UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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January 30, 2017

Mr. Paul Fessler, Senior VP
and 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 05000341/2016004 AND REPORT 05000341/2016501

Dear Mr. Fessler:

On December 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Fermi Power Plant, Unit 2 (Fermi 2). On January 5, 2017, the NRC inspectors discussed the results of this inspection with Mr. M. Caragher and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report. The NRC also completed its annual inspection of the Emergency Preparedness Program. This inspection began on January 1, 2016, and issuance of this letter closes Inspection Report Number 2016501.

The NRC inspectors documented four findings of very low safety significance (Green) in this report. Each of the findings involved violations of NRC requirements. In addition, the inspectors identified one performance deficiency that was associated with a Severity Level IV violation of NRC requirements evaluated through the traditional enforcement process. Two licensee-identified violations were also documented in this report. One of these licensee-identified violations was determined to be of very low safety significance and the other one was evaluated through the traditional enforcement process as Severity Level IV. The NRC is treating each of these violations as Non-Cited Violation consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of the 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 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/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

Docket No. 50–341
License No. NPF–43

Enclosure:
IR 05000341/2016004; 05000341/2016501

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–341
License No:	NPF–43
Report No:	05000341/2016004; 05000341/2016501
Licensee:	DTE Energy Company
Facility:	Fermi Power Plant, Unit 2
Location:	Newport, MI
Dates:	October 1 through December 31, 2016
Inspectors:	B. Kemker, Senior Resident Inspector K. Pusateri, Acting Resident Inspector M. Bielby, Senior Operations Engineer T. Briley, Resident Inspector, Davis-Besse I. Hafeez, Reactor Engineer G. Hansen, Senior Emergency Preparedness Inspector V. Myers, Senior Health Physicist
Approved by:	K. Riemer, Chief Branch 2 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report 05000341/2016004; 10/01/2016–12/31/2016; Fermi Power Plant, Unit 2; Maintenance Effectiveness, Operability Determinations and Functionality Assessments, Surveillance Testing, Radiological Hazard Assessment and Exposure Controls.

This report covers a 3-month period of inspection by the resident inspectors and announced baseline inspections by regional inspectors. Four Green findings, all of which had an associated Non-Cited Violation (NCV) of the U.S. Nuclear Regulatory Commission (NRC) regulations, were identified. In addition, one Severity Level IV NCV of NRC regulations was 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 October 8, 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 November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated July 2016.

NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

Green. A finding of very low safety significance with an associated NCV of Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when plant operators discovered an oil leak coming from a flexible coupling upstream of the emergency diesel generator (EDG) 12 lube oil heater during surveillance testing. The licensee failed to have work instructions for maintenance on safety-related EDGs appropriate to the circumstances to ensure flexible coupling fasteners were correctly torqued as specified by the manufacturer to prevent leakage. The licensee entered this violation into its corrective action program (CAP) as Condition Assessment Resolution Document (CARD) 16-25666 and replaced the leaking flexible coupling.

This performance deficiency was of more than minor safety significance because it was related to the equipment performance 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 EDG 12 flexible coupling oil leak resulted in unplanned inoperability and unavailability of this onsite emergency power source. The finding was determined to be of very low safety significance because it did not represent an actual loss of function of a single train for greater than its Technical Specification (TS) allowed outage time nor did it represent a loss of function of a non-TS train designated as high safety significant in accordance with the licensee's Maintenance Rule Program. The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified. (Section 1R12.b.1)

Green. The inspectors identified a finding of very low safety significance with an associated NCV of TS 3.3.8.1, "Loss of Power (LOP) Instrumentation," and TS 3.8.1, AC [Alternating Current] Sources – Operating." The licensee failed to satisfy applicable action requirements for inoperable loss of voltage and degraded voltage instrument

channels, inoperable EDGs, and an inoperable offsite power circuit when power was lost to the station transformer 64 auto voltage tap changer and one-half of the instrument channels for engineered safety features bus 64C due to failure of line side potential transformer fuses on April 24, 2016. The licensee entered this performance deficiency into its CAP as CARDs 16-23392, 16-25194 and 16-28120. As an immediate corrective actions the licensee established an expectation to enter Limiting Condition for Operation (LCO) 3.3.8.1 when any of the LOP instrumentation channels are tripped. Other corrective actions included additional training for licensed operators.

This performance deficiency was of more than minor safety significance because a failure to correctly implement TS LCO requirements has the potential to lead to a more significant safety concern if left uncorrected. Specifically, a failure to declare an LCO not met, enter the applicable condition(s), and follow the applicable actions could reasonably result in operations outside of established safety margins or analyses. The finding was determined to be of very low safety significance during a detailed Significance Determination Process review since the delta core damage frequency (ΔCDF) was determined to be less than 1.0E-6/year. The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of training. Specifically, licensed operators failed to correctly apply the TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources due to lack of knowledge and unfamiliarity with the equipment conditions they faced during the event [IMC 0310, H.9]. (Section 1R15.b.1)

Cornerstone: Barrier Integrity

Green. The inspectors identified a finding of very low safety significance with an associated NCV of TS 5.5.7, "Ventilation Filter Testing Program." The licensee failed to perform testing of the standby gas treatment system (SGTS) high-efficiency particulate air (HEPA) filters that demonstrated a penetration and system bypass of less than 0.05 percent. The licensee entered this violation into its CAP as CARD 16–28812. The licensee declared the Division 1 SGTS subsystem inoperable until testing was performed satisfactorily and evaluated the extent of condition on the control room filtration system.

This performance deficiency was of more than minor safety significance because it was associated with the procedure quality attribute for the control room and auxiliary building and adversely affected the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, by not adequately testing the SGTS HEPA filters, the ability of the SGTS to collect and treat the design leakage of radionuclides from the primary containment to the secondary containment during an accident could not be assured. The finding was determined to be of very low safety significance because it involved only a degradation of the radiological barrier function provided by the SGTS. The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified. (Section 1R22.b.1)

Cornerstone: Occupational Radiation Safety

Green. A finding of very low safety significance with an associated NCV of TS 5.7.2, "High Radiation Area," was self-revealed when a locked high radiation area (LHRA) was found to be unlocked. The licensee immediately locked the LHRA and performed follow-up surveys. Subsequent actions included providing additional training for radiation protection technicians. This issue was entered into the licensee's CAP as CARD 16-28186.

The inspectors determined the performance deficiency was more than minor because it impacted the program and process attribute of the Occupational Radiation Safety cornerstone and adversely affected the cornerstone objective to ensure adequate protection of worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Specifically, not locking LHRAs could lead to inadvertent worker entry into high dose rate areas without knowledge of the radiological conditions. The finding was determined to be of very low safety significance because it did not involve as-low-as-reasonably-achievable planning for work controls, there was no overexposure nor substantial potential for an overexposure, and the licensee's ability to assess dose was not compromised. The inspectors determined the finding affected the cross-cutting area of human performance and the cross-cutting aspect of avoid complacency because individuals did not plan for the possibility of mistakes and implement appropriate error reduction tools. Specifically, the radiation protection technician did not ensure a lock verification was performed on the padlock as required by station procedures [IMC 0310, H.12]. (Section 2RS1.1.b.1)

Other Findings

Severity Level IV. The inspectors identified a Severity Level IV NCV of the NRC's reporting requirements in 10 CFR 50.73(a)(1), "Licensee Event Report System." The licensee failed to submit a required Licensee Event Report (LER) within 60 days after discovery on September 16, 2016, of an operation or condition which was prohibited by the plant's TSs and an event or condition that could have prevented the fulfillment of the safety function to remove residual heat and mitigate the consequences of an accident. The inspectors concluded the licensee failed to satisfy the applicable regulatory reporting requirements due to unwarranted delay in evaluating conditions from the event with respect to compliance with the TSs and reporting requirements. The licensee subsequently submitted LER 05000341/2016-009-00, "Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation," on December 20, 2016, to report the event. The licensee entered this issue into its CAP as CARD 16-30164.

Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined the performance deficiency was of minor significance based on "No" answers to the more-than-minor screening questions. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to report as required by 10 CFR 50.73(a)(1). No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor significance and therefore not a finding. (Section 1R15.b.2)

Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

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

- On October 26, a single control rod scrammed during control rod surveillance testing due to a blown scram pilot fuse and reactor power reduced to about 98 percent. The unit was returned to 100 percent on October 27.
- On October 29, the licensee reduced power to 91 percent to perform control rod testing. The unit was returned to 100 percent later that day.
- On November 7, the licensee removed the unit from service for a planned maintenance outage to replace one of two main power transformers, identify and plug a main condenser tube leak, repair reactor recirculation motor-generator set ‘A’ speed control, and complete additional maintenance. The unit was restarted on November 11, synchronized to the electrical grid on November 13, and returned to 100 percent power on November 20 after a series of control rod sequence exchanges to establish the control rod pattern for full power operation.
- On December 3, the licensee reduced power to 90 percent to perform control rod testing. The unit was returned to 100 percent later that day.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee’s preparations for winter conditions to verify the plant’s design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee’s procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified operator actions were appropriate as specified by plant specific procedures. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors’ reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather problems:

- Circulating water system;
- General service water system; and

- Ultimate heat sink (UHS) reservoir.

The inspectors also verified adverse weather protection problems were entered into the licensee's CAP 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 winter seasonal readiness preparation inspection sample as defined in Inspection Procedure (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 residual heat removal (RHR) and RHR service water (RHRSW) subsystems during Division 1 RHR/RHRSW subsystems maintenance;
- Reactor core isolation cooling system (single train risk significant system); and
- Standby liquid control system.

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 CAP 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:

- Auxiliary building first floor, reactor building component cooling water and high pressure coolant injection hatch area;
- Auxiliary building second floor, Division 1 switchgear room;
- Reactor building second floor, Division 2 emergency equipment cooling water (EECW) area;
- Reactor building third floor, general area; and
- RHR complex, Division 1 EDGs.

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 CAP 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

No findings were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On October 29 and November 5, the inspectors observed fire brigade activation for fire drills in the turbine building at the reactor feedwater pump lubricating oil skid. Based on these observations, the inspectors evaluated the readiness of the plant fire brigade to

fight fires. The inspectors verified the licensee identified deficiencies, openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate firefighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

This inspection constituted one annual fire protection drill inspection sample as defined in IP 71111.05AQ.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07)

.1 Annual Heat Sink Performance (71111.07A)

a. Inspection Scope

The inspectors observed the licensee's performance testing of the Division 2 EECW heat exchanger. The inspectors assessed the condition of the heat exchanger by direct observation of the performance test, review of the test results, and discussion with licensee engineering staff. The inspectors verified the acceptance criteria were satisfactorily met and verified no deficiencies existed that would adversely impact the heat exchanger's ability to transfer heat to the emergency equipment service water system to ensure the licensee was adequately identifying and addressing problems that could affect the performance of the heat exchanger.

The inspectors also evaluated the licensee's silt level inspection and silt removal from the Division 2 UHS reservoir by review of the inspection results and discussion with licensee engineering staff. The inspectors verified the acceptance criteria were satisfactorily met and verified no deficiencies existed that would adversely performance of the UHS.

In addition, the inspectors verified heat sink performance-related problems were entered into the licensee's CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one annual heat sink performance inspection sample as defined in IP 71111.07.

b. Findings

No findings were identified.

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 annual examinations in the simulator on November 22. 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 and satisfied the inspection program expectation for the resident inspectors to observe annual operator requalification simulator testing during the training cycle in which it was not observed by the NRC during the biennial portion of this IP.

b. Findings

No findings were identified.

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

a. Inspection Scope

On November 7, the inspectors observed licensed operators in the control room perform plant cooldown and transition to shutdown cooling operation at the start of planned maintenance outage PO 16-02. Also, on November 11, the inspectors observed licensed operators in the control room perform power ascension activities following plant start up from the planned maintenance outage. These activities 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 CAP 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.

.3 Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the annual operating test, administered by the licensee from November 7, 2016, through December 9, 2016, as required by 10 CFR 55.59(a). The results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee's licensed operator requalification training program to meet the requirements of 10 CFR 55.59.

This inspection constituted one annual licensed operator requalification examination results 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 the following degraded performance issues involving risk-significant structures, systems, and components (SSCs):

- CARD 16-25666, lube oil leak on EDG 12 during surveillance; and
- CARD 16-26876, high pressure brake bottle for mechanical draft cooling tower fan C is high out-of-specification 2025 psig [Pounds per Square Inch Gage].

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 CAP 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

(1) Inadequate Work Instructions for Maintenance on Flexible Couplings for EDGs

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 plant operators discovered an oil leak coming from a flexible coupling upstream of the EDG 12 lube oil heater during surveillance testing. The licensee failed to have work instructions for maintenance on safety-related EDGs appropriate to the circumstances to ensure flexible coupling fasteners were correctly torqued as specified by the manufacturer to prevent leakage.

Discussion: On July 17, 2016, during the performance of surveillance testing on EDG 12, plant operators discovered a 0.5 liter per minute oil leak coming from a flexible coupling upstream of the lube oil heater. Consequently, operators shut down the engine and removed it from service. The EDG was inoperable for about 12 hours to replace the leaking flexible coupling.

The inspectors reviewed the licensee’s apparent cause evaluation for this problem and concurred with its conclusions. The direct cause was fasteners on the flexible coupling were not properly tightened when maintenance was last performed in 2012 to the manufacturer’s recommended torque value of 90-100 inch-pounds. The apparent cause was the maintenance work order instructions inappropriately specified tightening the fasteners “wrench tight” rather than using the manufacturer’s recommended torque value. The licensee visually inspected the coupling upon disassembly and found no significant misalignment at the connection and the sealing surfaces appeared to be in good condition. The licensee sent the flexible coupling to a laboratory for failure analysis. Testing performed at the laboratory concluded the average wrench tight torque on this coupling was about 40 inch-pounds. During testing, the laboratory was able to recreate the leak when the fasteners were torqued to only 40 inch-pounds. Once the fasteners were torqued to 90-100 inch-pounds, leakage was stopped.

The licensee determined the extent of condition for this problem applied to thirty-three flexible couplings installed on each of the four EDGs. The licensee visually inspected the remainder of these flexible couplings for evidence of leakage at operating pressure and for degraded conditions that may lead to leaks. No leakage or degradation was found. The licensee also reviewed its work order history on the EDG flexible couplings

and determined this was an isolated occurrence. The flexible coupling leak was following re-work of a previous leak in 2012 due to a different cause (i.e., a misalignment problem). The EDG vendor (Fairbanks-Morris) confirmed the remainder of the undisturbed couplings were installed from the factory using the manufacturer's recommended torque value.

Analysis: The inspectors determined the licensee's failure to have work instructions for maintenance on safety-related EDGs appropriate to the circumstances to ensure flexible coupling fasteners were correctly torqued as specified by the manufacturer, 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 EDG 12 flexible coupling oil leak resulted in unplanned inoperability and unavailability of this onsite emergency power source. 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 [Significance Determination Process] 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, "SDP for Findings At-Power," dated June 19, 2012, since the reactor was operating at power when this issue was discovered. 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 determined it was a licensee performance deficiency of very low safety significance (Green) because it: (1) was not a deficiency affecting the design or qualification of a mitigating SSC, (2) did not represent a loss of system and/or function, (3) did not represent an actual loss of function of at least a single train for greater than its TS allowed outage time OR two separate safety systems out-of-service for greater than its TS allowed outage time, and (4) did not represent an actual loss of function of one or more non-TS trains or equipment designated as high safety significant in accordance with the licensee's Maintenance Rule Program for greater than 24 hours.

The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

Enforcement: Title 10 of the CFR, Part 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 July 17, 2016, the licensee failed to have instructions for performing maintenance on safety related EDGs that were appropriate to the circumstances to ensure flexible coupling fasteners were correctly torqued as specified by the manufacturer to prevent leakage. The licensee entered this violation into its CAP as CARD 16-25666. Corrective actions included replacing the leaking flexible coupling and performing post-maintenance testing to ensure no leakage, adding the manufacturer's torque specifications to flexible coupling replacement technical requirements to support future work order instructions, and completing a work order to tighten the affected EDG 12 flexible coupling to 90-100 inch-pounds.

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 NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy.
(NCV 05000341/2016004-01, Inadequate Work Instructions for Maintenance on Flexible Couplings for EDGs)

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:

- Recurring 120 kilovolt offsite power source inoperability due to N-1 contingency; and
- Emergent maintenance during the week of October 31 - November 4 on EDG 14 and Division 2 SGTS, planned maintenance on the west control rod drive pump, and diving activities at the general service water pump house.

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 problems associated with the management of plant risk for maintenance and emergent work activities were entered into the licensee's CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted two 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)

a. Inspection Scope

The inspectors reviewed the following issues:

- CARD 16-25194, additional evaluation required on the operability determination for CARD 16-23392;
- CARD 16-00204, manhole 16947B cable vault sump pump trips circuit breaker;
- CARD 16-25374, request operational guidance for G4100F052;
- CARD 16-27602, evaluate acceptability of opening the reactor building-5 hatch and EDG missile shield opening;
- CARD 16-28738, control rod drop analysis licensing/design basis unanalyzed condition;
- CARD 16-28580, discrepancy in DC-6356, Volume I, Revision 0;
- CARD 16-28906, one or more low pressure turbine stop valves is delayed in fully closing; and
- CARDs 16-29068 and 16-29153, potential impact of a tornado on the EDGs.

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 UFSAR, Technical Requirements Manual, Emergency Plan, Fire Protection Plan, regulatory commitments, or other elements of the current licensing basis when degraded and/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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

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

b. Findings

(1) Failure to Correctly Interpret and Implement TS Requirements for LOP Instrumentation and AC Electrical Power Functions

(Closed) Unresolved Item 05000341/2016002-03, LOP Instrumentation TS 3.3.8.1 Applicability Following Bus 64C Potential Transformer Fuse Failures

Introduction: The inspectors identified a finding of very low safety significance with an associated NCV of TS 3.3.8.1, "Loss of Power Instrumentation," and TS 3.8.1, AC Sources – Operating." The licensee failed to satisfy applicable action requirements for inoperable loss of voltage (LOV) and degraded voltage (DGV) instrument channels, inoperable EDGs, and an inoperable offsite power circuit when power was lost to the station transformer 64 auto voltage tap changer and one-half of the instrument channels for engineered safety features (ESF) bus 64C due to failure of line side potential transformer fuses on April 24, 2016.

Description: On April 24, 2016, a loss of output from the line-to-neutral potential transformers occurred on the 4160 volt alternating current (VAC) 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 LOV and DGV relaying for ESF bus 64C. The licensee subsequently discovered all six of the primary side fuses to the line side potential transformers had blown. Although the actual cause for the blown fuses was not conclusively determined, the licensee determined the most likely cause was 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. On May 3, 2016, the licensee removed the unit from service, deenergized station transformer 64, and replaced the blown fuses to restore power to the affected circuits.

Station transformer 64 supplies offsite power to Division 1 4160 VAC class 1E ESF buses 64B and 64C, as well as 4160 VAC balance-of-plant buses 64A and 64V. Each of the two Division 1 ESF buses are also supplied backup power from two EDGs (bus 64B from EDG 11 and bus 64C from EDG 12). The two EDGs are not run in parallel; each supplies a load group comprising about half of the division's emergency power requirements. Undervoltage protection for each ESF bus is provided by LOV and DGV relaying schemes. The TS characterizes these two undervoltage protective relaying schemes as two different protective functions. Each relaying scheme is monitored by four relays. A group of two redundant relays are connected across the line side potential transformer secondaries and another group of two relays are connected across the bus side potential transformer secondaries of each ESF bus. For either the LOV or DGV relaying schemes to cause an undervoltage tripping of an ESF bus, it would require two coincidental half-trips (i.e., one of the two line side relays to trip and one of the two bus side relays to trip). This is commonly referred to as a "one-out-of-two-taken twice" actuation logic.

The inspectors noted the licensee did not consider the de-energized LOP instrument channels (i.e., two each of the four LOV and DGV channels) for Division 1 ESF bus 64C to be inoperable and; therefore, it did not enter the applicable action requirements of TS 3.3.8.1. The licensee had concluded the affected LOP 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 instrument channels. The

questions included whether the potential transformers were part of the LOP instrumentation described in TS 3.3.8.1 and whether applicable surveillance requirements (SRs) had been satisfied prior to and during the event. The licensee entered this issue into its CAP as CARD 16-25194 for further evaluation. The inspectors opened URI 05000341/2016002-03 to determine whether the licensee had correctly applied the TS limitations and satisfied applicable regulatory reporting requirements.

In response to the inspectors' questions, the licensee completed an engineering evaluation on September 16, 2016. The licensee concluded that the affected Division 1 LOP instrument channels were inoperable and; therefore, it should have met the applicable action requirements of TS 3.3.8.1. TS 3.3.8.1 requires the LOP instrumentation system to have four operable LOV and DGV channels for each ESF bus. With the bus 64C LOV and DGV relays connected across the phase-to-neutral end of the line side potential transformers remaining tripped due to loss of power, there was no way to reset these tripped relays in situ to return to initial conditions or to perform surveillance testing of the affected channels to satisfy the applicable TS SRs without a change in the method of testing.

The inspectors noted for an ESF bus with one or more LOP instrument channels inoperable, TS 3.3.8.1, Required Action A.1 requires restoring the inoperable LOP instrument channels to operable status within 72 hours. If this required action is not met, Required Action B.1 requires immediately declaring the associated EDG inoperable, which then requires entry into TS 3.8.1, Condition A. Since TS 3.3.8.1 was applicable with Fermi 2 operating in Modes 1 through 3, the affected bus 64C LOP instrument channels were required to be operable from the time of the event (April 24 at 4:44 p.m.) until Fermi 2 entered Mode 4 (May 4 at 3:25 p.m.). The elapsed time of the missed TS 3.3.8.1 LCO entry (9 days and 22.68 hours) was greater than the completion time of TS 3.3.8.1, Required Actions A.1 and B.1, which were not performed. The inspectors noted TS 3.3.8.1 was also applicable with Fermi 2 operating in Mode 4 while the associated EDG was required to be operable by TS 3.8.2, "AC Sources – Shutdown." However, TS 3.8.2 requires only one division of the Class 1E onsite power sources to be operable. From the time Fermi 2 entered Mode 4 until power was restored to the affected LOP instrument channels (May 8 at 6:18 p.m.), both Division 2 EDGs were operable.

Immediately after the event occurred, the voltage on ESF buses 64B and 64C was approximately 120 VAC (metered volts), which was below the minimum required bus voltage of 121.3 VAC for operability of the Division 1 offsite AC electrical power source. As a result, the licensee was required to satisfy the applicable action requirements of TS 3.8.1, Condition D. Operators manually adjusted the load tap changer on station transformer 64 to restore voltage above 121.3 VAC on the two ESF buses about 2½ hours into the event.

The licensee determined, in the absence of adequate voltage on ESF buses 64B and 64C to guarantee resetting the DGV relays upon a design basis accident auto start of ESF equipment in order to stay connected to the preferred offsite power source, the DGV safety function could not be satisfied as required by TS 3.3.8.1. The plant's design basis credits the voltage boost from the automatic operation of the load tap changer after RHR and core spray pumps start on an ESF actuation to restore voltage within its control band, which would also allow the DGV relays to reset. Consequently, with the loss of automatic control of the load tap changer, the Division 1 AC electrical power

source (or circuit) lost its design safety function. The inspectors noted for one inoperable offsite power circuit, TS 3.8.1, Required Action D.1 requires performance of SR 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. The elapsed time of the missed TS 3.8.1, Condition D entry from April 24 at 4:44 p.m. to 7:20 p.m. (2.60 hours) was greater than the completion time of TS 3.8.1, Condition D.1, which was not performed.

The licensee also determined EDG 12 lost its voltage reference needed to synchronize with offsite power upon restoration of offsite power following a design basis accident. Therefore, the licensee should also have satisfied the applicable action requirements of TS 3.8.1 for the inoperable EDG. The inspectors noted for one inoperable EDG, TS 3.8.1, Condition A, includes six required actions (A.1 through A.6). Required Actions A.1, A.2, A.3, A.4, and A.5 are required to be completed within 1, 4, 8, 24, and 72 hours, respectively, and Required Action A.6 is required to be completed within 14 days.

Technical Specification 3.8.1, Required Action A.1 requires performance of SR 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.2 is conditional and requires declaring required feature(s), supported by the inoperable EDG, inoperable when the redundant required feature(s) are inoperable within 4 hours from discovery of the inoperable EDG concurrent with inoperability of redundant required feature(s). Redundant required feature failures consist of inoperable feature(s) associated with a division redundant to the division that has an inoperable EDG; in this case, inoperable required features in Division 2 since EDG 12 (Division 1) was inoperable. Required Action A.3, requires verification of combustion turbine generator (CTG) 11-1 availability to supply Division 1 electrical loads during a SBO once every 8 hours. Required Action A.4 requires verification that the remaining operable EDGs are not inoperable due to a common cause failure <u>or</u> the performance of SR 3.8.1.2 to verify each operable EDG starts and achieves the required steady state voltage and frequency within 24 hours. Required Action A.5 is conditional and requires restoration of CTG 11-1 within 72 hours from discovery of Condition A concurrent with CTG 11-1 not available. Required Action A.6 requires restoring the inoperable EDG to operable status within 14 days. The elapsed time of the missed TS 3.8.1 LCO entry from April 24 at 4:44 p.m. to May 4 at 3:25 p.m. (9 days and 22.68 hours) was greater than the completion times of TS 3.8.1, Conditions A.1 through A.4, which were not performed. Inasmuch as required actions and completion times for Condition A were not satisfied, Required Action G.1, which required entry into Mode 3 within 12 hours, was also not met. In response to the inspectors' questions, the licensee verified Required Action A.5 was not applicable since (although it was not being verified at the time as required by Required Action A.3) CTG 11-1 was available from the time of the event until Fermi 2 entered Mode 4. However, Required Action A.2 was applicable during this time since redundant required feature(s) were inoperable.

From the time of the event until Fermi 2 entered Mode 4, surveillance testing was performed on the two Division 2 EDGs (EDGs 13 and 14), rendering them inoperable. Since EDG 12 was also inoperable during this time, the licensee should also have satisfied the applicable action requirements of TS 3.8.1 for inoperable EDGs in both divisions. The inspectors noted for inoperable EDGs in both divisions, TS 3.8.1, Required Action C.1 requires the licensee to restore both EDGs in one division to operable status within 2 hours. EDGs 13 and 14 were inoperable for testing from

2:55 p.m. to 10:15 p.m. on April 27 and from 12:33 a.m. to 4:46 a.m. on April 30. In addition, EDG 13 was inoperable from 5:06 p.m. to 6:06 p.m. and 7:57 p.m. to 10:07 p.m. on April 26, and EDG 14 was inoperable from 9:09 a.m. to 10:03 a.m. and 3:35 p.m. to 4:11 p.m. on April 30. Inasmuch as the required action and completion time for Condition C was not satisfied during three of these six periods of time, Required Action G.1, which required entry into Mode 3 within 12 hours, was also applicable. However, this condition was met since the longest period of inoperable EDGs in both divisions was 7.33 hours. Therefore, though having inoperable EDGs in both divisions resulted in a loss of safety function of the onsite AC electrical power sources, no violation of TS 3.8.1 was identified.

The inspectors reviewed the licensee's direct cause evaluation in CARD 16-28120, "Review Operations Response to LOP Instrumentation Inoperability in CARD 16-23392," to understand why licensed operators failed to correctly apply the TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources. The evaluation attributed the cause to potential lack of knowledge and unfamiliarity with the equipment conditions. Operators did not have the correct mental model of the LOP instrument channels and understand the effect the blown fuses had on the LOV and DGV relays that tripped due to loss of power. Operators also failed to recognize the impact of losing the automatic control function of the station transformer 64 load tap changer and failed to follow the guidance in the system operating procedure to declare the associated ESF buses inoperable when the load tap changer was in "manual" with bus voltage outside the allowable band. In addition, operators did not identify the loss of the reference voltage needed to synchronize EDG 12 with offsite power upon restoration of offsite power following a design basis accident with respect to operability of the EDG.

<u>Analysis</u>: The inspectors determined the licensee's failure to satisfy applicable TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources, was contrary to the requirements of TS 3.3.8.1 and TS 3.8.1, 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 correctly implement TS LCO requirements has the potential to lead to a more significant safety concern if left uncorrected. Specifically, a failure to declare an LCO not met, enter the applicable conditions, and follow the applicable actions could reasonably result in operations outside of established safety margins or analyses. 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 examples related to this issue.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated October 7, 2016, the inspectors determined this finding affected the Mitigating Systems cornerstone, specifically the Mitigating SSCs and Functionality 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 2, "Mitigating Systems Screening Questions," and determined it would require a detailed risk evaluation because the finding represented a loss of system and/or function.

Detailed Risk Evaluation

To evaluate the risk significance of the finding, a Senior Reactor Analyst used the Fermi 2 Standardized Plant Analysis Risk (SPAR) Model, Version 8.21 and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations, Version 8.1.4.

Two modifications were made to the Fermi 2 SPAR model by Idaho National Laboratory from a previous risk analysis. The first modification of the SPAR model was performed to remove the assumed dependency between the operator action to vent containment and the operator action to start/control RHR in the suppression pool cooling mode. This change was made consistent with the current SPAR model philosophy that these two actions are separate enough in time that the failure to vent the containment is independent from the failure to start/control RHR. The second modification allowed continued core injection using the standby feedwater system (with a probability of 91 percent) and the control rod drive system (with a probability of 19 percent) even after containment vent system failure. These probabilities of standby feedwater system and control rod drive system success after containment failure are based on the types and probabilities of drywell and suppression pool failures that could occur to the containment and the effects on each type of failure on the systems. The applicable information was taken from the licensee's "Accident Sequence Analysis Notebook," [EF2-PRA-002, Revision 1].

The ΔCDF was evaluated for three (3) different exposure times as outlined below. The assumptions for each exposure time are given below.

- <u>ΔCDF Associated with Exposure Time 1 and Assumptions</u>:

    - EDG 12 was assumed to be unavailable.

    - The exposure time was assumed to be 10 days, which is rounded up to the nearest day.

    - Using the Fermi 2 SPAR model with the above assumptions, the ΔCDF for internal and external events was determined to be 7.5E-8/year. The dominant core damage sequence was determined to be an initiating event of a fire in Division 2 Switchgear Room with 4160 VAC bus 65E damage and with a failure of the following equipment: standby feedwater, reactor core isolation cooling, suppression pool cooling, shutdown cooling, containment spray, containment venting, and late core injection.

- <u>ΔCDF Associated with Exposure Time 2 and Assumptions</u>:

    - Offsite power to Division 1 was assumed to be unavailable during design basis accidents. Division 1 ESF buses 64B and 64C were assumed to be failed.

    - The exposure time was assumed to be 2.5 hours.

    - Using the Fermi 2 SPAR model with the above assumptions, the ΔCDF for internal and external events was determined to be 2.2E-9/year.

- <u>ΔCDF Associated with Exposure Time 3 and Assumptions</u>:

  - Emergency core cooling system loads on Division 1 ESF buses 64B and 64C were assumed to be recoverable after restoration of offsite power to Division 1 following design basis accidents. The probability of recovery of emergency core cooling system loads on the Division 1 ESF buses 64B and 64C after restoration of offsite power to Division 1 was evaluated using the SPAR-H method (per NUREG/CR-6883). The human error probability for recovery was determined to be 2.2E-2 with high stress a performance shaping factor for both diagnosis and action.

  - EDG 12 was assumed to be unavailable.

  - The exposure time was assumed to be 24 hours.

  - Using the Fermi 2 SPAR model with the above assumptions, the ΔCDF for internal and external events was determined to be 3.4E-11/yr.

<u>Evaluation of Total ΔCDF</u>:

The total ΔCDF for internal and external events is the sum of the delta risk for each of the exposure times or 7.7E-8/year.

Based on the results of the detailed risk evaluation, the inspectors determined the finding was 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 training. Specifically, licensed operators failed to correctly apply the TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources due to lack of knowledge and unfamiliarity with the equipment conditions they faced during the event [IMC 0310, H.9].

<u>Enforcement</u>:

1. <u>LOP Instrumentation Inoperability</u>

   Technical Specification 3.3.8.1, “LOP Instrumentation,” states, in part, the LOP instrumentation for 4160 VAC emergency bus LOV and DGV functions shall be operable during Modes 1, 2, and 3. TS 3.3.8.1, Required Action A.1, states, in part with one or more emergency buses with one or more channels inoperable, restore the inoperable channel(s) to operable status within 72 hours. TS 3.3.8.1, Required Action B.1, states, in part, with the required action and associated completion time of Condition A not met, immediately declare the associated EDG inoperable.

   Contrary to the above, from April 24 at 4:44 p.m. to May 4 at 3:25 p.m., with four 4160 VAC emergency bus 64C LOV and DGV channels inoperable due to loss of power, the licensee failed to satisfy TS 3.3.8.1, Required Actions A.1 and B.1. The failure to satisfy these TS required actions is a violation of TS 3.3.8.1.

2. EDG 12 Inoperability

Technical Specification 3.8.1, "AC Sources – Operating," states, in part, two EDGs per Class 1E electrical division shall be operable in Modes 1, 2, and 3. For one EDG inoperable, Condition A has six required actions. TS 3.8.1, Required Action A.1, states, in part, perform SR 3.8.1.1 for operable offsite circuit(s) within 1 hour and once per 8 hours thereafter. TS 3.8.1, Required Action A.2, states, in part, declare required feature(s) supported by the inoperable EDG inoperable when the redundant required feature(s) are inoperable within 4 hours from discovery of an inoperable EDG concurrent with inoperability of redundant required feature(s). TS 3.8.1, Required Action A.3, states, in part, verify the status of CTG 11-1 once per 8 hours. TS 3.8.1, Required Action A.4, states, in part, determine operable EDG(s) are not inoperable due to common cause failure within 24 hours or perform SR 3.8.1.2 for operable EDG(s) within 24 hours.

Contrary to the above, from April 24 at 4:44 p.m. to May 4 at 3:25 p.m., with one EDG (EDG 12) inoperable, the licensee failed to satisfy TS 3.8.1, Required Actions A.1 through A.4. In addition, with the required actions and associated completion times of Condition A not met, the licensee failed to satisfy TS 3.8.1, Required Action G, to be in Mode 3 within 12 hours. The failure to satisfy these TS required actions is a violation of TS 3.8.1.

3. Division 1 AC Electrical Power Circuit Inoperability

Technical Specification 3.8.1, "AC Sources – Operating," states, in part, two qualified circuits between the offsite transmission network and the onsite Class 1E AC electrical power distribution system shall be operable in Modes 1, 2, and 3. For one offsite circuit inoperable, TS 3.8.1, Required Action D.1, states, in part, perform SR 3.8.1.1 for the operable offsite circuit within 1 hour and once per 8 hours thereafter.

Contrary to the above, from April 24 at 4:44 p.m. to 7:20 p.m., with one offsite circuit (i.e., the Division 1 AC electrical power circuit) inoperable, the licensee failed to satisfy TS 3.8.1, Required Action D.1. The failure to satisfy this TS required action is a violation of TS 3.8.1.

The licensee entered this violation into its CAP as CARDs 16-23392, 16-25194 and 16-28120. As immediate corrective actions, the licensee established an expectation to enter LCO 3.3.8.1 when any of the LOP instrumentation channels are tripped. Other corrective actions included additional training for licensed operators.

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 05000341/2016004-02, Failure to Correctly Interpret and Implement TS Requirements for LOP Instrumentation and AC Electrical Power Functions)**.

URI 05000341/2016002-03 is closed.

(2) Failure to Satisfy 10 CFR 50.73 Reporting Requirements for Loss of LOP Instrumentation and AC Electrical Power Safety Functions

Introduction: The inspectors identified a Severity Level IV NCV of the NRC's reporting requirements in 10 CFR 50.73(a)(1), "Licensee Event Report System." The licensee failed to submit a required LER within 60 days after discovery on September 16, 2016, of an operation or condition which was prohibited by the plant's TSs and an event or condition that could have prevented the fulfillment of the safety function to remove residual heat and mitigate the consequences of an accident. The inspectors concluded the licensee failed to satisfy the applicable regulatory reporting requirements due to unwarranted delay in evaluating conditions from the event with respect to compliance with the TSs and reporting requirements.

Discussion: On April 24, 2016, a loss of output from the line to neutral potential transformers occurred on 4160 VAC 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 LOV and DGV relaying for ESF bus 64C. As discussed above in Section 1R15.1.b.1, the inspectors identified the licensee did not correctly interpret and satisfy applicable TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources immediately following the event. This resulted in an operation or condition which was prohibited by the plant's TSs. In addition to the noncompliance with the TS LCO requirements, a loss of safety function of the onsite AC electrical power sources was created when surveillance testing was performed on the Division 2 EDGs while EDG 12 was inoperable.

Shortly after the event, the inspectors questioned the licensee whether its immediate operability determination was correct and whether the applicable TS LCO requirements were entered for the failure of the high side potential transformer fuses. Discussion of these questions continued through the month of May, and on May 23 the licensee provided the inspectors a licensing position paper supporting its immediate operability determination. The inspectors challenged a number of the assumptions and conclusions in the position paper during continuing discussions and on June 27, the licensee initiated CARD 16-25194 to request a formal engineering evaluation to support the operability determination.

The licensee completed the engineering evaluation on September 16, 2016 and concluded the affected Division 1 LOP instrument channels were inoperable and; therefore, it should have met the applicable action requirements of TS 3.3.8.1. In addition, the licensee's evaluation concluded that with the loss of automatic control of the load tap changer, the Division 1 AC electrical power source (or circuit) was inoperable until operators manually adjusted the load tap changer to restore the transformer output voltage above the minimum required voltage about 2½ hours into the event. Therefore, the licensee should also have satisfied the applicable action requirements of TS 3.8.1 for the inoperable offsite electrical power source during this time. Furthermore, the licensee determined EDG 12 had lost its voltage reference needed to synchronize with offsite power upon restoration of offsite power following a design basis accident. This condition existed for almost 10 days. During this time, one or both Division 2 EDGs were inoperable concurrently with EDG 12 on six separate occasions. As a result, the licensee should have satisfied the applicable action requirements of TS 3.8.1 for the inoperable onsite AC power sources.

The inspectors noted the TS definition of operable does not allow a grace period before an SSC that is not capable of performing its specified function is declared inoperable. Thus, an assessment of the functionality of the station transformer 64 load tap changer and the operability of the LOP instrumentation and AC power sources was required to establish whether the degraded/nonconforming condition warranted starting the TS required action completion times for the affected LCOs. This is consistent with the NRC staff's Operability Determination Process guidance in IMC 0326, "Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety," dated December 3, 2015, for addressing degraded and nonconforming conditions because the affected systems and components perform specified functions described in the UFSAR or other elements of the current license basis. Although the licensee made an immediate operability determination, this determination later proved to be incorrect based upon incomplete knowledge and understanding of the degraded/nonconforming condition. When the inspectors asked questions raising significant doubts in the licensee's immediate operability determination after the event occurred, a prompt operability determination was warranted. As stated in the guidance:

> "A prompt operability determination of SSC operability is a follow up to an immediate determination of SSC operability. A prompt determination is warranted when additional information, such as supporting analysis, is needed to confirm the immediate determination."
>
> "A prompt determination, when needed, should be done without delay. Licensees should make continuing progress toward completing the determination. A reasonable expectation of operability should exist while the prompt determination is being done."
>
> "There is no explicit time limit for completing a prompt determination. Nevertheless, timeliness is important and should depend on the safety significance of the issue. For example, it may be appropriate to make a prompt operability determination within a few hours for situations involving highly safety significant SSCs. Prompt determinations can often be done within 24 hours of discovery even if complete information is not available. If more time is needed to gather additional information (such as a vendor analyses or calculations) the licensee can evaluate the risk importance of the additional information to decide whether to prolong the operability determination. TSs completion time is one factor that can be used in determining an appropriate time frame within which a prompt determination should be completed. However, in all cases a prompt determination should be done consistent with the risk significance of the SSC."

In this instance, inoperability of the affected LOP instrumentation would require restoring the affected channels to operable status within 72 hours. Inoperability of the AC power sources with the unit operating at power would require completion of various actions from 1 hour to 14 days, or changing to Modes 3 and 4 in 12 and 36 hours, respectively. In this context, the delay in completing a prompt operability determination until September 16 would be considered excessive. In response to the inspectors' questions, the licensee acknowledged the untimely prompt operability determination and initiated CARD 16-27374, "Technical Evaluation TE-R14-16-022 Was Not Developed in a Timely Manner," for evaluation and identification of appropriate corrective actions.

The inspectors determined the licensee's failure to correctly interpret and satisfy applicable TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources following the event on April 24 was reportable under 10 CFR 50.73(a)(2)(i)(B) as an operation or condition which was prohibited by the plant's TSs. In addition, having inoperable EDGs in both divisions resulted in a loss of safety function of the onsite AC electrical power sources that was reportable under 10 CFR 50.73(a)(2)(v)(B) and (D) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to remove residual heat and mitigate the consequences of an accident, respectively. The licensee subsequently submitted LER 05000341/2016-009-00, "Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation," on December 20, to report the event. Refer to Section 4OA3.6 of this inspection report for the inspectors' review and closure of the LER.

The inspectors reviewed the NRC staff's reporting guidance in NUREG 1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," Revision 3, to evaluate whether the licensee met the regulatory reporting requirements. The inspectors noted the licensee was required by 10 CFR 50.73(a)(1) to submit an LER within 60 days after the discovery of the event or condition. As stated in the guidance:

> "The discovery date is generally the date when the event was discovered rather than the date when an evaluation of the event is completed. For example, if a technician sees a problem, but a delay occurs before an engineer or supervisor has a chance to review the situation, the discovery date (which starts the 60-day clock) is the date that the technician sees a problem."

> "However, in some cases, such as discovery of an existing but previously unrecognized condition, it may be necessary to undertake an evaluation in order to determine if an event or condition is reportable. If so, the guidance provided in Regulatory Issue Summary (RIS) 2005-20, Revision 1, "Revision to NRC Inspection Manual Part 9900 Technical Guidance, 'Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety," dated April 16, 2008, which applies primarily to operability determinations, is appropriate for reportability determinations as well. This guidance indicates that the evaluation should proceed on a time scale commensurate with the safety significance of the issue and that, whenever reasonable expectation no longer exists that the equipment in question is operable, or significant doubts begin to arise, appropriate actions, including reporting, should be taken."

It should be noted RIS 2005-20 was superseded by the current guidance document (i.e., IMC 0326) after Revision 3 to NUREG 1022 was issued; however, the guidance in the above two paragraphs has not changed. Accordingly, the inspectors considered the appropriate discovery date for reporting purposes based on the guidance. Although the event was discovered on April 24, 2016 and significant doubts with respect to operability existed before the end of May, the inspectors chose September 16, 2016, since this was the date when the licensee completed the engineering evaluation concluding the event was an operation or condition prohibited by the plant's TSs and a loss of safety function for the onsite AC power sources. Based on this date, the inspectors found that submittal of LER 05000341/2016-009-00 on December 20, 2016, was greater than 60 days and would not meet NRC's regulation. Considering the excessive delay in completing the

engineering evaluation to assess operability of the affected LOP instrumentation channels and AC power sources along with the additional delay in completing the LER after the evaluation was completed, the inspectors concluded the licensee failed to meet the reporting requirements for timely submitting the LER.

Analysis: The inspectors determined the licensee's failure to report the conditions in accordance with the requirements in 10 CFR 50.73 was 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 the performance deficiency was not a finding of more than minor significance based on "No" answers to the more-than-minor screening questions. The inspectors also reviewed the examples of minor issues in IMC 0612, Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no examples related to this issue.

Violations of 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. This violation was also associated with a performance deficiency that has been evaluated as having minor safety significance by the SDP. The SDP, however, does not specifically consider regulatory process impact. Thus, although related to a common regulatory concern, it is necessary to address the violation and performance deficiency using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated performance deficiency. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to make a report to the NRC as required by 10 CFR 50.73(a)(1).

No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor safety significance and therefore not a finding.

Enforcement: Title 10 of the CFR, Section 50.73(a)(1) requires, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event. 10 CFR 50.73(a)(2)(i)(B) requires that the licensee report any operation or condition which was prohibited by the plant's TSs. In addition, 10 CFR 50.73(a)(2)(v)(B) requires that the licensee report any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to remove residual heat. Also, 10 CFR 50.73(a)(2)(v)(D) requires that the licensee report any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident.

Contrary to the above, the licensee failed to submit a required LER within 60 days after discovery of a condition on September 16, 2016, which was prohibited by the plant's TSs as required by 10 CFR 50.73(a)(2)(i)(B), could have prevented the fulfillment of the safety function of structures or systems that are needed to remove residual heat as required by 10 CFR 50.73(a)(2)(v)(B), and could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident as required by 10 CFR 50.73(a)(2)(v)(D). The condition involved inoperable LOP instrument channels and inoperable AC power sources following an event on April 24, 2016.

The licensee subsequently submitted LER 05000341/2016-009-00, “Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation,” on December 20, 2016, to report the event. The licensee entered this issue into its CAP as CARD 16-30164 to evaluate the cause for its failure to satisfy the reporting requirements and to identify appropriate corrective actions.

Because this violation was not repetitive or willful, and was entered into the licensee’s corrective action program, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016004–03, Failure to Satisfy 10 CFR 50.73 Reporting Requirements for Loss of LOP Instrumentation and AC Electrical Power Safety Functions)**

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:

- Work order (WO) 46136191, disassemble, inspect, clean and repair as necessary discharge check valve;
- WO V163140100, test 4160 volt breaker 65W-W4 (east standby feedwater system pump B) and WO 34695193; replace oil filter canisters on N2103C002; and
- WO 46439717, replace C4100F010 and WO 46439557, replace C4100F014.

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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted three 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 Planned Outage (PO 16-02)

a. Inspection Scope

On November 7, 2016, the licensee removed the unit from service for a planned maintenance outage to replace one of two main power transformers, identify and plug a main condenser tube leak, repair reactor recirculation motor-generator set ‘A’ speed control, and complete additional maintenance. The unit was restarted on November 11, 2016, synchronized to the electrical grid on November 13, 2016 and returned to 100 percent power on November 20, 2016, after a series of control rod sequence exchanges to establish the control rod pattern for full power operation.

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 inventory addition;
- reactor coolant system 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 plant heat up and entry into Mode 2 (Startup) 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 CAP 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.

.2 New Fuel Receipt Inspection

a. Inspection Scope

The inspectors observed new fuel receipt inspection, observed fuel handling operations, and reviewed the licensee's fuel handling procedures involving the receipt of new fuel assemblies in preparation for the upcoming Cycle 18 refueling outage.

This inspection was not considered to be a completed 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:

- Procedure 42.302.03, channel functional test of division 2 4160 volt Bus 65E undervoltage circuits;
- Procedure 43.404.002, Division 2 SGTS filter performance test; and
- Procedure 24.202.01, high pressure coolant injection pump and valve operability test at 1025 psi.

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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one in-service test and two routine surveillance tests, for a total of three surveillance testing inspection samples as defined in IP 71111.22. In addition, the inspectors did not identify any performance degradation in the reactor coolant system leakage for the entire cycle. The reactor coolant system leak detection inspection sample was not performed as defined in IP 71111.22, Section-02.

b. Findings

(1) Inadequate Testing of Standby Gas Treatment System Filters

Introduction: The inspectors identified a finding of very low safety significance with an associated NCV of TS 5.5.7, "Ventilation Filter Testing Program." The licensee failed to perform testing of the SGTS HEPA filters that demonstrated a penetration and system bypass of less than 0.05 percent.

Description: The inspectors reviewed the licensee's performance of surveillance testing that was accomplished in accordance with procedure 43.404.001, "Standby Gas Treatment Filter Performance Test Division 1," Revision 41, and procedure 43.404.002, "Standby Gas Treatment Filter Performance Test Division 2," Revision 40. These procedures were performed to satisfy TS 5.5.7, which requires testing of the SGT filtration system in accordance with NRC Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Revision 2 and American Society of Mechanical Engineers (ASME) N510 – 1980, "Testing of Nuclear Air-Cleaning Systems," to demonstrate a penetration and system bypass of less than 0.05 percent. As described in the UFSAR, the safety function of the SGTS is to minimize the offsite release of radioactive materials that leak from the primary containment into the secondary containment following a design basis accident to limit the offsite and control room dose to the guidelines of 10 CFR 50.67.

Each SGTS subsystem contains a filtration system, which includes charcoal absorbers and HEPA filters that are credited when assessing control room and public dose during design basis accident conditions. The licensee performs dispersed oil particulate testing, by which particles are injected upstream of the HEPA filter and particulate concentration is measured both upstream and downstream of the HEPA filter. These values are then used to determine the percent bypass, which is compared to the TS limit of 0.05 percent.

During review of HEPA filter surveillance testing performed on the Division 1 SGTS subsystem on April 22, 2015 and the Division 2 SGT subsystem May 4, 2015, the inspectors identified that, given the minimum sensitivity of the downstream detector and the upstream concentration achieved, the licensee would not have been able to detect a penetration of 0.05 percent. Specifically, the licensee would only have been able to detect penetration of approximately 0.1 percent and 0.06 percent for the Division 1 and Division 2 subsystems, respectively. Furthermore, ASME N510 – 1980 specifies that the generator output and/or penetrometer adjustment ensure penetrometer sensitivity high enough to permit detection of leaks at least two times smaller than the maximum leak allowed by specifications. For Fermi 2, this would mean the procedure needed to ensure a leak of 0.025 percent or smaller was detectable.

The licensee performed the surveillance testing again on October 20, 2016 for Division 1 and November 2, 2016 for Division 2. The inspectors observed the testing on

November 2, 2016 and reviewed the results of both tests. The inspectors noted the results for Division 2 met the detection criteria of 0.025 percent or lower, while the results for Division 1 again did not meet the detection criteria with a minimum detection capability of approximately 0.08 percent. In response to the inspectors' identification of the absence of adequate testing criteria in the procedures and the unsatisfactory test results for Division 1 during testing on October 20, 2016, the licensee declared the Division 1 SGTS subsystem inoperable. Satisfactory testing was subsequently performed for Division 1 on November 9, 2016.

Analysis: The inspectors determined the licensee's failure to perform testing of the SGTS HEPA filters that demonstrated a penetration and system bypass of less than 0.05 percent was contrary to the requirements of TS 5.5.7, 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 associated with the procedure quality attribute for the control room and auxiliary building and adversely affected the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, by not adequately testing the SGTS HEPA filters, the ability of the SGTS to collect and treat the design leakage of radionuclides from the primary containment to the secondary containment during an accident could not be assured. 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 October 7, 2016, the inspectors determined this finding affected the Barrier Integrity Cornerstone, specifically the auxiliary/reactor building contributor, and would require review using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," June 19, 2012. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," and determined this finding was a licensee performance deficiency of very low safety significance (Green) because it involved only a degradation of the radiological barrier function provided by the SGTS.

The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

Enforcement: Technical Specification 5.5.7 requires, in part, that the licensee demonstrate an in-place test of the SGTS HEPA filters shows a penetration and system bypass less than 0.05 percent when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980.

Contrary to the above, prior to November 2, 2016, the licensee failed to conduct in-place testing sufficient to show a penetration and system bypass of less than 0.05 percent when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980. In addition, the licensee did not meet ASME N510-1980 to have the

generator output and/or penetrometer adjustment that ensure penetrometer sensitivity high enough to permit detection of leaks at least two times smaller than the maximum leak allowed by specifications (i.e., 0.025 percent). The licensee entered this violation into its CAP as CARD 16-28812. The licensee declared the Division 1 SGT subsystem inoperable until testing was performed satisfactorily and evaluated the extent of condition on the control room filtration system. Additional corrective actions planned include a procedure change to add a minimum upstream concentration requirement that, for the minimum sensitivity of the instrument currently in use, would result in being able to detect a penetration of 0.025 percent or less.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016004-04, Inadequate Testing of SGTS Filters)**

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

a. Inspection Scope

The regional inspectors performed an in-office review of the latest revisions to the Emergency Plan and Emergency Action Levels.

The licensee transmitted the Emergency Plan and Emergency Action Level revisions to the NRC pursuant to the requirements of 10 CFR 50, Appendix E, Section V, "Implementing Procedures." The NRC's review was not documented in a Safety Evaluation Report and did not constitute approval of licensee-generated changes; therefore, this revision is subject to future inspection.

This Emergency Action Level and Emergency Plan Changes inspection constituted one inspection sample as defined in IP 71114.04.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a licensee emergency drill on October 11, 2016, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The drills were planned to be evaluated and were included in the performance indicator data regarding drill and exercise performance. The inspectors observed emergency response operations in the control room simulator and technical support center to determine whether the event classifications, notifications, and protective action recommendations were performed in

accordance with procedures. The inspectors also attended the licensee's drill critique to compare any inspector-observed weaknesses with those identified by the licensee's staff in order to evaluate the critique and to verify whether the licensee's staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents.

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

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

.1 High Radiation Area and Very High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors assessed the controls in 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 TS and procedures.

These inspection activities supplemented those documented in NRC Inspection Report 05000341/2016002 and constituted a partial inspection sample as defined in IP 71124.01.

b. Findings

(1) Failure to Lock an Area Meeting LHRA Conditions

Introduction: A finding of very low safety significance with an associated NCV of TS 5.7.2, "High Radiation Area," was self-revealed when a LHRA was found to be unlocked.

Description: On October 13, 2016, a radiation protection technician (RPT) and several other individuals exited a LHRA on a mezzanine that was controlled by a ladder guard and padlock. Later in the same shift, another RPT was assigned to provide job coverage in the LHRA and upon reporting to the area, noticed the padlock was not locked. The RPT subsequently locked the padlock and notified supervision. Follow-up surveys indicated dose rates of up 1,100 millirem/hour at 30 centimeters. The licensee determined after exiting the LHRA, the first RPT, who was responsible for locking the LHRA, thought the padlock was fully engaged and locked, but did not have a verification performed by another individual as required by procedure MRP06, "Accessing High Radiation, Locked High Radiation, and Very High Radiation Areas at Fermi 2."

Analysis: The inspectors determined the failure to lock a LHRA, as required by TS 5.7.2, was reasonably within the licensee's ability to foresee and prevent, and therefore constituted a performance deficiency. In accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined the performance deficiency was more than minor because it impacted the program and process attribute

of the Occupational Radiation Safety cornerstone and adversely affected the cornerstone objective to ensure adequate protection of worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Specifically, not locking LHRAs could lead to inadvertent worker entry into high dose rate areas without knowledge of the radiological conditions.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated October 7, 2016, the inspectors determined this finding affected the Occupational Radiation Safety Cornerstone and would require review using IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process." dated August 19, 2008. The finding was determined to be of very-low safety significance (Green) because it did not involve as-low-as-reasonably-achievable planning for work controls, there was no overexposure nor substantial potential for an overexposure, and the licensee's ability to assess dose was not compromised.

The inspectors determined the finding affected the cross-cutting area of human performance and the cross-cutting aspect of avoid complacency because individuals did not plan for the possibility of mistakes and implement appropriate error reduction tools. Specifically, the RPT did not ensure a lock verification was performed on the padlock as required by station procedures [IMC 0310, H.12].

Enforcement: Technical Specification 5.7.2 requires, in part, that accessible areas with radiation levels such that an individual could receive in 1 hour a dose equivalent > 1000 millirem but < 500 Rads at 1 meter be provided with locked doors to prevent unauthorized entry.

Contrary to the above, on October 13, 2016, an area meeting these conditions was not locked to prevent unauthorized entry. The licensee immediately locked the padlock and performed follow-up surveys. Subsequent actions included providing additional training for RPTs. This issue was entered into the licensee's CAP as CARD 16-28186.

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 05000341/2016004-05, Failure to lock an area meeting Locked High Radiation Area Conditions)**

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

.1 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down select effluent radiation monitoring systems to evaluate whether the monitor configurations aligned with Offsite Dose Calculation Manual (ODCM) descriptions and to observe the materiel condition of the systems.

The inspectors walked down selected components of the gaseous and liquid discharge systems to evaluate whether equipment configuration and flow paths align with plant documentation and to assess equipment materiel condition. The inspectors also assessed whether there were potential unmonitored release points, building alterations

that could impact effluent controls, and ventilation system leakage that communicated directly with the environment.

For equipment or areas associated with the systems selected for review that were not readily accessible, the inspectors reviewed the licensee's materiel condition surveillance records.

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

As available, the inspectors observed selected portions of the routine processing and discharge of radioactive gaseous effluent to evaluate whether appropriate treatment equipment was used and the processing activities aligned with discharge permits.

The inspectors determined if the licensee has made significant changes to its effluent release points.

As available, the inspectors observed selected portions of the routine processing and discharging of liquid waste to determine if appropriate effluent treatment equipment was being used and that radioactive liquid waste was being processed and discharged in accordance with procedure requirements and aligned with discharge permits.

These inspection activities constituted one complete inspection sample as defined in IP 71124.06.

b. Findings

No findings were identified.

.2 Calibration and Testing Program (02.03)

a. Inspection Scope

The inspectors reviewed calibration and functional tests for select effluent monitors to evaluate whether they were performed consistent with the ODCM. The inspectors assessed whether National Institute of Standards and Technology traceable sources were used, primary calibration represented the plant nuclide mix, secondary calibrations verified the primary calibration, and calibration encompassed the alarm set points.

The inspectors assessed whether effluent monitor alarm set points were established as provided in the ODCM and procedures.

The inspectors evaluated the basis for changes to effluent monitor alarm set points.

These inspection activities constituted one complete inspection sample as defined in IP 71124.06.

b. Findings

No findings were identified.

.3 Sampling and Analyses (02.04)

a. Inspection Scope

The inspectors reviewed select effluent sampling activities and assessed whether adequate controls had been implemented to ensure representative samples were obtained.

The inspectors reviewed select effluent discharges made with inoperable effluent radiation monitors and assessed whether controls were in place to ensure compensatory sampling was performed consistent with the ODCM and that those controls were adequate to prevent the release of unmonitored effluents.

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

The inspectors reviewed the results of the inter-laboratory comparison program to evaluate the quality of the radioactive effluent sample analyses and assessed whether the inter-laboratory comparison program included hard-to-detect isotopes as appropriate.

These inspection activities constituted one complete inspection sample as defined in IP 71124.06.

b. Findings

No findings were identified.

.4 Instrumentation and Equipment (02.05)

a. Inspection Scope

The inspectors reviewed the methodology used to determine the effluent stack and vent flow rates to determine if the flow rates were consistent with plant documentation, and that differences between assumed and actual stack and vent flow rates did not affect the results of the projected public doses.

The inspectors assessed whether surveillance test results for TS required ventilation effluent discharge systems met TS acceptance criteria.

These inspection activities supplemented those documented in NRC Inspection Report 05000341/2016003 and constituted one complete inspection sample as defined in IP 71124.06.

b. Findings

No findings were identified.

.5 Dose Calculations (02.06)

a. Inspection Scope

The inspectors reviewed significant changes in reported dose values compared to the previous radiological effluent release report to evaluate the factors, which may have resulted in the change.

The inspectors reviewed radioactive liquid and gaseous waste discharge permits, as available, to assess whether the projected doses to members of the public were accurate.

The inspectors evaluated the isotopes that are included in the source term to assess whether analysis methods were sufficient to satisfy detectability standards. The review included the current Part 61 analyses to ensure hard-to-detect radionuclides are included in the source term.

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

The inspectors reviewed the latest Land Use Census to assess whether changes have been factored into the dose calculations.

For select radioactive waste discharges, the inspectors evaluated whether the calculated doses where within the 10 CFR 50, Appendix I and TS dose criteria.

The inspectors reviewed select records of abnormal radioactive waste discharges to ensure the discharge was monitored by the discharge point effluent monitor. Discharges made with inoperable effluent radiation monitors, or unmonitored leakages were reviewed to ensure that an evaluation was made to account for the source term and projected doses to the public.

These inspection activities constituted one complete inspection sample as defined in IP 71124.06.

b. Findings

No findings were identified.

.6 Problem Identification and Resolution (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with the effluent monitoring and control program were being identified by the licensee at an appropriate threshold and were properly addressed for resolution. In addition, the inspectors evaluated the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving radiation monitoring and exposure controls.

These inspection activities constituted one complete inspection sample as defined in IP 71124.06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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 CAP 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 CAP 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.

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

.1 (Closed) Licensee Event Report 05000341/2016-004-00, "Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather"

On July 13, 2016, a severe thunderstorm warning was issued for Monroe County including the Fermi 2 site. Due to the high winds encountered, the TS limiting pressure for the secondary containment pressure boundary was not met 26 times for a total of 44 seconds. Most instances were 1 to 2 seconds in duration, with the longest recorded instance lasting 6 seconds. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The highest recorded pressure was +0.26 inches water column. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. All plant equipment responded as required to the changing environmental conditions and the reactor building heating, ventilation, and air conditioning (HVAC) system returned secondary containment pressure below the TS limit.

The licensee completed an 8-hour notification call (Event Notification 52084) on July 13, 2016, to report the inoperable secondary containment as required by 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. The licensee submitted licensee event report (LER) 05000341/2016-004-00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C)

as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses limit. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

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

LER 05000341/2016-004-00 is closed.

.2 <u>(Closed) Licensee Event Report 05000341/2016-005-00, "Secondary Containment Pressure Exceeded Technical Specification Due to Reactor Building HVAC Restart During High Winds"</u>

On August 2, 2016, while restoring the east train of reactor building HVAC after a surveillance test on the Division 2 SGTS subsystem, the TS limiting pressure for the secondary containment pressure boundary was not met for approximately 1 second. The maximum secondary containment pressure observed was approximately -0.120 inches water column. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC along with the SGTS already in operation returned secondary containment pressure below the TS limit.

The cause of this momentary loss of the secondary containment safety function was determined to be the combined effects of the reactor building HVAC startup sequence with high wind gust conditions outside the reactor building. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. During reactor building HVAC startup, the exhaust fan starts prior to the supply fan. Then respective dampers open in the same order to maintain a negative pressure in the reactor building. Although the licensee determined the associated time delay relays functioned as intended, it noted there was limited margin to ensure pressure would not increase during the startup sequence. As a corrective action, the licensee implemented a design change to increase the time delay between the start of the exhaust fan and the supply fan.

The licensee completed an 8-hour notification call (Event Notification 52149) on August 2, 2016, to report the inoperable secondary containment as required by 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. The licensee submitted LER 05000341/2016-005-00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could

have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably foresee and prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses limit. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

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

LER 05000341/2016-005-00 is closed.

.3 (Closed) Licensee Event Report 05000341/2016-007-00, "Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather"

On August 27, 2016, a severe thunderstorm warning was issued for Monroe County including the Fermi 2 site. Due to the high winds encountered, the TS limiting pressure for the secondary containment pressure boundary was not met six times. Each occurrence was approximately 1 second in duration. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The highest recorded pressure was +0.05 inches water column. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system returned secondary containment pressure below the TS limit.

The licensee completed an 8-hour notification call (Event Notification 52205) on August 27, 2016, to report the inoperable secondary containment as required by 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. The licensee submitted LER 05000341/2016-007-00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses limit. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum

throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

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

LER 05000341/2016-007-00 is closed.

.4 <u>(Closed) Licensee Event Report 05000341/2016-008-00, "Past Instances of Secondary Containment Pressure Exceeding Technical Specification Due to Adverse Weather"</u>

On November 15, 2016, the licensee completed a past reportability review of instances when secondary containment pressure exceeded the TS limit due to known effects of high winds between September 1, 2013 and September 30, 2016. This review was performed after the licensee had identified several recent events involving the loss of the secondary containment function due to high wind conditions, which were reported in separate LERs in 2016. Numerous instances were found during the past three years wherein digital secondary containment pressure recorder data showed the TS limiting value for secondary containment vacuum had been exceeded. Most instances were from 1 to 2 seconds in duration, with none of the recorded instances lasting longer than 30 seconds. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The highest recorded pressure during the 3-year period was +1.269 inches water column. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. In each instance, all plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system or SGTS returned secondary containment pressure below the TS limit without additional operator action.

The licensee submitted LER 05000341/2016-008-00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material. Because the instances described in this LER occurred in the past and there was no known loss of safety function at the time of discovery, no event notification was made under the corresponding requirement in 10 CFR 50.72.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was inoperable during each instance due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at any time. Upon receipt of an accident signal, the SGTS would have automatically started (or remained in operation) and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses limit. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release. As a corrective action to address these recurring events, in mid-December, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

The inspectors determined the licensee's failure to report these instances was contrary to 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." Accordingly, the inspectors documented a licensee-identified NCV in Section 4OA7 of this inspection report.

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

LER 05000341/2016-008-00 is closed.

.5 <u>(Closed) Licensee Event Report 05000341/2016-006-00, "Inadequate Interpretation of Technical Specifications Related to Mechanical Draft Cooling Tower Fan Brake System Leads to Condition Prohibited by Technical Specifications, Loss of Safety Function, and Unanalyzed Condition"</u>

During the Component Design Basis Inspection (CDBI) completed by the NRC in August 2016, the inspectors identified the licensee had been incorrectly interpreting TS requirements for inoperable mechanical draft cooling tower (MDCT) fans when the fan brakes were non-functional and documented a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion V for the licensee's failure to establish an appropriate procedure to address non-functional MDCT motor brakes (NRC Inspection Report 05000341/2016007).

For an UHS divisional reservoir to be operable, TS 3.7.2 requires two MDCT fans in that division to be operable. The MDCT fans have a brake system to prevent fan over speed during a tornado. The licensee had previously considered a MDCT fan and UHS reservoir to be inoperable due to non-functionality of the brake system only when a tornado watch or warning was in effect for the area near Fermi 2. The correct interpretation of TS 3.7.2 would be to declare the MDCT fans and UHS reservoir inoperable any time the brake system was non-functional. Following discovery of the incorrect interpretation of the TS requirements, the licensee reviewed the past operability of the MDCTs when the brake system was non-functional for the past three years. The review identified fifteen occurrences when the brake system was non-functional that should have resulted in entry into TS 3.7.2 for inoperable MDCT fans and UHS. These fifteen occurrences resulted in operations or conditions prohibited by the plant's TS since TS required actions were not completed within their completion times. In addition, five of the fifteen occurrences were also instances where the plant configuration was such that it could have prevented the fulfillment of the safety function of structures or systems needed to remove residual heat, control the release of radioactive material, or mitigate the consequences of an accident. Finally, four of the fifteen occurrences were instances where the plant was in an unanalyzed condition that significantly degraded plant safety.

The licensee completed a notification call (Event Notification 52202) on August 6, 2016, to report an unanalyzed condition related to inoperability of MDCT fans due to non-functioning brakes that had occurred on April 6, 2016. This resulted in an unanalyzed condition because the plant configuration at the time (i.e., an inoperable Division 1 UHS and EDGs coincident with testing of a Division 2 EDG) would not support safe shutdown capability in the event of a tornado. The licensee reported this as required by 10 CFR 50.72(b)(3)(ii)(B) as an event or condition that resulted in the nuclear plant being in an unanalyzed condition that significantly degrades plant safety. The licensee completed its past operability review on August 31, 2016 and identified five

additional instances of unanalyzed conditions within the past three years and reported these in Event Notification 52214. The licensee updated this later event notification on October 20, 2016 to revise the earlier notification, stating there were actually only four additional instances of unanalyzed conditions within the past three years.

The licensee submitted LER 05000341/2016–006–00 to report all of the above events. The fifteen instances of inoperable MDCT fans, for which the licensee failed to satisfy TS 3.7.2 required actions, were reported as required by 10 CFR 50.73(a)(2)(i)(B) as operations or conditions prohibited by the plant's TS. The five instances of loss of safety function were reported as required by 10 CFR 50.73(a)(2)(v)(B), (C), or (D) as events or conditions that could have prevented the fulfillment of a safety function of structures or systems needed to remove residual heat, control the release of radioactive material, or mitigate the consequences of an accident. In addition, the four instances of unanalyzed conditions were reported as required by 10 CFR 50.73(a)(2)(ii)(B) as events or conditions that resulted in the nuclear power plant being in an unanalyzed condition that significantly degraded plant safety. It should be noted that two instances separately listed in Event Notification 52214 from February 2014, 2016 were combined and counted as one instance in the LER.

The inspectors reviewed the two original 10 CFR 50.72 event notifications, the one event notification update, and the LER to determine whether the licensee satisfied the 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." The inspectors determined the information provided in the event notifications and the LER did not change the conclusion of the NRC's initial review conducted during the CDBI; however, it did provide additional information on the extent of the licensee's noncompliance with the applicable TS limitations that was not known during the CDBI. Inasmuch as the fifteen TS non-compliances described in the LER were the result of the performance issue already identified by the NRC during the CDBI, no additional finding was identified during this review.

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

LER 05000341/2016-006-00 is closed.

.6 <u>(Closed) Licensee Event Report 05000341/2016-009-00, "Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation"</u>

On April 24, 2016, a loss of output from the line-to-neutral potential transformers occurred on 4160 VAC 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 LOV and DGV relaying for ESF bus 64C. As discussed in Section 1R15.1.b.1 of this inspection report, the inspectors identified that the licensee did not correctly interpret and satisfy applicable TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources immediately following the event. This resulted in an operation or condition which was prohibited by the plant's TSs. In addition to the noncompliance with the TS LCO requirements, a loss of safety function of the onsite AC electrical power sources was created when surveillance testing was performed on the Division 2 EDGs while EDG 12 was inoperable.

The inspectors reviewed this issue and concluded the licensee's failure to satisfy the applicable TS LCO requirements for inoperable LOP instrument channels and inoperable AC power sources was contrary to the requirements of TS 3.3.8.1 "Loss of Power (LOP) Instrumentation," and TS 3.8.1, "AC Sources – Operating." Accordingly, the inspectors documented a finding of very low safety significance with an associated NCV of TS 3.3.8.1 and TS 3.8.1. In addition, the inspectors documented a Severity Level IV NCV of 10 CFR 50.73(a)(1), "Licensee Event Report System," because the licensee failed to submit an LER within 60 days after discovery. As discussed in Section 1R15.2 of this inspection report, the inspectors concluded that the licensee failed to satisfy the regulatory reporting requirements due to unwarranted delay in evaluating conditions from the event with respect to compliance with the TSs and reporting requirements.

The licensee submitted LER 05000341/2016–009–00 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 TSs. The licensee also reported the event in accordance with 10 CFR 50.73(a)(2)(v) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (B) remove residual heat, and (D) mitigate the consequences of an accident. 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 05000341/2016–009–00 is closed.

4OA5 Other Activities

.1 Follow Up Inspection for Three or More Severity Level IV Traditional Enforcement Violations in the Same Area in a 12-Month Period (92723)

This inspection was conducted in accordance with IP 92723, "Follow Up Inspection for Three or More Severity Level IV Traditional Enforcement Violations in the Same Area in a 12-Month Period," to assess the licensee's evaluation of five Severity Level IV NCVs that occurred within the area of impeding the regulatory process from July 1, 2015, to June 30, 2016. These violations were documented in NRC Inspection Reports as: (1) NCV 05000341/2015301-01; (2) NCV 05000341/2016001-03; (3) NCV 05000351/2016001-05; (4) NCV 05000341/2016001-10; and (5) a licensee-identified NCV documented in NRC inspection report 05000341/2016001.

The inspection objectives were to:

- Provide assurance that the causes of multiple Severity Level IV traditional enforcement violations were understood by the licensee;
- Provide assurance that the extent of condition and extent of cause of multiple Severity Level IV traditional enforcement violations were identified; and
- Provide assurance that licensee corrective actions for traditional enforcement violations were sufficient to address the causes.

The inspectors reviewed the licensee's cause evaluations associated with each of the Severity Level IV violations and apparent cause evaluation, "Adverse Trend in Reportability Related Issues." Additionally, the inspectors reviewed Quick Hit Self-Assessment Report, "Fermi 2 Preparation for NRC Follow Up Inspection 92723." The inspectors reviewed corrective actions to address the identified causes. The inspectors also held discussions with licensee personnel to ensure the causes were understood and corrective actions were appropriate to address the causes.

a. Evaluation of the Inspection Requirements

(1) Review of Problem Identification

i. Determine that the licensee's evaluation identifies how each of the issues were identified, how long each issue existed, and prior opportunities for identification

The inspectors determined the licensee's evaluation documented how each of the issues were identified, how long they existed, and whether there were prior opportunities for identification.

Each issue was individually evaluated through the licensee's corrective action program. Additionally, the licensee performed an apparent cause evaluation to review the five Severity Level IV violations collectively as an adverse trend and also completed a pre-NRC inspection self-assessment. The licensee's apparent cause determination documented a timeline of each violation, the event that led to each violation and the resulting actions from the violation.

(2) Evaluate Cause, Extent of Condition, and Extent of Cause Evaluations

i. Determine that the group of Severity Level IV violations received an evaluation at an appropriate level of detail using a systematic method(s) to identify cause(s)

The inspectors determined the Severity Level IV violations were reviewed collectively using a systematic process to identify any common cause(s). A Barrier Analysis analytical tool was used to evaluate different barriers that could have identified or eliminated the issues. Four barriers, oversight, training, written guidance and worker experience, were determined to be less than adequate or needing improvement. The licensee determined the violation associated with inadequate examination security in the simulator was not related to the other violations; therefore, the licensee's apparent cause evaluation mainly focused on the four reportability-related violations.

The inspectors determined the licensee's evaluation contained an appropriate level of detail. All four barriers were analyzed for each reportability event and the bases of their inadequacy were documented. In addition to the barrier analysis, the licensee also assessed the cause(s) for individual violations through the corrective action program. The licensee identified causes for each individual violation and prescribed corrective actions for each cause identified. The inspectors verified each Severity Level IV violation was adequately evaluated in accordance with the licensee's CAP requirements.

ii. Determine that the evaluation included a consideration of how prior occurrences in the same traditional enforcement area (willfulness, regulatory process, or consequences) were addressed by the licensee

The five Severity Level IV traditional enforcement violations in the impeding the regulatory process area were identified in a relatively short timeframe (six months). There were no Severity Level IV traditional enforcement violations issued by the NRC during the previous 5 years. Therefore, there were no prior occurrences to be addressed by the licensee in its evaluation.

iii. Determine that the evaluation addresses the extent of the condition and the extent of cause of the problem

The inspectors reviewed the individual CAP items for each of the Severity Level IV violations as well as the self-assessment performed by the licensee. The inspectors determined the licensee's CAP process augmented by the apparent cause evaluation addressed the extent of condition. The individual CAP items considered the extent of condition and addressed each of the deficiencies. The licensee performed searches in the CAP and determined the causes of the identified condition were limited to a consistent understanding of the reportability requirements. In accordance with its procedural requirement, the licensee did not perform an extent of cause review because it was not required to perform one for an apparent cause evaluation. The inspectors determined this was acceptable because the lack of understanding of reportability issues did not extend to other station processes.

(3) Evaluate Corrective Actions

i. Determine that appropriate corrective action(s) are specified for each cause identified for the group of violations or that there is an evaluation indicating that no actions are necessary

The inspectors determined appropriate corrective actions were specified for the causes identified for each of the Severity Level IV violations. The licensee's apparent cause evaluation identified two common apparent causes for the four Severity Level IV reportability-related violations and assigned corrective actions to address those causes. The licensee developed a new procedure to provide guidance for reportability and development of LERs. The new procedure also detailed the expected required licensing and operations oversight for reportable events, including the expected scope of each review.

In addition to the assigned corrective actions, the licensee also identified a number of improvement opportunities in the personnel training areas and enhancements for its procedures. The inspectors reviewed these enhancement actions and identified no deficiencies.

The licensee concluded the violation associated with inadequate examination security in the simulator was not related to the reportability violations; therefore, no common causes were assigned to this violation. The inspectors concurred with this determination. The licensee for this issue revised the procedure to verify both sides of the hard cards are cleaned prior to conducting simulator assessments and evaluations.

ii. Determine that the corrective actions have been prioritized with consideration of the regulatory compliance

The inspectors determined corrective actions were adequately prioritized with consideration of regulatory compliance. The licensee had revised or supplemented all incomplete or incorrect 10 CFR 50.72 and 10 CFR 50.73 reports. A number of procedure changes to provide guidance for determining immediate reportability and developing LERs was implemented. These procedure changes also detailed the required oversight for operations and licensing departments for dealing with reportable events. Additionally, training was provided to licensing engineers and all senior reactor operators for reportability issues, emphasizing conservative decision making.

The procedure change and event tailgating associated with inadequate examination security in the simulator was completed.

iii. Determine that a schedule has been established for implementing and completing the corrective actions

The inspectors determined a schedule was established for implementing and completing the corrective actions. All the prescribed corrective actions were completed. The inspectors conducted a sample review of completed corrective actions and did not identify any discrepancies.

iv. Determine that measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence

Measures of success were developed for determining the effectiveness of the corrective actions. The licensee plans to assess corrective action effectiveness by monitoring and reviewing event notifications, LERs, and corrective action documents that request licensing review for a period of 6 months against the guidance provided in NUREG 1022, "Event Report Guidelines 10 CFR 50.72 and 50.73, Revision 3."

No effectiveness review was determined to be necessary associated with inadequate examination security in the simulator.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Resident Inspectors' Exit Meeting

The inspectors presented the inspection results to Mr. M. Caragher and other members of the licensee's staff on January 5, 2017. 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 Radiation Safety Program inspection were presented to Mr. E. Kokosky and other members of the licensee's staff on November 4, 2016. The licensee acknowledged the findings presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

- The results of the Follow Up Inspection for Three or More Severity Level IV Traditional Enforcement Violations in the Same Area in a 12-Month Period (IP 92723) were presented to Mr. E. Kokosky and other members of the licensee's staff on November 10, 2016. The licensee acknowledged the findings presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

- The Annual Review of Emergency Action Level and Emergency Plan Changes were discussed by telephone with Mr. N. Avrakotos, on December 16, 2016. The licensee acknowledged the findings presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

- The Review of the 2016 Licensed Operator Annual Operating Test Results were discussed by telephone with Mr. M. Donigian on December 14, 2016. The licensee acknowledged the findings presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violations

The following two violations of very low safety significance (Green) or Severity Level IV were identified by the licensee and are violations of NRC requirements that meet the criteria of the NRC Enforcement Policy for being dispositioned as Non-Cited Violations.

- Title 10 of the CFR, Section 50.72(a)(1)(ii), requires, in part, that the licensee shall notify the NRC Operations Center via the Emergency Notification System of those non-emergency events specified in Paragraph (b) that occurred within three years of the date of discovery. 10 CFR 50.72(b)(3) requires, in part, that the licensee shall notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the applicable conditions. 10 CFR 50.72(b)(3)(v)(C) requires, in part, that the licensee report any event or condition, that at the time of discovery, could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

  10 CFR 50.73(a)(1) requires, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event. 10 CFR 50.73(a)(2)(v)(C) requires, in part, that the licensee report any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

  Contrary to the above:

  1. Between September 1, 2013 and September 30, 2016, the licensee failed to notify the NRC Operations Center via the Emergency Notification System of numerous non-emergency events specified in Paragraph (b) within eight hours of the events. These events involved the loss of safety function of the secondary containment when secondary containment pressure exceeded the TS limit due to known effects of high winds.

  2. The licensee failed to submit required LERs within 60 days after the discovery of numerous events between September 1, 2013 and September 30, 2016. These events involved the loss of safety function of the secondary containment when secondary containment pressure exceeded the TS limit due to known effects of high winds.

  Violations of 10 CFR 50.72 and 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to make reports to the NRC as required by 10 CFR 50.72(a)(1)(ii) and 10 CFR 50.73(a)(1). The licensee entered this violation into its CAP as CARD 16-27023.

- Title 10 of the CFR, Section 20.1501, requires, in part, that each licensee shall make, or cause to be made, surveys of areas that may be necessary for the licensee to comply with the regulations in this part and are reasonable for the circumstances to evaluate the magnitude and extend of radiation levels and the potential radiological hazards of the radiation levels. 10 CFR 20.1902(b) states

that the licensee shall post each high radiation area with a conspicuous sign or signs bearing the radiation symbol and the words “CAUTION, HIGH RADIATION AREA” or “DANGER, HIGH RADIATION AREA.”

Contrary to the above, on August 17, 2016, the licensee failed to conduct reasonable surveys to evaluate radiation levels to ensure compliance with the posting requirements of 10 CFR 20.1902(b) during activities known to cause changes in radiation levels. Specifically, the licensee failed to ensure surveys were performed while draining the annulus of the multi-purpose canister, which is an evolution known to change radiological conditions. An unposted high radiation area was identified several hours later when radiation protection personnel entered the area to perform surveys to ensure compliance with the container’s Certificate of Compliance. This violation was entered into the licensee’s CAP as CARD 16-26586. The finding was assessed in accordance with IMC 0609, Appendix C, “Occupational Radiation Safety SDP” and determined to be of very-low safety significance because it did not involve as-low-as-reasonably-achievable planning or work controls, there was no overexposure nor substantial potential for an overexposure, and the ability to assess dose was not compromised.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

N. Avrakotos, Manager, Radiological Emergency Response Preparedness
L. Bennett, Director, Nuclear Operations
M. Caragher, Executive Director, Nuclear Production
W. Colonnello, Director, Nuclear Project Management
K. Dittman, Acting Manager, Plant Support Engineering
D. Domski, Engineer, Plant Systems Engineering
M. Donigian, Supervisor, Operations Training
J. Haas, Supervisor, Licensing
D. Hemmele, Superintendent, Nuclear Operations
E. Kokosky, Director, Organization Effectiveness
R. Laburn, Manager, Radiation Protection
K. Locke, General Supervisor - Electrical, Plant Systems Engineering
S. Maglio, Manager, Licensing
R. Matuszak, Manager, Plant Systems Engineering
D. Noetzel, Director, Nuclear Engineering
K. Polson, Site Vice President
W. Raymer, Director, Nuclear 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

K. Riemer, Chief, Reactor Projects, Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000341/2016004-01	NCV	Inadequate Work Instructions for Maintenance on Flexible Couplings for EDGs (Section 1R12.b.1)
05000341/2016004-02	NCV	Failure to Correctly Interpret and Implement TS Requirements for LOP Instrumentation and AC Electrical Power Functions (Section 1R15.b.1)
05000341/2016004-03	NCV	Failure to Satisfy 10 CFR 50.73 Reporting Requirements for Loss of LOP Instrumentation and AC Electrical Power Safety Functions (Section 1R15.b.2)
05000341/2016004-04	NCV	Inadequate Testing of SGTS Filters (Section 1R22.b.1)
05000341/2016004-05	NCV	Failure to Lock an Area Meeting Locked High Radiation Area Conditions (Section 2RS1.1.b.1)

Closed

05000341/2016004-01	NCV	Inadequate Work Instructions for Maintenance on Flexible Couplings for EDGs (Section 1R12.b.1)
05000341/2016004-02	NCV	Failure to Correctly Interpret and Implement TS Requirements for LOP Instrumentation and AC Electrical Power Functions (Section 1R15.b.1)
05000341/2016002-03	URI	LOP Instrumentation TS 3.3.8.1 Applicability Following Bus 64C Potential Transformer Fuse Failures (Section 1R15.b.1)
05000341/2016004-03	NCV	Failure to Satisfy 10 CFR 50.73 Reporting Requirements for Loss of LOP Instrumentation and AC Electrical Power Safety Functions (Section 1R15.b.2)
05000341/2016004-04	NCV	Inadequate Testing of SGTS Filters (Section 1R22.b.1)
05000341/2016004-05	NCV	Failure to Lock an Area Meeting Locked High Radiation Area Conditions (Section 2RS1.1.b.1)
05000341/2016-004-00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather (Section 4OA3.1)
05000341/2016-005-00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Reactor Building HVAC Restart During High Winds (Section 4OA3.2)
05000341/2016-007-00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather (Section 4OA3.3)
05000341/2016-008-00	LER	Past Instances of Secondary Containment Pressure Exceeding Technical Specification Due to Adverse Weather (Section 4OA3.4)

05000341/2016-006-00	LER	Inadequate Interpretation of Technical Specifications Related to Mechanical Draft Cooling Tower Fan Brake System Leads to Condition Prohibited by Technical Specifications, Loss of Safety Function, and Unanalyzed Condition (Section 4OA3.5)
05000341/2016-009-00	LER	Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation (Section 4OA3.6)

Discussed

05000341/2015301-01	NCV	Inadequate Examination Security on a Simulator Reset (Section 4OA5.1)
05000341/2016001-03	NCV	Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Loss of Reactor Protection System Trip Safety Functions (Section 4OA5.1)
05000341/2016001-05	NCV	Failure to Satisfy 10 CFR 50.73 Reporting Requirements for a Condition Prohibited by the Plant's Technical Specifications (Section 4OA5.1)
05000341/2016001-10	NCV	Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Primary Containment Isolation Valve Actuations (Section 4OA5.1)

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

- CARD 15-20015; Evaluate Raising Circulating Water Pump Hose Heater Setpoints
- CARD 15-20227; Ice Formation on Protective Screen for Suction Side of North Turbine Building HVAC Supply Fan
- CARD 15-21200; Circuit Water Pump House Switchgear Room Heating Inadequate
- CARD 15-21241; No Heat in the Railroad Airlock with P1100 Isolated
- CARD 15-26310; Shift Number 5 Crew Learning Opportunity for Procedure Use and Adherence
- CARD 16-20002; Turbine Building HVAC Heating Steam Abnormalities
- CARD 16-28724; 27.000.04 Attachment 1 Implementation of Freeze Protection Measures Partial Complete
- CARD 16-29696; Heaters in Division 2 Residual Heat Removal Pump Room not Functioning Properly
- WO 42959690; Perform 27.000.04 Attachment 1 Implementation of Freeze Protection Measures

1R04 Equipment Alignment

- CARD 16-28543; Single Rod Scram of Control Room 26-07
- CARD 16-28575; Unplanned Engineered Safety Feature Actuation Following Surveillance Test on Fuel Pool Vent Radiation Monitor
- CARD 16-29216; NRC Identified Issue Concerning Reactor Core Isolation Cooling Standby Checklist
- CARD 16-29272; Degraded Reactor Core Isolation Cooling Insulation Found During Walk Down
- CARD 16-29276; NRC Identified Concern
- Diagram 6M721-2082; Standby Liquid Control System; Revision AB
- Diagram 6M721-2083; RHR Division 2; Revision BW
- Procedure 23.139; Standby Liquid Control System; Revision 49
- Procedure 23.205; Residual Heat Removal System; Revision 131
- Procedure 23.206; Reactor Core Isolation Cooling System; Revision 98
- Procedure 23.208; RHR Complex Service Water Systems; Revision 110
- Sketch 6M721-5704; Standby Liquid Control System Functional Operating Sketch; Revision I
- Sketch 6M721-5706-1; RHR Division 2; Revision AI
- Sketch 6M721-5709-1; Reactor Core Isolation Cooling System Sketch; Revision AM

1R05 Fire Protection

- CARD 16-28037; NRC Concern: Evaluation of Carbon Dioxide Hose Conditions Documented in CARD 16-00254
- CARD 16-28704; Fire Drill Package for Fire Drill Conducted on October 26 with Shift 3 and Frenchtown Fire Department did not Document De-brief Items
- Fire Brigade Drill; Scenario Number 11; October 26, 2016

- Procedure FP-AB-1-6d; Auxiliary Building First Floor Mezzanine, Zone 6, Elevation 603'6"; Revision 4
- Procedure FP-AB-2-9b; Auxiliary Building, Division 1 Switchgear Room, Zone 9, Elevation 613'6"; Revision 3
- Procedure FP-RB-2-10b; Reactor Building, Emergency Equipment Cooling Water, South, Zone 10, Elevation 613'6"; Revision 4
- Procedure FP-RB-3-15a; Reactor Building Thermal Recombiner System Area, Zone 15, Elevation 641'6"; Revision 3
- Procedure FP-RHR-1-11-EDG; RHR Complex, EDG 11 Room, Elevation 590'0"; Revision 4
- Procedure FP-RHR-1-11-OS; RHR Complex, EDG 11 Oil Storage Room, Elevation 590'0"; Revision 4
- Procedure FP-RHR-1-12-EDG; RHR Complex, EDG 12 Room, Elevation 590'0"; Revision 6
- Procedure HR-1-12-OS; RHR Complex, EDG 12 Oil Storage Room, Elevation 590'0"; Revision 3
- WO 42327950; Perform Annual Fire Drill with (Offsite) Frenchtown Fire Department

1R07 Heat Sink Performance

- Heat Exchanger Inspection Report; WO 43424541 – EECW Division 2 Heat Exchanger; September 23, 2016
- WO 43424541; Clean EECW Division 2 "B" Plate Type Heat Exchanger
- WO 44737052; Perform Division 2 UHS Silt Removal

1R11 Licensed Operator Requalification Program

- Procedure 22.000.02; Plant Startup to 25% Power; Revision 95
- Procedure 22.000.03; Power Operation 25% to 100% to 25%; Revision 100
- Procedure 22.000.04; Plant Shutdown From 25% Power; Revision 79
- Procedure 22.000.05; Pressure/Temperature Monitoring During Heat-up and Cool-down; Revision 48

1R12 Maintenance Effectiveness

- Apparent Cause Evaluation 16-26876; Mechanical Draft Cooling Tower Fan brake Nitrogen Supply Issues; Revision 0
- Apparent Cause Evaluation; CARD 16-25666; Lube Oil Leak on EDG 12 Flex Coupling; Revision 0
- Calculation of the Mechanical Draft Cooling Tower Fan Brake Nitrogen Supply; Report 90073-01 Prepared by Cygna Energy Services, Michael K. Bunner and Steven M. Aparicio; Revision 2; January 17,1990
- CARD 16-24435; Mechanical Draft Cooling Tower Fan D Brake High Pressure Nitrogen Bottle Pressure High
- CARD 16-25043; Mechanical Draft Cooling Tower Fan C Brake High Pressure Nitrogen Bottle Pressure High
- CARD 16-25666; Lube Oil Leak on EDG 12 During Surveillance
- CARD 16-25846; Observed Leakage Past E1100F184 And F185 While Performing 24.204.01
- CARD 16-26214; 2016 Component Design Basis Inspection – Mechanical Draft Cooling Tower A Fan Brake Nitrogen Pressure Low
- CARD 16-26377; 2016 Component Design Basis Inspection – Documentation Issue (Calculation 90073 01) for Mechanical Draft Cooling Tower Fan Brake 100 PSI Cylinder Upper Limit

- CARD 16-26762; 2016 Component Design Basis Inspection – Inadequate Interpretation of TS related to Mechanical Draft Cooling Tower Fan Brake System
- CARD 16-26876; High Pressure Brake Bottle for Mechanical Draft Cooling Tower Fan C is High Out of Service at 2025 PSIG
- CARD 16-26955; 2016 Component Design Basis Inspection – Additional Instances of Unanalyzed Conditions Related to Mechanical Draft Cooling Tower Fan Brake System
- CARD 16-27115; Wrong E11R400A/B/C/D Acceptable Range in Central Component Data Base Technical Instrument Data
- CARD 16-27748; Revise (Post) vendor Calculation 90073 01 to Correct Mechanical Draft Cooling Tower Brake Limitation
- CARD 16-28291; NQA, Gaps Identified During Review of ACE Performed for CARD 16-25666 EDG 12 Lube Oil Leak
- CARD 16-28802; Reactor Water Cleanup System Isolation
- Equipment Apparent Cause Evaluation CARD 16-26876; High Pressure Brake Bottle for Mechanical Draft Cooling Tower Fan C is High Out of Service at 2025 PSIG
- Procedure 23.208; Residual Heat Removal Complex Service Water Systems; Revision 110
- WO 45687237; Repair Lube Oil Leak Upstream of R3001C019 Standby Lube Oil Pump

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

- CARD 16-25832; Step Change in Gassing Levels in MUT 2B
- CARD 16-26108; Condenser Tube Leak in Northwest Hotwell Quad
- CARD 16-28228; Division 1 Off-site Power Inoperable due to DC6447 Operations Department Expectations (ODE-12) Predicted Threshold for Voltage Drop Exceeded
- CARD 16-28232; 120kV Off-site Source Declared Inoperable due to Internal N-1 Loss of Coolant Accident Contingency
- CARD 16-28235; Division 1 Off-site Power Inoperable Again due to DC6447 (ODE-12) Predicted Threshold for Voltage Drop Exceeded
- CARD 16-28241; Discrepancy Between Main Control Room Indication on Megavar Load and Internal Transmission Company/Statements of Consideration Indication
- CARD 16-28286; Internal N-1 Contingency Threshold Exceeded Four Times On October 17, 2016
- CARD 16-28444; 120kV Off-site Source Declared Inoperable Due to Internal N-1 Loss of Coolant Accident Contingency
- Fermi 2 Control Room Log; October 15 through 16, 2016
- Fermi 2 Control Room Log; October 24, 2016
- Nuclear Plant Operating Agreement for the Fermi 2 Nuclear Power Plant; NUC-001: R2
- ODE-12; LCOs; Revision 38 and 40
- ODMI 15-007; Increase in Main Turbine Generator Bearing Vibration; Revision 0
- ODMI 16-009; Reactor Recirculation Motor Generator Set A Scoop Tube Lock; Revision 0
- ODMI 16-011; MUT 2B Gassing; Revision 0
- ODMI 16-013; Spurious Half Main Steam Isolation Valve Channel D Isolation; Revision 0
- UFSAR Section 8.2-11; Revision 20

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

- Apparent Cause Evaluation CARD 16-23392; Loss of PT Secondary Voltages on 64A and 64C; Revision 0
- CARD 16-00204; Manhole 16947B Cable Vault Sump Pump Trips Circuit Breaker
- CARD 16-23392; SST 64 / Bus 64A Loss of Voltage Indication with Trouble Alarm
- CARD 16-23773; Found Incorrect Fuses Installed in 64V Primary PT

- CARD 16-23784; 64B Pot XFMR Primary Fuses not in Conformance with EJ Spec
- CARD 16-23788; Evaluate 4.16kV and 480V PT Secondary 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
- CARD 16-25374; Request Operational Guidance for G4100F052
- CARD 16-27374; Technical Evaluation TE-R14-16-022 was not Developed in a Timely Manner
- CARD 16-27381; Procedure 23.320 Allows SS64 LTC to be Placed in Manual Contrary to Design Basis
- CARD 16-27602; Evaluate Acceptability of Opening the RB-5 Hatch and Emergency Diesel Generator Missile Shield Opening
- CARD 16-28120; Review Operations Response to LOP Instrumentation Inoperability in CARD 16-23392
- CARD 16-28419; No Power to Sump Pump for Cable Vault 16947B
- CARD 16-28445; X4103F154 EDG 13 Diesel Room Return Air Damper has two Blades in the Closed Position
- CARD 16-28580; Discrepancy in DC-6356 Volume I Revision 0
- CARD 16-28738; Non-Conservative Fermi 2 Control Rod Drop A Licensing/Design Basis
- CARD 16-28906; One or More Low Pressure Turbine Stop Valve is Delayed in Fully Closing
- CARD 16-29068; OE323248R20161007 Potential Impact of a Tornado on the Emergency Diesel Generators
- CARD 16-29153; OE 323248 – Potential Impact of a Tornado on the Emergency Diesel Generators
- CARD 16-30164; NRC Violation – Failure to Submit Licensee Event Report Within 60 Days
- DC-6447; Auxiliary Power System Analysis; Volume 1
- DC-6685; Secondary Containment Loop Seals; Revision 0
- Diagram 6I721-2578-04; Relaying & Metering Diagram 416V S.S. Bus #64A & 68K; Revision M
- Diagram 6I721-2578-07; Relaying and Metering Diagram 4160V ESS Bus 64C; Revision O
- Equipment Apparent Cause Evaluation CARD 16-23392; SST 64 / Bus 64A Loss of Voltage Indication with Trouble Alarm; Revision 0
- EFA T41-16-006; Error in Calculation DC-6356 Volume I Revision 0; Revision 0
- EFA T41-16-007; Impact of Generic Safety Evaluation Release Path on Radiological Consequences of the Control Rod Drop Accident; Revision 0
- Event Notification 16-0016; Unanalyzed Condition for Control Rod Drop Accident at Low Power
- IEEE 338-1977; IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Safety Systems
- IEEE 603-1991; IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations
- LER 05000341/2016-009-00; Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation; Revision 0
- NRC Inspection Manual Chapter 0326; Operability Determinations and Functionality Assessments for conditions Adverse to Quality or Safety; December 3, 2015
- NRC Regulatory Guide 1.118; Periodic Testing of Electric Power and Protection Systems; Revision 3
- NRC Regulatory Issue Summary 2001-09; Control of Hazard Barriers
- NRC Regulatory Issue Summary 2013-05; NRC Position on the Relationship Between General Design Criteria and Technical Specification Operability
- NUREG-1022; Event Report Guidelines 10 CFR 50.72 and 50.73; Revision 3
- NUREG-1022; Event Report Guidelines 10 CFR 50.72 and 50.73; Revision 3

- NUREG-1443; Standard Technical Specifications, General Electric BWR/4 Plants; Volume 1; Revision 4.0
- ODMI 16-005; SST 64/ Bus64A & 64C Trouble; Revision A
- Procedure 43.302.08; Calibration and Functional Test of Division 1 4160 Volt Bus 64C Undervoltage Relays; Revision 36
- TE-R14-16-022; Engineering Functional Analysis on Impacts Caused by the Loss of Bus 64C Line PT Voltage to LOP Instrumentation (CARDs 16-23392 & 16-25194); Revision 0
- TE-R14-16-022; Engineering Functional Analysis on Impacts Caused by the Loss of Bus 64C Line PT Voltage to LOP Instrumentation (CARDs 16-23392 & 16-25194); Revision 1
- UFSAR Section 8.2.1.3; Revision 20

1R19 Post-Maintenance Testing

- Procedure 24.307.35; Diesel Generator Service Water, Diesel Fuel Oil Transfer and Starting Air Operability Test – EDG 12; Revision 55
- WO 34695193; Replace Oil Filter Canisters on N2103C002
- WO 46136191; Disassemble, Inspect, Clean and Repair as Necessary Discharge Check Valve
- WO 46136245; Personnel Monitoring Team Verify Proper Operation of Check Valve per 24.307.35
- WO 46439557; Replace the Demineralizer Water Isolation Valve C41000F014 for Standby Liquid Control Storage Tank
- WO 46439717; Replace the Demineralizer Water Isolation Valve C41000F010 for Standby Liquid Control Storage Tank
- WO V163140100; Refurbish 4160V Breaker 65W—W4 (East Standby Feed Water System Pump B)

1R20 Outage Activities

- CARD 16-29060; Main Steam Line Radiation Monitor Channels not Meeting Technical Specification Acceptance Criteria
- CARD 16-29094; South Reactor Feed Pump Would not Trip
- CARD 16-29099; Unexpected Response During South Reactor Feed Pump ‘Failure to Reset’ Troubleshooting
- CARD 16-29108; Increasing Trend Noted for Iodine 131, Cesium 134, and Cesium 137 During Planned Outage 16-2
- Procedure 22.000.02; Plant Startup to 25% Power; Revision 95
- Procedure 22.000.03; Power Operation 25% to 100% to 25%; Revision 100
- Procedure 22.000.04; Plant Shutdown From 25% Power; Revision 79
- Procedure 22.000.05; Pressure/Temperature Monitoring During Heat-up and Cool-down; Revision 48
- Procedure 23.205; Residual Heat Removal System; Revision 131
- Work Control Conduct Manual MWC-13; Outage Nuclear Safety; Revision 9

1R22 Surveillance Testing

- American Society of Mechanical Engineers Publication; Testing of Nuclear Air-Cleaning Systems, ANSI/ ASME N510—1980; 5/31/80
- CARD 16-28812; NRC Question Regarding Alignment of ANSI N510–1980 Standard with SGTS Testing Procedure
- Drawing 42.302.03; Revision 42
- Drawing I-2572-29; Revision N
- Drawing I-2578-09; Revision Q

- Drawing SD-2500-01; Revision BH
- Fermi 2 IST TM Plan; Revision 1
- Fermi 2 IST for Pumps and Valves Part 2; IST Program; Revision 1
- Fermi 2 IST Program for Pumps and Valves Part 10; IST Program Technical Positions; Revision 0
- Fermi 2 IST Program for Pumps and Valves Part 3; IST Pump Scope Table; Revision 1
- Fermi 2 IST Program for Pumps and Valves Part 4; IST Valve Testing Program; Revision 1
- Fermi 2 IST Program for Pumps and Valves Part 5; IST Valve Scope Table; Revision 1
- Fermi 2 IST Program for Pumps and Valves Part 6; IST Check Valve Condition Monitoring Plans; Revision 1
- Fermi 2 IST Program for Pumps and Valves Part 7; IST Program Relief Requests; Revision 0
- Fermi 2 IST Program for Pumps and Valves Part 8; IST Program Cold Shutdown Justifications; Revision 1
- Fermi 2 IST Program for Pumps and Valves Part 9; IST Program Refueling Outage Justifications; Revision 0
- NRC Regulatory Guide 1.52; Design, Testing, and Maintenance Criteria for Post-Accident Engineered-safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-water-Cooled Nuclear Power Plants; March 1978; Revision 2
- Procedure 24.202.01; High Pressure Coolant Injection Pump and Valve Operability Test at 1025 PSI; Revision 110
- Procedure 42.302.03; Channel Functional Test of Division 2 4160 Volt bus 65E Undervoltage Circuits; Revision 42
- Procedure 43.404.001; Standby Gas Treatment Filter Performance Test Division 1; Revision 41
- Procedure 43.404.002; Standby Gas Treatment Filter Performance Test Division 2; Revision 40
- WO 37354780; Perform 43.404.002 Division 2 Standby Gas Treatment Filter Performance Test
- WO 37456472; Perform 43.404.001 Division 1 Standby Gas Treatment Filter Performance Test
- WO 43070911; Perform 42.302.03 4160 V Bus 65E (EDG13) Division 2, Undervoltage Circuits, C/FUNC
- WO 43339695; Perform 24.202.01 High Pressure Coolant Injection Pump Flow Test and Valve Stroke at 1025 PSI
- WO 46484916; Perform 43.404.001 Division 1 Standby Gas Treatment Filter Performance Test

1EP4 Emergency Action Level and Emergency Plan Changes

- 10CFR50.54(q) Screen Number 2016-01E; January 8, 2016
- 10CFR50.54(q) Screen Number 2016-05S; February 5, 2016
- 10CFR50.54(q) Screen Numbers 2015-117S through 2015-126S; January 22, 2016
- 10CFR50.54(q) Screen Numbers 2016-01S through 2016-04S; January 22, 2016
- Card 15-23841; Emergency Action Level and Emergency Plan Changes Inspection
- Card 16-20506; NQA Audit Deficiency: ERO Positions Are Not in Alignment with the RERP Plan
- CARD 16-21814; RERP 2016 Improvement Plan
- EP 101; Classification of emergencies; Revisions 40 and 41
- EP 590; 10CFR50.54(q) Screens and Evaluations; Revision 0
  Fermi 2 Radiological Emergency Response Preparedness Plan; Revisions 45 and 46

2RS1 Radiological Hazard Assessment and Exposure Controls

- CARD 16-26522; 2 Dose Rate Alarms During Independent Spent Fuel Storage Installation Canister #4
- CARD 16-26586; Unposted High Radiation was Discovered While Performing Radiological Survey
- CARD 16-28186; Inadequate LHRA Controls for OSSF Mezzanine
- Electronic Dosimeter Alarm Evaluation; August 17, 2016
- Pre-Job Brief Checklist; August 16, 2016
- Procedure 35.710.044; MPC Transport; Revision 9A
- Radiological Survey 03232-R16; OSSF Mezzanine; October 13, 2016
- Radiological Survey; 02452-R16
- Radiological Survey; 02467-R16
- Radiological Survey; 02470-R16
- Radiological Survey; 02471-R16
- Radiological Survey; 02472-R16
- Radiological Survey; 02473-R16
- Radiological Survey; 02477-R16
- Radiological Survey; 02720-R16
- RWP 16-1055; 2016 Independent Spent Fuel Storage Installation Campaign; Revision 03
- RWP Job coverage Record; August 17, 2016

2RS6 Radioactive Gaseous and Liquid Effluent Treatment

- CARD 14-23236; Self-assessment Recommendation: Recalculate SPING Low Range Noble Gas Setpoints Based on February 10, 2014, Positive Noble Gas Sample
- CARD 14-25989; Elevated RB SPING Low Range Noble Gas Readings
- CARD 15-26164; Benchmark Recommendations: ODCM – Land Use Census and Critical Receptor
- CARD 16-22405; Elevated Reported Tritium Analysis Results for Effluent Samples
- Fermi 2 – 2014 Annual radioactive Effluent Release Report
- Fermi 2 – 2015 Annual radioactive Effluent Release Report
- Gaseous Effluent – RB SPING Surveillance – Weekly Package; November 1, 2016
- NPRP-14-0047; Recalculation of RB SPING Setpoint Based on 2/10/14 Sample; May 1, 2014
- Offsite Dose Calculation Manual; Revision 22
- Procedure 62.000.110; Evaluation of dose Rate Due to Radioactive Particulates, Iodine, and Tritium in gaseous Effluents; Revision 7
- Procedure 62.000.111; gaseous Effluent Dose Due to Iodines, Particulates, and Tritium; Revision 7
- Procedure 62.000.112; Noble Gas Site Boundary Dose Rate and Setpoint Evaluation; Revision 7
- Procedure 62.000.113; Noble Gas Site Boundary Air Dose and Release Evaluation; Revision 6A
- Release Permit; 15DW1; March 19, 2015
- SGTS Division 2 SPING Surveillance – Weekly Package; November 1, 2016
- Spent Fuel Pool Exhaust Surveillance – Weekly Package; November 1, 2016
- WO 37788360; Perform 64.080.110 Circulating Water System Decant Line Radiation Monitor Calibration
- WO 38565413; Perform 64.080.218 OSS BLDG Vent Exhaust PRM Calibration
- WO 42287264; Perform 64.080.206 – RB SPING Calibration – D11P280

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

- CARD 16-25580; Inclement Weather Results in Unplanned Limited Condition of Operation Entry, Emergency Operating Procedure Entry, Abnormal Operating Procedure Entry, and 8 Hour Report to NRC
- CARD 16-26102; Reactor Building Pressure > - .125" Waste Collector During Start of RBHVAC With East Train
- CARD 16-26762; 2016 Component Design Basis Inspection – Inadequate Interpretation of TS Related to Mechanical Draft Cooling Tower Fan Brake System
- CARD 16-26776; 2016 CDBI – Electrical Calculation Implementation Concerns
- CARD 16-26798; Inadequate Interpretations of Technical Specifications Identified by NRC
- CARD 16-26814; Inclement Weather Results in Unplanned LCO entry, EOP Entry, and 8 Hour Report to NRC
- CARD 16-26955; 2016 Component Design Basis Inspection – Additional Instances of Unanalyzed Conditions related to Mechanical Draft Cooling Tower Fan Brake System
- CARD 16-27023; Past Instances of Secondary Containment Inoperability Due to High Winds
- CARD 16-27111; Change Mechanical Draft Cooling Tower Fan Nitrogen Bottles Minimum Maximum Limits in Auto Tour
- Event Notification 52084; Secondary Containment Technical Specification Not Met
- Event Notification 52146, Secondary Containment Technical Specification Not Met
- Event Notification 52202; Unanalyzed Condition Related to the Inoperability of Mechanical Draft Cooling Tower
- Event Notification 52205, Secondary Containment Technical Specification Not Met
- Event Notification 52214; Unanalyzed Condition Related to the Inoperability of Mechanical Draft Cooling Tower
- LER 05000341/2016-004-00; Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather
- LER 05000341/2016-005-00; Secondary Containment Pressure Exceeded Technical Specification Due to Reactor Building HVAC Restart During High Winds
- LER 05000341/2016-006-00; Inadequate Interpretation of Technical Specifications Related to Mechanical Draft Cooling Tower Fan Brake System Leads to Condition Prohibited by Technical Specifications, Loss of Safety Function, and Unanalyzed Condition
- LER 05000341/2016-007-00; Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather
- LER 05000341/2016-008-00; Past Instances of Secondary Containment Pressure Exceeding Technical Specification Due to Adverse Weather
- LER 05000341/2016-009-00; Emergency Diesel Generator Inoperable Due to Open Circuit on Loss of Power Instrumentation
- NUREG-1022; Event Report Guidelines 10 CFR 50.72 and 50.73; Revision 3

4OA5 Other Activities

- Apparent Cause Evaluation CARD 16-21857; Adverse Trend in Reportability Related Issues; Revision 0
- CARD 15-21427; TS 3.3.1.1, Reactor Protection System Inst. Bases is Overly Conservative which Unnecessarily Causes Entry into Short Duration LCO (1 Hr)
- CARD 15-25243; Missed Technical Specification (TS) Entry – D2 EECW – UHS SSO July 2015
- CARD 15-26003; Hard Card Found Marked Up in Simulator During 2015 ILO Exam
- CARD 15-27661; NRC Severity Level IV NCV for Integrity of Exams and Tests at Fermi 2

- CARD 16-20564; NRC Senior Resident issues/Questions Associated with LER 2015-006 (Correspondence No. NRC-15-0094)
- CARD 16-20566; NRC Question on Reportability of CARD 15-25243
- CARD 16-21249; NRC Question on LER 2015-005
- CARD 16-21658; NRC SR Question on TS 3.3.1.1 Entry when Turbine Bypass Valves Opened on 1/6/16
- CARD 16-21857; Adverse Trend in Reportability Related Issues
- CARD 16-26065; NRC Violation – Severity Level IV NCV 05000341/2016001-03; Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Loss of Reactor Protection System Trip Safety Functions
- CARD 16-26066; NRC Violation – Severity Level IV NEC 05000341/2016005; Failure to Satisfy 10 CFR 50.73 Reporting Requirements for a Condition Prohibited by the Plant's Technical Specifications
- CARD 16-26069, NRC Violation - Severity Level IV NCV 05000341/2016001-10; Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Primary Containment solation Valve Actuations
- CARD 16-26545; NRC Violation – Inadequate Examination Security on a Simulator Reset
- General Regulatory Reporting Requirements List (GRRR List); Revision 63
- Licensing/Safety Engineering Conduct Manual Form MLS05006; Reportability Evaluation Worksheet; August 22, 2016
- Licensing/Safety Engineering Conduct Manual Implementing Procedure MLS05-100; Licensee Event Reports (LERS); Revision 0
- Licensing/Safety Engineering Conduct Manual MLS05; Notifications/General Regulatory Reporting Requirements; Revision 21
- Nuclear Licensing Work Instruction 0250; Licensee Event Report; Revision 0
- Nuclear Training Work Instruction 5.12; Conduct of Simulator Assessments & Evaluation; Revision 18
- Quick Hit Self-Assessment; Fermi 2 Preparation for NRC Follow Up Inspection 92723; November 1, 2016

LIST OF ACRONYMS USED

ΔCDF	Delta Core Damage Frequency
10 CFR	*Code of Federal Regulations*
AC	Alternating Current
ADAMS	Agencywide Document Access and Management System
ASME	American Society of Mechanical Engineers
CARD	Condition Assessment Resolution Document
CDBI	Component Design Basis Inspection
CTG	Combustion Turbine Generator
DGV	Degraded Voltage
EDG	Emergency Diesel Generator
EECW	Emergency Equipment Cooling Water
ESF	Engineered Safety Features
HEPA	High Efficiency Particulate Air
HVAC	Heating, Ventilation, and Air Conditioning
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHRA	Locked High Radiation Area
LOP	Loss of Power
LOV	Loss of Voltage
MDCT	Mechanical Draft Cooling Tower
NCV	Non-Cited Violation
NRC	U.S. Nuclear Regulatory Commission
ODE	Operations Department Expectations
ODCM	Offsite Dose Calculation Manual
ODMI	Operations Decision Making Issue
PARS	Publicly Available Records System
psig	Pounds per Square Inch Gage
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RIS	Regulatory Issue Summary
RPT	Radiation Protection Technician
SDP	Significance Determination Process
SGTS	Standby Gas Treatment System
SPAR	Standardized Plant Analysis Risk
SR	Surveillance Requirement
SSC	Structure, System, and/or Component
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
VAC	Volts Alternating Current
WO	Work Order

SUBJECT: FERMI POWER PLANT, UNIT 2—NRC INTEGRATED INSPECTION REPORT 05000341/2016004 AND REPORT 05000341/2016501

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