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

August 4, 2016

Mr. Paul Fessler
Chief Nuclear Officer
DTE Energy Company
Fermi 2 - 210 NOC
6400 North Dixie Highway
Newport, MI 48166

SUBJECT: FERMI POWER PLANT, UNIT 2—NRC INTEGRATED INSPECTION REPORT 05000341/2016002

Dear Mr. Fessler:

On June 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Fermi Power Plant, Unit 2 (Fermi 2). On July 12, 2016, the NRC inspectors discussed the results of this inspection with Mr. K. Polson and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report.

The NRC inspectors documented five findings of very low safety significance (Green) in this report. Four of these findings involved violations of NRC requirements. In addition, the inspectors documented a licensee-identified violation that was determined to be of very low safety significance in this report. The NRC is treating each of these violations as Non-Cited Violations consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of these Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001, with copies to: (1) the Regional Administrator, Region III; (2) the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and (3) the NRC Resident Inspector at the Fermi 2 Power Plant.

In addition, if you disagree with the cross-cutting aspect assignment 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 Fermi 2 Power Plant.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records System (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/

Billy Dickson, Chief
Branch 5
Division of Reactor Projects

Docket No. 50–341
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–341
License No:	NPF–43
Report No:	05000341/2016002
Licensee:	DTE Energy Company
Facility:	Fermi Power Plant, Unit 2
Location:	Newport, MI
Dates:	April 1 through June 30, 2016
Inspectors:	B. Kemker, Senior Resident Inspector P. Smagacz, Resident Inspector J. Bozga, Reactor Inspector M. Doyle, Reactor Engineer M. Jones, Reactor Inspector I. Kahn, Reactor Inspector V. Myers, Senior Health Physicist G. O'Dwyer, Reactor Inspector V. Petrella, Reactor Inspector
Approved by:	B. Dickson, Chief Branch 5 Division of Reactor Projects

Enclosure

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SUMMARY

Inspection Report 05000341/2016002; 04/01/2016–06/30/2016; Fermi Power Plant, Unit 2; Fire Protection, Heat Sink Performance, Identification and Resolution of Problems, Follow Up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by the resident inspectors and announced baseline inspections by regional inspectors. Five Green findings, four of which had an associated Non-Cited Violation (NCV) of the U.S. Nuclear Regulatory Commission (NRC) regulations, were identified. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

Green. The inspectors identified a finding of very low safety significance with an associated NCV of Technical Specification (TS) 5.4, "Procedures." During fire protection walkdowns in safety-related and risk-significant areas of the plant, the inspectors identified multiple instances of the licensee's failure to implement procedural requirements for implementing its fire protection program as required by TS 5.4.1.d, specifically for the controls of combustible materials. The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions. As immediate corrective actions, the licensee rectified all of the inspector-identified issues, performed walkdowns inspecting all fire storage cabinets in the plant, and directed individual departments to examine all other storage cabinets for combustible materials. Any additional discrepancies found during these walkdowns were promptly corrected.

The finding was of more than minor safety significance because it was related to the Initiating Events Cornerstone attribute of Protection Against External Factors (Fire) and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during plant operations. Specifically, the failure to properly control combustible materials in safety-related and risk-significant plant areas could increase the likelihood of a fire in these areas causing a plant transient and/or affecting plant equipment. The finding was determined to be a licensee performance deficiency of very low safety significance since redundant safe shutdown systems would have remained available during a postulated fire scenario in the affected locations. The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of avoid complacency. The licensee's failure to follow its fire protection program implementing procedure requirements involved several work groups and had existed for a sufficient period of time, such that individuals were accustomed to and accepted the discrepancies between what was required by the licensee's fire protection program and the actual condition of materials in the plant. (IMC 0310, H.12) (Section 1R05.1.b)

Green. A finding of very low safety significance was self-revealed when a reactor recirculation system runback occurred during power ascension due to a loss of feedwater heater drains caused by a feedwater heater level control valve malfunction. The control valve malfunction occurred because the licensee had failed to use correct material in the component during maintenance in October 2010. No violation of regulatory requirements was identified because the feedwater heating system is not safety-related and the applicable maintenance procedures were not covered under 10 CFR Part 50, Appendix B.

The finding was of more than minor safety significance because it was related to the Equipment Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the control valve malfunction resulted in a reactor recirculation system runback. In addition, the finding was sufficiently similar to IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," Examples 4(b) and 4(f), to conclude it was not of minor significance because there was an adverse safety impact (i.e., a plant transient) due to the licensee's failure to meet its technical requirements. The finding was determined to be a licensee performance deficiency of very low safety significance because it did not cause a reactor scram. The inspectors concluded that because the error occurred greater than three years ago, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified. (Section 4OA2.2.b.(2))

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very-low safety significance with an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to have a procedure that prescribed instructions to determine the average silt level in the residual heat removal (RHR) reservoir to ensure the stand-alone document ensures silt levels in the reservoir are maintained below the proceduralized limit of 3 inches. Specifically, in 2014 and 2015, the licensee failed to include the documented reservoir surveys or a method to determine the average silt levels in the RHR reservoir. After discussing the issue with the responsible site staff for the 2014 inspection, the licensee was able to locate the reservoir survey map outside of the quality records system; the records for 2015 were not provided. The licensee entered this issue into its corrective action program, verified that additional margin existed, and confirmed the reservoirs were still able to maintain their required design volume with the silt accumulation.

The performance deficiency was determined to be more-than-minor because if left uncorrected it would have the potential to lead to a more significant safety concern. Specifically, since licensee procedures failed to prescribe instructions for silt depth determination, and failed to prescribe how responsible site staff determines an average reservoir silt level based on diver inspection reports, both quality related activities, the potential exists for an unacceptable condition to go unnoticed, affecting service water systems operability. The finding was of very-low safety significance because the finding did not represent a loss of system operability and/or function. The inspectors did not assign a cross-cutting aspect because the finding was not indicative of current performance. (Section 1R07.1.b)

Green. A finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when the Division 1 low pressure coolant injection (LPCI) outboard injection motor-operated valve failed to open during surveillance testing. The licensee failed to have preventive maintenance work instructions and procedures for safety-related motor control center (MCC) inspections appropriate to the circumstances, such that appropriate steps were incorporated to ensure spare terminal screws were maintained tight. The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions. Corrective actions for the event included revising preventive maintenance work instructions and procedures to include instructions to check accessible spare terminal screws for tightness, personnel training, and inspection of all engineered safety feature MCC positions with relays susceptible to loose or missing screws and for susceptible contactor orientations.

The finding was of more than minor safety significance because it was related to the Equipment Reliability attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure of the Division 1 LPCI outboard isolation valve to stroke open affected the LPCI loop select logic function to respond to a design basis event. The finding was determined to be of very low safety significance based on a detailed significance determination process review since the delta core damage frequency was determined to be less than 1.0E–6/year. The inspectors concluded that because the inadequate procedures were in use for greater than three years, this issue would not be reflective of current licensee performance, and no cross-cutting aspect was identified. (Section 4OA3.5)

Other Findings

Green. The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 26.205(c) and (d). The licensee failed to schedule and control the work hours of two maintenance craftsmen performing work covered under 10 CFR 26.4(a) by not ensuring the individuals had, at a minimum, a 34-hour break in any 9-day period as required by §26.205(d)(2)(ii). The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions.

The finding was of more than minor safety significance because a failure to schedule and control the work hours of workers performing covered work, if left uncorrected, would become a more significant safety concern since it could reasonably result in human performance errors due to fatigue that could result in plant transients and/or affect the function of safety-related systems or components. The finding was determined to be a licensee performance deficiency of very low safety significance based on a qualitative evaluation of the potential consequences of the performance issue since there were no human performance related incidents attributed to the two maintenance craftsmen while they were not in compliance with the work hour limits. The inspectors concluded this finding affected the cross-cutting area of problem identification and resolution and the cross-cutting aspect of evaluation. The licensee did not thoroughly evaluate the problem after it was identified and reached an incorrect conclusion because it failed to sufficiently understand the regulatory requirements and

the basis for its decisions that contributed to the non-compliance with the §26.205 work hour requirements (P.2). (Section 4OA2.2.b.(1))

Licensee-Identified Violations

A violation of very low safety significance that was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation and corrective action tracking numbers are listed in Section 4OA7 of this inspection report.

REPORT DETAILS

Summary of Plant Status

Fermi 2 Power Plant was operated at or near 100 percent power during the inspection period with the following exceptions:

- On April 17, the licensee reduced power to about 62 percent to perform full core power suppression testing to identify the location of a fuel bundle with a small fuel element defect. The unit was returned to 100 percent power on April 22.

- On April 23, the licensee reduced power to about 68 percent to perform a control rod pattern adjustment. The unit was returned to 100 percent the following day.

- On May 3, the licensee removed the unit from service for a planned maintenance outage to repair failed potential transformer circuits for 4160 volt buses 64A and 64C, and to complete additional maintenance. The unit was restarted on May 12, synchronized to the electrical grid on May 13, and returned to 100 percent power on May 18.

- On June 10, the licensee reduced power to about 82 percent, fully inserted two control rods and removed them from service for maintenance on hydraulic control units. The unit was returned to full power the following day.

- On June 11, the licensee reduced power to about 76 percent to perform maintenance on a high pressure turbine control valve unitized actuator, control rod sequence exchanges, and scram time testing of two control rods following maintenance on hydraulic control units. The unit was returned to full power on June 13.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

The inspectors evaluated the licensee's plant features and procedures for operation and continued availability of offsite and alternate alternating current (AC) power systems. The inspectors interviewed plant personnel and reviewed the licensee's communications protocols between the Transmission System Operator (TSO) and the plant to verify the appropriate information was being exchanged when issues arose that could impact the offsite power system. Aspects considered in the inspectors' review included:

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

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

During the week of April 18 through 22, the inspectors performed a walkdown of the switchyards to observe the material condition of the offsite power sources and also reviewed the status of outstanding work orders (WOs) to assess whether corrective actions for any degraded conditions were scheduled with the TSO with the appropriate priority.

In addition, the inspectors verified problems associated with the availability and reliability of the offsite and alternate AC power systems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected condition assessment resolution documents (CARDs) were reviewed to verify corrective actions were appropriate and implemented as scheduled.

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

b. Findings

No findings were identified.

.2 Readiness for Impending Hot Summer Weather Conditions

a. Inspection Scope

The inspectors evaluated the licensee's preparations for hot summer weather conditions, focusing on the supplemental cooling water, residual heat removal service water (RHRSW), emergency equipment service water (EESW), and diesel generator service water systems. During the week of June 6 through 10, the inspectors performed a detailed review of severe weather and plant de-winterization procedures and performed general area plant walkdowns. The inspectors focused on plant specific design features and implementation of procedures for responding to or mitigating the effects of hot summer weather conditions on the operation of the plant. The inspectors reviewed system health reports and system engineering summer readiness review documents for the above systems.

In addition, the inspectors verified adverse weather related problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one seasonal extreme weather readiness inspection sample as defined in IP 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns (71111.04Q)

a. Inspection Scope

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

- Division 2 emergency diesel generator (EDG) 13 and EDG 14 during planned maintenance on Division 1 EDG 12;
- Division 2 non-interruptible air subsystem during planned maintenance on Division 1 non-interruptible air subsystem; and
- Division 1 RHR and RHRSW subsystems during planned maintenance on Division 2 RHR and RHRSW subsystems.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones. The inspectors reviewed operating procedures, system diagrams, TS requirements, 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 were available. The inspectors observed operating parameters and examined the material condition of the equipment to verify there were no obvious deficiencies.

In addition, the inspectors verified problems associated with plant equipment alignment were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted three partial system walkdown inspection samples as defined in IP 71111.04.

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 focusing on the availability, accessibility, and condition of firefighting equipment in the following risk-significant plant areas:

- Turbine Building Second Floor, Main Generator Exciter and Stator Water Cooling;
- Auxiliary Building Sub-Basement, High Pressure Coolant Injection;
- Auxiliary Building Third Floor, Divisional Battery Rooms;

- Circulating Water Pump House; and
- Reactor Building First and Second Floors, Division 1 RHR Heat Exchanger Room.

The inspectors reviewed these fire 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 Protection 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 Report with later additional insights, their potential to impact equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. The inspectors verified fire hoses and extinguishers were in their designated locations and available for immediate use; fire detectors and sprinklers were unobstructed; transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

In addition, the inspectors verified problems associated with plant fire protection were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted five quarterly fire protection inspection samples as defined in IP 71111.05AQ.

b. Findings

Failure to Control Combustible Materials

Introduction. The inspectors identified a finding of very low safety significance with an associated NCV of TS 5.4, "Procedures." During fire protection walkdowns in safety-related and risk-significant areas of the plant, the inspectors identified multiple instances of the licensee's failure to implement procedural requirements for implementing its fire protection program as required by TS 5.4.1.d, specifically for the controls of combustible materials.

Description. During fire protection walkdowns in safety-related and risk-significant areas of the plant during April and May, the inspectors identified multiple instances of the licensee's failure to follow its procedural requirements for the controls of combustible materials. Items identified included:

- an expired Transient Combustible Permit (TCP) in the Division 1 Direct Current (DC) MCC Area;
- combustible paste staged and not included on the TCP in the Division 1 Battery Room;
- an electric welding unit, hoses, and other materials stored in the Division 2 Switchgear Room that were not incorporated into the TCP, nor otherwise approved for storage in the room;

- a combustible storage cabinet containing combustible materials that were not evaluated and approved by the posted permit in the Circulating Water Pump House; and
- oil containers stored in an unapproved storage cabinet in the General Service Water Pump House.

These items belonged to several work groups within the licensee's organization, including operations and maintenance. It was also evident that the conditions present with the storage cabinets had existed for many months.

The inspectors reviewed licensee procedure MOP–11, "Fermi 2 Operations Conduct Manual Chapter 11 – Fire Protection," Revision 17, which implements the requirements of the licensee's fire protection program and contains guidance for the control of combustible materials in the plant. Section 4.7.3 of this procedure required a TCP to be submitted to the fire protection specialist for review when introducing combustible materials in the plant. Items identified by the inspectors during walkdowns of the Division 1 Battery and Division 2 Switchgear Rooms required a TCP; however, existing TCPs for these areas were not updated by the fire protection specialist nor were new TCPs submitted for his review when new combustible materials were introduced into the areas. Section 4.7.9 required that two days before the expiration of a TCP the requester is to be notified that all equipment associated with the TCP needs to be removed, or if the material is still required, a permanent plant storage permit should be obtained. This was not done for equipment staged in the Division 1 DC MCC Area and Division 2 Switchgear Room. Section 4.8.1 required an evaluation for storage of combustible/flammable liquids and aerosols in storage cabinets. The items found by the inspectors in storage cabinets in the Circulating Water Pump House and General Service Water Pump House were contrary to the requirements of this section because the items had not been evaluated and approved prior to their storage in the cabinets.

Analysis. The inspectors determined the licensee's failure to follow its procedure standard for implementing its fire protection program was contrary to the requirements of TS 5.4, "Procedures," and was therefore a performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined this performance deficiency was of more than minor safety significance, and thus a finding, because it was related to the Initiating Events Cornerstone attribute of Protection Against External Factors (Fire) and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during plant operations. Specifically, the failure to properly control combustible materials in safety-related and risk-significant plant areas could increase the likelihood of a fire in these areas causing a plant transient and/or affecting plant equipment. The inspectors reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and concluded Example 4k was not sufficiently similar to the performance deficiency since the example considered only a limited quantity of transient combustibles in a single fire zone and did not account for broader fire protection program implementation issues like expired and incomplete TCPs, unapproved/unevaluated combustible materials found in more than one plant area, and unapproved/unevaluated combustible/flammable liquids in storage cabinets.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated June 19, 2012, the inspectors determined this finding would require review using IMC 0609, Appendix F, “Fire Protection Significance Determination Process,” dated September 20, 2013, because it involved a failure to adequately implement fire prevention and administrative controls for combustible materials. The inspectors characterized this finding using IMC 0609, Appendix F, Attachment 1, “Fire Protection SDP Phase 1 Worksheet,” dated September 20, 2013, and assigned it to the Fire Prevention and Administrative Controls category. The inspectors answered “yes” to IMC 0609, Appendix F, Question 1.3.A, “Is the reactor able to reach and maintain safe shutdown (hot or cold) condition?” since redundant safe shutdown systems remained available during a postulated fire scenario in the affected locations. Therefore, this finding was determined to be a licensee performance deficiency of very low safety significance (Green).

The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of avoid complacency. The licensee’s failure to follow its fire protection program implementing procedure requirements involved several work groups and had existed for a sufficient period of time, such that individuals were accustomed to and accepted the discrepancies between what was required by the licensee’s fire protection program and the actual condition of materials in the plant. (IMC 0310, H.12)

Enforcement. Technical Specification 5.4.1.d requires that written procedures shall be established, implemented, and maintained covering the implementation of the fire protection program. Licensee procedure MOP–11, “Fermi 2 Operations Conduct Manual Chapter 11 – Fire Protection,” Revision 17, implements the requirements of the licensee’s fire protection program and contains guidance for the control of combustible materials in the plant.

Contrary to the above, as of May 27, 2016, the licensee failed to implement the requirements of MOP–11 by not including all transient combustible materials on approved TCPs as specified in Section 4.7.3, having a TCP expire without a storage evaluation for materials that remained in the area as specified in Section 4.7.9, and storing unapproved/unevaluated combustible materials in storage cabinets as specified in Section 4.8.1. Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee’s corrective action program, it is being treated as a Non Cited Violation consistent with Section 2.3.2.a of the NRC Enforcement Policy **(NCV 05000341/2016002–01, Failure to Control Combustible Materials)**. The licensee entered this violation into its corrective action program as CARD 16–24413.

As immediate corrective actions, the licensee rectified all of the inspector-identified issues, performed walkdowns inspecting all fire storage cabinets in the plant, and directed individual departments to examine all other storage cabinets for combustible materials. Any additional discrepancies found during these walkdowns were promptly corrected. Long-term corrective actions included re-writing MOP–11 to further clarify fire protection program requirements with respect to the proper control of combustible materials in the plant.

1R06 Flooding (71111.06)

.1 Underground Cable Vaults

a. Inspection Scope

The inspectors selected for examination underground bunkers/manholes subject to flooding that contained cables whose failure could disable safety-related and/or risk-significant equipment. The inspectors determined the cables were not submerged, splices were intact, and appropriate cable support structures were in place. In those areas where dewatering devices were used, such as a sump pump, the device was functional and level alarm circuits were set appropriately to ensure the cables would not be submerged. In those areas without dewatering devices, the inspectors verified adequate drainage of the area was available or the cables were qualified for submergence conditions. The inspectors performed a walkdown of the following underground bunkers/manholes subject to flooding:

- Manholes 16946 and 16947B.

In addition, the inspectors verified problems associated with potential degradation of safety-related and/or risk-significant cables due to submergence or wetting were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one underground cable vaults inspection sample as defined in IP 71111.06.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07)

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

a. Inspection Scope

The inspectors reviewed operability determinations, completed surveillances, vendor manual information, associated calculations, performance test results, and heat exchanger inspection results associated with the Division 2 emergency equipment cooling water (EECW) heat exchanger and the Division 2 RHR heat exchanger. These heat exchangers were chosen based on their risk-significance in the licensee's probabilistic safety analysis, their important safety-related mitigating system support functions, and their operating history.

For the EECW heat exchanger and the RHR heat exchanger, the inspectors assessed the adequacy of the differential pressure testing, thermal-hydraulic performance testing, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs to ensure proper heat transfer of the heat exchangers. This was accomplished by reviewing whether: (1) the test method used was consistent with accepted industry practices, or equivalent; (2) the test conditions were consistent with the selected

methodology; (3) the test acceptance criteria were consistent with the design basis values; and (4) the results of heat exchanger performance testing were acceptable. The inspectors also reviewed whether: (1) the test results appropriately considered differences between testing conditions and design conditions; (2) the frequency of testing based on trending of test results was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values; and (3) the test results considered test instrument inaccuracies and differences.

The inspectors reviewed whether: (1) the methods used to inspect and clean the heat exchanger were consistent with as-found conditions identified, expected degradation trends, and industry standards; (2) the licensee's inspection and cleaning activities had established acceptance criteria consistent with industry standards; and (3) the as-found results were recorded, evaluated, and appropriately dispositioned such that the as-left condition was acceptable.

In addition, the inspectors reviewed the condition and operation of the EECW heat exchanger and the RHR heat exchanger to determine consistency with design assumptions in heat transfer calculations and as described in the Updated Final Safety Analysis Report. This included an assessment of the number of plugged tubes compared to pre-established limits based on capacity and heat transfer assumptions. The inspectors reviewed whether the licensee evaluated the potential for water hammer and established adequate controls and operational limits to prevent heat exchanger degradation due to excessive flow-induced vibration during operation. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchangers.

The inspectors reviewed the performance of the ultimate heat sink (UHS) and safety-related service water systems and their subcomponents such as piping, intake screens, pumps, valves, etc. by tests or other equivalent methods to ensure availability and accessibility to the in-plant cooling water systems. Specifically, the inspectors reviewed the UHS in accordance with IP 71111.07, "Heat Sink Performance," Section 02.02, Sub Sections d.4 and d.6.

The inspectors reviewed the licensees operation of service water system and UHS. This included the review of licensee procedures for a loss of the service water system or UHS and the verification that instrumentation, which is relied upon for decision making, was available and functional. In addition, the inspectors verified that macrofouling was adequately monitored, trended, and controlled by the licensee to prevent clogging. The inspectors verified the licensee's biocide treatments for biotic control were adequately conducted and the results monitored, trended, and evaluated. The inspectors also reviewed strong pump-weak pump interaction and design changes to the service water system and the UHS. The inspectors also verified the licensee maintained adequate pH, calcium hardness, etc.

The inspectors performed a system walkdown on the safety-related service water systems to assess their structural integrity. In addition, the inspectors reviewed: (1) available testing and inspections results; (2) the licensee's disposition of any active thru-wall pipe leaks; and (3) the history of thru-wall pipe leakage to identify any adverse trends since the last NRC inspection. For buried or inaccessible piping, the inspectors reviewed the licensee's pipe testing, inspection, or monitoring program to verify structural integrity, and to ensure any leakage or degradation was appropriately

identified and dispositioned by the licensee. The inspectors reviewed whether the periodic piping inspection program adequately detected and corrected protective coating failure, corrosion, and erosion. The inspectors also reviewed operational history and inservice test vibration monitoring results for the deep draft vertical pumps to ensure the licensee adequately monitored and resolved any adverse trends related to them.

In addition, the inspectors reviewed corrective action documents related to the EECW and RHR heat exchanger and heat sink performance issues to verify the licensee had an appropriate threshold for identifying issues and to evaluate the effectiveness of the corrective actions.

These inspection activities constituted three triennial heat sink performance inspection samples as defined in IP 71111.07.

b. Findings

Inadequate Procedure Used for Measuring and Determining Average Silt Levels in the Service Water Reservoir

Introduction. A finding of very-low safety significance with an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to establish instructions for measuring and determining the average silt level for the RHR reservoir. Specifically, instructions prescribing measurement of silt levels in the RHR reservoir and for calculating the average silt depth are not provided to the third-party diver inspection team or responsible site oversight, so the effect of silting on operability could be adequately evaluated and documented.

Description. Procedure MES–52, Fermi 2 Engineering Support Conduct Manual, Chapter 52, "Generic Letter (GL) 89–13 Safety Related Service Water Monitoring Program," Revision 6, documents program commitments for testing and inspection. Section 3.2.1, identifies GL 89–13 Recommended Action I: Implement monitoring and treatment programs to significantly reduce flow blockage due to biofouling. Under recommendation Action I, "Surveillance Technique A," recommends: Visual inspections of service water intake for biofouling, sediment, and corrosion." In response to this GL 89–13 recommendation, the licensee committed to implementing monitoring and treatment programs to significantly reduce the incidents of flow blockage problems at Fermi 2 due to biofouling. These programs include performance testing of heat exchangers and other components, trending of surveillance data for any degradation of systems and components, periodic monitoring of systems for microfouling, chemical treatment of the service water systems, and periodic maintenance activities for systems not included in the performance testing program (CM RACTS 90089). The licensee established on-going monitoring periodic maintenance events P244 and P245 to meet this GL 89–13 commitment action.

Events P245 and P244, were established to perform Division 1 and Division 2 RHR reservoir zebra mussel and ball valve inspection dives, respectively, to meet GL 89–13 commitment under RACTS 90089, as referenced above in MES–52. The technical requirements of the periodic maintenance activity establish periodic inspection and cleaning of the Division 1 and RHR reservoir structure to ensure reliable operation of RHRSW, EESW, and diesel generator service water pumps and RHRSW cross-tie

valves. At the time of this inspection the licensee provided the following implementation details documented under these P244 and P245 events:

1. Determine and document average depth of sediment. Must be less than 3 inches.

2. Remove and document any debris in reservoir.

3. Document the extent of macrofouling.

4. Inspect and document condition of structure (floor, walls, and columns).

5. Inspection to be videotaped when conditions permit.

During the inspection, inconsistencies were identified by the inspectors in the supplemental documentation providing the basis for the average silt depth determined in the work orders reviewed from February 2014 through October 2015. When the inspectors requested the basis for the average silt depth in the RHR reservoir, the licensee located the silt depth survey for 2014 reservoir inspections after discussions with the maintenance staff who was responsible for performing the observation; the sedimentation depth chart was not located for the 2015 reservoir inspections. The licensee issued CARD 16–24183 to document the need to supplement the work orders with quality-related silt depth surveys used to determine the effect of silting on system operability. The inspectors determined that although licensee procedure require the documentation of an average silt depth, the procedures fail to prescribe instructions for measuring and documenting the silt depth in the reservoir and how to determine the average. The licensee determined the identified silt levels in the 2014 survey were well within the margin identified in calculation DC–0559, Volume 1, Revision D. Additionally, the licensee determined the RHR reservoirs were still able to maintain the required design volume with the silt accumulation identified. The licensee plans to clean the RHR reservoir as a part of the scheduled 2016 inspections.

Analysis. The inspectors determined the licensee's failure to prescribe adequate instructions for measuring and determining average silt level in the RHR reservoir for comparison against established acceptance criteria, was contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion V, and was a performance deficiency. The performance deficiency was determined to be more-than-minor because if left uncorrected it would have the potential to lead to a more significant safety concern. Specifically, since licensee procedures failed to prescribe instructions for silt depth determination and failed to prescribe how responsible site staff determines an average reservoir silt level based on diver inspection reports, both activities affecting quality, the potential exists for an unacceptable condition to go unnoticed, affecting service water systems' operability.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, and Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated June 19, 2012, the inspectors answered "No" to all of the questions. The inspectors confirmed the finding did not result in a loss of operability or functionality per Inspection Manual Chapter 0326, "Operability Determination and Functionality Assessments for Conditions Adverse to Quality or Safety," since the licensee trend reports indicated steady trending, and the licensee was able to show the RHR reservoirs were still able to maintain their required design volume

with the silt accumulation based on documented sediment survey maps. Therefore, this finding was of very-low safety significance (Green).

The inspectors determined there was no cross-cutting aspect associated with this finding because the cause of the performance deficiency (i.e., the development of the procedures) occurred more than three years ago and was not representative of current licensee performance.

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

Contrary to the above, as of May 16, 2016, the licensee failed to establish an RHR reservoir inspection procedure appropriate to the circumstances. Specifically, the licensee failed to prescribe instructions that provided appropriate detail on how to measure reservoir silt level and how to calculate a representative average silt level in the RHR reservoir so the effect of silting on system operability could be evaluated. Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's corrective action program, this violation is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy (**NCV 05000341/2016002–02, Inadequate Test Procedure Used for Measuring and Determining Average Silt Levels in the Service Water Reservoir**). The licensee entered this violation into its corrective action program as CARD 16–24183 with an action to correct the procedure.

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

The inspectors observed licensed operators during simulator training on April 6. The inspectors assessed the operators' response to the simulated events focusing on alarm response, command and control of crew activities, communication practices, procedural adherence, and implementation of Emergency Plan requirements. The inspectors also observed the post-evaluation critique to assess the ability of the licensee's evaluators to identify performance deficiencies. The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

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

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observations During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

From April 18 through 22, the inspectors observed licensed operators in the Control Room perform full core power suppression testing to identify the location of a fuel bundle with a small fuel element defect. This activity required heightened awareness, additional detailed planning, and involved increased operational risk. The inspectors evaluated the following areas:

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

The performance in these areas was compared to pre-established operator action expectations, procedural compliance, and task completion requirements.

In addition, the inspectors verified problems related to licensed operator performance were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

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

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated the licensee's handling of selected degraded performance issues involving the following risk-significant structures, systems, and components (SSCs):

- CARD 15–29239, EDG 12 Diesel Generator Service Water Pump Trips/Loses Power During 24.307.02; and
- CARD 15–27759, P4300 TBCCW [Turbine Building Closed Cooling Water] System Has Exceeded its Maintenance Rule Performance Criteria.

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the SSCs. Specifically, the inspectors independently verified the licensee's handling of SSC performance or condition problems in terms of:

- appropriate work practices;
- identifying and addressing common cause failures;
- scoping of SSCs in accordance with 10 CFR 50.65(b);
- characterizing SSC reliability issues;
- tracking SSC unavailability;
- trending key parameters (condition monitoring);
- 10 CFR 50.65(a)(1) or (a)(2) classification and reclassification; and
- appropriateness of performance criteria for SSC functions classified (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSC functions classified (a)(1).

In addition, the inspectors verified problems associated with the effectiveness of plant maintenance for risk-significant SSCs were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

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

b. Findings

No findings were identified.

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

a. Inspection Scope

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

- emergent maintenance during the week of April 10 through 16 on standby liquid control pump A and planned maintenance on EDG 11;
- emergent maintenance during the week of April 17 through 23 on the rod control system, planned maintenance on Division 1 Control Center heating, ventilation, and air conditioning subsystem, and Division 1 battery cell 32 replacement preparations;
- emergent maintenance during the week of April 25 through 29 on station transformer 64;
- emergent maintenance during the week of May 22 through 28 on Main Steam Tunnel temperature instrument B21N612A, testing on the high pressure coolant injection system, and diving activities at the General Service Water Pump House; and
- planned maintenance during the week of June 20 through 24 including Division 2 core spray subsystem maintenance.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each of the above activities, the inspectors reviewed the scope of maintenance work in the plant's daily schedule, reviewed Control Room logs, verified plant risk assessments were completed as

required by 10 CFR 50.65(a)(4) prior to commencing maintenance activities, discussed the results of the assessment with the licensee's probabilistic risk analyst and/or shift technical advisor, and verified plant conditions were consistent with the risk assessment assumptions. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid, redundant safety-related plant equipment necessary to minimize risk was available for use, and applicable requirements were met.

In addition, the inspectors verified maintenance risk-related problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted five maintenance risk assessment and emergent work control inspection samples as defined in IP 71111.13.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

.1 Operability Determinations and Functionality Assessments

a. Inspection Scope

The inspectors reviewed the following issues:

- CARD 16–23134, Division 1 Battery Declared Inoperable Due to Installed Individual Cell Charger While in Equalize Charge; and
- CARD 16–13392, Transformer 64/Bus 64A Loss of Voltage Indication with Trouble Alarm.

The inspectors selected these potential operability/functionality issues based on the safety significance of the associated components and systems. The inspectors verified the conditions did not render the associated equipment inoperable/non-functional or result in an unrecognized increase in plant risk. When applicable, the inspectors verified the licensee appropriately applied TS limitations, appropriately returned the affected equipment to an operable or functional status, and reviewed the licensee's evaluation of the issue with respect to the regulatory reporting requirements. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. When applicable, the inspectors also verified the licensee appropriately assessed the functionality of SSCs that perform specified functions described in the Updated Final Safety Analysis Report, Technical Requirements Manual, Emergency Plan, Fire Protection Plan, regulatory commitments, or other elements of the current licensing basis when degraded or nonconforming conditions were identified.

In addition, the inspectors verified problems associated with the operability or functionality of safety-related and risk-significant plant equipment were entered into the licensee's corrective action program with the appropriate characterization and

significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted two operability determination and functionality assessment inspection samples as defined in IP 71111.15.

b. Findings

Loss of Power Instrumentation TS 3.3.8.1 Applicability Following Bus 64C Potential Transformer Fuse Failures

Introduction. The inspectors opened an Unresolved Item to further evaluate the applicability of TS 3.3.8.1, "Loss of Power (LOP) Instrumentation," following the failure of potential transformer fuses that caused half of the bus 64C LOP and degraded voltage relays to de-energize.

Description. On April 24, 2016, a loss of output from the line to neutral potential transformers occurred on 4160 volt AC busses 64A and 64C. This resulted in the loss of bus indications, loss of automatic control of station transformer 64 load tap changer, and actuation of half of the LOP and degraded voltage relaying for safety-related bus 64C. The licensee subsequently discovered all six of the primary side fuses to the potential transformers had blown. Although the actual cause for the blown fuses was not conclusively determined, the most likely cause was attributed to an intermittent low energy transient on the secondary side of station transformer 64 or a transient on the 120 kilovolt electrical grid supplying the transformer.

The inspectors noted the licensee did not consider the de-energized LOP and degraded voltage instrument channels to be inoperable, and therefore, did not enter the applicable action requirements of TS 3.3.8.1. The licensee had concluded the affected LOP and degraded voltage instrument channels remained operable since their safety function was believed to have been satisfied while they were de-energized and tripped. The inspectors raised several questions with the licensee concerning the operability of the affected LOP and degraded voltage instrument channels. The questions included whether the potential transformers were part of the LOP and degraded voltage instrumentation described in TS 3.3.8.1 and whether applicable surveillance requirements had been satisfied for the instrumentation prior to and during the event. The licensee entered this issue into its corrective action program as CARD 16–25194 for further evaluation.

This issue of concern is considered an Unresolved Item pending additional review by the inspectors to determine whether the licensee had correctly applied the TS limitations and satisfied applicable regulatory reporting requirements (**URI 05000341/2016002–03, Loss of Power Instrumentation TS 3.3.8.1 Applicability Following Bus 64C Potential Transformer Fuse Failures**).

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

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

- WO 45041173; Replace 2PA Cell #32 Due to Low Intercell Voltage;
- WO 44745836; High Vibration West Stator Water Cooling Pump/Motor;
- WO 43815058; Replace Division 2 Intermediate Range Monitor Bypass Switch – C5100M004;
- WO 45417640; Broken Nylon Threaded Rod Fastener;
- WO 37494067; Modify EECW Inlet/Outlet Piping and Replace Tube Bundle on P5002B004;
- WO 43431112; Replace Division 2 EECW Makeup Pump; and
- WO 42287408; Perform 35.307.001 for EDG 12 Fast Start.

The inspectors reviewed the scope of the work performed and evaluated the adequacy of the specified post-maintenance testing. The inspectors verified the post-maintenance testing was performed in accordance with approved procedures, the procedures contained clear acceptance criteria that demonstrated operational readiness and the acceptance criteria were met, appropriate test instrumentation was used, the equipment was returned to its operational status following testing, and the test documentation was properly evaluated.

In addition, the inspectors verified problems associated with post-maintenance testing activities were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Unit 2 Forced Outage (FO 16–01)

a. Inspection Scope

On May 3, the licensee removed the unit from service for a planned maintenance outage to repair failed potential transformer circuits for 4160 volt buses 64A and 64C, and to complete additional maintenance. The unit was restarted on May 12, synchronized to the electrical grid on May 13, and returned to 100 percent power on May 18.

The inspectors evaluated the licensee's conduct of outage activities to assess the control of plant configuration and management of shutdown risk. The inspectors reviewed configuration management to verify the licensee maintained defense-in-depth commensurate with the shutdown risk plan; and reviewed major outage work activities to ensure correct system lineups were maintained for key mitigating systems. Other outage activities evaluated included the licensee's control of the following:

- SSCs that could cause unexpected reactivity changes;
- flow paths, configurations, and alternate means for reactor coolant system (RCS) inventory addition;
- RCS level instrumentation;

- radiological work practices;
- switchyard activities and the configuration of electrical power systems in accordance with the TSs and shutdown risk plan; and
- SSCs required for decay heat removal and for establishing alternate means for decay heat removal, including instrumentation.

The inspectors observed portions of the plant cool down to verify the licensee controlled the plant cool down and transition to shutdown cooling operations in accordance with the TSs. The inspectors also observed portions of the restart activities including reactor startup and plant heat up to verify TS requirements and administrative procedure requirements were met prior to changing operational modes or plant configurations.

The inspectors interviewed operations, engineering, work control, radiological protection, and maintenance department personnel and reviewed selected procedures and documents.

In addition, the inspectors verified problems associated with the conduct of outage activities were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

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

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- 24.307.14, Emergency Diesel Generator 11 – Start and Load Test;
- 24.139.02, Standby Liquid Control Pump and Valve Operability Test;
- 24.608, Rod Worth Minimizer Functional Test, and 54.000.07, Core Performance Parameter Check;
- 24.203.03, Division 2 Core Spray System Pump and Valve Operability and Automatic Actuation; and
- 74.000.19, Chemistry Routine Surveillances, Attachment 8 – Standby Liquid Control Sodium Pentaborate Surveillance – Monthly – Modes 1 and 2.

The inspectors observed selected portions of the test activities to verify the testing was accomplished in accordance with plant procedures. The inspectors reviewed the test methodology and documentation to verify equipment performance was consistent with safety analysis and design basis assumptions, 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, and appropriate testing acceptance criteria were satisfied. When applicable, the inspectors also verified test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable.

In addition, the inspectors verified problems associated with surveillance testing activities were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted two in-service tests and three routine surveillance tests, for a total of five surveillance testing inspection samples as defined in IP 71111.22.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

.1 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors assessed the licensee's current and historic isotopic mix, including alpha emitters and other hard-to-detect radionuclides. The inspectors evaluated whether survey protocols were reasonable to identify the magnitude and extent of the radiological hazards.

The inspectors determined if there have been changes to plant operations since the last inspection that may have resulted in a significant new radiological hazard for onsite individuals. The inspectors evaluated whether the licensee assessed the potential impact of these changes and implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard. The inspectors reviewed the last two radiological surveys from selected plant areas and evaluated whether the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements as needed to verify conditions were consistent with documented radiation surveys.

The inspectors assessed the adequacy of pre-work surveys for select radiologically risk-significant work activities.

The inspectors evaluated the radiological survey program to determine if hazards were properly identified. The inspectors discussed procedures, equipment, and performance of surveys with radiation protection staff and assessed whether technicians were knowledgeable about when and how to survey areas for various types of radiological hazards.

The inspectors reviewed work in potential airborne areas to assess whether air samples were being taken appropriately for their intended purpose and reviewed various survey records to assess whether the samples were collected and analyzed appropriately. The inspectors also reviewed the licensee's program for monitoring contamination which has the potential to become airborne.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed select radiation work permits (RWPs) used to access high radiation areas and evaluated the specified work control instructions or control barriers. The inspectors also assessed whether workers were made aware of the work instructions and area dose rates.

The inspectors reviewed electronic alarming dosimeter dose and dose rate alarm setpoint methodology. For selected electronic alarming dosimeter occurrences, the inspectors assessed the worker's response to the alarm, the licensee's evaluation of the alarm, and any follow-up investigations.

The inspectors reviewed the licensee's methods for informing workers of changes in plant operations or radiological conditions that could significantly impact their occupational dose.

The inspectors reviewed the labeling of select containers of licensed radioactive material that could cause unplanned or inadvertent exposure to workers.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitors material leaving the radiologically controlled area and assessed the methods used for control, survey, and release of material from the area. As available, the inspectors observed health physics personnel surveying and releasing material for unrestricted use.

The inspectors observed workers leaving the radiologically controlled area and assessed their use of tool and personal contamination monitors and reviewed the licensee's criteria for use of the monitors.

The inspectors assessed whether instrumentation was used at its typical sensitivity levels based on appropriate counting parameters or whether the licensee had established a de facto release limit.

The inspectors selected several sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact. The inspectors also evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, RWPs, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated the licensee's use of electronic alarming dosimeters in high noise areas as high radiation area monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee properly employed an NRC approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in work areas with significant dose rate gradients.

For select airborne area RWPs, the inspectors reviewed airborne radioactivity controls and monitoring, the potential for significant airborne levels, containment barrier integrity, and temporary filtered ventilation system operation.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials stored within pools and assessed whether appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

.5 High-Radiation Area and Very-High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors observed posting and physical controls for high radiation areas and very high radiation areas to assess adequacy.

The inspectors conducted a selective inspection of posting and physical controls for high radiation areas and very high radiation areas to assess conformance with performance indicators.

The inspectors reviewed procedural changes to assess the adequacy of access controls for high and very high radiation areas to determine whether procedural changes substantially reduced the effectiveness and level of worker protection.

The inspectors assessed the controls in the high radiation areas greater than 1 rem/hour and areas with the potential to become high radiation areas greater than 1 rem/hour for compliance with TSs and procedures.

The inspectors assessed the controls for very high radiation areas and areas with the potential to become very high radiation areas. The inspectors also assessed whether individuals were unable to gain unauthorized access to these areas.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

.6 Radiation Worker Performance and Radiation Protection Technician Proficiency (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance and assessed their performance with respect to radiation protection work requirements, the level of radiological hazards present, and RWP controls.

The inspectors assessed worker awareness of electronic alarming dosimeter set points, stay times, or permissible dose for radiologically significant work as well as expected response to alarms.

The inspectors observed radiation protection technician performance and assessed whether the technicians were aware of the radiological conditions and RWP controls and whether their performance was consistent with training and qualifications for the given radiological hazards.

The inspectors observed radiation protection technician performance of radiation surveys and assessed the appropriateness of the instruments being used, including calibration and source checks.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

.7 Problem Identification and Resolution (02.08)

a. Inspection Scope

The inspectors assessed whether problems associated with radiological hazard assessment and exposure controls were being identified at an appropriate threshold and were properly addressed for resolution. For select problems, the inspectors assessed the appropriateness of the corrective actions. The inspectors also assessed the licensee's program for reviewing and incorporating operating experience.

The inspectors reviewed select problems related to human performance errors and assessed whether there was a similar cause and whether corrective actions taken resolve the problems.

The inspectors reviewed select problems related to radiation protection technician error and assessed whether there was a similar cause and whether corrective actions taken resolve the problems.

These inspection activities constituted one inspection sample as defined in IP 71124.01.

b. Findings

No findings were identified.

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

.1 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected three to five work activities of the highest exposure significance or involve work in high dose rate areas.

The inspectors reviewed the radiological work planning as-low-as-reasonably-achievable (ALARA) evaluations, initial and revised exposure estimates, and exposure mitigation requirements. The inspectors determined if the licensee had reasonably grouped the radiological work into work activities.

The inspectors assessed whether the licensee's planning identified appropriate dose reduction techniques; appropriately considered alternate reduction features; and defined reasonable dose goals. The inspectors evaluated whether the licensee's ALARA assessment had taken into account decreased worker efficiency from use of respiratory protective devices and/or heat stress mitigation equipment. The inspectors determined if the licensee's work planning considered the use of remote technologies and dose reduction insights from industry and plant-specific operating experience. The inspectors assessed whether these ALARA requirements were integrated into work procedure and/or RWP documents. The inspectors compared the results achieved with the

intended dose established in the ALARA planning. The inspectors compared the person-hour estimates provided by work groups to the radiation protection group with the actual work activity time results, and evaluated the accuracy of these time estimates. The inspectors evaluated the reasons for any inconsistencies between intended and actual work activity doses.

The inspectors evaluated whether post-job reviews were conducted to identify lessons learned and entered into the licensee's corrective action program.

These inspection activities constituted one inspection sample as defined in IP 71124.02.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors assessed whether the assumptions and basis for the current annual collective exposure estimate were reasonably accurate. The inspectors assessed source term reduction effectiveness and reviewed applicable procedures for estimating exposures from specific work activities.

The inspectors reviewed the assumptions and bases in ALARA work planning documents for selected activities and verified that the licensee has established measures to track, trend, and if necessary to reduce, occupational doses for ongoing work activities.

The inspectors determined whether a dose threshold criteria was established to prompt additional reviews and/or additional ALARA planning and controls and evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors determined if adjustments to exposure estimates were based on sound radiation protection and ALARA principles or if they are just adjusted to account for failures to control the work. The inspectors evaluated whether there was sufficient station management review and approval of adjustments to exposure estimates and that the reasons for the adjustments were justifiable.

The inspectors reviewed selected occasions with inconsistent or incongruent results from the licensee's intended radiological outcomes to determine whether the cause was attributed to a failure to adequately plan work activities, or failure to provide sufficient management oversight of in-plant work activities, or failure to conduct the work activity without significant rework, or failure to implement radiological controls as planned.

These inspection activities constituted one inspection sample as defined in IP 71124.02.

b. Findings

No findings were identified.

.3 Problem Identification and Resolution (02.06)

a. Inspection Scope

The inspectors reviewed self-assessments and/or audits performed of the ALARA program and determined if these reviews identified problems or areas for improvement.

The inspectors assessed whether problems associated with ALARA planning and controls were being identified by the licensee at an appropriate threshold and properly addressed for resolution.

These inspection activities constituted one inspection sample as defined in IP 71124.02.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05)

.1 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors assessed select portable survey instruments that were available for use for current calibration and source check stickers, and instrument material condition and operability.

The inspectors observed licensee staff demonstrate performance checks of various types of portable survey instruments. The inspectors assessed whether high-range instruments responded to radiation on all appropriate scales.

The inspectors walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. The inspectors compared monitor response with actual area conditions for selected monitors.

The inspectors assessed the functional checks for select personnel contamination monitors, portal monitors, and small article monitors to verify they were performed in accordance with the manufacturer's recommendations and licensee procedures.

These inspection activities constituted one inspection sample as defined in IP 71124.05.

b. Findings

No findings were identified.

.2 Calibration and Testing Program (02.03)

a. Inspection Scope

The inspectors assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded

instrument performance. The inspectors assessed whether appropriate corrective actions were implemented in response to indications of degraded instrument performance.

The inspectors reviewed the methods and sources used to perform whole body count functional checks before daily use and assessed whether check sources were appropriate and aligned with the plant's isotopic mix. The inspectors reviewed whole body count calibration records since the last inspection and evaluated whether calibration sources were representative of the plant source term and that appropriate calibration phantoms were used. The inspectors looked for anomalous results or other indications of instrument performance problems.

The inspectors reviewed select containment high-range monitor calibration and assessed whether an electronic calibration was completed for all range decades, with at least one decade at or below 10 rem/hour calibrated using an appropriate radiation source, and calibration acceptance criteria was reasonable.

The inspectors reviewed select monitors used to survey personnel and equipment for unrestricted release to assess whether the alarm setpoints were reasonable under the circumstances to ensure that licensed material was not released from the site. The inspectors reviewed the calibration documentation for each instrument selected and discussed the calibration methods with the licensee to determine consistency with the manufacturer's recommendations.

The inspectors reviewed calibration documentation for select portable survey instruments, area radiation monitors, and air samplers. The inspectors reviewed detector measurement geometry and calibration methods for portable survey instruments and area radiation monitors calibrated onsite and observed the licensee demonstrate use of the instrument calibrator. The inspectors assessed whether appropriate corrective actions were taken for instruments that failed performance checks or were found significantly out of calibration, and that the licensee had evaluated the possible consequences of instrument use since the last successful calibration or performance check.

The inspectors reviewed the current output values for instrument calibrators. The inspectors assessed whether the licensee periodically measured calibrator output over the range of the instruments used with measuring devices that have been calibrated by a facility using National Institute of Standards and Technology traceable sources and corrective factors for these measuring devices were properly applied in its output verification.

The inspectors reviewed the licensee's 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," source term to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

These inspection activities constituted one inspection sample as defined in IP 71124.05.

b. Findings

No findings were identified.

.3 Problem Identification and Resolution (02.04)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by the licensee at an appropriate threshold and were properly addressed for resolution. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring instrumentation.

These inspection activities constituted one inspection sample as defined in IP 71124.05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index—High Pressure Injection Systems

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported Mitigating Systems Performance Index (MSPI) – High Pressure Injection Systems Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in Nuclear Energy Institute (NEI) 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule database, Licensee Event Reports (LERs), and maintenance and test data from April 2015 through March 2016, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constituted one MSPI - High Pressure Injection Systems Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index—Emergency AC Power System

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported MSPI – Emergency AC Power System Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions

and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule database, LERs, and maintenance and test data from July 2015 through March 2016, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constituted one MSPI – Emergency AC Power System Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

.3 RCS Leakage

a. Inspection Scope

The inspectors verified the RCS Leakage Performance Indicator. The inspectors reviewed the licensee's RCS leakage tracking surveillance test data from April 2015 through March 2016, to validate the accuracy of the licensee's submittals. To determine the accuracy of the performance indicator data reported during this period, performance indicator definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors also reviewed the licensee's corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constituted one RCS Leakage Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's corrective action program at an appropriate threshold, adequate attention was being given to timely corrective actions, and adverse trends were identified and addressed. Some minor issues were entered into the licensee's corrective action program as a result of the inspectors' observations; however, they are not discussed in this report.

This inspection was not considered to be an inspection sample as defined in IP 71152.

b. Findings

No findings were identified.

.2 Annual In-depth Review Samples

a. Inspection Scope

The inspectors selected the following issues for in-depth review:

- CARD 15–23513, Part 21 Event #51078 Issued Against Bentley System Inc. STAAD Pro Software Requires Evaluation;
- CARD 16–21883, Unplanned Power Change from 90 – 58 Percent Reactor Power; and
- CARD 16–22814, Possible MGA [General Administrative Conduct Manual] 17 Working Hour Limit Violation.

As appropriate, the inspectors verified the following attributes during their review of the licensee's corrective actions for the above CARDs and other related CARDs:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause, and previous occurrences;
- evaluation and disposition of operability/functionality/reportability issues;
- classification and prioritization of the resolution of the problem commensurate with safety significance;
- identification of the root and contributing causes of the problem; and
- identification of corrective actions, which were appropriately focused to correct the problem.

The inspectors discussed the corrective actions and associated evaluations with licensee personnel.

In addition, during the week of April 18, 2016, the inspectors reviewed the licensee's evaluations and corrective actions for the findings and/or violations given enforcement discretion in NRC Inspection Report 05000341/2014–403, "Inspection of Implementation of Interim Cyber Security Milestones 1 – 7," dated January 15, 2015 (ML15016A396). The inspection constituted one additional annual in-depth inspection sample. The inspection results are discussed in NRC Inspection Report 05000341/2016406.

This inspection constituted a total of four annual in-depth review inspection samples as defined in IP 71152.

b. Findings and Observations

(1) Failure to Control the Work Hours of Covered Workers

Introduction. The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 26.205(c) and (d). The licensee failed to schedule and

control the work hours of two maintenance craftsmen performing work covered under 10 CFR 26.4(a) by not ensuring the individuals had, at a minimum, a 34-hour break in any 9-day period as required by §26.205(d)(2)(ii).

Description. The inspectors reviewed CARD 16–22779, "Fatigue Management Work Hour Violation: MGA–17 Section 4.2.1 (34-Hour Break in 9-Day Period)," which described a licensee-identified violation of 10 CFR 26.205(c) and (d) for the failure to ensure two maintenance craftsmen had a 34-hour break in any 9-day period as required by §26.205(d)(2)(ii). Aside from the violation itself, the inspectors had no issues of concern with the results of the licensee's investigation and corrective actions. Accordingly, a licensee-identified NCV of 10 CFR 26.205(c) and (d) is documented in Section 4OA7 of this inspection report.

The problem was identified when the two maintenance craftsmen reported to work on Sunday, April 3, to work an overtime shift as requested by maintenance supervision. The craftsmen were sent home by their supervisor when the violation was identified about ½ hour after reporting to work for their shift. The licensee completed an investigation and determined the two craftsmen were in violation of the 34-hour break in any 9-day period requirement prior to the end of their previous shift on Saturday, April 2, after 9:30 p.m. Both craftsmen worked that night until 11:30 p.m., exceeding a 9-day period by two hours. The two craftsmen had worked nine consecutive days since Saturday, March 26.

Rather than restarting the 34-hour break clock after the two craftsmen were sent home on Sunday, April 3, a maintenance supervisor cleared out the time input for both craftsmen from the licensee's work-hour controls database as if the workers had remained away from work so that the day would be counted as a day off. The two craftsmen were then called in to work on Monday, April 4, and worked the remainder of the week through Friday, April 8. One of the maintenance craftsmen initiated CARD 16–22814, "Possible MGA–17 Working Hour Limit Violation," to question whether this practice was another possible Work Hours Rule violation. The CARD was closed with a maintenance supervisor stating there was confusion as to when the two craftsmen should report back to work and that no covered work was performed by them on Sunday, April 3. The conclusion was the maintenance craftsmen completed covered work at 11:30 p.m. on Saturday, April 2, and did not perform covered work again until Monday, April 4, at 3:30 p.m., which would be a 39 hour break.

Based on review of the licensee's investigation for CARD 16–22814, the inspectors questioned licensee management whether the two maintenance craftsmen's work hours were appropriately scheduled and controlled as required by §26.205(c) and (d), since it appeared the original licensee-identified violation had been compounded by maintenance supervision because the craftsmen were required to report to work on Monday, April 4, without having an uninterrupted 34-hour break after working ten consecutive days. Furthermore, since the two craftsmen worked the remainder of the week through Friday, April 8, they actually worked fourteen consecutive days without the required 34-hour break.

The inspectors consulted with technical staff in the Office of Nuclear Reactor Regulation and Region III to understand the Work Hours Rule requirements with respect to this issue. The staff noted that in accordance with §26.205(b)(3), if an individual begins or resumes performing for the licensee any of the duties listed in §26.4(a) during the

calculation period, the licensee shall include in the calculation of the individual's work hours all work hours worked for the licensee, including hours worked performing duties that are not listed in §26.4(a), and control the individual's work hours under the requirements of §26.205(d). Therefore, when the craftsmen reported to work on Sunday, April 3, for an overtime shift at the behest of the licensee that time was required to be included under work hour calculations since the craftsmen were performing a duty for the licensee even though they were sent home prior to actually performing any covered work. In this case, reporting to work for a scheduled shift was considered performing a duty for the licensee.

The staff further noted the provision for a 34-hour break in any rolling 9-day period serves both to prevent and mitigate cumulative fatigue. It is intended to be an uninterrupted break period affording individuals the opportunity for two consecutive sleep periods without an intervening work period. As stated in the Federal Register Notice for the final Part 26 Rule: "The 34-hour break periods will not only provide some opportunity for recovery sleep, but also time that individuals need to meet the many daily living obligations that they cannot otherwise readily meet. Without such long break opportunities, individuals must either forego activities that can be important to general mental and physical fitness (e.g., family interactions, exercise, recreation, doctor appointments) or sacrifice sleep and increase their sleep debt, resulting in impairment on the job."

The inspectors considered whether this issue should be treated as licensee-identified since a maintenance craftsman employed by the licensee had generated the CARD that identified this second Work Hours Rule violation. However, the inspectors determined the issue was more appropriately characterized as NRC-identified because the inspectors identified during their review of the CARD that the licensee's investigation of the issue had reached an incorrect conclusion, for which no corrective actions would have been taken.

Analysis. The inspectors determined the failure to schedule and control the work hours for two maintenance craftsmen performing work covered under 10 CFR 26.205(a) was contrary to the requirements of §26.205(c) and (d), and was therefore, a performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined this performance deficiency was of more than minor safety significance; and thus a finding, because a failure to schedule and control the work hours of workers performing covered work, if left uncorrected, would become a more significant safety concern since it could reasonably result in human performance errors due to fatigue that could result in plant transients and/or affect the function of safety-related systems or components. The inspectors also reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found two examples related to worker fatigue. However, both of these examples involved individual occurrences where waivers were inappropriately utilized rather than a failure to schedule and control the work hours for covered workers.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated June 19, 2012, the inspectors determined this finding would require evaluation using IMC 0609, Appendix M, "Significance Determination Process Using

Qualitative Criteria," dated April 12, 2012, since it was a programmatic issue associated with multiple cornerstones that could not readily be evaluated under any of the other SDP appendices. The inspectors concluded the finding was of very low safety significance (Green) based on a qualitative evaluation of the potential consequences of the performance issue since there were no human performance related incidents attributed to the two maintenance craftsmen while they were not in compliance with the work hour requirements.

The inspectors concluded this finding affected the cross-cutting area of problem identification and resolution and the cross-cutting aspect of evaluation. The licensee did not thoroughly evaluate the problem after it was identified and reached an incorrect conclusion because it failed to sufficiently understand the regulatory requirements and the basis for its decisions that contributed to the non-compliance with the §26.205 work hour requirements (P.2).

Enforcement. Title 10 CFR 26.205, Paragraph (a) requires, in part, "Any individual who performs duties identified in Paragraphs 26.4(a)(1) through (a)(5) shall be subject to the requirements of this section."

Title 10 CFR 26.4, Paragraph (a)(4) identifies individuals who are "Performing maintenance or onsite directing of the maintenance of SSCs that a risk-informed evaluation process has shown to be significant to public health and safety."

Title 10 CFR 26.205, Paragraph (c) requires, in part, "Licensees shall schedule the work hours of individuals who are subject to this section consistent with the objective of preventing impairment from fatigue due to the duration, frequency, or sequencing of successive shifts."

Title 10 CFR 26.205, Paragraph (d)(2)(ii) requires, in part, "Licensees shall ensure that individuals have, at a minimum, a 34-hour break in any 9-day period."

Contrary to the above, from March 26, 2016, through April 8, 2016, two individuals who performed duties identified in §26.4(a)(4) were not scheduled work hours as required by §26.205(c). Specifically, the individuals were excluded from the work hour limits specified in §26.205(d)(2)(ii). As a result, the individuals were not provided a 34-hour break in any 9-day period. Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's corrective action program, it is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy **(NCV 05000341/2016002–04, Failure to Control the Work Hours of Covered Workers)**. The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions as CARD 16–23996.

(2) Failure to Use Correct Material in a Feedwater Heater Level Control Valve Resulted in a Loss of Feedwater Heater Drains and a Reactor Recirculation System Runback

Introduction. A finding of very low safety significance was self-revealed when a reactor recirculation system runback occurred during power ascension due to a loss of feedwater heater drains caused by a feedwater heater level control valve malfunction. The control valve malfunction occurred because the licensee had failed to use correct

material in the component during maintenance in October 2010. No violation of regulatory requirements was identified because the feedwater heating system is not safety-related and the applicable maintenance procedures were not covered under 10 CFR 50, Appendix B.

Description. On February 27, 2016, the licensee reduced power to about 78 percent to perform a control rod pattern adjustment, remove a heater drains pump from service for valve maintenance, and perform main turbine control, stop, and bypass valve testing. During power ascension on February 28, a reactor recirculation system runback from 90 percent power to 58 percent power occurred when feedwater heater drains were lost due to a feedwater heater level control valve malfunction. The reactor recirculation runback occurred while Control Room operators were attempting to restore pumped forward heater drains with the center heater drains pump. After starting to pump forward heater drains, the 5 South emergency drain line (EDL) air-operated control valve did not fully close as expected. When operators stopped pumping forward with the center heater drains pump, the 5 South heater drain line to flash tank check valve closed as expected for normal system response, making up half of the logic for the #3 reactor recirculation runback limiter and also initiating a series of feedwater heater system perturbations that ultimately resulted in a runback when the 5 North heater drain line to flash tank check valve also closed causing the #3 reactor recirculation runback limiter to actuate.

The inspectors reviewed the licensee's root cause evaluation for the event and concurred with its conclusions. The root cause was a Nitrile O-ring seal, rather than the specified Viton O-ring seal, was procured and installed in the 5 South heater EDL control valve actuator piston during preventive maintenance on the valve in October 2010. This, possibly compounded by a stem packing leak during the last operating cycle, resulted in degradation and ultimately the malfunction of the actuator. In June 1998, in response to internal operating experience with low temperature Nitrile elastomer seal failures in high temperature areas of the plant (including steam leaks from packing), the licensee replaced the Nitrile O-ring seals with Viton O-ring seals in a large number of its air-operated valves in the Turbine Building Steam Tunnel, including the 5 South heater EDL control valve. Nitrile is rated for continuous use up to 240 degrees Fahrenheit (°F), while Viton is rated for continuous use up to 400°F. During preventive maintenance on the valve in October 2010, an error was made by a maintenance planner who failed to ensure the correct high temperature material as prescribed in the licensee's preventive maintenance technical requirements was used. The work order was originally planned specifying an 8½ inch diameter Viton O-ring. Maintenance craftsmen discovered during the work that this was the incorrect size O-ring for the actuator and requested a maintenance planner correct the work order and obtain an appropriate 10¾ inch diameter O-ring. However, the maintenance planner either did not refer to the preventive maintenance technical requirements that specified the use of high temperature parts or failed to identify the correct material and a 10¾ inch diameter Nitrile O-ring was provided instead of one made from Viton. The material discrepancy was not recognized and the O-ring was installed in the valve actuator. Subsequent to the event, the licensee replaced the degraded Nitrile O-ring in the 5 South heater EDL control valve with a new one made of Viton.

Analysis. The inspectors determined the licensee's failure to use correct material (i.e., a Viton O-ring vice a Nitrile O-ring) in the 5 South heater EDL control valve actuator in accordance with its preventive maintenance technical requirements was a performance

deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” dated September 7, 2012, the inspectors determined this performance deficiency was of more than minor safety significance, and thus a finding, because it was related to the Equipment Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the 5 South heater EDL control valve malfunction resulted in a reactor recirculation system runback. The inspectors also reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," dated August 11, 2009, and noted there were examples (4b and 4f) wherein licensee requirements were not met and the performance issues were not considered to be of minor significance when there was an adverse safety impact. In this case, the performance deficiency resulted in a plant transient.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated June 19, 2012, the inspectors determined this finding affected the Initiating Systems Cornerstone, specifically the Transient Initiators contributor, and would require review using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” dated June 19, 2012, since at the time of the event the reactor was operating at power. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," and answered “No” to Question B, “Did the finding cause a reactor scram AND the loss of mitigation equipment relied upon to transition the plant from the onset of the scram to a stable shutdown condition (e.g. loss of condenser, loss of feedwater)?” Therefore, this finding was determined to be a licensee performance deficiency of very low safety significance (Green).

The inspectors concluded that because the error occurred greater than three years ago, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

Enforcement. No violation of regulatory requirements was identified because the feedwater heating system is not safety-related and the applicable maintenance procedures were not covered under 10 CFR Part 50, Appendix B. This issue was determined to be a finding **(FIN 05000341/2016002–05, Failure to Use Correct Material in a Feedwater Heater Level Control Valve Resulted in a Loss of Feedwater Heater Drains and a Reactor Recirculation System Runback)**. The licensee entered this finding into its corrective action program as CARD 16–21883.

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

.1 (Closed) Licensee Event Report 05000341/2015–009–00, “Condition Prohibited by Technical Specification Due to Missed Entry into LCO [Limiting Condition for Operation] Condition”

On July 28, 2015, the licensee removed the Division 2 EECW subsystem and UHS from service to perform scheduled maintenance. Upon completion of the maintenance later that day, the licensee identified a required action of TS 3.7.2, Condition B, for an inoperable UHS reservoir was not completed. A note in the action statement to enter the applicable conditions and required actions of TS 3.8.1 for EDGs made inoperable by an

inoperable UHS reservoir was not performed. TS 3.8.1, Required Actions A.1 and B.1, require performance of TS Surveillance Requirement 3.8.1.1 to verify the correct breaker alignment and indicated power availability of each required electrical circuit within 1 hour and once per 8 hours thereafter. Required Action A.3, requires verification of combustion turbine generator (CTG) 11–1 availability to supply Division 1 electrical loads during a station blackout once every 8 hours. The elapsed time of the missed TS 3.8.1 LCO entry from 4:00 a.m. to 9:15 p.m. (17.25 hours) was greater than the completion times of TS 3.8.1, Conditions A.1, B.1, and A.3, which were not performed. Inasmuch as required actions and completion times for Conditions A and B were not satisfied, Condition G, which required entry into Mode 3 within 12 hours, was also not met. Upon discovery of the missed required actions on July 28, the licensee promptly performed them to verify the offsite power circuits were operable and CTG 11–1 was available.

The inspectors reviewed this issue and documented a Severity Level IV NCV of 10 CFR 50.73(a)(1), "Licensee Event Report System," in NRC Inspection Report 05000341/2016-001 because the licensee failed to submit a required LER within 60 days after the discovery of this condition prohibited by the plant's TS as required by 10 CFR 50.73(a)(2)(i)(B). The inspectors also documented a licensee-identified NCV of TS 3.7.2 and TS 3.8.1 in the inspection report associated with the licensee's non-compliance with the TS requirements.

The licensee submitted LER 05000341/2015–009–00 to report this event in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation or condition which was prohibited by the plant's TS. The inspectors determined the information provided in the LER did not raise any new issues or change the conclusion of the initial review.

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

LER 05000341/2015–009–00 is closed.

.2 (Closed) Licensee Event Report 05000341/2015–006–00, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water"

(Closed) Licensee Event Report 05000341/2015–006–01, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water," Supplement 1

a. Inspection Scope

On September 13, 2015, control room operators manually scrammed the reactor and tripped the main turbine generator due to a loss of cooling water supply to non-safety-related systems in the Turbine Building, including the main turbine oil and station air systems. Previously, control room operators had briefed and dispatched non-licensed operators to swap the TBCCW heat exchangers from the east train to the west train. During the transfer, control room operators received alarms indicating the existence of a leak in one of the heat exchangers from the general service water system into the TBCCW system. This condition resulted in overfilling the TBCCW expansion tank, lifting the expansion tank relief valve, and eventually the loss of both operating TBCCW pumps. Since TBCCW provides cooling to various Turbine Building components, including the station air compressors and reactor feedwater pump lubricating oil coolers, this condition resulted in a loss of station air system pressure and also required operators to stop the reactor feedwater pumps. Standby feedwater pumps were then

used to control reactor pressure vessel (RPV) water level. As instrument air header pressure degraded, secondary containment isolation dampers drifted closed. Reactor Building pressure exceeded the TS minimum requirement of -0.125 inches water for over 3 minutes, resulting in a loss of secondary containment function. About 40 minutes after the scram, operators closed the main steam isolation valves (MSIVs) due to low air system pressure, necessitating the use of safety relief valves to control reactor pressure. When main condenser pressure reached the high condenser pressure setpoint, a valid automatic primary containment isolation signal for MSIVs and drain valves actuated. The drain valves automatically went closed at this time.

The inspectors evaluated operator actions during the event and documented this review in NRC Inspection Report 05000341/2015003. The inspectors reviewed the cause of the TBCCW heat exchanger tube failure, which resulted in the manual reactor scram, and documented a finding of very low safety significance with an associated NCV of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," in NRC Inspection Report 05000341/2016001 due to the licensee's failure to incorporate industry operating experience to perform adequate preventive maintenance on the TBCCW heat exchangers.

On September 14, 2015, the licensee completed a notification call (Event Notice 51391) to report the manual reactor scram in accordance with 10 CFR 50.72(b)(2)(iv)(B) as an event or condition that resulted in actuation of the reactor protection system (RPS) when the reactor is critical. The licensee also reported the loss of secondary containment function in accordance with 10 CFR 50.72(b)(3)(v)(C) as an event or condition, that at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. On November 5, 2015, the licensee submitted LER 05000341/2015–006–00 to report the manual reactor scram in accordance with 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in manual or automatic actuation of the RPS. The licensee also reported the loss of secondary containment function in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of a safety function needed to control the release of radioactive material.

During the first quarter of 2016, the inspectors reviewed the 10 CFR 50.72 event notification and the LER and documented a Severity Level IV NCV of the NRC's reporting requirements in 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System," in NRC Inspection Report 05000341/2016001. The inspectors identified the licensee had failed to make a required 8-hour non-emergency notification call to the NRC Operations Center and failed to submit a required LER within 60 days after discovery of the valid actuation of the primary containment isolation logic for Groups 4, 13, and 15 primary containment isolation valves when RPV water level reached the Level 3 setpoint following the manual reactor scram as required by 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A).

During its review of the above reporting discrepancies, the licensee identified the closure of MSIVs and the subsequent valid automatic actuation signal for MSIVs and drain valves that occurred when main condenser vacuum reached the high condenser pressure primary containment isolation setpoint was also not correctly reported. The manual and automatic actuations of primary containment isolation valve logic for the MSIVs were reportable under 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A)

as an event or condition that resulted in the valid actuation of general containment isolation signals affecting multiple MSIVs. Accordingly, the inspectors documented a licensee-identified NCV of 10 CFR 50.72(a)(1) and 10 CFR 50.73(a)(1) in NRC Inspection Report 05000341/2016001.

The licensee subsequently made an 8-hour notification call to the NRC Operations Center via the Emergency Notification System on February 27, 2016, (Event Notice 51391, third update) to address the10 CFR 50.72 reporting discrepancies. The inspectors reviewed the revised event notification and determined the information provided did not raise any new issues or change the conclusion of the initial review. The licensee submitted LER 05000341/2015–006–01 on April 15, 2016, to address the 10 CFR 50.73 reporting discrepancies and to provide additional details. The inspectors determined the information provided in the revised LER did not raise any new issues or change the conclusion of the initial review, which was documented in NRC Inspection Report 05000341/2016001.

This inspection constituted two event follow-up inspection samples as defined in IP 71153.

LER 05000341/2015–000–00 and LER 05000341/2015–006–01 are closed.

.3 (Closed) Licensee Event Report 05000341/2015–010–00, "Manual Actuation of Reactor Core Isolation Cooling [RCIC] System Due to a Leak in the Standby Feedwater System"

On September 13, 2015, control room operators manually scrammed the reactor and tripped the main turbine generator due to a loss of cooling water supply to non-safety-related systems in the Turbine Building, including the reactor feedwater pumps. Standby feedwater pumps were then used to control RPV water level after the reactor scram. On September 14, 2015, operators manually actuated the RCIC system to control RPV water level after an unisolable through-wall leak developed on standby feedwater system drain piping.

On September 14, 2015, the licensee completed a notification call (Event Notice 51391, first update) to report the manual initiation of the RCIC system as required by 10 CFR 50.72(b)(3)(iv)(A). On November 5, 2015, the licensee submitted LER 05000341/2015–006–00, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water," which reported this event (along with the loss of TBCCW system event) in accordance with 10 CFR 50.73(a)(2)(iv)(A).

During the first quarter of 2016, the inspectors reviewed the 10 CFR 50.72 event notification and the LER and noted the licensee had not followed the guidance contained in NUREG 1022, "Event Report Guidelines 10 CFR 50.72 and 50.73," Revision 3. The inspectors found the licensee had reported multiple unrelated events in the same Event Notification and in the same LER, contrary to the NUREG 1022 guidance. Although the reporting guidance was not followed, the regulatory requirements to actually make the reports for the manual RCIC actuation were satisfied and therefore no violation was identified.

The inspectors evaluated operator actions during the event and documented this review in NRC Inspection Report 05000341/2015003. The inspectors reviewed the cause of the loss of standby feedwater system event and documented this review in NRC Inspection Report 05000341/2016001. No findings were identified during these reviews.

The licensee submitted LER 05000341/2015–010–00 on April 15, 2016, to separate the reporting of the manual RCIC actuation from the manual reactor scram event reported in LER 05000341/2015–006–00. The inspectors determined the information provided in LER 05000341/2015–010–00 did not raise any new issues or change the conclusion of the initial review.

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

LER 05000341/2015–010–00 is closed.

.4 (Closed) Licensee Event Report 05000341/2015–011–00, "Reactor Protection System and Containment Isolation Actuation Due to Reaching Reactor Water Level 3 Setpoint"

On September 14, 2015, a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves was actuated. A reactor operator who was maintaining RPV water level and reactor pressure following the plant scram the day before did not initiate RCIC system flow in time to maintain level above the Level 3 RPS actuation setpoint. Since all control rods were already fully inserted into the reactor, the RPS safety function was already fulfilled. Control room operators verified primary containment isolation valve isolations occurred as expected and promptly restored RPV level with manual operation of the RCIC system. The inspectors evaluated operator actions during the event and documented a finding of very low safety significance with an associated NCV of TS 5.4, "Procedures," in NRC Inspection Report 05000341/2016001.

On September 14, 2015, the licensee completed a notification call (Event Notice 51391, second update) to report the inadvertent Level 3 RPS actuation as required by 10 CFR 50.72(b)(3)(iv)(A). On November 5, 2015, the licensee submitted LER 05000341/2015–006–00, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water," which reported this event (along with the loss of TBCCW system event) in accordance with 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in automatic actuation of the RPS.

During the first quarter of 2016, the inspectors reviewed the 10 CFR 50.72 event notification and the LER and documented a Severity Level IV NCV of the NRC's reporting requirements in 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System," in NRC Inspection Report 05000341/2016001. The inspectors identified the licensee had failed to make a required 8-hour non-emergency notification call to the NRC Operations Center and failed to submit a required LER within 60 days after discovery of the valid actuation of the primary containment isolation logic for Groups 4, 13, and 15 primary containment isolation valves when RPV water level reached the Level 3 setpoint as required by 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A).

In addition to the above reporting discrepancies, the inspectors also noted the licensee had not followed the guidance contained in NUREG 1022, "Event Report Guidelines 10 CFR 50.72 and 50.73," Revision 3. The inspectors found the licensee had reported multiple unrelated events in the same Event Notification and in the same LER, contrary to the NUREG 1022 guidance. Although the reporting guidance was not followed, the regulatory requirements to actually make the reports for the inadvertent Level 3 RPS actuation were satisfied, and therefore, no additional violation was identified.

The licensee subsequently made an 8-hour notification call to the NRC Operations Center via the Emergency Notification System on February 27, 2016, (Event Notice 51391, third update) to address the 10 CFR 50.72 reporting discrepancies. The inspectors reviewed the revised event notification and determined the information provided did not raise any new issues or change the conclusion of the initial review. The licensee submitted LER 05000341/2015–011–00 on April 15, 2016, to separate the reporting of the valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves from the manual reactor scram event reported in LER 05000341/2015-006-00. The inspectors determined the information provided in LER 05000341/2015-011-00 did not raise any new issues or change the conclusion of the initial review.

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

LER 05000341/2015–011–00 is closed.

.5 (Closed) Licensee Event Report 05000341/2016–002–00, "Both Residual Heat Removal Low Pressure Coolant Injection Divisions Inoperable Due to Inoperable Injection Valve"

a. Inspection Scope

On January 22, 2016, both divisions of the RHR system were declared inoperable for the LPCI mode of operation due to a failure of the Division 1 LPCI outboard injection motor operated valve. While performing the Division 1 RHR pump and valve operability surveillance test, the injection valve closed properly but failed to re-open during its required stroke time test. With this valve closed and unable to automatically open, LPCI into the RPV from both divisions of RHR would be prevented if the LPCI loop select logic selected the Division 1 reactor recirculation loop for injection; therefore, this failure rendered both divisions of RHR inoperable for the LPCI function. The licensee entered TS 3.5.1, Condition K, which required immediate entry into TSO 3.0.3.

The licensee completed a notification call (Event Notice 51676) on January 23, 2016, to report the event in accordance with 10 CFR 50.72(b)(3)(v)(D) as an event or condition, that at the time of discovery, could have prevented the fulfillment of the safety function of structures or systems needed to mitigate the consequences of an accident.

The licensee submitted LER 05000341/2016–002–00 to report the event in accordance with 10 CFR 50.73(a)(2)(v)(D) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems needed to mitigate the consequences of an accident, and also in accordance with 10 CFR 50.73(a)(2)(vii)(D) as an event where a single cause or condition caused at least one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system designed to mitigate the consequences of an accident.

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

b. Findings

Failure to Implement Adequate Preventive Maintenance on Spare Terminals in Safety-Related Motor Control Centers

Introduction. A finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when the Division 1 LPCI outboard motor-operated injection valve failed to open during surveillance testing. The licensee failed to have preventive maintenance work instructions and procedures for safety-related MCC inspections appropriate to the circumstances, such that appropriate steps were incorporated to ensure spare terminal screws were maintained tight.

Discussion. On January 22, 2016, both divisions of the RHR system were declared inoperable for the LPCI mode of operation due to a failure of the Division 1 LPCI outboard injection motor-operated valve. While performing the Division 1 RHR pump and valve operability surveillance test, the outboard injection valve closed properly but failed to re-open during its required stroke time test.

The safety function of the LPCI mode of the RHR system is to inject water from the suppression pool into the RPV via injection lines connected to the reactor recirculation loop piping following a large break loss-of-coolant accident (LOCA). Since a large break LOCA could occur in either one of the two reactor recirculation loops, the LPCI loop select logic function is designed to select the undamaged reactor recirculation loop for LPCI injection. Under the conditions of the event, with the Division 1 outboard injection valve closed and unable to open, had a LOCA occurred in the opposite loop or elsewhere in the RPV-connected piping systems, automatic LPCI injection to the RPV would have been prevented.

The inspectors reviewed the licensee's root cause evaluation for the event and concurred with its conclusions. The direct cause was the valve's MCC control power closing contactor did not have full freedom of movement because a small screw (i.e., foreign material) was found lodged in it. During troubleshooting, the contactor was removed from the MCC and was manually cycled on a workbench. While manually cycling the contactor, a screw fell out of it. The screw had dropped into the contactor from a control relay on a spare terminal located above the contactor, blocking the close contactor's moveable arm mechanism. The root cause was technical requirements specific to check all fasteners for tightness were not adequately implemented into work instructions and procedures for MCC inspections during preventive maintenance. The work instructions and procedures lacked sufficient detail to ensure spare screw terminals remained tight. Over time, due to repeat cycling of breakers and relays in the MCC, the screw self-extracted, fell into the contactor, and prevented the contactor from functioning properly.

Analysis. The inspectors determined the licensee's failure to have preventive maintenance work instructions and procedures for safety-related MCC inspections appropriate to the circumstances, such that appropriate steps were incorporated to ensure spare terminal screws were maintained tight, was contrary to the requirements of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," and was therefore a licensee performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined this

performance deficiency was of more than minor safety significance, and thus a finding, because it was related to the Equipment Reliability attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure of the Division 1 LPCI outboard isolation valve to stroke open affected the LPCI loop select logic function to respond to a design basis event. The inspectors also reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no similar examples.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated June 19, 2012, the inspectors determined this finding affected the Mitigating Systems Cornerstone, specifically the Mitigating Systems contributor, and would require review using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” dated June 19, 2012. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," and answered “Yes” to question A.2, “Does the finding represent a loss of system and/or function?” Therefore, a detailed risk evaluation was required.

To evaluate the risk significance of the finding, the Region III Senior Reactor Analyst used the Fermi 2 Standardized Plant Analysis Risk Model Version 8.21 (modified previous to this evaluation to account for RPV injection after containment failure) and the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations Version 8.1.4 software. The increase in core damage frequency (CDF) was analyzed assuming the safety function of LPCI during design basis LOCAs was lost. The exposure time was assumed to be 1.8 hours since this was the duration when the ability of the LPCI loop select logic scheme to select the correct loop for injection was nonfunctional.

For the finding, the CDF was only affected during LOCA scenarios. The Senior Reactor Analyst performed a bounding assessment for the delta CDF (ΔCDF) by setting all four RHR/LPCI pumps fail-to-run values to "True" (i.e., failed) and solving the LOCA scenarios. The resultant ΔCDF was 8.3E–10/year.

Based on the detailed risk evaluation, the inspectors determined the finding was of very low safety significance (Green) because the ΔCDF was less than 1.0E–6/year.

The inspectors concluded that because the inadequate procedures were in use for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

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

Contrary to the above, prior to January 22, 2016, the licensee failed to have preventive maintenance work instructions and procedures for safety-related MCC inspections appropriate to the circumstances, such that steps were incorporated to ensure spare terminal screws were maintained tight. Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee’s corrective

action program, it is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy (**NCV 05000341/2016002–06, Failure to Implement Adequate Preventive Maintenance on Spare Terminals in Safety-Related Motor Control Centers**).

The licensee entered this violation into its CAP for evaluation and identification of appropriate corrective actions (CARD 16–20614). Corrective actions for the event included revising preventive maintenance work instructions and procedures to include instructions to check accessible spare terminal screws for tightness, personnel training, and inspection of all engineered safety feature MCC positions with relays susceptible to loose or missing screws and for susceptible contactor orientations.

LER 05000341/2016–002–00 is closed.

4OA5 Other Activities

.1 Review of Institute of Nuclear Power Operations Report

The inspectors reviewed the Institute of Nuclear Power Operations Special Focus Team Visit Report for the Fermi 2 Plant conducted in February 2016. During this review, the inspectors did not identify any new safety significant issues.

4OA6 Management Meetings

.1 Resident Inspectors' Exit Meeting

The inspectors presented the inspection results to Mr. K. Polson and other members of the licensee's staff on July 12, 2016. The licensee acknowledged the findings presented. Proprietary information was examined during this inspection, but is not specifically discussed in this report.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- The results of the radiological hazard assessment and exposure controls; occupational ALARA planning and controls; and radiation monitoring instrumentation inspection with Mr. B. Rumans and other members of the licensee's staff on May 6 and May 27, 2016. The licensee acknowledged the issues presented. The inspectors confirmed none of the potential report input discussed was considered proprietary.

- The results of the triennial heat sink inspection with Mr. K. Polson and other members of the licensee's staff on May 20, 2016. The licensee acknowledged the issues presented. The inspectors confirmed none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violations

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

Title 10 CFR 26.205, Paragraph (a) requires, in part, "Any individual who performs duties identified in Paragraphs 26.4(a)(1) through (a)(5) shall be subject to the requirements of this section."

Title 10 CFR 26.4, Paragraph (a)(4) identifies individuals who are "Performing maintenance or onsite directing of the maintenance of SSCs that a risk-informed evaluation process has shown to be significant to public health and safety."

Title 10 CFR 26.205, Paragraph (c) requires, in part, "Licensees shall schedule the work hours of individuals who are subject to this section consistent with the objective of preventing impairment from fatigue due to the duration, frequency, or sequencing of successive shifts."

Title 10 CFR 26.205, Paragraph (d)(2)(ii) requires, in part, "Licensees shall ensure that individuals have, at a minimum, a 34-hour break in any 9-day period."

Contrary to the above, from March 26, 2016, through April 3, 2016, two individuals who performed duties identified in §26.4(a)(4) were not scheduled work hours as required by §26.205(c). Specifically, the individuals were inappropriately excluded from the work hour limits specified in §26.205(d)(2)(ii). As a result, the individuals were not provided a 34-hour break in any 9-day period.

The violation was determined to be of very low safety significance based on a qualitative evaluation of the potential consequences of the performance issue since there were no human performance related incidents attributed to the two maintenance craftsmen while they were not in compliance with the work hour limits. The licensee entered this violation into its corrective action program as CARD 16–22779.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

L. Bennett, Superintendent, Nuclear Operations
M. Caragher, Director, Nuclear Production
W. Colonnello, Director, Nuclear Work Management
K. Dittman, Acting Manager, Plant Support Engineering
D. Domski, Engineer, Plant Systems Engineering
J. Haas, Supervisor, Licensing
D. Hemmele, Superintendent ILO/NLO, Nuclear Operations
L. Kantola, Manager, Outage and Work Management
E. Kokosky, Director, Organization Effectiveness
T. LaCroix, Superintendent, Instrumentation & Controls Maintenance
K. Locke, General Supervisor - Electrical, Plant Systems Engineering
R. Matuszak, Manager, Plant Systems Engineering
S. Maglio, Manager, Licensing
L. Peterson, Director, Nuclear Engineering
G. Piccard, Manager, Nuclear Operations
K. Polson, Site Vice President
W. Raymer, Manager, Maintenance
B. Rumans, General Supervisor, Radiation Protection Technical Services
P. Southwell, General Supervisor, Radiation Protection ALARA
S. Ward, Senior Engineer, Licensing

U.S. Nuclear Regulatory Commission

B. Dickson, Chief, Reactor Projects Branch 5

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000341/2016002–01	NCV	Failure to Control Combustible Materials (Section 1R05.1.b)
05000341/2016002–02	NCV	Inadequate Test Procedure Used for Measuring and Determining Average Silt Levels in the Service Water Reservoir (Section 1R07.1.b)
05000341/2016002–03	URI	Loss of Power Instrumentation TS 3.3.8.1 Applicability Following Bus 64C Potential Transformer Fuse Failures (Section 1R15.1.b)
05000341/2016002–04	NCV	Failure to Control the Work Hours of Covered Workers (Section 4OA2.2.b.(1))
05000341/2016002–05	FIN	Failure to Use Correct Material in a Feedwater Heater Level Control Valve Resulted in a Loss of Feedwater Heater Drains and a Reactor Recirculation System Runback (Section 4OA2.2.b.(2))
05000341/2016002–06	NCV	Failure to Implement Adequate Preventive Maintenance on Spare Terminals in Safety-Related Motor Control Centers (Section 4OA3.5)

Closed

05000341/2016002–01	NCV	Failure to Control Combustible Materials (Section 1R05.1.b)
05000341/2016002–02	NCV	Inadequate Test Procedure Used for Measuring and Determining Average Silt Levels in the Service Water Reservoir (Section 1R07.1.b)
05000341/2016002–04	NCV	Failure to Control the Work Hours of Covered Workers (Section 4OA2.2.b.(1))
05000341/2016002–05	FIN	Failure to Use Correct Material in a Feedwater Heater Level Control Valve Resulted in a Loss of Feedwater Heater Drains and a Reactor Recirculation System Runback (Section 4OA2.2.b.(2))
05000341/2015–009–00	LER	Condition Prohibited by Technical Specification Due to Missed Entry into LCO Condition (Section 4OA3.1)
05000341/2015–006–00	LER	Reactor Scram Due to Loss of Turbine Building Closed Cooling Water (Section 4OA3.2)
05000341/2015–006–01	LER	Reactor Scram Due to Loss of Turbine Building Closed Cooling Water, Supplement 1 (Section 4OA3.2)
05000341/2015–010–00	LER	Manual Actuation of Reactor Core Isolation Cooling System due to a Leak in the Standby Feedwater System (Section 4OA3.3)
05000341/2015–011–00	LER	Reactor Protection System and Containment Isolation Actuation due to Reaching Reactor Water Level 3 Setpoint (Section 4OA3.4)

05000341/2016–002–00	LER	Both Residual Heat Removal Low Pressure Coolant Injection Divisions Inoperable Due to Inoperable Injection Valve (Section 4OA3.5)
05000341/2016002–06	NCV	Failure to Implement Adequate Preventive Maintenance on Spare Terminals in Safety-Related Motor Control Centers (Section 4OA3.5)

Discussed

05000341/2016001–05	NCV	Failure to Satisfy 10 CFR 50.73 Reporting Requirements for a Condition Prohibited by the Plant's Technical Specifications (Section 4OA3.1)
05000341/2016001–04	NCV	Failure to Incorporate Operating Experience into Preventive Maintenance Activities Associated with the TBCCW System (Section 4OA3.2)
05000341/2016001–10	NCV	Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Primary Containment Isolation Valve Actuations (Sections 4OA3.2 and 4OA3.4)
05000341/2016001–09	NCV	Inadvertent Reactor Water Low Level Reactor Protection System Actuation Due to Operator Error (Section 4OA3.4)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather

- AQP–0001; Control of DTE Energy Owned Switchyard, Transformers, and Peaker Equipment at Fermi; Revision 4
- AQP–002; International Transmission Company – Fermi Interface 120 Kilovolt and 345 Kilovolt Switchyards; Revision 6
- CARD 15–20120; International Transmission Company Performing 120 Kilovolt Mat Operations Without Notifying the Main Control Room
- CARD 15–20159; Document Change Request for Operations Department Expectation ODE–12
- CARD 15–20233; Recommend Changing Conduct Manuals Regarding Potential Missiles Near the 120 and 345 Kilovolt Switchyards
- CARD 15–20234; Request Removal of Material Near 345 Kilovolt Mat
- CARD 15–21298; Evaluation Actions in Abnormal Operating Procedure to Manually Restore Power to Modular Power Unit 1 and/or 2 May Be Inadequate
- CARD 15–23630; Delay in Resolving N-1 Contingency
- CARD 16–20451; Received 11D50, CTG 11-1 Trouble Alarm
- CARD 16–23417; NRC House Keeping Finding
- CARD 16–24243; 2A Main Unit Transformer Cooler Group 6 Breaker Tripped and Will Not Re-Close
- Letter NRC–06–0013 from D. Cobb, DTE Energy to US Nuclear Regulatory Commission; Subject: Detroit Edison's 60-Day Response to Generic Letter 2006–02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power; April 3, 2006
- Letter NRC–07–003 from D. Cobb, DTE Energy to US Nuclear Regulatory Commission; Subject: Detroit Edison's Response to Request for Additional Information Regarding Resolution of Generic Letter 2006–02 (TAC Nos. MD0947 through MD1050), dated December 5, 2006; January 26, 2007
- NRC Bulletin 2012–01; Design Vulnerability in Electric Power System; July 27, 2012
- NRC Generic Letter 2006–02; Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power; February 1, 2006
- NRC Information Notice 90–42; Failure of Electrical Power Equipment Due to Solar Magnetic Disturbances; June 19, 1990
- NUC–001; Nuclear Plant Operating Agreement for the Fermi 2 Nuclear Power Plant; Revision 9
- ODE–12; Operations Department Expectation – Limiting Conditions for Operation; Revision 33
- Operations Conduct Manual MOP–04–100–01; Shiftly Communications with Midcontinent Independent System Operator/Systems Operation Center; Revision 0
- Procedure 20.000.01; Acts of Nature; Revision 49
- Procedure 20.300.GRID; Grid Disturbance; Revision 7
- Procedure 20.300.Offsite Bases; Loss of Offsite Power Bases; Revision 2
- Procedure 20.300.Offsite; Loss of Offsite Power; Revision 12
- Procedure 20.300.SBO Bases; Loss of Offsite and Onsite Power Bases; Revision 8
- Procedure 20.300.SBO; Loss of Offsite and Onsite Power; Revision 22

- Procedure 27.000.05; Operator Rounds; Revision 30
- Procedure 27.000.06; Hot Weather Operations; Revision 5
- Procedure 27.322; Mayfly Infestation Preparation Plan; Revision 13
- WO 42280989; Perform 27.000.04 Attachment 6 Removal of Freeze Protection Measures
- WO 42285764; Perform 23.324 Installation of CTG Aux Cooling Hoses
- WO 42287419; Perform Annual Inspection and Cleaning on CTG–11–1 Control House Air Conditioning Cooling Unit

1R04 Equipment Alignment

- CARD 15–27860; Non-Q Fuses Installed in 2PB2–15 Circuit 5
- CARD 15–29734; The Resolution of CARD 15–27860 Failed to Address Configuration Control Issue
- Drawing M–2015; Diagram Station and Control Air; Revision CJ
- Drawing M–2084; Diagram Residual Heat Removal (R.H.R.) Division 1; Revision BM
- Drawing M–5706–2; Residual Heat Removal (R.H.R.) Division 1 Functional Operating Sketch; Revision Z
- Drawing M–5734; Emergency Diesel Generator System Functional Operating Sketch; Revision BF
- Procedure 23.129; Station and Control Air System; Revision 106
- Procedure 23.205; Residual Heat Removal System; Revision 130
- Procedure 23.208; RHR Complex Service Water Systems; Revision 108
- Procedure 23.307; Emergency Diesel Generator System; Revision 121

1R05 Fire Protection

- CARD 15–20998; NRC Discovered Expired Fire Extinguishers
- CARD 15–24634; Evaluate Replacement of Fire Jockey Pump Pressure Control Valve
- CARD 15–25192; Penetration E-8880-43 Was Compromised During Cable Termination for EDP–37122
- CARD 15–25805; Flammable Storage Lockers Not Listed on Prints
- CARD 15–26313; Fire Header Jockey Pump Backpressure Control Valve Not Working Properly
- CARD 15–27838; Operation Department Performance Indicator for Fire Impairments Greater Than 13 Weeks Old Is at Threshold (Declining)
- CARD 15–27969; Inappropriate Carbon Dioxide Fire Extinguishers Are Being Supplied for Hot Work
- CARD 15–28079; Re-evaluate Continuous Fire Watch Rules
- CARD 16–20051; 8-Hour Discharge Test Not Performed as Required by Procedure
- CARD 16–23463; Combustible Material Left Unattended
- CARD 16–23616; Transient Combustible Permits Expired
- CARD 16–23646; Material Staged without Transient Combustible Permit
- CARD 16–24331; NRC Identified Concern
- CARD 16–24379; NRC Identified Concern
- CARD 16–24400; Non-compliances with Flammable Liquids Locker Controls, Repeat Audit Deficiencies
- CARD 16–24413; Emerging Trend with Transient Combustible Storage
- Design Calculation 4921; Volume 1; Revision H
- Fire Protection Pre Plan FP–AB–3–14a; Auxiliary Building, East Battery Room, Zone 14, El. 643’6”; Revision 3

- Fire Protection Pre Plan FP–AB–3–14e; Auxiliary Building, Division II Switchgear Room, Zone 14, El. 643'6"; Revision 3
- Fire Protection Pre Plan FP–RB–SB–4A; High Pressure Coolant Injection Pump and Turbine Room, Zone 4; Revision 4
- Operations Conduct Manual MOP–11; Fire Protection; Revision 16
- Operations Conduct Manual MOP–23; Plant Storage; Revision 2
- Procedure 20.000.22; Plant Fires; Revision 44
- Procedure 28.507.01; Fire Barrier Inspection; Revision 10
- Procedure 28.507.03; Fire Door Inspection – Balance of Plant; Revision 29
- Updated Final Safety Analysis Report; 9.5.1.2.3.3; Sprinkler Systems
- Updated Final Safety Analysis Report; Figure 9A–3; Fire Protection Evaluation Reactor and Auxiliary Buildings Basement Plan (Elevation 562.0)
- Updated Final Safety Analysis Report; Table 9.5; Fire Protection Equipment and Devices List

1R06 Flood Protection Measures

- CARD 12–23595; Include Low Voltage Power, I&C Cables Between MH16946 & 16947 into the Cable Condition Monitoring Program
- CARD 15–23128; NRC Question Related to Low Voltage Cable Submergence During License Renewal Interview (Potential Non-LR Part 50 Issue)
- CARD 15–25014; Water Found in Electrical Cable Vault 16946B
- CARD 15–27068; Exposed Cable in Manhole 16554
- CARD 15–29876; No Power to Sump for Manhole 16946A
- CARD 16–00204; Manhole 16947B Cable Vault Sump Pump Trips Circuit Breaker
- CARD 16–24332; MRC Cognitive Trend Identified – Cable Vault Sump Issues (Y4100)
- Engineering Support Conduct Manual MES-60; Electrical Cable Monitoring Program; Revision 6

1R07 Heat Sink Performance

- Alarm Response Procedure 7D3; Division 1 Reservoir Level Abnormal; Revision 17
- Alarm Response Procedure 7D3; Division 2 Reservoir Level Abnormal; Revision 18
- CARD 13–22945; 1B EECW Heat Exchanger Plate Pack Length Below Acceptance Criteria
- CARD 13–22987; 1B EECW Heat Exchanger Work Almost Performed Incorrectly
- CARD 14–20240; Through-Wall Leak on Division 2 RHRSW Piping and Repair
- CARD 16–22390; 2016 NRC UHS Inspection Self-Assessment Deficiency – No Acceptance Criteria for RHR Mechanical Draft Cooling Tower Sparger Plugging
- CARD 16–22474; NRC UHS Self-Assessment Deficiency - Incorrect EECW Heat Exchanger Test Differential Pressure Correction Factor
- CARD 16–24033; NRC UHS Inspection Identified Excessive Corrosion on RHRSW 1D Pump Weld
- CARD 16–24034; NRC UHS Inspection Identified Corrosion Buildup on Diesel Generator Service Water Pumps
- CARD 16–24077; NRC UHS Inspection Identified Finger Loose Nut on Division 2 EECW Heat Exchanger
- CARD 16–24078; NRC UHS Inspection Identified Corrosion Concern on P4500F403B
- CARD 16–24103; NRC UHS Inspection Identified Excessive Corrosion on RHRSW 1A Pump Weld
- CARD 16–24145; NRC UHS Inspection Identified EDG 12 Heat Exchanger Channel Cover Corrosion
- CARD 16–24183; 2016 NRC UHS Inspection – Inconsistent Work Documentation of RHR Reservoir Inspections
- CARD 16–24186; NRC UHS Inspection Questioned Extent Of Condition for CARD 16–24077

- CHS–AUX–12; Fermi 2- Chemistry Specification; Revision 32
- DC–0182; RHRSW Mechanical Draft Cooling Towers – Post LOCA Analysis of UHS; Revision G
- DC–0559; Volume of Reservoir – RHR Complex; Revision D
- DC–6286 Vol. I; EECW Heat Exchanger Performance Requirements with Plugging; Revision A
- DER 96–1306; RHRSW Division 2 Reservoir Silt Accumulation >1”
- Design Specification Number 3071–545; EECW Heat Exchangers P4400B001A, P4400B001B, P4400B001C, P4400B001D; Revision B
- Drawing 6C721N–2303; RHR Complex; Revision AC
- Drawing 6WM–E11–5302–1; Vent Piping – RHR Pumps Discharge Lines to Heat Exchangers; Revision B
- DSN 36904; Support Buried Pipe Inspection And Installation Of Guided Wave Permanently Installed Monitoring Sys; April 18, 2013
- Engineering Support Conduct Manual MES–52; GL 89–13 Safety-Related Service Water Monitoring Program; Revision 6
- Engineering Support Conduct Manual MES–71, Buried Pipe Inspection Program; Revision 5
- M–N–2196; Supports Reservoir Crosstie; Revision D
- PEP 03; MOV Program Manual; Revision 07
- Procedure 24.000.02; Shiftly, Daily, and Weekly Required Surveillances; Revision 144
- Procedure 24.000.02; Shiftly/Daily – Mode 1,2,3 – Control Room; May 8, 2016
- Procedure 24.204.02; RHR Valve Lineup and System Filled Verification; Revision 31
- Procedure 24.205.11; Ultimate Heat Sink Cross-Connect Valve Operability Test; Revision 8
- Procedure 24.208.03; Division 2 EESW and EECW Makeup Pump And Valve Operability Test completed April 8, 2015; Revision 73
- SIR–07–183–NPS; Alternate Plugging Criteria for the RHR Heat Exchanger Tubes; August 17, 2007
- TSR–34207; Increase in Engineered Safety Features Fan Cooler Heat Loads; Revision 0
- TSR–32598; Correct NRC SSDI Identified Discrepancies; March 15, 2004
- VMB9–37; MX25–BFD Plate Heat Exchanger Instruction Manual; Revision A
- WO 31785901; Opportunistic Inspection of 12” Main Fire Protection Header at Valves P8000F021, P8000F028, P8000F029
- WO 32772919; Perform MOV Thrust (Viper) Testing Per GL 96–05 Program
- WO 33869836; Clean and inspect P4400B001B Division 2 EECW Heat Exchanger
- WO 34640181; Perform Division 1 RHR Reservoir Zebra Mussel And Ball Valve Inspection Dive
- WO 34640293; Perform Division 2 RHR Reservoir Zebra Mussel And Ball Valve Inspection Dive
- WO 34640293; Perform Division 2 RHR Reservoir Zebra Mussel and Ball Valve Inspection Dive
- WO 36068018; Perform 39.NDE.008 for Inner Diameter Pitting Corrosion on RHR Complex Piping (Division 1 South Pump Room)
- WO 36070172; Perform 39.NDE.008 for Inner Diameter Pitting Corrosion on RHR Complex Piping-Division 2 North Pump Room
- WO 37575073; Perform 24.208.03 Measure Differential Pressure Across EECW Heat Exchanger with Division 2 EESW Pump And Valve Operability Test (Section 5.1)
- WO 37904983; Repair Through-Wall Leak From Division 2 RHRSW Piping By Replacing Elbow
- WO 37966519; Perform 24.208.03 Measure Differential Pressure Across EECW Heat Exchanger with Division 2 EESW Pump And Valve Operability Test (Section 5.1)
- WO 38577629; Perform Division 1 RHR Reservoir Zebra Mussel and Ball Valve Inspection Dive

- WO 38577646; Perform Division 1 RHR Reservoir Zebra Mussel and Ball Valve Inspection Dive
- WO 42417436; Opportunistic Inspection of 12” Main Fire Protection Header at Valves P8000F035, 36, and 37
- WO 44737052; Perform Division 2 UHS Silt Removal
- WO B861060100; Eddy Current Examination of Heat Exchanger

1R11 Licensed Operator Requalification Program

- Engineering Support Conduct Manual MES-70; Fuel Reliability Program; Revision 2
- Infrequently Performed Test or Evolution Review and Approval for Flux Suppression Testing 16-01; Revision 0
- Procedure 20.000.07; Fuel Cladding Failure; Revision 24
- Procedure 22.000.03; Power Operation 25% to 100% to 25%, Revision 97
- Procedure 23.623; Reactor Manual Control System; Revision 66
- Procedure 57.000.17; Determination of Defective Fuel Bundle Locations – Power Suppression Test Method; Revision 17

1R12 Maintenance Effectiveness

- Apparent Cause Evaluation CARD 16–22332; Turbine High Pressure Stop Valve 1 Closed, Isolating a Turbine Steam Lead; Revision 0
- CARD 15–27759; P4300 TBCCW System has Exceeded its Maintenance Rule Performance Criteria
- CARD 15–29239; EDG 12 Diesel Generator Service Water Pump Trips/Loses Power During 24.307.02
- CARD 15–29280; Breaker for 72C–2D Tripped When Closed During 24.307.02
- CARD 16–22332; #1 High Pressure Stop Valve Closed to 25 Percent While at 100 Percent Power
- CARD 16–22376; Request Investigation Into North Heater Drain Pump Discharge Pressure and Flow Oscillations During Reactor Power Reduction
- CARD 16–23650; Reevaluate TBCCW Maintenance Rule Classification
- CARD 16–24321; P4300 TBCCW System was Evaluated to be a(1)
- Equipment Apparent Cause Evaluation CARD 16–22332; #1 High Pressure Stop Valve Closed to 25 Percent While at 100 Percent Power; Revision 0
- Fermi 2 Operating License and Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report
- Maintenance Rule Expert Panel Meeting #280 Summary; December 18, 2015
- Maintenance Rule Expert Panel Meeting #286 Package; May 23, 2016
- NUMARC 93–01; Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants; Revision 4A
- Plant Health Committee Agenda; April 26, 2016
- WO 45099749; Test Continuity of Servo Valve Circuit, Identify Degraded Connections and Rework

1R13 Maintenance Risk Assessments and Emergent Work Control

- Operations Conduct Manual MOP–05; Control of Equipment; Revision 46
- Operations Conduct Manual MOP–05–100; Protected Equipment; Revision 0
- ODE–16; Operations Department Expectation – Risk Assessment and Operation of Equipment Out-of-Service; Revision 2

- ODE–20; Operations Department Expectation - Protected Equipment; Revision 19
- Risk Management Plan; General Service Water Diving Activities Downstream of Travelling Screens; Revision 1
- Risk Management Plan; Perform 44.030.250 Reactor Water Level (L2) Anticipated Transient Without Scram – Recirculation Pump Trip Division 2 Functional Test; Revision 0
- Risk Management Plan; T4100C013 – Reactor Building Heating, Ventilation, and Air Conditioning AC Motor Generator Set Center Vent Fan; Revision 0

1R15 Operability Determinations and Functionality Assessments

- American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) Standard 338–1977; IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Safety Systems; 1977
- Apparent Cause Evaluation 16–23392;
- CARD 15–24975; Missing Insulation on EDG 12 Exhaust Expansion Joint R3001D058
- CARD 16–20107; Snubber T23–I2837–43–G45 Positioned at End of Stroke
- CARD 16–20461; Potential Non-Q Part Installed in a Q Application
- CARD 16–20531; Penetration Seal Found Damaged
- CARD 16–20535; Legacy Deficiencies with Pipe Support Design Calculation
- CARD 16–21244; RCIC Outboard Pump Bearing Oil Was Very Dark in Color
- CARD 16–21934; EDG 13 Lube Oil Heater Maintaining Temperature High Out of Specification
- CARD 16–23134; Division 1 Battery Declared Inoperable Due to Installed Individual Cell Charger While in Equalize Charge
- CARD 16–23392; System Transformer 64 / Bus 64A Loss of Voltage Indication with Trouble Alarm
- CARD 16–23773; Found Incorrect Fuses Installed in 64V Primary Potential Transformer
- CARD 16–23784; 64B Potential Transformer Primary Fuses Not in Conformance with EJ Specification
- CARD 16–23788; Evaluate 4.16 Kilovolt and 480 Volt Potential Transformer Fuse Sizing
- CARD 16–23804; Division 2 Impacts for the Possibility of 2E Fuses
- CARD 16–25194; Additional Evaluation Required on the Operability Determination for CARD 16–23392
- Drawing 6I721–2578–04; Relaying and Metering Diagram 4160V SS Bus #64A & 68K; Revision M
- Drawing 6I721–2578–07; Relaying and Metering Diagram 4160V Bus 64C; Revision O
- Fermi 2 Operating License and Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report
- Loss of Power (LOP) Instrumentation – Licensing Position; Revision 00; May 20, 2016
- NUREG 1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” Revision 3
- Operational Decision Making Issue 16-005; Station Transformer 64 / Bus 64A & 64C Trouble; Revision A
- Procedure 42.302.08; Calibration and Functional Test of Division 1 4160 Volt Bus 64C Undervoltage Relays; Revision 36
- Regulatory Guide 1.118; Periodic Testing of Electric Power and Protection Systems; Revision 3
- Technical Evaluation TE–R32–16–011; Evaluate Use of a Single Cell Charger on Division 1 Battery 2PA; Revision A

1R18 Plant Modifications

- Apparent Cause Evaluation CARD 15–28111; Bus 64B Trips After Energizing Via B9 and Inserting the First Set of Load Shed Fuses and Link; Revision 0
- CARD 15–28111; Bus 64B Trips After Energizing Via B9 and Inserting the First Set of Load Shed Fuses and Link
- CARD 15–28196; Relay Settings Incorrect on Installed New Loss of Voltage Relays
- CARD 15–28217; Approved Modification Unable to Be Implemented as Planned

1R19 Post-Maintenance Testing

- Calculation R–8793; November 1971
- CARD 15–21299; NRC Identified – WO 42514834 Post Maintenance Test Lacks Acceptance Criteria
- CARD 15–21357; No Acceptance Criteria for Post Maintenance Test Current Checks
- CARD 15–22739; Investigate Possible Post Maintenance Test Failure
- CARD 15–26538; Valve Failed Local Leak Rate Testing Final Test
- CARD 15–26658; Lubrication Concerns on T4803F602
- CARD 15–27496; E1100F050B Actuator Linkage Cover Difficult to Reinstall
- CARD 15–27568; Failed Post Maintenance Test on E1100F050B
- CARD 15–27745; Failed Post Maintenance Test – P4400F603B Indicates Dual When Full Closed
- CARD 15–27902; Magnesium Rotor Motor Degraded on E2150F005A
- CARD 15–28126; Check Valve Fails Local Leak Rate Test – Post Maintenance Test
- CARD 15–28397; NRC Identified – Hydrostatic Test Had to Be Stopped to Replace a Test Gauge
- CARD 15–28452; Mechanical Joint Leakage Identified on the East TBCCW Heat Exchanger During the Tube Side Pressure Test
- CARD 15–28754; West TBCCW Tube Side Pressure Test Satisfactory, However Leakage Was Noted at the Channel to Shell Flanged Joints
- CARD 15–28912; Repetitive Issues with the Actuator Cover Plate on E1100F050B
- CARD 15–28917; B2103F028A and B2103F028B Stroke Times Outside of Inservice Testing Acceptance Criteria
- CARD 15–28948; Division 2 LPCI Testable Check Valve Remained in Open Position Following Full Stroke Test
- CARD 15–29629; RF 17 Delays Attributable to Emergent Issue with E1100F050B
- CARD 15–29924; No Clearance Between E1100F050B Air Actuator Pinion Gear Outer Spacer and Cover Plate
- CARD 16–23134; Division 1 Battery Declared Inoperable due to Installed Individual Cell Charger While in Equalize Charge
- CARD 16–23853; NRC Question Inter-cell Connection for Cell 32 to Cell 33 Resistance Did Not Meet Acceptance Criteria
- CARD 16–23861; Division 1 130/260 Volt DC Battery 2PA, Cells 30 and 104 Intercell Connection Resistance Values Greater Than 38 Micro-Ohms
- CARD 16–24482; Broken Nylon Threaded Rod Fastener
- CARD 16–24767; NRC Identified: FMR S-1440 Not Posted to Cumulative Change Calculation for 4160V Switchgear
- CARD 16–25243; EECWU Makeup Pump Suction Pipe Blockage
- Design Change Notice S–1440; Revision B
- Drawing I–2201–36; Schematic Diagram RHR Service Water Pump DE1151C001D; Revision T

- Fermi 2 Operating License and Technical Specifications
- Operational Decision Making Issue 16-004; Division 1 Battery; Revision A
- Procedure 24.208.03; Division 2 EESW and EECW Makeup Pump and Valve Operability Test; Revision 75
- Procedure 24.307.15; Emergency Diesel Generator 12 – Start and Load Test; Revision 58
- Procedure 27.129.01; Division 1 Control Air Compressor Auto Start Test; Revision 19
- Procedure 35.309.003; Division 1/Division 2 130/260 VDC Electrical System – General Maintenance; Revision 31A
- Procedure 42.309.02; Division 1/2 Quarterly 130/260 VDC Battery Check; Revision 39
- SOE 15–03; In-Service Testing Program Baseline Pump Test for Division 2 EECW Make-up Pump (P4400C002B); Revision 0
- WO 37494067; Modify EECW Inlet/Outlet Piping and Replace Tube Bundle on P5002B004
- WO 42282028; Perform 24.307.15 Section 5.2; EDG 12 Start and Load Test-Fast Start
- WO 43431112; Replace Division 2 EECW Makeup Pump
- WO 43815058; Replace Division 2 Intermediate Range Monitor Bypass Switch – C5100M004
- WO 44745836; High Vibration West Stator Water Cooling Pump/Motor
- WO 45041173; Replace 2PA Cell #32 Due to Low Intercell Voltage
- WO 45276156; Install Dynamic Absorber West Stator Water Cooling Pump/Motor per ERE 34590

1R20 Outage Activities

- CARD 16–23699; Reactor Recirculation Pump Suction Temperature Reading High at 1170 Degrees F
- CARD 16–23707; Scheduled Time Allotted to Perform Bus Shutdown for 64A Was Not Reflective of the Actual Time Necessary
- CARD 16–23773; Found Incorrect Fuses Installed in 64V Primary Potential Transformer
- CARD 16–23784; 64B Potential Transformer Primary Fuses Not in Conformance with EJ Specification
- CARD 16–23788; Evaluate 4.16 Kilovolt and 480 Volt Potential Transformer Secondary Fuse Sizing
- CARD 16–23799; Foreign Material Discovered During Bus Walkdown in 64B-B7 Bus Potential Transformer Cabinet
- CARD 16–23804; Division 2 Impacts for the Possibility of 2E Fuses
- CARD 16–23819; During Exercising Control Rods for Start Up, With Performing Out Notch, the Rod Movement Control Switch Is Making an Abnormal Noise and Sometimes Fails to Out Notch
- CARD 16–23836; Low Pressure Stop Valve #4 Not Full Closed
- CARD 16–23940; East Off Gas Chiller Tripped During System Startup
- CARD 16–23942; West Off Gas Chiller Tripped During System Startup
- CARD 16–23943; Lost Indication on Division 2 Core Spray Minimum Flow Valve
- CARD 16–23961; South Reactor Feedwater Pump Turbine Trip Will Not Reset
- Procedure 22.000.02; Plant Startup to 25 Percent Power; Revision 94
- Procedure 22.000.03; Power Operation 25 Percent to 100 Percent; Revision 98
- Procedure 22.000.05; Pressure/Temperature Monitoring During Heatup and Cooldown; Revision 47
- Procedure 23.205; Residual Heat Removal; Revision 130

1R22 Surveillance Testing

- American Society of Mechanical Engineers Code for Operation and Maintenance of Nuclear Plants, Subsection ISTB, Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants; 2004 Edition
- American Society of Mechanical Engineers Code for Operation and Maintenance of Nuclear Plants, Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants; 2004 Edition
- CARD 15–102030; RF17 Snubber As-Found Visual Examination Discrepancies
- CARD 15–26143; Pump E1151C001D Exceeded Inservice Testing Alert Criteria
- CARD 15–27672; Snubber N30-3259-G22 Failed Functional Test
- CARD 15–27762; Concerns with Seat Conditions E4150F006 During Motor Operated Valve Testing
- CARD 15–28295; Abnormal Indications When EDG 12 Was Synchronized to the Grid Across C6 Breaker
- CARD 15–28512; Tracking CARD to Evaluate Check Valve Condition Monitoring Program
- CARD 15–29547; E1151C001B (RHRSW Pump B) Is in Vibration Alert Range for Inservice Testing Criteria
- CARD 15–29929; RHRSW D Should Be on Increased Frequency in Accordance with OM Code
- CARD 16–22968; A Standby Liquid Control System Pump will not Develop Required Flow
- CARD 16–22969; Standby Liquid Control System Vibration Meter Sensitivity not set correctly for Surveillance Testing
- Drawing M–5707; Core Spray System Functional Operating Sketch; Revision AE
- Fermi 2 Operating License and Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report
- Inservice Testing Program Evaluation 15–024; Snubber N30-3259-G22 Failed Functional Testing; Revision 1
- Inservice Testing Program Evaluation 16–012; Remove E1151C001B from Increased Frequency; Revision 0
- Procedure 22.000.05; Pressure/Temperature Monitoring During Heatup and Cooldown; Revision 47
- Procedure 23.307; Enclosure D; EDG Generator Curve; Revision 122
- Procedure 24.109.02; Turbine Bypass Valve Operability Test; Revision 35
- Procedure 24.139.02; Standby Liquid Control System and Check Valve Operability Test; Revision 47
- Procedure 24.203.03; Division 2 Core Spray System Pump and Valve Operability and Automatic Actuation; Revision 54
- Procedure 24.307.14; Emergency Diesel Generator 11 – Start and Load Test; Revision 57
- Procedure 24.402.01; Drywell and Suppression Chamber Vacuum Breaker Operability Test; Revision 36
- Procedure 24.605; APRM [Average Power Range Monitor] Calibration Above 25 Percent Power; Revision 1
- Procedure 24.608; Rod Worth Minimizer Functional Test; Revision 31
- Procedure 42.610.04; Division 2 Normal Supply Reactor Protection System (RPS) Electrical Protection Assembly Calibration/Functional Test; Revision 29
- Procedure 54.000.07; Core Performance Parameter Check; Revision 56
- Procedure 74.000.19; Chemistry Routine Surveillances; Revision 25
- Technical Evaluation TE–N30–15–068; Snubber N30–3259–G22 Functional Failure Evaluation; Revision 0

- Temporary Change Notice; Procedure 24.139.02; Standby Liquid Control System and Check Valve Operability Test; Revision 47

2RS1 Radiological Hazard Assessment and Exposure Controls

- CARD 15–27829; Locked High Radiation Area Stay Time Tracking – Reactor Building 5 Diving Observation
- CARD 15–29091; Degrading Surface Coating in Reactor Cavity Contributing to Cavity Decontamination Challenges
- CARD 16–20932; Refuel Floor Workers Near Miss Associated with High Radiation Trash Transfer
- CARD 16–23006; >= 50% Increase in Offgas Radiation Monitoring
- CARD 16–23025; Increased Off Gas Dose Rates Results in Increased Dose Rates in the Plant
- Evaluation of Setpoint, Check Source, and Self-Shielding for SAM11; March 7, 2002
- Nuclear Generation Memorandum; Scaling Factor Report; December 30, 2015
- Nuclear Generation Memorandum; The Impact of the Current Fermi 2 Radionuclide Mix on Radiation Surveys; April 11, 2014
- Nuclear Generation Memorandum; Updated Scaling Factor Sheets Based on Revision to MRP24; April 13, 2016
- Procedure 67.000.100; Radiological Posting and Markings; Revision 25
- Procedure 67.000.101; Performing Surveys and Monitoring Work; Rev. 42
- Radiation Protection Conduct Manual MRP–06; Accessing High Radiation, Locked High Radiation, and Very High Radiation Areas at Fermi 2; Revision 14
- Radiation Protection Conduct Manual MRP–31; Control of Keys for High Radiation, Locked High Radiation, and Very High Radiation Areas at Fermi 2; Revision 02
- RWP 161050; Reactor Water Clean Up Pump Seal Repair/Replacement; Revision 02
- RWP 161056; Tri-Nuke Filter Removal and Process RB–5 Demineralizer; Revision 00
- WO 38555653; Perform 64.713.050 Source Leak Testing
- WO 38557193; Perform 65.000.519 Licensed Sources Accountability
- Work Control Conduct Manual MWC–15; Elevated Risk Management; Revision 15

2RS2 Occupational ALARA Planning and Controls

- CARD 16–20723; Programmatic Source Term Reduction
- Procedure 63.000.100; Radiation Work Permits; Revision 42
- Procedure 63.000.200; ALARA Reviews; Revision 38
- Radiation Protection Conduct Manual MRP–02; Administrative Controls; Revision 20
- Reactor Water Clean Up Seal Replacement Special Station ALARA Committee Presentation; May 4, 2016
- RF17 Post Outage ALARA Report
- RWP 15–2018; E11 & E21 Systems Maintenance & Inspection; Revision 2
- RWP 15–2032; Reactor Building Emergent Issues & RHRSW Pipe Replacement; Revision 2
- RWP 15–3016; MSIVs – Inspect, Transfer and Rework in the Drywell and Reactor Building Steam Tunnel; Revision 4
- RWP 15–4002; RB5 – Reactor Core Alterations, Bridge Maintenance, Local Power Range Monitor Replacement and Support Activities; Revision 2

2RS5 Radiation Monitoring Instrumentation

- 5XLB Calibration Worksheet; Various Dates
- AMS–4 Calibration Form; Various Dates
- ARGOS–5AB Calibration Form; Various Dates

- Calibration Certificate DTE Energy Fermi 2 DCM2000/SOR/R; Various Dates
- Calibration of the ABACOS–2000 Halgeson Standup Counting System; December 4, 2014
- Calibration of the ABACOS–2000 Halgeson Standup Counting System; December 9, 2015
- CARD 15–21384; Division 1 Containment High Range Radiation Monitor Does Not Meet Acceptance Criteria
- CARD 15–27070; Division 2 Two Minute Holdup Radiation Monitor Fails Calibration
- F&J L–12P Air Sampler Calibration Form; Various Dates
- Gamma Calibrator Dose Rate Verification Form; June 23, 2015
- GEM5 Calibration Data Form; Various Dates
- IPM9D Calibration Form; Various Dates
- Ludlum 177 Calibration Form; Various Dates
- PCM–1B Calibration Form; Various Dates
- Procedure 65.000.156; Radiological Instrumentation Source Checking; Revision 0
- SAM11 Calibration Form; Various Dates
- Telepole Calibration Form; Various Dates
- WI–RPO–027; Work Instruction for Area and Installed Radiation Monitors for Pre Job Planning; Revision 4
- WO 37223327; Perform 64.120.041 Containment Area High Range Radiation Monitor Division 2 Electrical Calibration
- WO 37545765; Perform 64.120.041 Containment Area High Range Radiation Monitor Division 2 Radiation Calibration
- WO 38481708; Perform 64.080.601 Source Checks For Liquid and Gaseous Radiation Monitors

4OA1 Performance Indicator Verification

- NEI 99 02; Regulatory Assessment Performance Indicator Guideline; Revision 7
- Performance Indicator BI02; RCS Identified Leak Rate; April 30, 2016
- Performance Indicator MS06; MSPI Emergency AC Power System; April 30, 2016
- Performance Indicator MS07; MSPI High Pressure Injection System; April 30, 2016

4OA2 Problem Identification and Resolution

- Apparent Cause Evaluation CARD 16–22049; Lessons Learned for Troubleshooting Efforts; Revision 1
- Calculation No. DC–6451; Seismic Qualification of Drywell Cooling Unit T4700B011; Revision A
- Calculation No. DC–6624; Drywell Cooler #2 Seismic Evaluation; Revision A
- Calculation No. DC–6637; Drywell Cooler #1 Seismic Evaluation; Revision A
- CARD 15–23513; Part 21 Event #51078 Issued Against Bentley System Inc. STAAD Pro Software Requires Evaluation
- CARD 16–21863; N22FF409B 5S EDL Would Not Close As Expected
- CARD 16–21883; Unplanned Power Change from 90 – 50 Percent Reactor Power
- CARD 16–21945; N22F409B – Heater Drains Feedwater Heater 5S Emergency Drain to Condenser Level Control Valve Air Operator Failure Review
- CARD 16–22049; Lessons Learned for Troubleshooting Efforts
- CARD 16–22525; Nitrile Piston Seal Installed in N22F409A
- CARD 16–22779; Fatigue Management Work Hour Violation: MGA 17 Section 4.2.1 (34 Hour Break in 9 Day Period)
- CARD 16–22814; Possible MGA 17 Working Hour Limit Violation
- CARD 16–22939; Station Fatigue Management Knowledge Gap

- CARD 16–23185; 5 South and 5 North Feed Water Heater Level Instabilities
- CARD 16–23735; NRC Identified – Calculation Discrepancy Identified During NRC Audit of STAAD.Pro Part 21 Recovery Actions
- CARD 16–23996; Potential NRC Violation of 10 CFR Part 26 Work Hour Rule Requirements
- Federal Register, Volume 73, Number 62, Rules and Regulations; Nuclear Regulatory Commission, 10 CFR Part 26, RIN 3150–AF12, Fitness for Duty Programs, Final Rule; March 31, 2008
- Root Cause Evaluation CARD 16–21883; Unplanned Power Change from 90 – 50 Percent Reactor Power; Revision 0

4OA3 Follow-Up of Events and Notices of Enforcement Discretion

- Abnormal Operating Procedure AOP 20.128.01; Loss of Turbine Building Closed Cooling Water System; Revisions 15 and 16
- CARD 06–22311; Blown Control Power Fuse on E1150–F017B, 72CF–4B While Performing 24.204.03 – FME Issue
- CARD 15–25243; Missed TS Entry – Division 2 EECW-UHS Safety System Outage July 2015
- CARD 15–26469; FO 15–02: Leak at Weld at Weldolet for Drain Valve N2103F326
- CARD 15–26472; Total Loss of TBCCW Following Heat Exchanger Swap
- CARD 15–26521; Level 3 Actuation While Maintaining RPV Level/Pressure With RCIC and Safety Relief Valves
- CARD 15–26653; Forced Outage 15-02 RCIC Assessment
- CARD 16–20564; NRC Senior Resident Issues/Questions Associated With LER 2015–006
- CARD 16–20566; NRC Question on Reportability of CARD 15–25243
- CARD 16–20614; E1150F017A Failed to Stroke Open During 24.204.01
- Control Room Logs; September 13 through 15, 2015
- Emergency Operating Procedure 29.100.01 SH 1, “RPV Control,” Revision 14
- Event Notification 51391; original and 3 updates
- Event Notification 51676
- Fermi 2 Operating License and Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report
- LER 05000341/2015–006–00; Reactor Scram Due to Loss of Turbine Building Closed Cooling Water
- LER 05000341/2015–006–01; Reactor Scram Due to Loss of Turbine Building Closed Cooling Water; Supplement 1
- LER 05000341/2015–009–00; Condition Prohibited by Technical Specification Due to Missed Entry into LCO Condition
- LER 05000341/2015–010–00; Manual Actuation of Reactor Core Isolation Cooling System due to a Leak in the Standby Feedwater System
- LER 05000341/2016–002–00; Both Residual Heat Removal Low Pressure Coolant Injection Divisions Inoperable Due to Inoperable Injection Valve
- LER 05000341/2016–011–00; Reactor Protection System and Containment Isolation Actuation due to Reaching Reactor Water Level 3 Setpoint
- NUREG 1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” Revision 3
- Root Cause Evaluation CARD 15–26472; Forced Outage 15–02; Total Loss of TBCCW Following Heat Exchanger Swap; Revision 0
- Root Cause Evaluation CARD 16–20641; E1150F017A Failed to Stroke Open During 24.204.01; Revision 0

LIST OF ACRONYMS USED

°F	Degrees Fahrenheit
ΔCDF	Delta Core Damage Frequency
10 CFR	Title 10 of the *Code of Federal Regulations*
AC	Alternating Current
ADAMS	Agencywide Document Access and Management System
ALARA	As-Low-As-Reasonably-Achievable
CARD	Condition Assessment Resolution Document
CDF	Core Damage Frequency
CTG	Combustion Turbine Generator
DC	Direct Current
EDG	Emergency Diesel Generator
EDL	Emergency Drain Line
EDP	Engineering Design Package
EECW	Emergency Equipment Cooling Water
EESW	Emergency Equipment Service Water
GL	Generic Letter
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
LOP	Loss of Power
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
MGA	General Administrative Conduct Manual
MSIV	Main Steam Isolation Valve
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SDP	Significance Determination Process
SSC	Structure, System, and/or Component
TBCCW	Turbine Building Closed Cooling Water
TCP	Transient Combustible Permit
TS	Technical Specification
TSO	Transmission System Operator
UHS	Ultimate Heat Sink
URI	Unresolved Item
WO	Work Order

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records System (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/

Billy Dickson, Chief
Branch 5
Division of Reactor Projects

Docket No. 50–341
License No. NPF–43

Enclosure: IR 05000341/2016002

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RidsNrrDirsIrib Resource
Cynthia Pederson
Darrell Roberts
Richard Skokowski
Allan Barker
Carole Ariano
Linda Linn
DRPIII
DRSIII
ROPreports.Resource@nrc.gov

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