probability of effective evacuation of the general public prior to containment failure. Using the 'Containment failure Probability Distribution" from the Monticello Individual Plant Examination, Figure 4.4-5, the SRAs computed a value of 0.3 for the probability that effective evacuation of the general public occurred prior to containment failure. Thus, the delta-LERF was computed to be 8.4E-8.

In summary, the delta core damage frequency (CDF) was computed as 2.8E-7 and the delta LERF was computed as 8.4E-8. The collective risk for this finding due to internal events risk and LERF was of very low safety significance (Green).

Enforcement

Title 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that conditions adverse to quality are promptly identified and corrected. Additionally, Criterion XVI requires, in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions are taken to preclude repetition. Contrary to this requirement, the licensee failed to perform the annual testing of the 2RS to 2R transformer underground feeder cables, as prescribed in CAPR 01152518-04, during the time period after placing the cables in service following the September 2008 forced outage, until the plant scram on October 21, 2011. As a result, the licensee was unable to adequately monitor the performance of the 2RS to 2R transformer feeder cables prior to the cables faulting, which ultimately resulted in a 2R transformer lockout and a reactor scram. Because the violation was of very low safety significance and was entered into the licensee's corrective action program (CAP 01309402), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000263/2011005-02; Inadequate Completion of CAPRs Associated with 2RS to 2R Feeder Cable Testing)

.2 November 19, 2011, Reactor Scram Caused By Turbine Control Oil Fluctuations Encountered During Turbine Bypass Valve Testing

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled outage that began on November 19, 2011, and continued through December 10, 2011. Subsequent to an extensive investigation and requisite repairs to the turbine control oil system, the licensee performed a reactor startup (November 27, 2011) and attempted to place the turbine online (November 28, 2011). Due to unacceptable turbine control oil pressure fluctuations observed during the main turbine roll, the licensee decided to shutdown the reactor and return to Mode 4 (November 29, 2011) to facilitate additional investigation and maintenance on the turbine control oil system. The forced outage was completed and the plant returned to power operation on December 10, 2011. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed each reactor shutdown and cooldown; outage equipment configuration and risk management; electrical lineups; selected clearances; control and monitoring of decay heat removal; control of containment activities; personnel fatigue management; startup and heatup activities; and identification and resolution of problems associated with the outage. The inspectors' primary focus during this forced outage was evaluating the licensee's actions associated with identifying and correcting the cause of the cause of the turbine control oil system pressure fluctuations.

This inspection constituted one other outage sample as defined in IP 71111.20-05.

b. Findings

Introduction

A finding of very low safety significance and NCV of TS 3.3.2.1, “Control Rod Block Instrumentation,” was self-revealed to the operating crew, when normal startup testing could not be accomplished due to improperly configured equipment. Specifically, the operating crew transitioned from Mode 4 to Mode 2 with the rod worth minimizer (RWM) mode switch in the BYPASS position. With the RWM mode switch in the BYPASS position and the required actions of 3.3.2.1(c) not met, the requirements of TS 3.3.2.1, that the RWM be operable in Mode 1 and Mode 2 when thermal power is less than or equal to 10 percent rated thermal power, cannot be met.

Description

On November 27, 2011, the operating crew was making preparations for starting up the reactor. At approximately 16:57, Mode 2 was entered when the Mode switch was taken to STARTUP. As part of their normal startup testing, the operators commenced Procedure 0212, “Rod Worth Minimizer Operability Test.” The general purpose of this test is to ensure that the RWM is capable of monitoring the selection and movement of control rods and inserting withdrawal blocks and/or select errors when control rods are selected and/or attempted to be withdrawn out of sequence. Step 7 of Procedure 0212 directs the operator to “WITHDRAW the first permissible rod to Position 02.” Step 8 of the procedure directs the operator to “Attempt to withdraw the first rod in the next group in the sequence.” While attempting to withdraw the control rod per Step 8, the operator noted that the control rod began to step out. Since no control rod movement was expected, the operator immediately stopped withdrawing the control. The crew promptly restored the second control rod to the full in position and identified that the RWM Mode switch was not in the correct position to support Mode 2 operation (BYPASS vs. OPERATE). Because the crew was unaware of the configuration of the RWM switch, they did not have the dedicated operator and necessary controls that would normally need to be in place if the plant was starting up with the RWM inoperable, as required by TS 3.3.2.1, Action “C.” Subsequent to restoring the RWM Mode switch to operate, the crew successfully completed the 0212 procedure.

The preliminary investigation revealed that the plant was properly configured for startup on November 26, 2011, but in response to an emergent equipment issue with the reactor water cleanup system, the operators changed the Mode switch from REFUEL to SHUTDOWN. To support startup on November 27, 2011, the operating crew performed Procedure 0074, “Control Rod Drive Exercise,” but failed to return the RWM Mode switch to ‘Operate,’ as required by Step 29 of the procedure. The failure to complete the 0074 procedure and the incorrect configuration of RWM Mode switch for Mode 2 operation, were not identified by the crew prior to entering Mode 2. Actions taken by the licensee in response to this event included declaring the event a reactivity management event; making an NRC notification under 50.72(b)(3)(v)(D); resetting their site event clock; providing additional training for the applicable operating crew; and revising procedures associated with this event to clarify the sequencing of key activities associated with the transition between Mode 4 and Mode 2. The licensee entered this issue into their corrective action program (CAP 01314953).

Analysis

The inspectors determined that the licensee's failure to properly control the configuration of the RWM prior to entering an operating mode that required its operability was a performance deficiency because it was the result of the failure to meet a requirement or a standard, the cause was reasonably within the licensee's ability to foresee and correct, and should have been prevented. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting area of Human Performance, having work practices components, and involving aspects associated with personnel work practices support human performance, specifically in the areas of pre-job briefing, self and peer checking, and proper documentation of activities. [H.4(a)]

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 impacted the Configuration Control attribute of the Initiating Events Cornerstone's objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors applied IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," to this finding. The inspectors utilized Column 1 of the Table 4a worksheet to screen the finding. The inspectors answered 'No' to the questions associated with transient initiators and screened the finding to be of very low safety significance (Green).

Enforcement

Monticello Nuclear Generating Plant TS 3.3.2.1, requires, in part, that the RWM be operable in Mode 1 and Mode 2 when thermal power is less than or equal to 10 percent rated thermal power, unless TS 3.3.2.1, Condition C, is invoked and met. Contrary to this requirement, during a reactor startup on November 27, 2011, the licensee transitioned from Mode 4 to Mode 2 with the RWM Mode switch in the BYPASS position, and without the necessary controls required by Condition 'C' in place. The BYPASS position of the RWM Mode switch renders the RWM blocking function inoperable. Because the violation was of very low safety significance and was entered into the licensee's corrective action program (CAP 01314953), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000263/2011005-03; Rod Worth Minimizer Inoperable During Reactor Plant Startup)

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:

- OSP-EDG-0535-12; 12 EDG load reject test (routine);
- OSP-EDG-0535-11; 11 EDG load reject test (routine);

- ISP-NIP-0586; 2-of-4 voter channel functional test (routine);
- 0032; emergency core cooling system pump start permissive sensor test (routine); and
- 0051; main steam line high flow group I instrument test (routine).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers 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 five routine surveillance testing samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

.1 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

Since the last NRC inspection of this program area, the Emergency Plan, Revision 35, and A.2-101, Classification of Emergencies, Revision 44, were implemented based on your determination, in accordance with 10 CFR 50.54(q), that the changes resulted in no decrease in effectiveness of the Plan and that the revised Plan, as changed, continues to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the Emergency Action Level changes made between December 2010 and November 2011 to evaluate for potential decreases in effectiveness of the Plan. However, this review does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety.

This emergency action level and emergency plan changes inspection constituted one sample as defined in IP 71114.04-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Public and Occupational Radiation Safety

2RS8 Occupational Dose Assessment (71124.08)

.1 Shipment Preparation (02.01)

a. (Closed) Unresolved Item (URI) 5000263/2011004-03; Shipping and Transportation of a Radioactively Contaminated Condensate Demineralizer Vessel

The inspectors reviewed licensee procedures, surveillances, surveys, records of packaging and labeling, and the disposal manifest associated with the shipping and transportation of a radioactively contaminated condensate demineralizer vessel. This inspection activity supplemented the sample documented in IR 05000263/2011004, Section 2RS8, and defined in IP 71124.08.05, and closes URI 05000263/2011004-03.

b. Findings

Introduction: One self-revealed finding of very low-safety significance (Green) and an associated NCV of 10 CFR 71.5 were reviewed by the inspectors for the failure to appropriately block and brace a radioactively contaminated demineralizer vessel within a transport package. Specifically, the licensee failed to ensure a bulk package was appropriately prepared for transport as required by Department of Transportation (DOT) regulations in accordance with 49 CFR 173.24(b)(2).

Description: On July 14, 2011, workers at the low-level radioactive waste disposal facility in Clive, Utah, identified that a radioactively contaminated demineralizer vessel had punctured and penetrated the side of its transport package. The demineralizer vessel and related components were shipped by the licensee for disposal as low-level radioactive waste at the Clive, Utah, facility.

The licensee placed the demineralizer vessel and associated components within a sealand container, which was then placed within an enclosed vehicle. The licensee then transported the package to Clive, Utah, for disposal. Upon arrival, disposal facility personnel noted that part of the demineralizer vessel had punctured the transport package and was protruding from the sealand container. Disposal facility personnel performed radiological surveys and determined that there was no spread of radiological contamination as a result of the compromised transport package.

Disposal facility personnel notified the licensee of the compromised transport package and the licensee documented the issue in its CAP as condition report (CR) 01294652. A licensee investigation determined that the demineralizer vessel was not properly blocked and braced by the licensee to ensure that the package contents would not shift while in transit.

Analysis: The failure to appropriately block and brace a component within a transport package prior to shipment was determined to be a performance deficiency, in that, the licensee failed to prevent the demineralizer vessel from shifting within the package during transit, resulting in damage to the package. This performance deficiency was within the licensee's ability to foresee and correct, and should have been prevented. The finding was not subject to traditional enforcement since the incident did not have a significant safety consequence, did not impact the NRC's ability to perform its regulatory function, and was not willful.

The inspectors reviewed IMC 0612, Appendix E, "Examples of Minor Issues," and there were no examples of similar performance deficiencies. Consequently, the inspectors reviewed the minor screening questions in IMC 0612, Appendix B, "Issue Screening," and determined that the finding was more than minor because the performance deficiency could be reasonably viewed as a precursor to a significant event. Specifically, penetration of the transportation package by its contents could lead to the inadvertent spread of radioactive contamination in the public domain.

The inspectors used IMC 0612, Appendix D, "Public Radiation Safety Significance Determination Process," to determine the significance of the finding. Specifically, the issue did not involve radioactive material control, the effluent release program, or the environmental monitoring program. The finding did not involve radioactive material transportation above radiation limits, a certificate of compliance issue, the failure to make emergency notifications, or low-level burial ground acceptance. A breach of the transportation package occurred during transit. However, the shipment contained less than a Type A quantity of material and there was no loss of package contents or release of radiological contamination. Consequently, the inspectors determined that the finding was of very low safety significance (Green).

The inspectors reviewed IMC 0612, Appendix F, “Examples of Cross-Cutting Aspects,” and determined that this finding had a cross-cutting aspect in the area of Problem Identification and Resolution (P.2.b) because the licensee did not effectively incorporate pertinent industry operating experience into their transportation program to ensure the components are appropriately blocked and braced to prevent damage to the transport package.

Enforcement: Title 10 CFR 71.5(a) states, in part, “each licensee who transports licensed material outside the site of usage, as specified in the NRC license, or where transport is on public highways, or who delivers licensed material to a carrier for transport, shall comply with the applicable requirements of the DOT regulations in 49 CFR Parts 107, 171 through 180, and 390 through 397, appropriate to the mode of transport.”

Specifically, 49 CFR 173.24(b)(2), states, in part, “each package used for the shipment of hazardous materials under this subchapter shall be designed, constructed, maintained, filled, its contents so limited, and closed, so that under conditions normally incident to transportation… the effectiveness of the package will not be substantially reduced…”

Contrary to the above, on July 14, 2011, part of the demineralizer vessel was found to be protruding from its transport package upon arrival at its destination. Because this violation was of very low safety significance and it was entered into the licensee’s CAP, this violation is being treated as an NCV, in accordance with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000263/2011005-04; Failure to Properly Block and Brace a Radioactive Package for Transport)**

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Residual Heat Removal System performance indicator (PI) for the period from the 4th Quarter 2010 through the 3rd Quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator narrative logs; issue reports; MSPI derivation reports; event reports, and NRC Integrated Inspection Reports for the period of the 4th Quarter 2010 through the 3rd Quarter 2011 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 residual heat removal system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for the period from the 4th Quarter 2010 through the 3rd Quarter 2011. 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 the 4th Quarter 2010 through the 3rd Quarter 2011 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 cooling water system 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 that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of July 2011 through December 2011, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: OBD/OBN/Mode Restraints/ODMIs prior to startup from Forced Outage

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting a list of issues that needed to be reviewed or resolved prior to startup from an October 2011 forced outage. The inspectors reviewed several pertinent documents, observed forced outage activities, and attended licensee PORC (plant operations review committee) meetings to determine whether items outstanding on the operable but degraded (OBD)/operable but nonconforming (OBN) lists, mode restraints, and ODMIs were reviewed, resolved, or addressed by the licensee. The focus of this inspection was to ensure that these issues were appropriately handled and, where reasonable, corrected prior to startup. The inspectors determined that prior to startup, all mode restraint issues were corrected, and the ODMIs and items on the OBD/OBN lists were reviewed and addressed in a reasonable manner, considering the nature of the forced outage. Specifically, for OBD/OBN items and ODMIs, the inspectors determined that the licensee's plans for resolution, as outlined in the licensee's startup documentation, contained reasonable proposed actions and timelines.

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

b. Findings

No findings were identified.

.5 Selected Issue Follow-Up Inspection: Turbine Front Standard Repairs to Address Turbine Control Oil System Pressure Fluctuations

a. Inspection Scope

During the performance of a routine quarterly turbine control valve surveillance test, a reactor scram occurred during the part of the activity which tested the speed load changer. During the operation of the speed load changer, prior to the point where the speed load changer engages the control valves, turbine control oil experienced pressure fluctuations that were sufficient to actuate the turbine-generator load reject pressure switches, which resulted in a reactor scram. During the time period of November 19, 2011, to December 8, 2011, the inspectors evaluated the licensee's efforts to determine the cause of the turbine control oil fluctuations, and monitored the maintenance activities performed on at the turbine front standard to correct the issue.

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

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

.1 Automatic Reactor Scram Due To a 2R Transformer Lockout

a. Inspection Scope

The inspectors reviewed the plant's response to an automatic reactor scram which occurred on October 21, 2011. Following a 2R transformer lockout, many of the plant's safety-related and non-safety related loads automatically transferred from their normal source of power, the 2R transformer, to an alternate source of offsite power, the 1R transformer. During this sequence, pumps that normally supplied water to the reactor (feedwater and recirculating pumps) and the condenser (circulating water pumps) temporarily lost power and shut down, as designed. This series of events quickly resulted in an automatic reactor scram due to low reactor vessel water level. In addition, as designed, one of the reactor feedwater pumps automatically restarted, and was used in conjunction with the other feedwater pump to control water level in the reactor vessel. Following the scram, plant personnel used safety relief valves (SRVs) and the HPCI system to maintain pressure control until plant conditions were established to support the use of the turbine bypass valves.

Following the 2R transformer lockout, the inspectors observed three notable equipment malfunctions. These malfunctions included a failure of the breaker between the 1R transformer and the 13 non-safety related bus to close during the automatic power transfer; a failure of the 11 reactor feedwater pump to restart when manually initiated from the control room following a automatic pump trip due to high reactor vessel water level; and a failure of the 11 EDG ESW pump to operate properly subsequent to the automatic start of 11 EDG. In response to the malfunctions, the operators cross-tied non-safety electrical loads to powered buses as necessary, utilized the 12 reactor feedwater pump for level control, and cross-tied 11 EDG ESW to a non-safety related service water supply in order to maintain the 11 EDG available for use during the event.

The initiating event for the 2R transformer lockout was determined to be a single phase to ground fault in one of the normal offsite power feeder cables, located between 2RS and 2R station transformers. The inspectors observed operator response to the scram, and reviewed unit log entries, relevant plant computer data, and plant procedures during and after the event. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. Findings

Subsequent to the reactor scram, due to ongoing plant maintenance and complications associated with the plant transient, the licensee identified that both EFTs were rendered inoperable, but failed to recognize and report this to the NRC as a potential loss of safety function within eight hours, as required by 10 CFR 50.72. This issue will be further discussed in Section 4OA7 of this report.

.2 Automatic Reactor Scram Caused by Turbine Control Oil Pressure Fluctuations Encountered During Planned Turbine Control Valve Testing

a. Inspection Scope

The inspectors reviewed the plant's response to an automatic reactor scram which occurred on November 19, 2011. The scram occurred during routine quarterly testing of the turbine control valves at a point in the testing where the speed load changer was being utilized to slightly close the turbine control valves in order to cause the No. 1 turbine bypass valve to open. While lowering the speed load changer, operators received an alarm that indicated they had received a half scram signal. Operators discontinued adjustments to the speed load changer to investigate the source of the alarm, and 10 seconds later, they received a full reactor scram. Immediately following the reactor scram, the plant stabilized and there were no complications.

The inspectors responded to the control room following the reactor scram, to observe licensee response and to review activities taking place prior to the scram, for insights into the initiating event. The licensee's data showed that before, during, and after the scram, there were several actuations of four pressure switches designed to scram the reactor when low oil pressure for the turbine hydraulic control system was sensed. The licensee assembled a troubleshooting team to investigate the cause of the pressure switch actuations. Inspectors observed the efforts of the team and plant operators to identify and correct the issue.

Following initial investigations, the licensee replaced a degraded component in the turbine control system that was designed to dampen normal pressure oscillations in the turbine control oil. Ultimately, the troubleshooting team determined that the cause of the oil pressure fluctuations that were sensed by the pressure switches was electrolysis in the hydraulic control system gears and bearings (housed in the front standard of the turbine). The licensee determined that the electrolysis was caused by inadequate electrical grounding of the generator rotor, located at the opposite end of the turbine shaft. The lack of adequate grounding led to electric currents being transmitted to the gears and bearings in the front standard, which caused accelerated electrical corrosion of the components (a phenomenon known as electrolysis). The licensee determined that the degradation of these components led to the rapid control oil pressure fluctuations, which caused the November 19, 2011, reactor scram.

The inspectors observed operator response following the scram, and reviewed unit log entries, relevant plant computer data, and plant procedures during and after the event. In addition, the inspectors observed the licensee's actions to replace and restore the degraded components in the turbine control system, repair the device used to electrically ground the generator rotor, and start up the reactor. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.3 (Closed) Licensee Event Report (LER) 05000263/2011-006: Intake Structure Fire Suppression System Blockage

This event, which occurred on September 2, 2011, involved the licensee's discovery of a blockage condition within the fire protection sprinkler system piping in the plant intake structure. On August 26, 2011, during the performance of Surveillance Test 0323-01, "Fire Protection System Sprinkler Functional Tests," the licensee found blockage at valve FP-171-10, an inspector test valve located at the most remote end of the intake structure sprinkler system.

After failed attempts to clear the blockage locally, the licensee performed an investigation and found significant blockage in the fire sprinkler line upstream of the inspector test valve, as well as in three vertical risers to sprinkler heads. The blockage condition rendered the sprinkler system incapable of passing flow to portions of the intake structure, which contained safety-related pumps used for response to and mitigation of accidents. Due to the discovery of the significant blockage, and because the licensee could not immediately determine the extent of the blockage condition, on September 2, 2011, the site concluded the sprinkler suppression piping was not capable of operating per its design due to the significant fouling. The condition was reported to the NRC under 10 CFR Part 50.72(b)(3)(ii)(B) and 10 CFR Part 50.73(a)(2)(ii)(B) as an unanalyzed condition that significantly degraded plant safety.

The licensee performed a root cause analysis of the event, disassembled portions of the piping found to be blocked, and performed radiographic testing to determine the extent of the blockage. The majority of the blockage was determined to be on the west end of the intake structure which mainly affected Division II residual heat removal service water pumps and motors. The licensee also performed laboratory analysis of the blockage substance, and it was determined to be made up of internal pipe corrosion byproducts. The licensee determined that the cause of the blockage condition was accelerated internal pipe corrosion due to improper installation of the sprinkler system piping in 1983. Specifically, they concluded that the installation did not comply with design requirements for providing the required slope to ensure proper draining of the system.

Corrective actions included flushing the system, internal piping inspections, plans to restore affected portions of the sprinkler piping to compliance with the design sloping requirements, and plans to perform periodic internal inspections and testing to validate that the sprinklers will perform their intended functions. The inspectors determined that the licensee's actions were reasonable to prevent recurrence of the blockage condition. The intake structure fire protection sprinkler system blockage issue was evaluated in more detail as part of a special inspection. Four licensee-identified violations and one NRC-identified finding associated with this issue were documented in Inspection Report 05000263/2011010. Documents reviewed as part of this inspection 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.

.4 Followup of Notice of Enforcement Discretion (NOED) 11-3-001: Monticello TS 3.8.1 Emergency Diesel Generator Load Rejection Surveillance Requirement Issue

a. Inspection Scope

The inspectors reviewed the plant's response to an NOED that was required for both EDGs becoming inoperable unexpectedly at the same time. On September 29, 2011, as a result of the licensee's discovery that they had been inadequately demonstrating that both EDGs could meet a surveillance requirement associated with load rejection capability, the licensee declared the 11 and 12 EDGs inoperable and entered the applicable LCO Action Statements. The licensee requested and was granted an NOED to extend the Action Completion Time for LCO 3.8.1.F from 12 hours to 5 days. The LCO extension allowed the site time to develop a new surveillance testing procedure that met the design requirements, and perform the required EDG testing to restore operability.

The inspectors concluded that once the issue was discovered, the licensee's efforts to identify and correct the condition were reasonable to restore operability of the EDGs and exit the NOED.

The inspectors' evaluation of licensee actions and closure of a URI associated with the NOED is discussed in detail in Section 1R15. Additionally, the inspectors' evaluation of an LER associated with this event, and the results of that review, are discussed separately in Section 4OA3. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.5 (Closed) Licensee Event Report (LER) 05000263/2011-007: Both Emergency Diesel Generators Declared Inoperable Due to Inadequate Surveillance

This event, which occurred on September 29, 2011, involved the licensee's discovery that they had been inadequately demonstrating that both EDGs could meet the surveillance requirement for load rejection capability. As a result, the licensee declared both the 11 and 12 EDGs inoperable and entered the applicable LCO Action Statements. The licensee requested and was granted an NOED to allow the site time to develop a new procedure that met the design requirements and perform the required EDG testing.

One NRC-identified NCV associated with the LER is discussed below, along with additional information regarding the event and the licensee's corrective actions.
The inspectors also reviewed the NOED and licensee actions following issuance of the NOED, and closed out an associated URI. The results of those reviews are discussed in Section 1R15 and, separately, in Section 4OA3. Documents reviewed as part of this inspection 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.

Introduction: The inspectors identified a Severity Level IV NCV and associated finding of very low safety significance of 10 CFR 50.73(a)(2)(vii)(A-D), "Licensee Event Report System," for the failure to report an event to the NRC within 60 days, where a single cause or condition caused two independent trains to become inoperable in a single system designed to help maintain safe reactor shut down, remove residual heat, control radioactive releases, or mitigate accidents. Although both EDGs were declared inoperable due to the same testing inadequacy, the licensee failed to recognize that the inoperability of both EDGs due to a single common cause was reportable to the NRC within 60 days under the 50.73 common cause criterion.

Description: On September 27, 2011, while performing an engineering focused self-assessment, the licensee identified a potential issue associated with the testing methodology used to demonstrate each EDG's capability to withstand the rejection of an electrical load that is equivalent to the single largest post-accident electrical load. Specifically, the licensee questioned whether or not their current EDG testing methodology actually demonstrated that the EDGs could withstand the rejection of a load of a size as described in their design basis documents. Following additional calculations and analysis, on September 29, the licensee concluded that the surveillance procedure was not adequately testing the EDGs in accordance with design requirements.

The licensee determined that they had never adequately demonstrated that both EDGs could meet the TS surveillance requirements associated with load rejection. Following this conclusion, the licensee invoked Surveillance Requirement 3.0.1, and declared both the 11 and 12 EDGs inoperable and entered the applicable LCO Action Statements. The Action Statements entered by the licensee required them to shutdown the plant within 12 hours. Following risk assessments and evaluation of plant conditions, the licensee requested and was granted an NOED to extend the Action Completion Time for LCO 3.8.1.F from 12 hours to 5 days. The LCO time extension gave the site time to develop and implement a new surveillance procedure which adequately verified each EDG's capability to withstand the rejection of an electrical load equivalent to the single largest post-accident electrical load.

The licensee determined that the cause of the event was an inadequate surveillance test procedure resulting from a failure to fully reflect the changes enacted through the implementation of the Improved Technical Specifications in 2006. Corrective actions for this issue included development of new test procedures for both diesel generators, which included the appropriate test acceptance criteria and testing methodologies, and satisfactorily testing both EDGs utilizing these procedures. Subsequent to successful testing, both EDGs were declared operable. The licensee also evaluated this issue under their CAP and performed an extent of condition to determine whether similar issues affected other EDG surveillance procedures. No other related issues were identified by the licensee.

The licensee determined that this issue was reportable under 10 CFR Part 50.72(b)(3)(v)(A-D) and 50.73(a)(2)(v)(A-D) as an event or condition that, at the time of discovery, could have prevented the fulfillment of a safety function. After evaluating the issue and successfully testing the load reject capability of both EDGs, the licensee determined that no loss of safety function had occurred.

During the inspectors' review of the LER associated with this event, the inspectors identified that, although the licensee had reported the potential loss of safety function for the EDGs under 50.73(a)(2)(v)(A-D), they had failed to identify all applicable LER reporting codes on their report to the NRC. Specifically, the inspectors noted that the licensee had failed to report the event under the criterion that required reporting events where a single cause or condition led to two trains within the same system becoming inoperable. The inspectors determined, in consultation with NRC Headquarters staff, that since the surveillance testing inadequacy represented a single cause or condition that led to both of the EDGs being declared inoperable, 50.73(a)(2)(vii)(A-D), "Common-Cause Inoperability of Independent trains of Channels," was also applicable. As a result, the inspectors concluded that the failure to report the event under the common cause criterion within 60 days was a violation of 10 CFR 50.73(a)(2)(vii).

<u>Analysis</u>: The inspectors determined that the failure to report within 60 days an event where a single cause or condition caused two independent trains to become inoperable in a single system, designed to help shut down the reactor, remove residual heat, control radioactive releases, and mitigate accidents, as required by 10 CFR 50.73(a)(2)(vii)(A-D) was a performance deficiency. The inspectors reviewed this issue in accordance with IMC 0612, Appendix B, and the discussion for Block 7, Figure 2, Paragraph 2.a.v., and determined that a failure to report was an example of a violation that could impact the regulatory process and was subject to Traditional Enforcement. However, if possible, the underlying technical issue was required to be evaluated using the SDP. The NRC used the SDP results to feed into the determination of the severity of the Traditional Enforcement violation.

The inspectors determined that the underlying technical issue involved the licensee's failure to develop and implement adequate EDG testing procedures during their transition to Improved Technical Specifications in 2006, which resulted in both EDGs being declared TS inoperable, but remaining available for use. The inspectors determined that the issue was more than minor, because it was associated with the Mitigating Systems Cornerstone attributes of Human Performance and Procedure Quality, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Using IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined that the finding had very low safety significance because they answered 'No' to all five questions contained in Column 2 of the Table 4a worksheet. As a result, the inspectors determined that the finding had very low safety significance (Green).

In accordance with the NRC Enforcement Policy, this violation was categorized as Severity Level IV because it was an example where the licensee failed to make a report required by 10 CFR 50.73. Specifically, it represented a failure to identify all applicable reporting codes on an LER that may impact the completeness or accuracy of other information submitted to the NRC. The inspectors evaluated the underlying technical issue utilizing the SDP and determined the finding to be of very low safety significance. The inspectors also determined that the contributing cause that provided the most insight into the performance deficiency affected the cross-cutting area of Problem Identification and Resolution, having CAP components, and involving aspects associated with properly classifying and evaluating for reportability conditions adverse to quality [P.1(c)].

Enforcement: Title 10 CFR 50.73(a)(2)(vii)(A-D) requires, in part, that the licensee shall report within 60 days an event where a single cause or condition caused two independent trains to become inoperable in a single system designed to shut down the reactor and maintain it in a safe shutdown condition; remove residual heat; control the release of radioactive material; or mitigate the consequences of an accident. Contrary to the above, on November 29, 2011, the licensee failed to report within 60 days an event where a single cause or condition resulted in two independent trains becoming inoperable in a single system designed to help maintain safe reactor shut down; remove residual heat; control radioactive releases; and mitigate accidents. Specifically, the licensee failed to report that the September 29, 2011, inoperability of both EDGs was due to a single common cause, and that it met the common cause criterion for reporting.

In accordance with Section 6.9.d.9 and 6.9.d.10 of the Enforcement Policy, the violation was classified as Severity Level IV because it was an example where the licensee failed to make a report required by 10 CFR 50.73; it represented a failure to identify all applicable reporting codes on an LER that may impact the completeness or accuracy of other information submitted to the NRC; and the underlying technical issue was evaluated by the SDP and determined to be of very low safety significance. Because this violation was of a very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as Action Request (AR) 01318116; "Missed 10 CFR 50.73(a)(2)(vii) report to NRC," this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000263/2011005-05; Failure to Make a Required 60 Day Event Report Per 10 CFR 50.73(a)(2)(vii)(A-D))

This finding was evaluated separately from the Traditional Enforcement violation; therefore, the finding was assigned a separate tracking number (FIN 05000263/2011005-06; Failure to Make a Required 60 Day Event Report Per 10 CFR 50.73(a)(2)(vii)(A-D)).

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 11, 2012, the inspectors presented the inspection results to Mr. T. O'Connor 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:

- On October 7, 2011, the inspectors presented the Operator Licensing Biennial Review Inspection results to John Grubb, Plant Manager, and other members of the licensee staff. The licensee acknowledged the issues presented.
- The results of the Emergency Preparedness Program Inspection were discussed with Mr. G. Holthaus on November 30, 2011; and
- Resolution of the URI via a telephone update with Ms. S. O'Connor, Regulatory Affairs Analyst, on November 29, 2011.

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

4OA7 Licensee-Identified Violations

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

- The licensee identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Criterion XI requires, in part, that "A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents." Contrary to this requirement, on September 29, 2011, the licensee identified that they had failed to utilize a test program which incorporated all requirements from the applicable design documents to demonstrate that both EDGs would perform satisfactorily in service. Specifically, the test procedures being used by the licensee to demonstrate operability of the EDGs did not contain the correct load rejection testing requirements from the applicable design documents. As a result, the licensee determined that they had never demonstrated that they met load rejection surveillance requirement 3.8.1.7, and that both EDGs were inoperable.

  The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedure Quality and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Using IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined that the finding had very low safety significance because they answered 'No' to all five questions contained in Column 2 of the Table 4a worksheet. The licensee developed new test procedures which included the appropriate acceptance criteria and test methodologies, satisfactorily tested both EDGs, and entered this issue into their CAP as AR 01305683, "CDBI FSA-Question on Definition of Post Accident Load in TS and AR 1306107, largest post-accident load greater than in test OSP-ECC-0566."

- The licensee identified a finding of very low safety significance (Green) and associated Severity Level IV NCV of 10 CFR 50.72(b)(3)(v)(D).
  Title 10 CFR 50.72(b)(3)(v)(D) requires, in part, that operating reactor licensees shall notify the NRC within eight hours of the occurrence of any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident. Contrary to this requirement, on November 1, 2011, the licensee identified that they had failed to make a required non-emergency notification within eight hours for a safety system functional failure of the CREF and CRV systems. Specifically, on October 21, 2011, following a reactor scram, the No. 11 EDG ESW pump was declared inoperable due to low cooling water pump flow. The loss of this pump

resulted in the No. 11 EDG, 'A' CREF, and 'A' CRV being declared inoperable when the redundant ‘B’ Division CREF and CRV systems were already out-of-service due to preplanned maintenance. As a result, the licensee entered TS 3.0.3 due to both CRV and CREF systems being inoperable. The licensee failed to recognize that this represented a potential loss of safety function at the time of the event.

The inspectors determined that the failure to report required plant events or conditions to the NRC was a performance deficiency, and it had the potential to impede or impact the regulatory process. The NRC dispositions violations of 10 CFR 50.72 using the traditional enforcement process, and if possible, the underlying technical issue is evaluated using the SDP. The underlying technical issue was associated with both trains of CREF/CRV being inoperable and unavailable during a scram, resulting from a lockout of the 2R transformer. This issue was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). In accordance with IMC 0609, because both trains of the CREF/CRV system were inoperable and unavailable, the regional SRAs performed a Phase 3 risk evaluation to determine the risk significance of the issue. As a result of the SRA’s evaluation, the inspectors determined that the finding had very low safety significance. Because the failure to make the required 50.72 report had the potential to impede or impact the regulatory process, the inspectors used the Traditional Enforcement process to disposition the issue. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV. The licensee entered the issue into their CAP as AR 1310956, “Missed 8 Hour Report,” and made the required 50.72 report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. O’Connor, Site Vice President
J. Grubb, Plant Manager
W. Paulhardt, Operations Manager
N. Haskell, Site Engineering Director
K. Jepson, Assistant Plant Manager
S. Radebaugh, Maintenance Manager
M. Holmes, Chemistry Manager
A. Zelie, Radiation Protection Manager
P. Kissinger, Regulatory Affairs Manager
J. Sternisha, Corporate General Manager - Training
M. Peterson, Corporate General Supervisor – Simulators
P. Norgaard, Supervisor Operations Continuing Training
G. Holthaus, Sr. Emergency Preparedness Coordinator
Al Zelie, Radiation Protection Manager
S. O’Connor, Regulatory Affairs Analyst

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000263/2011005-01	NCV	'E' Condensate Demineralizer Alarm Response Procedure Limits Exceeded (Section 1R13)
05000263/2011005-02	NCV	Inadequate Completion of CAPRs Associated with 2RS to 2R Feeder Cable Testing (Section 1R20.1)
05000263/2011005-03	NCV	Rod Worth Minimizer Inoperable During Reactor Plant Startup (Section 1R20.2)
05000263/2011005-04	NCV	Failure to Properly Block and Brace a Radioactive Package for Transport (Section 2RS8)
05000263/2011005-05	NCV	Failure to Make a Required 60 Day Event Report Per 10 CFR 50.73(a)(2)(vii)(A-D) (Section 4OA3.5)
05000263/2011005-06	FIN	Failure to Make a Required 60 Day Event Report Per 10 CFR 50.73(a)(2)(vii)(A-D) (Section 4OA3.5)

Closed

05000263/2011005-01	NCV	'E' Condensate Demineralizer Alarm Response Procedure Limits Exceeded (Section 1R13)
05000263/2011004-01	URI	NOED for Emergency Diesel Generator Load Rejection Surveillance Requirement 3.8.1.7 (Section 1R15.2)
05000263/2011005-02	NCV	Inadequate Completion of CAPRs Associated with 2RS to 2R Feeder Cable Testing (Section 1R20.1)
05000263/2011005-03	NCV	Rod Worth Minimizer Inoperable During Reactor Plant Startup (Section 1R20.2)
05000263/2011005-04	NCV	Failure to Properly Block and Brace a Radioactive Package for Transport (Section 2RS8)
05000263/2011004-03	URI	Shipping and Transportation of a Radioactively Contaminated Condensate Demineralizer Vessel (Section 2RS8)
05000263/2011006	LER	Intake Structure Fire Suppression System Blockage (Section 4OA3.3)
05000263/2011005-05	NCV	Failure to Make a Required 60 Day Event Report Per 10 CFR 50.73(a)(2)(vii)(A-D) (Section 4OA3.5)
05000263/2011005-06	FIN	Failure to Make a Required 60 Day Event Report Per 10 CFR 50.73(a)(2)(vii)(A-D) (Section 4OA3.5)
05000263/2011007	LER	Both Emergency Diesel Generators Declared Inoperable Due to Inadequate Surveillance (Section 4OA3.5)

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 1R01

1151; Winter Checklist; Revision 70
C.4-B.08.03.A; Loss of Heating Boiler; Revision 8

Section 1R04

2154-13; RCIC System Prestart Valve Checklist; Revision 25
2121; Plant Prestart Checklist RCIC System; Revision 14
NH-36251; RCIC (Steam Side); Revision 78
NH-36252; RCIC (Water Side); Revision 77
B.02.03-05; RCIC – System Operation; Revision 24
B.02.03-01; RCIC – Function and General Description of System; Revision 5
B.08.13-06; Control Room Heating and Ventilation and EFT—Figures; Revision 7
B.08.13-03; Control Room Heating and Ventilation and EFT—Instrumentation and Controls; Revision 13
B.08.13-05; Control Room Heating and Ventilation and EFT— System Operation; Revision 20
0466-02; 'B' EFT Filter Efficiency and Leak Tests; Revision 34
CAP 01273527; V-EAC-14A high discharge pressure
CAP 1233040; Broken Belt on V-ERF-12 'B' EFT Emergency Filter Fan
B.08.13-01; Control Room Heating and Ventilation and EFT— Function and General Description of System; Revision 10
B.08.13-02; Control Room Heating and Ventilation and EFT—Description of Equipment; Revision 9
NH-170037; Main Control Room CRV/EFT System; Revision 80

Section 1R05

Pre-Fire Strategy A.3-16; Corridor, Turbine Building East & West (Elevations 911' and 931'); Revision 11
Pre-Fire Strategy A.3-17; Turbine Building North Cable Corridor 941; Revision 5
Pre-Fire Strategy A.3-29; Security Diesel Building; Revision 6
Pre-Fire Strategy A.3-8; Cable Spreading Room; Revision 12
Pre-Fire Strategy A.3-33; EFT Building Third Floor; Revision 6

Section 1R06

CA-07-029; Reactor and Turbine Building & Intake Structure Water Height for Internal Flooding
CA-07-021; Reactor Building, Turbine Building & Intake Structure Water Height – Internal Flooding
CA-07-018; Service Water Break Flow Calculations
CA-06-084; Fire Protection Break Flow Calculation for Postulated Internal Flooding Scenarios
PRA-CALC-04-001; Flood Areas
PRA-CALC-04-003; Flood Source Identification

PRA-CALC-04-004, Flood Initiating Event Frequencies
PRA-CALC-04-005; Equipment Vulnerabilities to Flooding
PRA-CALC-04-006; Flood Scenarios and Effects

Section 1R11

FP-T-SAT-60; Systematic Approach to Training Overview; Revision 11
FP-T-SAT-71; NRC Exam Security Requirements; Revision 7
FP-T-SAT-80; Simulator Configuration Management; Revision 6
FP-T-SAT-81; Simulator Testing and Documentation; Revision 6
FP-OP-CTC-01; Control of Time Critical Operator Actions; Revision 2
OWI-01.08; NRC License Maintenance Responsibilities; Revision 16
OWI-03.07; Time Critical Operator Actions; Revision 1
QF-1081-01; Simulator Performance Test Procedure; Revision 2
M9100 LOR Biennial Training Plan 2010/2011; Revision 0
MT-LOR-1D-002L; License Maintenance; October 6, 2011
MT-LOR-JIT-005S; Power Restoration from 45 Percent Power; August 5, 2011
MT-LOR-JIT-003S; Startup JITT
AR 1247711; >25 Percent LOR Crew Failure; November 4, 2010
JPM B.09.08-005; Revision 4
JPM B.01-03-018; Revision 0
JPM C.2-05.B-09-001; Revision 0
JPM C.4-1-002; Revision 1
JPM B.09-13-007; Revision 0
Simulator Exercise Guide RQ-SS-120; Revision 0
Simulator Exercise Guide RQ-SS-121; Revision 0
Various LOR Feedback Summaries
Various Remedial Training Packages 2010-2011
Various NRC License Status Reports 1Q2009
Various SWO's 2010 – 2011
Various AR's 2010 - 2011
NOS Quarterly Assessment Reports, 3rd Quarter 2010; 1st Quarter 2011; 2nd Quarter 2011
Monticello Simulator Annual Certification Report; 1996, 1999
Simulator Transient Performance Test 2003; Reviewed February 19, 2004
Simulator Core Tests, Cycle 25; 2010
Simulator Annual Performance Tests, Cycle 25, 2010

- Transient Tests
- Steady State Performance Test
- Repeatability Test
- Real-time Test

Simulator Performance Test Procedure, Scram No. 119; March 15, 2007
Simulator Certification, "Four Year Simulator Certification Report"; January 27, 1999
Action Request 0130747; Simulator Deviation Form Paperwork not Completed Correctly; October 5, 2011

Section 1R12

AR 01232295; 16 Air Compressor Accruing Maintenance Rule Unavailability due to 16 Dryer Issue; November 18, 2010
AR 01237553; 16 Air Compressor Maintenance Rule Unavailability Red; October 16, 2010
AR 01250179; Operator Burden Tracking GAR; September 17, 2010
AR 01250523; SW-125-1 Difficult to Operate; September 20, 2010
AR 01254974; 12 Motor Generator Set Oil Cooler has High Vibrations; October 21, 2010
AR 01255422; ES-8 Controller Communication Error with 17 Air Compressor; October 23, 2010
AR 01255460; Unable to Meet Schedule due to Problems with 17 Air Compressor; October 24, 2010
AR 01261895; Valves SW-125-1 and SW-125-2 Require Frequent Replacement; December 8, 2010
AR 01262514; Air Compressor 17 Low Oil Level Following Preventive Maintenance; December 10, 2010
AR 01264496; Device Installed without Temporary Modification Processed; December 29, 2010
AR 01273017; Oil Level Low on 17 Air Compressor; February 28, 2011
AR 01279330; Low Suction and Discharge Pressure on Cooling Skid for K-1G; April 6, 2011
AR 01289993; Evaluate Adverse Trend with Air Compressor Cooling Pumps; August 25, 2011
AR 01301702; SW-125-1 Leaking by Badly; August 31, 2011
AR 01303250; 17 Air Dryer Inlet and Exhaust Valve Assembly Fails to Cycle; September 11, 2011
AR 01308110; Coolant Pump Suction Pressure is Low for 16 Air Compressor; October 13, 2011
FP-E-SE-02; Component Classification; Revision 6
Maintenance Rule (a)(1) Action/Performance Improvement Plan; S-122 - 16 Air Dryer and K-1F - 16 Air Compressor; September 29, 2010
Monticello Maintenance Rule Program Basis Document; Reactor Recirculation System; Revision 0
Monticello Maintenance Rule Program Basis Document; Service Water System; Revision 2
NH-36041; Piping and Instrumentation Drawing for Service Water System; Revision N
Operations Manual Section B.08.04.01; Instrument and Service Air; Revision 10
WO 416725; 12 Motor Generator Set Oil Cooler Valve has High Vibrations; July 30, 2011
WO 439419; SW-125-1 Fully Closed Water Leaking by Seat Badly; October 17, 2011
WR 72391; Disassemble and Inspect Valve SW-125-2; September 28, 2011

Section 1R13

CAP 01306770; Single Rod Scram while Performing 0010
WO 442930; Investigate Cause of Single Rod Scram while Performing 0010
Operation Manual, B.08-05; Fire Protection
CAP 01312079; Maximum Differential Pressure Exceeded for T-7E
C.6-080-DPAH-2215; Vessel T-7E D/P High; Revision 0
B.06.06-05, Part C; Placing Flow Indicating Controller in Automatic and Setpoint; Revision 29
CAP 01310588; XFMR Deluges Still Blocked from 12 EDG Scaffold Work
CAP 01313997; Reactor scram number 127 while Performing 1040-01 Quarterly Testing
QF-0571; Troubleshooting Plan—Reactor Scram during Turbine Generator Quarterly Testing
1040-01; Turbine Generator Quarterly
Steam Turbine Inspection Report—Front Standard Inspection for Monticello Nuclear Plant, Unit 1; November 5, 2007
Monticello Front Standard Inspection—Initial Findings; December 1, 2011
542 MN Turbine Monticello Nuclear Plant Reactor Scram Report; June 25, 1973

WO 00446169; Troubleshooting WO for Control Valve Fast Closure Relay
WO 00446481; Disassemble/Inspect turbine Front Standard Components
NX-8435-150-2; Turbine Control Diagram; Revision 79
NX-8435-150-1; Turbine Control Diagram; Revision 80

Section 1R15

CAP 01308390; SR 3.3.2.1 May not be Using an Independent Channel
EC 18939; Revise Channel Check Criteria for Selected ASDS Instruments; October 20, 2011
SCR 11-0478; Revised Select ASDS Instrument Channel Check Criteria; Revision 0
OSP-MSC-0573; Miscellaneous Operations Monthly Surveillances; Revision 6
0000-E; Operations Daily Log—Part E Completed 10-16-2011; Revision 92
NH-94670; Suppression Pool Temperature Monitoring System Cable Scheme Division I& Division II
0452; Suppression Pool Temperature Monitoring System (SPOTMOS) Instrument Calibration
White Paper for Surveillance Procedure OSP-MSC-0573 Operability Discussion; October 19, 2011
CAP 01309248; Clarification of Daily Rounds 0000-E Step 1 may be Warranted
CAP 01312380; CRD-111/50-31 has Excessive Steam Leakage
WO 445531; CRD-111/50-31 has Excessive Steam Leakage

Section 1R18

EC 18663; Connect DWS to CST for Keep Fill
WO 371354-23; Install T-Mod for Keep Fill
EC 18936; Furmanite Leak Seal for CV-6-13
EC 18988; Bypass Interlock POS-2375 for 11 Reactor Feedwater Pump
WO 00444230-09; Install TMOD for POS-2375 (EC 18988)
Operations Manual, B.06.05; Condensate and Reactor Feedwater

Section 1R19

WO 442712; LY-4107, Found Out of As-Found Tolerance
ISP-ASD-0574; Reactor Flooding Level Instrument Channel Calibration; Revision 3
4 AWI-04.05.06; Post-Maintenance Testing; Revision 18
WO 00444229; Raw Water Alarm Rec. on 11 EDG during Scram—Replace Pump; October 24, 2011
NX-9525-21; Emergency Service Water Pumps P111A & P111B; Revision 76
CAP 01309393; Raw Water Alarm was Received on 11 EDG during Rx Scram
CAP 01307712; Received Unexpected Annunciator ANN-93-A-19
WO 00444232; 13 Bus Failed to Re-energize; October 24, 2011
CAP 01309399; 13 Bus Failed to Re-energize
NE-36399-6; 1R Transformer SEC ACB 152-302 Control; Revision L
NX-7823-4-4; Primary Containment Isolation System
NX-7834-67-7; Reactor Protection System
NF-100338; RPS Channel A1 Analog Trip Cabinet C-304A Elementary Diagram
WO 378987-01; Replace K61A and K62A Agastat Relays
Work Plan 378987-01; Replace K61A and K62A Agastat Relays; Revision 17
WO 378987-01; Post Maintenance Testing and Return To Service Instructions; Revision 5
WO 393055-02; Replace K61C and K62C Agastat Relays

Work Plan 393055-02; Replace K61C and K62C Agastat Relays; Revision 6
WO 378987-01; Post Maintenance Testing and Return To Service Instructions; Revision 5

Section 1R20

CAP 01309402; 2R Transformer Lockout
CAP 01301545; PM Due Date Changed Without Appropriate Reviews
CAP 01298787; Deferral of PMRQ 9713-08: Test Cables from 2RS to 2R
CAP 01152518; 4 KV System MR Allowed Unavailability Times Exceeded in September
CAP 01311689; PM Deferral Justification Does Not Meet Standards
CAP 01150362; 3N4 Breaker Trip Resulting in Reactor Scram
CAP 01157287; Red KPI – NRC Crosscutting Aspect (H.4.c)
CAP 01151583; Cable Condition Monitoring Program Ineffective
CAP 01151315; Water Found in Manhole Containing Cables for 2R Transformer
CAP 01151402; Cable to 2R Transformer Not In Cable Monitoring Program
CAP 01314953; Ops Crew Failed to Recognize RWM Bypassed before Mode Change
C.1; Startup Procedure; Revision 71
0074; Control rod Drive Exercise; Revision 55
0212; Rod Worth Minimizer Operability Test; Revision 28
2150; Plant Prestart Checklist; Revision 39
CAP 01309460; CV-1729, 12 RHR Heat Exchanger RHRSW Outlet Has an Airline Leak
CAP 01309400; Turbine Bypass Valve Position Indication Failed
CAP 01309393; Raw Water Alarm was Received on No. 11 EDG during Reactor Scram
CAP 01309389; 11 RFP Could not be Restarted
2165; Scram Report; Reactor Scram 126
2165; Scram Report; Reactor Scram 127
WO 00446169; Troubleshooting WO for Control valve Fast Closure Relay
WO 00446481; Disassemble/Inspect Turbine Front Standard Components

Section 1R22

OSP-EDG-053-12; EDG Load Test; Revision 0
L-MT-11-062; Request for Enforcement Discretion to Allow for Performance of EDG Load Reject Testing in Accordance With a Revised Surveillance Test Methodology; October 3, 2011
OSP-EDG-053-11; EDG Load Test; Revision 1
CAP 01305683; CDBI FSA- Question on Definition of Post Accident Load in TS
EC 18798; 11 and 12 EDG Single Largest Load Evaluation
M9112L-09A-005; Power Range Neutron Monitor; Revision 0
ISP-NIP-0586; 2-of-4 Voter Channel Functional Test; Revision 3
0032 ECCS Pump Start Permissive Sensor; Revision 19
CAP 1143424; Preconditioning Question with Instrument Test/Cal Process
CAP 1246324; Station Review of NRC IR Finding 2009004-01
EC 15214; Acceptable Preconditioning of Select Pressure Switches; January 5, 2010
0051; Main Steam Line High Flow Group I Instrument Test; Revision 29
Operations Manual B.02.04-01; Main Steam—Function and General Description of System; Revision 9
Operations Manual B.02.04-03; Main Steam—Instrumentation and Controls; Revision 8

Section 1EP4

Monticello Emergency Plan; Revision 35
A.2-101; Classification of Emergencies; Revision 44
A.2-201; On-Site Protective Action; Revision 17
A.2-208; Core Damage Assessment; Revision 9
A.2-406; Off-Site Dose Projection; Revisions 22 and 23
A.2-504; Emergency Communicator Duties in the TSC and OSC; Revision 13
A.2-801; Responsibilities of the Emergency Manager; Revision 14
A.2-802; Activation and Operation of the EOF; Revision 13
A.2-803; Emergency Communications at the EOF; Revision 10
A.2-807; Off-Site Dose Assessment and Protective Action Recommendations; Revision 20

Section 4OA1

Monticello MSPI Derivation Report; Residual Heat Removal System; Unavailability Index, Unreliability Index, and Performance Limit Exceeded; November 4, 2011
Monticello MSPI Derivation Report; Cooling Water System; Unavailability Index, Unreliability Index, and Performance Limit Exceeded; November 4, 2011
CAP 01311541; Apparent Overconservatism in Reported RHR MSPI data
CAP 01221333; MO-2009 Failed to Properly Operate during Procedure 1381
CAP 01289462; BKR 152-503 (13 RHR pump) Failed to close
CAP 01288036; Unplanned TS Action No. 13 RHR pump
Unit Log Entries—RHR System; 4th Quarter 2010 through the 3rd Quarter 2011
Unit Log Entries—RHRSW System; 4th Quarter 2010 through the 3rd Quarter 2011
PRA-CALC-05-003; MSPI Basis Document; Revision 2
SE-0455 Maintenance Rule Search—RHR System; 4th Quarter 2010 through the 3rd Quarter 2011
SE-0455 Maintenance Rule Search—RHRSW System; 4th Quarter 2010 through the 3rd Quarter 2011
NH-36246; Residual Heat Removal System; Revision 80
NH-36247; Residual Heat Removal System; Revision 81
FG-PA-KPI-01; PI Data Reporting; Revision 00
FP-PA-PI-02; NRC/INPO/WANO PI Reporting; Revision 06
QF-0445; NRC/INPO/WANO Data Collection and Submittal Forms; various dates

Section 4OA2

FP-OP-OL-01; Operability / Functionality Determination; Revision 9
CAP 01309709; Items Identified by NRC on RFO 25 DW Closeout Inspection
CAP 01310132; TLD Empty Case Worn for Over 2 Months
CAP 01305559; GEH Part 21- SC 11-05 Failure to Include Seismic Input in Channel-Control Blade Interference Customer Guide
SC 11-05; GEH Part 21 Communication—Failure to Include Seismic Input in Channel-Control Blade Interference Customer Guidance; September 26, 2011
Operator Burden Reports; October 26, 2011
Outage Mode Change Reports; October 27, 2011
OBD/OBN Status Reports; October 26, 2011
Open Operational Decision Making Issues; October 26, 2011
CAP 00826605; GE Part 21 Notice (SC05-03) – Potential to Exceed Low Pressure TS Safety Limit

CAP 01253620; Track Resolution of Design Basis for ADS Bypass Timer
CAP 01079705; Develop a Licensing Basis for EDG Tornado SSCs Unprotected
CAP 01173169; Revise Technical Specifications for Core Spray
CAP 01177862; Figure 3.4.9-1 of Technical Specifications is Non-Conservative
CAP 01237578; Track Status of LAR Submittal for N2 Nozzles – Update PT Curves
CAP 01257284; Track the Revision of this Issue: 1973 HELB
CAP 01263913; MO-2035, Incorrect Voltage Used in MOV-2035 Calculation
CAP 01294288; Improper Filter Ring Installed on SRV G
CAP 01298757; PMT VT2 Examination not done per Code Requirements after Fixing Leak
CAP 01306899; Portions of Intake FP Sprinkler System may not Meet NFPA Requirements
CAP 01307211; Fire Fighting Strategy A.3-17 Fire Zone 17 Question
CAP 01309006; CRD-101/30-43, Drv Insert Riser Isol Valve is Leaking Water
Trend CAPs; dated July 2011 through December 2011
Monticello Performance Improvement and Sustainability Plan; Revision 1
CAP 1308257; BOS Finding: Ineffective Use of Site DRUM to Detect Decline
CAP 1298899; AR to Document Site Clock Reset on August 1, 2011
CAP 1276336; Adverse Trend in Outage Tagging
FP-PA-OE-01; Operating Experience Program; Revision 16
4 AWI-04.08.18; Performance Assessment Site Trending Program; Revision 0
FG-PA-DRUM-01; Department Roll-Up Meeting manual—Department Performance Trending; Revision 12
Performance Assessment Review Board Meeting Package; 12-6-2011
CAP 01288446; Adverse Trend in Equipment Performance during Rx Startup
CAP 01311051; Potential Adverse Trend in Unplanned LCO Entries
CAP 01316075; Adverse Trend in Ops Performance
CAP 01302978; Limited Support for Operating Experience Screen Team
SAR 01294995; Department Roll-Up Meeting Results – Maintenance; 3rd Quarter 2011
Department Roll-Up Meeting Results - RP; 3rd Quarter 2011
Department Roll-Up Meeting Results – Capital Projects and Major Projects (EPU); 3rd Quarter 2011
Department Roll-Up Meeting Results – Engineering; 3rd Quarter 2011
GAR 01300114; Department Roll-Up Meeting Results – Operations; 1st Quarter 2011
GAR 01300114; Department Roll-Up Meeting Results – Operations; 2nd Quarter 2011
SAR 01294995; Department Roll-Up Meeting Results – Maintenance; 1st and 2nd Quarter 2011
SAR 01249160; Site Roll-UP Meeting Results – 1st and 2nd Quarter 2010
Department Roll-Up Meeting Results - RP-Chem; 3rd Quarter 2010
SAR 01264947; Department Roll-Up Meeting Results – Maintenance; 4th Quarter 2010
GAR 01256195; Department Roll-Up Meeting Results – Operations; 3rd Quarter 2010
GAR 01268016; Department Roll-Up Meeting Results – Operations; 4th Quarter 2010
CAP 01317943; Backup Met Tower Wind Direction Computer Pnt not Functional

Section 4OA3

Operations Manual B.09.06-01; 4.16 KV Station Auxiliary; Revision 10
CAP 01309402; 2R Transformer Lockout
CAP 01309403; Reactor Scram Number 126
CAP 01309399; 13 Bus Failed to Re-energize
CAP 01309393; Raw Water Alarm was Received on 11 EDG during Rx Scram
CAP 01307712; Received Unexpected Annunciator ANN-93-A-19
CAP 01309400; Turbine Bypass Valve Position Indication Failed
Operations Manual C.1; Startup Procedure; Revision 70

2300; Reactivity Adjustment; Revision 5
2300 Attachment 1; Reactivity Management Plan; October 27, 2011
CAP 01310321; PS-1177A did not Reset during Startup
CAP 01310324; No. 1 BV Drifted Open while on PRO
NF-36298-1; Rev 97; Electrical Single Line
NF-36397; Rev Y; Meter & Relay Diagram
NE-36399-6; Rev L; 1R Transformer Sec ACB 152-302 Control
NE-36442-2; Rev 82; Generator Lock Out and Auto Transfer
NE-36399-4B; Rev H; 2R Transformer Sec ACB 152-301 Control
NE-36399-3; Rev J; 4.16 KV 2R Aux Tran Lockout Relay
NE-36401-2; Rev V; Reactor Feed Pump P-2A ACB 152-104 Control
NE-36404-3; Rev 76; Recir Pump MG Set ACB 152-103 Control
NE-36394-2; Rev 76; Circulating Water Pump ACB 152-305
NE-36399-2; Rev N; Auxiliary and Reserve Transformers
NE-36399-3A; Rev J; Nos. 12 and 13 4.16 KV Lockout Relay
NH-36241; Rev 82; NSSS P&ID
WO 00444232 09; 13 Bus Failed to Re-energize; October 24, 2011
WO 00444232 03; 13 Bus Failed to Re-energize; October 23, 2011
WO 00444232 06; 13 Bus Failed to Re-energize; October 24, 2011
Vendor Manual for GE Magneblast Circuit Breaker
Cable Testing Data
Vendor Manual for Bus under Voltage Relay & Synch Check Relay
CAP 01313496; Workers Entered Area Protected by Two Clearances While on One
CAP 01310956; Missed an 8-Hour Event Notification from Scram No. 126
QF-0428; Human Performance Event Investigation Tool (HUEIT)—Missed 8-hour Notification; November 14, 2011
Operations Memo 11-64; New Narrative Log Standard Entries for 3.0.3 Entries; December 14, 2011
CAP 01203212; Opportunities were Missed to Resolve Fire System Blockage
CAP 01302334; Sprinkler Piping In Intake Plugged with Clay-Like Debris
CAP 01180222; Intake Structure Sprinkler Blockage
0324; Fire Protection System – Sprinkler System Tests; Revision 44
RCE 01302334; Intake Structure Fire Sprinkler Piping Blockage; October 6, 2011
WO 00384321; Intake Sprinkler Test Valve Plugged; August 27, 2011
CAP 1306107; Largest Post-accident Load Greater than in Test OSP-ECC-0566
CAP 1306516; Correct EDG Load Drop Frequency Response Test
CAP 1304620 Observation- E1 Engineering In-progress Work Activity
EC 18798; 11 & 12 EDG Single Largest Load Evaluation; October 1, 2011
OSP-EDG-053-11; EDG Load Test; Revision 1
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CAP 01305683; CDBI FSA- Question on Definition of Post Accident Load in TS
Notice of Enforcement Discretion (NOED) 11-3-001: Monticello TS 3.8.1 EDG Load Rejection Surveillance Requirement Issue; October 5, 2011
Monticello Request for Enforcement Discretion to Allow for Performance of EDG Load Reiect Testing In Accordance with a Revised Surveillance Test Methodology; October 3, 2011
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Assessment 2010-002-5; Radiological Protection Including Radioactive Waste Control; June 2010
CRSD11-049; Energy Solutions Condition Report; Excel Energy MNGP 0726-07-0013 GSAP; July 14, 2011

FP-RP-RW-02; Radioactive Shipping Procedure; Revision 03
Monticello Shipment Log Index; 2009, 2010 and 2011
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NOS Observation Report 2011-007; Radiation Protection Including Radioactive Waste Control; May 2011
Ops Manual B.07.03-05; Processing of Phase Separators or Spent Resin Tank Using Centrifuge/Hopper Bypass to Radwaste RDS-100 Dewatering System Operation; Revision 16
Radioactive Material Shipment Package 09-46; April 2009
Radioactive Material Shipment Package 10-11; March 2010
Radioactive Material Shipment Package 10-23; May 2010
Radioactive Material Shipment Package 10-35; July 2010
Radioactive Material Shipment Package 11-54; April 2011
Radioactive Material Shipment Package 11-127; July 2011
R.11.07; Sampling and Analysis of Radioactive Resins; Revision 13
R.11.08; Selection and Entry of 10 CFR Part 61 Correlation Factors; Revision 08

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
ASDS	Alternate Shut Down System
CAP	Corrective Action Program
CAPR	Corrective Action To Prevent Recurrence
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CRD	Control Rod Drive
CRV	Control Room Ventilation
DOT	Department of Transportation
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EFT	Emergency Filtration Train
ESW	Emergency Service Water
FW	Feedwater
HEP	Human Error Probability
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IEL	Initiating Event Likelihood
IP	Inspection Procedure
IR	Inspection Report
JPM	Job Performance Measure
kV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LORT	Licensed Operator Requalification Training
MG	Motor Generator
MNGP	Monticello Nuclear Generating Plant
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NOED	Notice of Enforcement Discretion
NRC	U.S. Nuclear Regulatory Commission
OBD	Operable But Degraded
OBN	Operable But Nonconforming
PARS	Publicly Available Records System
PI	Performance Indicator
PIM	Plant Issue Matrix
PM	Post-Maintenance
PSF	Performance Shaping Factors
RCIC	Reactor Core Isolation Cooling
RP	Radiation Protection
RPS	Radiation Protection Specialist
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Cleanup
RWM	Rod Worth Minimizer

RWP	Radiation Work Permit
SAT	Systems Approach to Training
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SRV	Safety Relief Valve
SSC	Structure, System, and Component
SW	Service Water
TS	Technical Specification
USAR	Updated Safety Analysis Report
URI	Unresolved Item
WO	Work Order

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Sincerely,

/RA/

Kenneth Riemer, Branch Chief
Branch 2
Division of Reactor Projects

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Letter to T. O'Connor from K. Riemer dated February 1, 2012

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT -
NRC INTEGRATED INSPECTION REPORT 05000263/2011005

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