

August 10, 2007

Mr. Jack M. Davis  
Senior Vice President and  
Chief Nuclear Officer  
Detroit Edison Company  
Fermi 2 - 210 NOC  
6400 North Dixie Highway  
Newport, MI 48166

SUBJECT: FERMI POWER PLANT, UNIT 2, NRC INTEGRATED  
INSPECTION REPORT 05000341/2007004

Dear Mr. Davis:

On June 30, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Fermi Power Plant, Unit 2. The enclosed report documents the inspection findings which were discussed on July 6, 2007, with you and other members of your staff.

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

Based on the results of this inspection, five findings of very low safety significance were identified, four of which involved violations of NRC requirements. However, because these findings were of very low safety significance and because the issues were entered into your corrective program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Fermi 2 facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document 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/**

Christine A. Lipa, Chief  
Branch 4  
Division of Reactor Projects

Docket No. 50-341  
License No. NPF-43

Enclosure: Inspection Report 05000341/2007004  
w/Attachment: Supplemental Information

cc w/encl: J. Plona, Vice President,  
Nuclear Generation  
K. Hlavaty, Plant Manager  
R. Gaston, Manager, Nuclear Licensing  
D. Pettinari, Legal Department  
Michigan Department of Environmental Quality  
Waste and Hazardous Materials Division  
M. Yudasz, Jr., Director, Monroe County  
Emergency Management Division  
Supervisor - Electric Operators  
State Liaison Officer, State of Michigan  
Wayne County Emergency Management Division

J. Davis

-2-

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Letter to Jack M. Davis from Christine A. Lipa dated August 10, 2007

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No: 50-341  
License No: NPF-43

Report No: 05000341/2007004

Licensee: Detroit Edison Company

Facility: Fermi Power Plant, Unit 2

Location: Newport, Michigan

Dates: April 1 through June 30, 2007

Inspectors: R. Michael Morris, Senior Resident Inspector  
T. Steadham, Resident Inspector  
A. Dahbur, Reactor Engineer, DRS  
J. Rutkowski, Senior Resident Inspector, Davis Besse  
D. Schrum, Reactor Engineer, DRS  
A. Wilson, Reactor Engineer, DRP  
R. Winter, Reactor Engineer, DRS

Approved by: C. Lipa, Chief  
Branch 4  
Division of Reactor Projects

Enclosure

## SUMMARY OF FINDINGS

IR 05000341/2007004; 04/01/2007-06/30/2007; Fermi Power Plant, Unit 2; Fire Protection, Heat Sink, Maintenance Effectiveness, Operability Evaluations, and Problem Identification and Resolution.

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

### A. NRC-Identified and Self-Revealed Findings

#### **Cornerstone: Initiating Events**

- Green. The inspectors identified a finding of very low safety significance after the inspectors observed numerous fire hazards during a walkdown of several non-safety-related buildings located inside the protected area and the 120 kilovolt (kV) switchyard. These conditions increased the potential for a loss of offsite power from an external fire due to the loss of the 345 kV relay building and 120 kV relay building. The licensee removed the transient combustibles. The inspectors determined the finding was associated with cross-cutting aspect H.4(c), Human Performance, Work Practices.

This finding was considered more than minor because it increased the potential for a loss of offsite power due to an external fire. The finding was of very low safety significance because there was a reasonable potential for the licensee to identify and respond to a fire. Additionally, the emergency diesel generators were available and licensee control room staff were routinely trained in existing station procedures for addressing loss of offsite power. No violation of NRC requirements occurred. (Section 1R05.2)

#### **Cornerstone: Mitigating Systems**

- Green. The inspectors identified a finding of very low safety significance involving an NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control." The inspectors determined the licensee did not have analyses or adequate procedural guidance to ensure the emergency equipment cooling water (EECW) and emergency equipment service water (EESW) systems would be capable of operating with a high temperature in the drywell after a postulated station blackout event. The licensee entered the issue into their corrective action program to revise the station blackout procedure by providing additional guidance on restoring flow.

The finding was more than minor because the high temperature water in the drywell coolers and piping could cause two phase flow and water hammer in the EECW system.

In addition, a procedure instructed operations to turn on numerous drywell cooler fans which could cause the EECW and EESW systems to exceed their design temperatures for pumps, heat exchangers, and piping. This finding was evaluated using the Phase 2 SDP and determined to be of very low safety significance (Green), because of the low probability of station blackout event at Fermi. (Section 1R07.1)

- Green. An NCV of 10 CFR 50, Appendix B, Criterion V, "Procedures," for the failure to maintain adequate maintenance procedures to install the outboard mechanical seal for the reactor core isolation cooling pump was self-revealed when the seal failed. The procedure did not contain adequate guidance on the proper installation of the mechanical seal. As a result, the outboard seal was installed improperly and failed ten months later. The licensee replaced the seal and updated the maintenance procedure. The inspectors determined the finding was associated with cross-cutting aspect H.2(c), Human Performance, Resources.

This finding was considered more than minor because it contributed to a subsequent seal failure that affected pump operability as it increased pump unavailability more than a negligible amount. This finding was determined to be of very low safety significance because it did not represent a loss of high pressure safety injection, it did not result in an actual loss of the system for greater than 14 days, and it did not screen as potentially risk significant for external events. (Section 1R15)

#### **Cornerstone: Barrier Integrity**

- Green. The inspectors identified an NCV of paragraph (a)(1) of 10 CFR 50.65, "Maintenance Rule," for the failure to monitor the performance of the feedwater and residual heat removal injection check valve component class against licensee-established goals when the licensee classified the system as (a)(1) under the maintenance rule. The licensee developed goals but failed to monitor the component class against those goals. Consequently, the licensee failed to take appropriate corrective action as evidenced by the local leak rate test failure of both containment isolation valves in a feedwater injection penetration. The licensee entered the issue into their corrective action program to review the issue and develop corrective actions as appropriate and returned the component class to (a)(1) status. The inspectors determined the finding was associated with cross-cutting aspect P.2(b), Problem Identification and Resolution, Operating Experience.

This finding was considered more than minor because it was similar to a more than minor example in Appendix E of IMC 0612. Specifically, the component class was in (a)(1) status because the valves already exhibited significant equipment problems. This finding was determined to be of very low safety significance because the measured leakage rate was much less than 100 percent containment volume per day. (Section 1R12.1)

- Green. The inspectors identified an NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," for the failure to identify the cause and take appropriate corrective actions for a significant condition adverse to quality. The licensee failed to perform an adequate root cause related to an event when the total leakage through a containment penetration exceeded the maximum allowable Technical Specification limit. After the

issue was identified by the NRC, the licensee entered the issue into their corrective action program to further review the issue and develop additional corrective actions as appropriate. The inspectors determined the finding was associated with cross-cutting aspect P.1(c), Problem Identification and Resolution, Corrective Action Program Evaluations.

This finding was considered more than minor because if left uncorrected, the finding would become a more significant safety concern. Specifically, because the licensee did not arrive at the proper root cause, the licensee could not provide assurance that appropriate corrective actions to prevent recurrence were implemented. This finding was determined to be of very low safety significance because the measured leakage rate was much less than 100 percent containment volume per day. (Section 4OA2.4)

**B. Licensee-Identified Violations**

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



## REPORT DETAILS

### Summary of Plant Status

Unit 2 operated at or near full power throughout the inspection period.

#### 1. REACTOR SAFETY

##### **Cornerstone: Initiating Events, Barrier Integrity, Mitigating Systems, and Emergency Preparedness**

#### 1R01 Adverse Weather (71111.01)

##### a. Inspection Scope

The inspectors reviewed licensee procedures for mitigating the effects of the following adverse weather conditions:

- Hot Weather; and
- High Winds.

The inspectors reviewed severe weather procedures, emergency plan implementing procedures related to severe weather, and annunciator response procedures, as well as performed walkdowns. Additionally, the inspectors reviewed condition assessment resolution documents (CARDs) and verified problems associated with adverse weather were entered into the corrective action program with the appropriate significance characterization.

These activities completed one systems and one site inspection sample.

##### b. Findings

No findings of significance were identified.

#### 1R04 Equipment Alignment (71111.04Q)

##### a. Inspection Scope

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

- Emergency Diesel Generators (EDGs) 11 and 12, performed the week of April 23, 2007;
- 345 kilovolt (kV) and 120kv Switchyards, performed the week of June 4, 2007;
- Emergency Equipment Cooling Water (EECW) Division II, performed the week of June 18; and
- High Pressure Coolant Injection (HPCI), performed the week of June 18, 2007.

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones. The inspectors reviewed operating procedures, system diagrams, Technical Specification (TS) requirements, Administrative TS, 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 were aligned correctly.

In addition, the inspectors verified equipment alignment problems were entered into the corrective action program with the appropriate significance characterization.

These activities completed four quarterly partial system walkdown inspection samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection tours of the following risk-significant plant areas:

- Refueling Floor;
- Reactor Building, Second Floor;
- Auxiliary Building, Mezzanine Reactor Building Component Cooling Water Room;
- Division II, Switchgear Room;
- Turbine Building, Third Floor;
- Cable Tray Room;
- HPCI Room and Control Rod Drive Pump Room; and
- EDG 12.

The inspectors verified fire zone conditions were consistent with assumptions in the licensee's Fire Hazards Analysis. The inspectors walked down fire detection and suppression equipment, assessed the material condition of fire fighting equipment, and evaluated the control of transient combustible materials. In addition, the inspectors verified fire-protection-related problems were entered into the corrective action program with the appropriate significance characterization.

These activities completed eight quarterly fire protection - tour inspection samples.

b. Findings

No findings of significance were identified.

.2 345 kV and 120 kV Switchyard Relay Buildings (71111.05Q)

a. Inspection Scope

On June 7, 2007, the inspectors performed a fire protection inspection of the 345 kV and 120 kV switchyard relay building. As part of the walkdown of these areas, the inspectors assessed the storage of transient combustible and other stored items in the buildings.

These activities completed one quarterly fire protection - tour inspection sample.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) after the inspectors observed numerous fire hazards during a walkdown of non-safety-related switchyard relay buildings located inside the 345 kV and the 120 kV switchyard. These conditions increased the potential for a loss of offsite power from an external fire due to the relays in the 345 kV switchyard and 120 kV switchyard relay buildings. Because the buildings were non-safety related, no violation of regulatory requirements was identified.

Description: On June 7, 2007, the inspectors performed a walkdown of non-safety related 345 kV switchyard relay buildings located inside the protected area and the 120 kV switchyard that houses some controls for the station black out generator and transformer SS-64 relays associated with the standby feedwater (FW) system. During the walkdown, the inspectors identified numerous examples where combustible/flammable materials were not properly stored. Some of these examples included combustible/flammable materials not stored in fire-rated cabinets, ladders chain locked to cable trays, tables against cable trays, and boxes of miscellaneous combustibles next to cable conduit. These conditions were in violation of station expectations regarding the storage and control of combustible materials and housekeeping as described in Operations Conduct Manual, MOP 11, "Fire Protection."

The additional combustibles increased the risk of a fire in that if a fire occurred in these buildings, the fire and smoke could cause relays to trip, a loss of the related switchgear, and a subsequent trip of the main generator. None of these buildings had either automatic fire detection or suppression systems.

The licensee documented the inspectors' observations in CARD 07-23207. As discussed in this CARD, the licensee immediately removed all improperly stored flammable and combustible materials and removed the ladder. Additionally, the licensee revised the manual to include these buildings in their fire protection and housekeeping programs.

Analysis: The inspectors determined the failure to follow station procedures for the proper storage of transient combustible materials and use of temporary power sources was a performance deficiency warranting a significance evaluation in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued June 22, 2006. This finding was

considered more than minor because it could be reasonably viewed as a precursor to a significant event, specifically a loss of offsite power due to an external fire. This issue also affected the Mitigating Systems cornerstone objective to ensure that external factors, i.e., fire, flood, etc., do not impact the availability, reliability, and capability of systems that respond to initiating events in order to prevent core damage. The inspectors determined this event affected the cross-cutting area of H.4(c), Human Performance, Work Practices, because of the failure of licensee staff to require contractors to follow station procedures.

The inspectors performed a significance determination of this issue using IMC 0609, "Significance Determination Process" (SDP), dated November 22, 2005, Appendix F, "Fire Determination Significance Determination Process," dated February 28, 2005.

As stated, the failure to follow station procedures for the proper storage of transient combustible materials and location of ladders was a performance deficiency that was considered more than minor. This met the Phase I qualitative screening criteria as discussed in Appendix F. Per step 1.1 of this appendix, the inspectors determined this finding affected the category of Fire Prevention and Administrative Controls in that combustible material was not being properly controlled in these buildings.

Per step 1.2 of Appendix F, the inspectors determined this finding had a "low" degradation rating. Although these buildings were unoccupied and did not have automatic fire suppression or detection systems, the outside general area was a high traffic area and a fire would likely be noticed and reported to the main control room. In the event that offsite power were lost, EDGs were available and licensee control room staff were routinely trained in existing station procedures for addressing this event. Therefore, per step 1.3.1 of Appendix F, the inspectors concluded this finding was of very low safety significance (Green).

Enforcement: The inspectors concluded that no violation of regulatory requirements occurred because the buildings and contents were not safety related. As stated, the licensee entered the inspectors' observations into their corrective action program. This finding is described as FIN 05000341/2007004-01: Failure to Control Transient Combustibles.

## 1R07 Heat Sink Performance 71111.07B

### .1 Biennial Review of Heat Sink Performance

#### a. Inspection Scope

From March 26 through 29, 2007, a specialist inspector performed the biennial assessment of heat sink performance by reviewing documents associated with the Division I EECW heat exchanger, the HPCI room cooler, and the reactor core isolation cooling (RCIC) Room Cooler. These heat exchangers were chosen for review based on their risk assessment worth in the licensee's probabilistic safety analysis and their important safety-related mitigating system support functions.

While on-site, the inspectors verified the inspection, engineering, and maintenance activities were adequate to ensure proper heat transfer for those heat exchangers included in the inspection. This was done by reviewing heat transfer capability calculations, reviewing the methods used to test and inspect the heat exchangers, verifying the as-found results were appropriately dispositioned, and by personnel interviews. The inspectors also verified, by review of procedures, test results, and interviews, that chemical treatment and methods used to control biotic fouling corrosion and macro-fouling were sufficient to ensure required heat exchanger performance. The inspectors verified the condition and operation of these heat exchangers were consistent with design assumptions in heat transfer calculations by reviewing related procedures and surveillances. In addition, the inspector reviewed the emergency equipment service water (EESW) and EECW systems design in terms of limiting conditions for loss of coolant accident, main steam line break, and station blackout (SBO).

Also while onsite, the inspectors verified two attributes of the ultimate heat sink (UHS) as required by IP 71111-07B, Section 2.02, items d.1.d and d.4. The inspectors reviewed documentation to verify performance of the UHS. Specifically, the inspectors reviewed the availability of the UHS with bio-fouling conditions. In addition, the inspectors verified the ultimate heat sink capacity. This was done through review of licensee procedures and completed surveillance tests, or interviews with licensee engineers. These reviews were done to confirm that a program had been established and implemented consistent with licensee commitments to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

The inspectors reviewed condition reports associated with the selected heat exchangers or those related to the UHS to verify the licensee had an appropriate threshold for identifying issues. The inspectors also evaluated the effectiveness of the corrective actions for identified issues, including design changes and engineering justifications for operability. These reviews were done to ensure compliance with 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

The documents that were reviewed are included at the end of the report.

These activities completed three biennial heat sink performance inspection samples.

b. Findings

Restoration of Drywell Following SBO Event Does Not Control Rate of Heat Addition to EECW and No Analyses Were Performed for Potential Two Phase Flow and Water Hammer.

Introduction: The inspector identified a finding of very low safety significance (Green) involving an NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control." The inspector determined the licensee did not have analyses or adequate procedures to ensure the EECW and EESW systems were capable of operating for the high drywell temperatures after a postulated SBO event. Specifically, the high temperature water in the drywell coolers and piping could cause two phase flow and water hammer in the EECW system. In addition, a procedure instructed operations to turn on numerous

drywell cooler fans which could cause the EECW and EESW systems to exceed their design temperatures for pumps, heat exchangers, and piping.

Description: The EECW system is a closed loop cooling system used for cooling most safety-related room coolers and pumps. The design temperatures for EECW heat exchangers, supply piping, and pumps are 150°F Fahrenheit (°F), 95°F, and 120°F, respectively.

Per UFSAR Section 8.4, the Fermi SBO coping duration is four hours. Combustion Turbine Generator 11-1 is designated as an alternate AC power source for the plant and is available within one hour. Plant coping is controlled predominately by class IE DC power and steam driven sources until the alternate AC power is available for loading within one hour. The inspectors determined the temperatures as a result of an SBO would represent a significant challenge for the EECW and EESW systems. Specifically, design calculation DC 4976, "NUMARC Station Blackout Loss of Ventilation Effects on Temperature," Revision C, indicated drywell temperatures of 291°F after one hour, and 353°F after four hours with no area cooling. The licensee did not have an analysis to show the appropriate operator actions based on equipment temperature design limits and drywell heat up from decay heat. Potentially, the temperature limits will be exceeded for the EECW, EESW, and for the drywell equipment.

During review of the inspector's concerns, the licensee identified that the existing procedures, Emergency Operating Procedures, and Procedure 29.300.SBO, "Loss of Offsite and Onsite Power Abnormal Operating Procedure," Revision 0, did not provide adequate guidance to the plant's operation staff for preventing the design temperatures of the EECW system from being exceeded after numerous fan coolers were started in the drywell. Specifically, once power is restored to EECW, the operators close the P4400-F607A, EECW drywell return-side isolation valve, and verify closed/close the P4400-F606A, EECW drywell supply isolation valve. The operators then would start the EECW pump and manually restart each of the individual safety-related cooler fans. Procedure 29.300 then directs the operators to defeat the drywell isolations in accordance with the 29.ESP.23 procedure and gradually restore cooling water flow. Having restored cooling water flow, the drywell cooling fans would be started. The 1 and 2 drywell coolers would be in operation in slow speed in response to the high drywell pressure. The procedure directs the operators to start the remaining five drywell coolers. No additional caution or direction was provided regarding the potential for significant heat addition to the EECW system.

The inspectors determined that if the operators quickly re-initiate full drywell cooling, the instantaneous restoration of all drywell cooling could introduce a very high, short-term EECW heat load that is several multiples of the system design heat load as a result of the high temperature air in the drywell. In addition, the inspector was concerned with a potential water hammer in the EECW piping caused from two phase flow. Specifically, during an SBO, the temperature of the water in the drywell coolers and piping would be heated as drywell air temperature increased to 291°F. When operators restore the EECW flow to the coolers, the heated water inside the containment piping will be mixed with colder water, resulting in a potential for two phase flow (steam and water) and water hammer when the steam collapses. The licensee had not analyzed this condition for SBO temperature conditions.

The licensee stated that the EECW system does have a high temperature alarm and the operations staff would take actions based on that alarm. However, it is unknown whether the operations staff would attempt to reduce the amount of heat removed from the drywell or they would attempt to limit the temperature rise of the drywell, which would soon exceed the environmental qualification limits for that equipment.

In Card 07-21770, the licensee stated that their corrective action would be to revise Procedure 29.300 to direct the shutting down of the drywell cooler fans prior to flow restoration and then restoring fans, one at a time in a controlled fashion to manage the incremental heat addition to the EECW system. The inspectors noted that delayed restoration of cooling to the drywell will result in higher drywell temperatures and that the evaluation contained in Attachment 2 of CARD 07-21770 did not address this point.

Analysis: The inspectors determined that the failure to ensure that the EECW and EESW systems would be capable of operating at the high temperature in the drywell after a postulated SBO event was a performance deficiency.

The finding was more than minor because it affected the equipment performance attribute in the Mitigating Systems Cornerstone and was associated with the operability, availability, reliability, or function of the EECW and EESW systems following an SBO. The instantaneous restoration of all drywell cooling could introduce very high short term EECW heat loads that are several multiples of the system design heat load as a result of the high temperature air in the drywell. In addition, the inspectors were concerned that two phase flows (steam and water) and water hammer when the steam collapsed could affect the EECW system when operators restored the EECW flow to the coolers.

The Region III SRA assisted in the risk assessment of this performance deficiency. The one initiating event related to the performance deficiency is SBO. After reviewing the risk-informed inspection notebook for Fermi, the SRA determined that this performance deficiency could only affect large early release frequency (LERF) without affecting core damage frequency (CDF). This is because the mitigating functions for SBO shown in the Fermi notebook remained unaffected by the finding:

- emergency ac power, offsite power recovery within seven hours; and
- emergency ac power, offsite power recovery within one hour, and high pressure injection.

The SRA performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." The SRA determined that this was a "Type B" finding (i.e., had no impact on the determination of delta CDF). The SRA reviewed the SSCs listed in Table 6.1, "Phase 1 Screening-Type B Findings at Full Power," to determine if the finding was associated with an SSC(s) important to LERF. Fermi is a BWR-4 with a Mark I Containment. The SSCs listed in the table for Mark I Containments were:

- Containment Penetration Seals, Isolation Valves, Vent and Purge Systems;
- Suppression Pool Integrity;
- MSIV Leakage ; and
- Drywell/Containment Sprays.

The SRA determined that this finding was not associated with one of the SSCs listed above which are important to LERF. Therefore, this finding is best characterized as a finding of very low risk significance (Green).

The inspectors did not identify a cross-cutting aspect associated with this finding.

Enforcement: Title 10 CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures provide for verifying or checking the adequacy of design. Contrary to the above, the licensee failed to perform an analysis of the design to verify that the EESW and EECW Systems would have been capable of performing their required functions following an SBO event. Because this issue was of very low safety significance, and it was entered into the licensee's corrective action program (CARD 07-21770), this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000341/2007004-02)

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On June 6, 2007, the inspectors observed an operations support crew during the annual requalification examination in mitigating the consequences of events as part of the Blue Team, Emergency Preparedness Drill on the simulator. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

These activities represented one quarterly licensed operator requalification inspection sample.

b. Findings

No findings of significance were identified.



1R12 Maintenance Effectiveness (71111.12)

.1 Routine Evaluations (71111.12Q)

a. Inspection Scope

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

- CARD 07-21396, Division II Control Air Compressor Not Loading/Unloading as Expected; and
- CARD 06-21751, Check Valve Penetration Failure.

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

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b);
- characterizing system reliability issues;
- tracking system unavailability;
- trending key parameters (condition monitoring);
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification and/or re-classification; and
- verifying appropriate performance criteria for systems classified as (a)(2) and/or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization.

These activities completed two quarterly maintenance effectiveness inspection samples.

b. Findings

Introduction: The inspectors identified a Green non-cited violation (NCV) of paragraph (a)(1) of 10 CFR 50.65, "Maintenance Rule," for the failure to monitor the performance of the FW and residual heat removal (RHR) injection check valve component class against licensee-established goals when the licensee classified the system as (a)(1) under the maintenance rule.

Description: On November 14, 2001, the licensee initiated CARD 01-20794 to evaluate placing primary containment isolation valve system A7100 into (a)(1) status due to excessive valve performance problems. The licensee experienced 11 containment isolation valve local leak rate test (LLRT) failures over the previous two refueling cycles which exceeded the performance criterion of less-than-or-equal-to 10 LLRT failures per two refueling cycles. The licensee considered a maintenance rule LLRT failure to be a

measured leakage rate that exceeds 0.45 times the maximum allowable containment leakage,  $L_a$ .

The maintenance rule expert panel determined the FW and RHR isolation check valves constituted a significant contributor to the LLRT failures, created a component class for the FW and RHR valves, and placed that component class into their (a)(1) maintenance rule monitoring program. That class included, in part, the outboard FW isolation valves B2100F076A/B and the inboard FW isolation valves B2100F010A/B.

The original get-well plan was approved on February 26, 2002, and included the corrective actions and monitoring goals. Corrective actions included revising maintenance procedures, enhancing training, and extending the soft seat replacement frequency from every two to every three refueling outages. One of the monitoring goals was, "No LLRT failures for B2100F076A/B and B2100F010A/B subsequent to refueling outage (RF) 10."

During both RF09 and RF10, B2100F076B failed the as-found LLRT. Additionally, between both outages, the as-found LLRT results of the other three FW check valves exceeded administrative leakage limits. During RF10, the licensee re-lapped the valve seat for B2100F010B and determined similar actions were necessary for the other three valves. The licensee scheduled the work to be performed during RF11 for B2100F076A and B2100F010A and during RF12 for B2100F076B.

In December 2005, during an effort to reduce the open CARD backlog, the licensee reviewed CARD 01-20794 for closure. On January 24, 2006, the expert panel reviewed the system for return to (a)(2) status and concluded the cause of the LLRT failures was known, numerous corrective actions were taken, valve reliability improved, and the A7100 system, as a whole, was now well within its (a)(2) performance criteria. The expert panel returned the FW/RHR injection check valves to (a)(2) status on January 24, 2006.

Through interviews and document reviews, the inspectors learned the licensee measured performance improvement based on the entire A7100 system, which contained 188 valves, against the (a)(2) performance criteria instead of the performance of the monitored valves against their established goals. When the expert panel returned the component class to (a)(2), the relevant LLRT failure goal was still "subsequent to RF11" which had not yet taken place. The inspectors determined the goals were not reasonable because the inherent monitoring period of "subsequent to RF10" and later, "subsequent to RF11" did not allow for any meaningful monitoring of LLRT failures while the valves were in (a)(1) status.

On April 1, 2006, during RF11, both B2100F076A and B2100F010A failed their as-found LLRT with a total penetration leakage exceeding  $L_a$  constituting a functional failure. The inspectors concluded the corrective actions taken before the system was returned to (a)(2) status were not adequate as evidenced by the subsequent functional failure of both valves during RF11.

Although the licensee's maintenance rule procedures required goals to be established, there was no requirement to monitor the goals or to take corrective action if a goal was not met. For example, Procedure MMR 09, Revision 6, "Establishment of Get-Well Plans," described goal development but discussed neither the monitoring against those goals nor the required actions if a goal was not met. The inspectors identified three examples of how the failure to monitor the component class against licensee-established goals contributed to the failure to develop appropriate corrective actions.

#### Example 1

As part of the get-well plan, the licensee reviewed the preventative maintenance (PM) frequency for changing the valve soft seats. The PM frequency of every two refueling cycles was originally based on an EQ calculation which used laboratory temperature and radiation test data only. Using Arrhenius methodology, the licensee re-analyzed the normal environmental conditions and calculated the new soft seat lifetime to be 4.55 years. The soft seat replacement for B2100F076A was scheduled for RF10 since it was last replaced in RF08; however, immediately prior to RF10, the licensee deferred the PM to RF11 citing the revised EQ calculated service life. The licensee concluded the soft seat would not degrade to a degree that would cause LLRT failure as long as the replacement was still within the calculated EQ replacement life.

The inspectors determined the evaluation used to defer the soft seat replacement was inadequate because the licensee failed to consider the effects of other degradation mechanisms such as wear and erosion. The inspectors identified operating experience available to the licensee at the time of the evaluation that identified both wear and erosion as credible failure mechanisms. As documented in CARD 06-21751, the licensee had no historical evidence that the soft seats could physically last for more than two cycles and CARD 03-16598 documented an LLRT failure of B2100F076B during RF09 due to soft seat degradation as a result of normal operating conditions after only one cycle in operation. In Deviation Event Report 96-1361, dated May 10, 1997, the licensee determined that repeated impacts of the soft seat material against the valve seat as the material ages and hardens could have a rapid detrimental effect.

In memo TMPE-00-0466, dated December 22, 2000, the licensee concluded they could not estimate the service life of the soft seats due to normal operating conditions using Arrhenius methodology; and trending of seal performance, compression set, and hardness testing was needed to amend the time-at-temperature life estimates previously provided. The licensee had no knowledge of any such trend ever being performed.

NUREG/CR-4302, published in December 1985, identified the significant stressors and failure causes of the soft seat in these types of valves were from wear and erosion, not temperature and radiation. Through interviews, the inspectors learned the engineers who performed the PM frequency extension were not aware that wear and erosion were credible degradation mechanisms because they were unaware of any internal or external operating experience that identified wear and erosion as failure mechanisms. As documented in CARD 06-21751, the licensee determined the primary failure mechanism of B2100F076A during RF11 was soft seat erosion as a result of extended in-service time of the soft seat.

### Example 2

As described in Section 4OA2.4 of this report, both the licensee and the industry previously determined that continued operation at power levels insufficient to ensure the FW check valve discs remained full open carried a potentially high risk of valve degradation. While failures commonly seen with valve tapping have occurred at Fermi, the licensee failed to take corrective actions that would ensure the reliability of the valves from this phenomena. Specifically, because the licensee had already determined that operating at certain power levels carried a high probability of degrading the valves, the inspectors determined that, at a minimum, evaluating the necessity to track and/or control the time spent at such power levels was integral to ensuring valve reliability. The inspectors could find neither any operational constraints, precautions, or limitations to operating at those power levels nor any process that would trigger an evaluation of the effects on the valves should extended operation at those power levels occur.

### Example 3

The licensee identified inadequate procedural guidance as a cause of the excessive LLRT failures and identified the need to revise the associated maintenance procedures in the first revision of the get-well plan. The licensee identified the requirement to ensure the soft seat height above the hard seat was between 0.020 inch and 0.030 inch and revised Procedure 35.137.007, Spring Assist Closing Check Valve B2100F076A(B) Maintenance, on January 17, 2003, to include that verification. Procedure 35.137.005 was a similar procedure used for the inboard valves B2100F010A/B, but that procedure was not similarly revised.

During performance of Work Request (WR) 000Z031251 to replace the soft seat for B2100F010A during RF09, the as-left resilient seat height was between 0.030 inch and 0.050 inch indicating non-uniform soft seat extrusion which could have been caused by an improperly installed seat retaining ring. During RF11, B2100F010A experienced an LLRT failure coincident with B2100F076A as described above. The licensee determined the primary failure mechanism was soft seat degradation due to normal wear and misalignment of the internal shaft and the disc arm bore and misalignment of the disc to inbody seat; however, the licensee neither reviewed WR 000Z031251 nor identified the missing seat height acceptance criteria in Procedure 35.137.005 as described in Section 4OA2.4 of this report.

The inspectors determined that an improperly installed seat retaining ring could cause a subsequent LLRT failure and that Procedure 35.137.005 did not have sufficient guidance on how to properly install the seat retaining ring. Once identified, the licensee entered this issue into their corrective action program as CARD 07-22807 and issued a procedure revision request to modify the procedure accordingly.

Analysis: The inspectors determined the failure to monitor the FW/RHR check valve component class against licensee-established goals was a performance deficiency. This finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," because the system was in (a)(1) status as a result of previously exhibited significant equipment problems.

## Phase 1 Assessment

The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." In accordance with the "SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems], and B [Barrier Integrity] Cornerstones," the inspectors determined the finding was attributable to the Containment Barriers Cornerstone. Regarding Question 3 in the Containment Barriers Cornerstone, "Does the finding represent an actual open pathway in the physical integrity of reactor containment . . .," the inspector answered "yes." Therefore, an assessment using IMC 0609, Appendix H, "Containment Integrity Significance Determination Process" was warranted.

## Appendix H Assessment

The analyst determined this to be a Type B finding, which according to Appendix H are findings potentially important for containment integrity without affecting the likelihood of core damage. The screening criteria of Type B findings are listed in Table 6.1 of Appendix H. For a Mark I containment such as Fermi, a Phase 2 assessment is required for findings associated with containment isolation valves. Table 6.2 provides the Phase 2 assessment. For inspection findings involving containment leakage rates, if the as-found leakage rate is less than the values listed in Table 6.2, the finding is "Green." Table 6.2 states such leakage rates are less than 100 percent of the containment volume per day. This is also approximately the size of a 1-inch diameter hole in a Mark I containment according to IMC 0308, the technical basis document for Appendix H.

For the particular case at Fermi, the finding is associated with a leak rate of 7776 standard cubic feet per day. The containment volume is estimated at 163,000 cubic feet. The analyst estimated it would take about 21 days at this leak rate to leak the entire containment volume through the FW line containment isolation valves. Based on the estimated leak rate being much less than 100 percent containment volume per day for this Type B finding, the analyst concluded the total delta-CDF was much less than  $1 \times 10^{-7}$ , representing a Green finding.

The licensee entered this issue into their corrective action program as CARD 07-23048 and was still reviewing the issue to determine the necessary corrective actions. The finding is associated with the cross-cutting aspect of Problem Identification and Resolution, Operating Experience, because relevant operating experience was not adequately utilized by the licensee when maintenance was deferred (P.2(b)). The inspectors concluded the deferred maintenance was indicative of current licensee performance because the licensee last updated the PM deferral evaluation on May 3, 2005, which is within two years from the start of this inspection period.

Enforcement: 10 CFR 50.65 (a)(1), requires, in part, that the licensee shall monitor the performance or condition of structures, systems, or components (SSCs) within the scope of the rule against licensee-established goals in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions. When the performance or condition of an SSC does not meet established

goals, appropriate corrective action shall be taken. Contrary to the above, from December 18, 2001, to January 21, 2006, the time that the RHR/FW injection check valves were in the scope of the monitoring program, the licensee failed to develop reasonable goals, failed to monitor against the goals that were developed, and, therefore, did not take appropriate corrective actions when the performance of the RHR/FW injection check valves did not meet licensee-established goals as evidenced by the functional failure of the inboard and outboard "A" FW line isolation valves on April 1, 2006. This failure is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000341/2007004-03: Residual Heat Removal/Feedwater Injection Check Valves Inadequate Goal Monitoring in 10 CFR 50.65(a)(1) Status.)

.2 Periodic Evaluation of Maintenance Effectiveness (71111.12B)

a. Inspection Scope

The inspectors examined the two latest Maintenance Rule periodic evaluation reports completed for the periods of August 2003 through January 2005, and February 2005 through August 2006. The inspectors reviewed a sample of (a)(1) Action Plans, Performance Criteria, Functional Failures, and Condition Reports to evaluate the effectiveness of (a)(1) and (a)(2) activities. These same documents were reviewed to verify that the threshold for identification of problems was at an appropriate level and the associated corrective actions were appropriate. Also, the inspectors reviewed the Maintenance Rule procedures and processes. The inspectors focused the inspection on the following systems (samples):

- Auxiliary Electrical (4160 vac, 480 vac, CTG 11-1);
- Vital Power (Modular Power Units, Uninterruptible Power Supplies, Inverters);
- EDG;
- FW and RHR Check Valves (components); and
- Control Air.

During this inspection period, additional reviews of licensee root-cause evaluations and associated corrective actions for FW and RHR check valves were performed by the resident inspectors. See Section 1R12.1 of this report for further discussion.

The inspectors verified the periodic evaluation was completed within the time restraints defined in 10 CFR 50.65 (once per refueling cycle, not to exceed 24 months). The inspectors also ensured that the licensee reviewed its goals, monitored SSCs performance, reviewed industry operating experience, and made appropriate adjustments to the Maintenance Rule program as a result of the above activities.

The inspectors verified:

- the licensee balanced reliability and unavailability during the previous cycle, including a review of high safety significant SSCs;
- (a)(1) goals were met, corrective action was appropriate to correct the defective condition, including the use of industry operating experience, and (a)(1) activities and related goals were adjusted as needed; and

- the licensee had established (a)(2) performance criteria, examined any SSCs that failed to meet their performance criteria, and reviewed any SSCs that have suffered repeated maintenance preventable functional failures, including a verification that failed SSCs were considered for (a)(1).

In addition, the inspectors reviewed maintenance rule self-assessments and audit reports that addressed the maintenance rule program implementation.

This review completed five triennial inspection samples.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and operational activities affecting risk-significant and safety-related equipment listed below.

- Division II RHR Safety System Outage (SSO), during the week of April 30, 2007;
- EDG-11 SSO, during the week of April 30, 2007;
- No. 5 Circulating Water Pump and No. 6 General Service Water Pump Removal During Hot Weather, during the week of May 14, 2007;
- No. 5 Circulating Water Pump Return-to-Service with Down Power, during the week of June 4, 2007; and
- Main Unit Transformer 2A Cleaning, during the week of June 18, 2007.

These activities were selected based on their potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors reviewed the scope of maintenance work, 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. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

These activities completed five quarterly maintenance risk assessment and emergent work control inspection samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following CARDS to ensure either the condition did not render the involved equipment inoperable or result in an unrecognized increase in plant risk, and the licensee appropriately applied TS limitations and appropriately returned the affected equipment to an operable status:

- CARD 07-22680, Unacceptable Reading During Initial Performance of Surveillance Procedure;
- CARD 07-21265; RCIC Pump Seal Leak; and
- CARD 07-22833, Deteriorated Cables Found in Manhole.

The inspectors reviewed the technical adequacy of the licensee's operability evaluations and verified if operability was justified. The inspectors verified that the licensee considered other degraded conditions and their impact on compensatory measures for

the condition being evaluated. The inspectors referred to the final safety analysis report and other design basis documents during the review.

These activities completed three operability evaluation inspection samples.

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion V, "Procedures," for the failure to maintain adequate maintenance procedures to install the outboard mechanical seal for the RCIC pump.

Description: On May 5, 2006, the licensee was replacing the outboard mechanical seal on the RCIC pump because the present seal was leaking. The licensee performed the maintenance under WR 000Z061590 which utilized Procedure 35.206.003, Revision 26, "RCIC Pump Rotating Assembly Removal and Installation." Post-maintenance testing was completed and the pump was returned to service.

During the quarterly surveillance test on March 4, 2007, the outboard seal failed with a resulting leakage of approximately 3-5 gpm. The pump was removed from service to troubleshoot the cause of the seal failure and the failure was entered into the licensee's corrective action program as CARD 07-21265. Investigation identified all of the mechanical seal springs came out of the spring holder and spring pieces inside the seal housing as well as evidence of contact between the throttle bushing lock wire and the shaft sleeve.

The licensee determined the cause of the seal failure was the lack of adequate preload of the springs when the seal was installed during WR 000Z061590. The preload is established during reassembly by setting the seal 0.25 inch beyond the seal flange on the pump and tightening the hold down screws for the shaft sleeve. The licensee determined that Procedure 35.206.003 did not contain adequate guidance on setting the preload because it did not contain instructions to ensure the 0.25-inch gap existed. The



licensee installed a new seal, verified the 0.25-inch gap, and revised Procedure 35.206.003 accordingly.

Analysis: The inspectors determined the failure to properly install the outboard mechanical seal for the RCIC pump was a performance deficiency. This finding was determined to be more than minor in accordance with IMC 0612, because it was similar to an example of minor issues. Specifically, it contributed to a subsequent seal failure that affected pump operability as it increased pump unavailability more than a negligible amount. The inspectors assessed the finding using the SDP and determined the finding was associated with the Mitigating Systems Cornerstone. The finding did not represent a loss of high pressure injection safety function, did not result in an actual loss of RCIC for greater than 14 days, and did not screen as potentially risk significant for external events. Once identified, the licensee entered this issue into their corrective action program as CARD 07-21265 and revised the appropriate procedure. The inspectors determined the finding is associated with a cross-cutting aspect in the area of H.2(c), Human Performance, Resources, because the licensee did not maintain adequate procedures for performing maintenance on the RCIC pump.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Procedures," required, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstances. The licensee's quality assurance program committed the licensee to maintain the RCIC system as safety related. Contrary to the above, on May 5, 2005, the licensee failed to ensure that Procedure 35.206.003, Revision 26, included appropriate guidance on how to properly install the RCIC pump outboard mechanical seal. This failure is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000341/2007004-04: Failure to Properly Install RCIC Mechanical Seal)

#### 1R19 Post-Maintenance Testing (71111.19)

##### a. Inspection Scope

The inspectors reviewed post-maintenance testing (PMT) activities associated with the following scheduled maintenance:

- EDG 11 PMT Following 18-Month SSO;
- WR Q320050100, Replace Solenoid Valve, Division I North Control Air Compressor Unloading Cylinder;
- WR T210040100, Replace O-Rings and Resilient Seat on "A" Outboard Feedwater Supply Check Valve; and
- Work Order 24514897, Repair No. 5 Circulating Water Pump and Discharge Valve.

The inspectors reviewed the scope of the work performed and evaluated the adequacy of the specified PMT. The inspectors verified the PMT was performed in accordance with approved procedures, the procedures clearly stated acceptance criteria, and the acceptance criteria were met. The inspectors interviewed operations, maintenance, and engineering department personnel and reviewed the completed PMT documentation.

In addition, the inspectors verified PMT problems were entered into the corrective action program with the appropriate significance characterization.

These activities completed four PMT inspection samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- Reactor Water Cleanup Differential Flow Calibration and Functional Surveillance 44.020.152;
- WR 0980041022, Perform 43.401.300 LLRT Type C General;
- EDG 11 Fast Start Surveillance Following 18-Month SSO;
- 4160 V Bus 64B Undervoltage Circuit Surveillance;
- WR 3491060425, Perform 43.401.511 Section 6.5, Bypass Valve Leakage Calculated Total; and
- Job 0098070629, Perform 24.307.15, EDG 12 Slow Start Surveillance.

The inspectors reviewed the test methodology and test results to verify equipment performance was consistent with safety analysis and design basis assumptions. In addition, the inspectors verified surveillance testing problems were being entered into the corrective action program with the appropriate significance characterization.

These activities completed four routine and two containment isolation surveillance samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modifications (TMs) and verified the installation was consistent with design modification documents and the modifications did not adversely impact system operability or availability.

- TM 07-0009, Defeat K7 Vacuum Switch N30N2316A Main Turbine Protection Function; and

- TM 07-0010, Temporary Filters for the Main Unit Transformer Coolers.

The inspectors verified configuration control of the modifications was correct by reviewing design modification documents and confirmed appropriate post-installation testing was accomplished. The inspectors interviewed engineering and operations department personnel, and reviewed the design modification documents and 10 CFR 50.59 evaluations against the applicable portions of the TSs and UFSAR.

These activities completed two temporary plant modification inspection samples.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the licensee perform an emergency preparedness drill on April 10 and 11, 2007. The inspectors observed activities in the control room simulator. The inspectors also attended the post-drill facility critiques in the control room and the combined critique immediately following the drill. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the drill performance and ensure the licensee evaluators noted the same weaknesses and deficiencies and entered them into the corrective action program. The inspectors placed emphasis on observations regarding event classification, notifications, protective action recommendations, and communications with security. As part of the inspection, the inspectors reviewed the drill package and the licensee's critique documents.

These activities completed one drill evaluation inspection sample.

b. Findings

No findings of significance were identified.

#### 4. OTHER ACTIVITIES

##### **Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity**

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submittals for the performance indicators (PIs) listed below. The inspectors used PI definitions and guidance contained in Nuclear

Energy Institute Document 99-02, Revision 4, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PIs were reviewed:

- HPCI Mitigating System Performance Index (MSPI);
- Heat Removal System MSPI (RCIC); and
- RHR MSPI.

The inspectors reviewed selected applicable conditions and data from logs, Licensee Event Reports, and CARDS from January 1, 2007, through May 25, 2007, for each PI area specified above. The inspectors compared their independently-obtained data to the data contained in the Consolidated Data Entry MSPI Derivation Reports for Unavailability and Unreliability to ensure the licensee reported the data correctly.

These activities completed three performance indicator inspection samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's corrective action system at an appropriate threshold, adequate attention was being given to timely corrective actions, and adverse trends were identified and addressed.

These activities did not represent an inspection sample.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a screening review of each item entered into the licensee's corrective action program to identify trends that might indicate the existence of a more significant safety issue. The inspectors considered repetitive or closely related issues that may have been documented by the licensee outside the normal corrective action program, such as in:

- trend reports or PIs;
- major equipment problem lists;
- repetitive and/or rework maintenance lists;
- departmental problem/challenges lists;
- system health report;
- quality assurance audit/surveillance reports;
- self assessment reports;
- maintenance rule assessments; or
- corrective action backlog lists.

The inspectors verified the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program by comparing those issues identified by the NRC during the conduct of the plant status and inspectable area portions of the program with those issues identified by the licensee.

These activities completed one semi-annual trend inspection sample.

b. Issues

The inspectors noted an increase in the number of Human Performance-related events over the past two quarters. The inspectors noted three instances where safety-related motors were not replaced when originally planned because of inadequate work package preparation. In addition, the inspectors noted several instances of workers performing work on the wrong component. The inspectors also noted completed work packages with various minor documentation errors indicating a lack of attention to detail. Although none of these issues was more than minor, the inspectors were concerned that this low-level trend could escalate if not corrected. The licensee already identified this trend and developed a plan to address the causes.

The inspectors also noted that the lubricating oil reservoir for the RCIC pump turbine has had frequent level oscillations requiring more operator attention to ensure the oil level remains within normal limits. Although the inspectors previously inspected this issue, their monitoring of the oil level fluctuations will continue through the daily monitoring of plant status. Any future concerns that arise will be addressed through the appropriate inspection procedure.

.3 Operator Workarounds

The inspectors reviewed operator workarounds to verify the licensee was identifying operator workaround problems at an appropriate threshold, entering them into their corrective action program, and either proposing or implementing appropriate corrective actions. The inspectors evaluated the operator workarounds to determine if either the mitigating system function or the operator's ability to implement abnormal and emergency operating procedures were affected.

The inspectors also reviewed selected issues to identify operator workarounds that:

- were not evaluated by the licensee;
- were formalized as the long-term corrective action for a degraded or non-conforming condition (and, therefore, may not have been tracked by the licensee as an operator workaround); and
- increased the potential for personnel error.

These activities completed one operator workaround inspection sample.

b. Findings

No findings of significance were identified.

.4 Annual In-Depth Review: Failure to Perform an Adequate Root-Cause Evaluation

a. Inspection Scope

The inspectors reviewed a list of all level "1" CARDS closed within the past six months of this inspection period and chose CARD 06-21751 for an in-depth review because it was the subject of a Licensee Event Report and the licensee classified it as a significant condition adverse to quality. The inspectors reviewed the root-cause evaluation to determine if the cause of the condition was thoroughly evaluated, appropriate corrective actions were either taken or planned, and corrective actions were appropriately prioritized. The inspectors utilized guidance contained in Inspection Procedure 95001 to assist in the root-cause review.

These activities completed one problem identification and resolution, annual in-depth review sample.

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," for the failure to identify the cause and take appropriate corrective actions for a significant condition adverse to quality.

Description: On April 1, 2006, during RF11, both the inboard and outboard containment isolation valves for the "A" FW lines B2100F010A and 76A, respectively, failed their as-found LLRT test. The measured leakage for that penetration exceeded the allowable TS limit,  $L_a$ . The licensee entered this issue into their corrective action program as CARD 06-21751 and classified it as a significant condition adverse to quality and performed a root-cause evaluation (RCE).

The licensee identified the following root causes: "The root cause of the failure of B2100F076A is soft seat degradation caused by extended in-service time of three cycles and failure to perform the recommended PM at the end of two cycles of operation. The root cause of the failure of B2100F010A is soft seat degradation

due to normal environmental conditions exacerbated by wear between the internal shaft and the disc arm bore and slight misalignment of the disc to inbody seat.” CARD 06-21751 was closed on December 6, 2006.

Corrective actions as a result of this issue included repairing both valves and changing the PM frequency of the soft seat replacement from four years to three. The inspectors noted several concerns with the RCE. For both valves, the RCE focused on determining the failure mechanisms rather than determining what circumstances allowed the failure mechanisms to occur. For example, the licensee identified that B2100F076A failed its LLRT because the soft seat was not replaced after two cycles but failed to explore why the licensee approved it to be in service for a third cycle. In addition, the licensee identified internal misalignment as the cause for the B2100F010A LLRT failure but failed to explore what caused the misalignment. Consequently, the licensee did not take corrective actions to address why the failure mechanisms occurred.

As described in Section 1R12.1 of this report, the licensee did not replace the soft seat for B2100F076A during RF10 based primarily on an inadequate technical evaluation. The inspectors determined the licensee should have evaluated the effects of wear and erosion on the soft seat but failed to do so. Through interviews, the inspectors learned the licensee was unaware that wear and erosion were credible failure mechanisms which is why those mechanisms were not considered. The inspectors located industry operating experience that identified wear and erosion as significant stressors to the soft seats in these types of valves. Further, the licensee had an unreasonably high expectation that Arrhenius methodology alone could estimate the service life of the soft seats despite previous licensee documents, e.g., Deviation Event Report 96-1361 and TMPE-00-0466, that specifically identified otherwise. Therefore, the inspectors determined the deficiencies surrounding the technical evaluation that approved the B2100F076A soft seat to remain in service for three cycles constituted a more fundamental root cause with different corrective actions than limiting the PM frequency for the FW check valves to two cycles.

The inspectors also reviewed the maintenance history for B2100F010A. As documented in CARD 01-20794, this valve experienced an LLRT failure in RF08 (conducted during the fall of 2001) due to misalignment of the valve disc area and the valve seat. Corrective actions to address those alignment issues were completed by January 2004. On April 4, 2004, during RF09, this valve experienced an LLRT failure and was rebuilt under WR 000Z031251 utilizing the improved process as developed by CARD 01-20794; however, this valve again failed in RF11 partly due to misalignment of the disc to seating surface. The only corrective action taken on this valve after the RF11 failure was corrective maintenance to restore the valve. The licensee failed to address the continued misalignment issues in the RCE and therefore did not evaluate the adequacy of previous corrective actions which were ineffective in preventing the subsequent LLRT failure in RF11.

The inspectors noted the inboard valves were especially susceptible to flow-induced degradation because the disc arm was an integral part of the disc which prevented the disc from self-aligning to the seat as the internals wore. As described in memo NEPJ-88-0590 dated September 21, 1988, extended operation below approximately 70 percent power has the potential for increased valve degradation because the disc

would not be held fully open against the open stops. Additionally, operation at (or just below) 65 percent power with respect to the inboard valves, and at (or just below) 50 percent power with respect to the outboard valves, has a particularly high potential for degradation. The consequence, as described in NUREG/CR-5583, is the tapping of the disc against the open stop which can cause bushing wear, hinge pin failures, disc nut failures, and subsequent internal disc misalignment. Although all of those failure mechanisms have been observed with the licensee's FW check valves, power level history was not considered in the PM philosophy for the valves. The nine startup and shutdown sequences between RF09 and RF11 could have contributed to the misalignment of B2100F010A but was not considered in the RCE.

The licensee attributed the B2100F010A LLRT failure to service-related wear over the period of two operating cycles but did not identify the specific service-related mechanisms that either caused or contributed to the wear. The inspectors concluded that maintaining the PM frequency at two cycles would not ensure consistent successful as-found LLRTs without a concurrent mechanism to effectively manage the service-related factor(s) that contributed to either valve LLRT failure. Therefore, the inspectors considered the failure to manage those service-related wear mechanisms that caused the soft seat damage was a more fundamental root cause with different corrective actions than the licensee identified.

The licensee concluded that maintenance practices were not potential causes for either valve failing because, "two of three valves rebuilt in RF10 passed RF11 LLRT (B2100F010B and B2100F076B). This indicates that RF10 maintenance practices were satisfactory." Since both B2100F076A and B2100F010A were last rebuilt prior to RF10, the inspectors concluded that the licensee's basis for discounting maintenance practices in previous outages based on results seen from maintenance in RF10 was irrelevant to the cause of these two valve LLRT test failures. Further, the licensee could not supply any documentation showing that the RCE team reviewed previous work packages to attempt to identify any potential maintenance-related issues.

Lastly, the inspectors reviewed the personnel assigned to the root cause team and determined all 4 of the key team members (the ones that substantially performed the root cause evaluation) were substantially involved in previous evaluations of FW injection check valve failures. MQA12, Revision 8, "Cause Analysis and Corrective Action Determination" required that "the root cause evaluator shall not have had direct involvement in the event to be analyzed." The inspectors concluded that the lack of independence between the issue to be analyzed and the personnel performing the evaluation was a contributing factor in the licensee not performing an adequate root cause.

Analysis: The licensee's failure to perform an adequate root-cause evaluation for the LLRT failures of B2100F076A and B2100F010A during RF11 was a performance deficiency. This finding was determined to be more than minor in accordance with IMC 0612, Appendix E, because if left uncorrected, the finding would become a more significant safety concern. Specifically, because the licensee did not arrive at the proper root cause, the licensee could not provide assurance that appropriate corrective actions to prevent recurrence were implemented. Additionally, the inspectors identified more fundamental causes for the event which were not addressed by the corrective actions



developed by the RCE. This finding affected the Barrier Integrity cornerstone and is of very low safety significance as described in Section 1R12.1 of this report. Once identified, the licensee entered this issue into their corrective action program as CARD 07-22216. The inspectors determined that the finding is associated with a cross-cutting aspect in the area of P.1(c), Problem Identification and Resolution, Corrective Action Program, because the licensee did not thoroughly evaluate the problem and, therefore, failed to take appropriate corrective action.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," required that for significant conditions adverse to quality, measures shall be established to assure the cause of the condition is determined and corrective action taken to preclude repetition. The licensee classified the condition described in CARD 06-21751 as a significant condition adverse to quality. Contrary to the above, on December 13, 2006, when CARD 06-21751 was closed, the licensee failed to assure the cause for the LLRT failures of B2100F076A and B2100F010A during RF11 was identified and, therefore, failed to take appropriate corrective action to prevent repetition. This failure is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000341/2007004-05: Failure to Perform an Adequate Root-Cause Evaluation.)

.5 Annual In-Depth Review: CARD 06-20344, Division 1 Control Air Compressor Did Not Unload

a. Inspection Scope

The inspectors reviewed the events and circumstances surrounding the post-maintenance test failure of the Division I Control Air Compressor on January 25, 2006. The inspectors reviewed this issue because the equipment involved was safety-related and it represented a potential common mode failure for the other divisional compressor. The inspectors reviewed the licensee's apparent cause evaluation to ensure the condition was adequately addressed and appropriate corrective actions were taken.

These activities completed one problem identification and resolution, annual in-depth review sample.

b. Observations

During a post-maintenance test on the Division I Control Air Compressor, the compressor loaded but failed to unload and the licensee entered the issue into their corrective action program as CARD 06-20344. After troubleshooting, the licensee determined the yoke was wedged in the slots on the inlet valve and would not release. Because the yoke would not release, the compressor could not unload. The licensee identified some irregularities in the slots of the valve casting and sent the valve and yoke to the manufacturer for further analysis. The manufacturer determined that casting defects, in the form of slag in the valve slots, were present which allowed the yoke to bind in the valve.

Under WR Q320050100, the licensee replaced the inlet valve during the maintenance activity leading to the post-maintenance test so the valve failure was considered to be a work-in-progress issue. The licensee performed an apparent cause evaluation and

developed corrective actions in response to this event. As a result of this issue, the licensee returned the other stocked valves to the manufacturer for replacements, reviewed the other divisional compressor to ensure its inlet valve was not defective, and revised the licensee's source surveillance program to require a dimensional and visual inspection of the slots in the valve prior to shipping the valves to the site. The inspectors determined the apparent cause evaluation and corrective actions were appropriate to the circumstances.

No findings of significance were identified.

#### 4OA5 Other Activities

##### (Closed) Unresolved Item (URI) 05000341/2006015-03: Adequacy of Thermal Overload Relay Testing and Setpoints

During the special inspection at Fermi Power Plant, Unit 2, which was conducted between August 28 and September 26, 2006, the inspectors identified a URI concerning the adequacy of thermal overload (TOL) testing and setpoints for some Spectrum Motor Control Center (MCC) buckets. Specifically, several starter circuits were installed in locations that could experience higher temperatures than the temperature used to calibrate the TOL setpoints.

The inspectors noted several starter units were installed in areas of the plant that could experience high temperatures during accident conditions. The qualification test documentation for these starter circuits indicated the associated TOL devices were calibrated at 40°C. The licensee determined the ambient temperature where these circuits are located could exceed 40°C. The TOL devices consisted of an ambient temperature compensated relay with bi-metallic heaters. During the special inspection, the licensee concluded the design sizing of the TOL heaters for 140 percent of motor full load current and the functional testing of the MCC buckets at higher temperatures and currents provided assurance that the overload devices would function as required. Since the qualification test documentation did not identify whether the characteristics of the TOLs were verified at higher temperatures, the inspectors remained concerned that the TOL devices could cause undesirable trips of safety-related components during or after a design basis accident.

Following discovery, the licensee completed a preliminary evaluation and compared the methodology used for the TOL sizing criteria specified in Specification 3071-128-EZ-03 "Electrical Design Instructions Thermal Overload Heaters Sizing," and the Square-D sizing methodology. Based on the evaluation and examples provided in the preliminary evaluation, the licensee concluded the TOL sizing criteria specified in Specification 3071-128-EZ-03 was acceptable. The licensee also provided additional information which indicated the revised loss-of-coolant accident and high energy line break temperature profile showed the peak temperature in the areas where the MCCs are located would reach 68°C. This peak ambient temperature would last only for a very short duration and then would drop down to approximately 54°C. All required equipment operation associated with the affected MCC circuits would be completed prior to the MCCs reaching the peak temperature value.

Based on the inspectors' review of the licensee preliminary evaluation and TOL sizing criteria specified in Design Specification 3071-128-EZ-03, the inspectors determined the failure to evaluate the effect of higher ambient temperature on the TOLs associated with Spectrum MCC buckets and the TOL sizing criteria was a performance deficiency and a failure to comply with 10 CFR 50, Appendix B, Criterion III, "Design Control." Although the methodology used in the Design Specification 3071-128-EZ-03 was verified to be acceptable and additional evaluation showed the temperature-compensated TOL devices used in the MCC buckets would not cause nuisance tripping at the increased ambient temperature, the inspectors determined that the failure to comply with 10 CFR 50, Appendix B, Criterion III, constituted a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's enforcement policy. The licensee entered this issue into their corrective action program as CARD 06-25253 to revise appropriate documents to incorporate the TOL temperature compensation evaluation study. This unresolved item is closed.

This inspection activity does not represent an inspection sample for this report.

#### 40A6 Exit Meetings

##### .1 Exit Meeting Summary

On July 6, 2007, the inspectors presented the inspection results to Mr. J. Davis and other members of licensee management at the conclusion of the inspection. The inspectors asked the licensee whether any material examined during the inspection should be considered proprietary. No proprietary information was identified.

##### .2 Interim Exit Meetings

The following interim exit meetings were conducted for:

- Maintenance Effectiveness Periodic Evaluation with Mr. J. Plona, Director, Engineering, on April 27, 2007.
- Heat Sink Biennial Inspection with the licensee management and staff at the conclusion of the inspection on March 29, 2007 and on July 20, 2007.

#### 40A7 Licensee-Identified Violations

The following violation of very low significance was identified by the licensee and is a violation of NRC requirements, which meets the criteria of Section VI of the NRC Enforcement Manual for being dispositioned as an NCV.

- 10 CFR 50 Appendix B, Criterion III, "Design Control," required, in part, that design changes be subjected to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design or another designated organization. UFSAR Section 3.3.2.3, "The Ability of Category I Structures to Perform Despite Failure of Structures Not Designed for Tornado Loads," states that the design of the reactor building is to withstand the depressurization effects of a tornado without venting. As a result of the design calculation for the reactor building fifth floor

hatch cover, hold-down bolts were required to prevent lifting of the hatch during high winds. Contrary to this, on May 2, 2007, the reactor building fifth floor equipment hatch hold-down bolts were not installed without approval for their removal. Following the discovery, the hold-down bolts were reinstalled. The licensee determined the hatch had been inappropriately unbolted for approximately 18 years. This was identified in the licensee's corrective action program as CARD 07-22403. This finding is of very low safety significance because it did not affect the ability of safe shutdown equipment to perform the intended functions.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

### KEY POINTS OF CONTACT

#### Licensee

J. Davis, Senior Vice President and Chief Nuclear Officer  
K. Hlavaty, Plant Manager  
K. Amin, Engineer, Design Engineering  
M. Caragher, Director, Nuclear Engineering  
R. Gaston, Manager, Nuclear Licensing  
R. Haupt, System Engineer  
M. Koenenmann, Maintenance Rule Coordinator  
R. Libra, Director Nuclear Engineering  
E. Palmer, PSE, Mechanical/Civil  
G. Piccard, Manager, Radiation Protection  
K. Scott, Operations Manager  
G. Wojtowicz, PSE Engineer

#### NRC

C. Lipa, Chief, Division of Reactor Projects, Branch 4  
J. Lara, Chief, Division of Reactor Safety, Engineering Branch 3

### LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

#### Opened and Closed

05000341/2007004-01	FIN	Failure to Control Transient Combustibles (Section 1R05.2)
05000341/2007004-02	NCV	Restoration of Drywell Following SBO Event Does Not Control Rate of Heat Addition to EECW and No Analyses Was Performed For Potential Two Phase Flow and Water Hammer (Section 1R07.1)
05000341/2007004-03	NCV	Residual Heat Removal/Feedwater Injection Check Valves Inadequate Goal Monitoring in 10 CFR 50.65(a)(1) Status (Section 1R12.1)
05000341/2007004-04	NCV	Failure to Properly Install RCIC Mechanical Seal (Section 1R15)
05000341/2007004-05	NCV	Failure to Perform an Adequate Root-Cause Evaluation (Section 4OA2.4)

#### Closed

05000341/2006015-03	URI	Thermal Overload Setpoints
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#### Discussed

None.

## LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that 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.

### **Section 1R01: Adverse Weather Protection**

2007 Hot Weather Preparations: Job Status as of May 1, 2007  
CARD 07-21998: Breaker 8C on 2B Transformer Found in Tripped Condition; dated April 12, 2007  
CARD 07-22001: Fan Running Oil Pump Not Showing Flow; dated April 13, 2007  
CARD 07-22002: Adverse Trend in 2B Transformer Cooler Performance and Monitoring Capability; dated April 13, 2007  
CARD 07-22403: Bolts Not Installed Securing Refueling Floor Crane Bay Hatch Cover to the Floor in the Closed Position; dated May 2, 2007  
CARD 07-23184: Fan on Cooler #4 Not Running; June 7, 2007  
CARD 07-23185: Fan on 2A Transformer Not Running; dated June 7, 2007  
Fermi 2 UFSAR, Chapter 3, Section 3.3: Wind and Tornado Loadings; Rev 5, March 1992  
Operations Conduct Manual MOP05: Control of Equipment; Rev 23, April 5, 2007  
Operations Department Expectation ODE-12; LCOs: Rev 8, September 29, 2006  
Procedure 27.000.06: Hot Weather Operations; Rev 0, February 28, 2003  
Reportability Evaluation for the condition described in CARD 07-22403

### **Section 1R04: Equipment Alignment**

Drawing No. 5SD721-F-0001: One Line Diagram, 120KV Switchyard; dated October 11, 2006  
Drawing No. 6SD721M-0001: One Line Diagram, 345KV Yard; dated August 7, 2006  
Drawing No. 6SD721-2500-01: One Line Diagram Plant 4160V and 480V System Service Unit 2; Revision AI; dated October 25, 2006  
Drawing No. 6M721-5708-1: High Pressure Coolant Injection System Functional Operating Sketch; Revision AK, dated May 18, 2006  
Drawing No. 6M721-5729-2: Emergency Equipment Cooling Water, Division II, Functional Operating Sketch, Revision AO; dated April 27, 2006  
Procedure 23.127: Reactor Building Closed Cooling Water/Emergency Equipment Cooling Water System; Revision 106  
Procedure 23.202: High Pressure Coolant Injection System; Revision 92

### **Section 1R05: Fire Protection**

CARD 07-23207: NRC SRI Identified Fire Protection and Housekeeping Deficiencies in 345kV/120kV Relay Houses; dated June 8, 2007  
Evaluation of Fermi 2 Fire Protection for Switchgear Areas: dated June 11, 2007  
USFAR Figure 9A-10: Fire Protection Evaluation Reactor and Auxiliary Buildings Fifth Floor Plan; Rev 14, November 2006  
Compensatory Firewatch Rounds / Relief Checklist; April 19, 2007  
MOP11: Fire Protection; Revision 11 dated February 16, 2007

### **Section 1R07: Heat Sink Performance**

File No. 1801: Qualification Engineering EG-54, Hydraulic Actuator Type EG-R; Revision A  
Environmental Qualification Report for GS-2N RCIC Turbine Electrical Accessories and Electronic Control System; Revision 1  
DC-6286: EECW HX Performance Requirements With Plugging; dated February 21, 2006  
DC-4995: Assessment of I&C Equipment Operability in Dominant Areas of Concern During Station Blackout; Revision C  
DC-4972: Mechanical Calculations for Station Blackout; dated May 27, 1997  
Engineering Library No. 20458: Environmental Qualification Report for GS-2N RCIC Turbine Electrical Accessories and Electronic Control System; dated March 27, 1980  
DC-4975: Assessment of Equipment Operability in Dominant Areas of Concern; Revision A  
DC-4976: NUMARC Station Blackout Loss of Ventilation Effects on Temperature; dated November 14, 2005  
DC-0182: Operability Evaluation for Design Basis Tornado Delayed RHR Cooling Tower Fan Repair Scenario; Revision B  
EDP-29805: EECW Heat Exchanger Replacement; dated April 4, 2000  
DC-5806, Volume I: EECW Design Basis Requirements; Revision B  
DC-5806, Volume II: EESW Design Basis Requirements; Revision 0  
DC-0182: RHRSW Mechanical Draft Cooling Towers - Post LOCA Analysis of UHS; Revision E  
MES54: Heat Exchanger Component Monitoring Program; Revision 0  
29.300: SBO Loss of Offsite and Onsite Power Abnormal Operating Procedure; Revision 0  
SOP 23.208: RHR Complex Service Water Systems; Revision 85  
Surveillance: Perform 47.207.01 Heat Exchanger Performance EECW D1-P4400B001A; dated September 30, 2005  
Surveillance: Perform 47.207.01 Heat Exchanger Performance EECW D1-P4400B001A; dated October 26, 2006  
Surveillance: Perform 47.207.01 Heat Exchanger Performance EECW D1-P4400B001C; dated September 30, 2005  
Vendor Manual: MX25-BFD Plate Heat Exchanger; Revision 0  
Memorandum to Mr. Orser: Fermi 2 Conformance to Station Blackout Rule 10 CFR 50.63; dated June 12, 1991  
Memorandum to Mr. Zyduck: Corrosion Rates; dated July 13, 2005  
CARD 03-11884: Potential Release Path Not Accounted For in the OCDM; dated June 5, 2003  
CARD 06-21247: RHR HX Eddy Current Testing Preparation Issues; dated March 13, 2006  
CARD 04-24254: Higher Than Expected Pressure Drops in Division 1 and 2 EESW; dated September 16, 2004  
CARD 06-24375: Current EECW/RBCCW Water Chemistry Not Accurately Reflected in System Design Specification; dated June 30, 2006  
SE 99-0009: EECW Heat Exchanger Replacement; Revision B  
List of CARDS for Heat Sink Inspection: dated March 26, 2007  
EESW and EECW Maintenance History for three Years; dated March 28, 2007  
Sample Data Division 1 UHS Reservoir for March 2006 to March 2007; dated March 27, 2007  
CARD 07-21757: NRC Inspection; Revise DC-4995 Volume 1 EQ Qualification Time. Aging Time Was Used Incorrectly; dated March 29, 2007 (NRC-Identified)  
CARD 07-21770: NRC UHS Inspection RFI-12: Restoration of Drywell Following SBO Event Does Not Control Rate of Heat Addition to EECW; dated March 29, 2007 (NRC-Identified)

### **Section 1R11: Licensed Operator Requalification**

Sequence of Events for June 6, 2007 Drill: Revised May 21, 2007

Nuclear Plant Event Notification Form: dated June 6, 2007, Time 0840

Nuclear Plant Event Notification Form: dated June 6, 2007, Time 0956

Nuclear Plant Event Technical Data Form: dated June 6, 2007, Time 0934

### **Section 1R12: Maintenance Effectiveness**

MMR Appendix D: Fermi 2 Maintenance Rule Conduct Manual - Guidelines for Determining Functional Failures and Maintenance Preventable Functional Failure; Revision 5

MMR Appendix F: Fermi 2 Maintenance Rule Conduct Manual - Maintenance Rule Performance Criteria; Revision 6

Enrico Fermi 2 Maintenance Rule Periodic Assessment, August 2003 - January 2005: dated May 12, 2006

Enrico Fermi 2 Maintenance Rule Periodic Assessment Report, February 2005 - August 2006; dated November 16, 2006

System Health Fermi 2 - R1100 Aux Electrical - CTG11-1, Fourth Quarter 2006

System Health Fermi 2 - Component Check Valves, Fourth Quarter 2006

System Health Fermi 2 - P5000 Compressed Air System, First, Second, Third, and Fourth Quarter 2006

System Health Fermi 2 - R 30 EDGs, Fourth Quarter 2006

System Health Fermi 2 - R3100/R3101 Vital Power, MPUs, UPSA&B, Fourth Quarter 2006

CTG11-1 Get-Well Plan, Revision A

Vital Power R30 Get-Well Plan, Revision 0

Emergency Diesel Generators (R3000) Get-Well Plan, Revision F

Feedwater and RHR Injection Check Valves Get-Well Plan, Revision F

Control Air Get-Well Plan, Revision A

Expert Panel Meeting Summaries for period January 2004 - January 2007

CARD 05-24252: CTG11-1 Unable to Obtain Base Load (13-15 MW) during monthly Surveillance; dated July 17, 2005

CARD 05-26451: NRC Concern - Procedure 24.307.34 Starting Air Operability Test - EDG 11 and Associated EDG Tests; dated November 16, 2005

CARD 06-21724: LLRT Failure of B2100F010A; dated March 31, 2006

CARD 06-22976: PMT Failure for UPS "A" Inverter Frequency; dated April 29, 2006

CARD 06-23766: Revise the B2100F010A/B Inboard Feedwater Valves by Changing from a One-Piece Swing-arm/Disc to a Two-Piece wing-arm and Disc; dated June 1, 2006

CARD 07-22276: NRC Question Regarding Need for Cotter Pin in P5002D001; dated April 26, 2007

CARD 07-21396: Division 2 Control Air Compressor Not Loading / Unloading as Expected; dated March 10, 2007

Procedure 35.622.003, Revision 26; Control Air Compressor Maintenance

Non Interruptible Air Supply Maintenance Rule Functional Failure Evaluations From April 1, 2004, through April 1, 2007

Work Request P735050100: Replace Solenoid Valve, Division 1 North Control Air Compressor Unloading Cylinder; dated January 26, 2006

Work Request Q339050100: Replace Suction and Discharge Valves; dated June 7, 2005

Control Air System Maintenance Rule Scope Determination; dated January 31, 1995



### **Section 1R13: Maintenance Risk Assessment and Emergent Work Evaluation**

Actual Risk Profile Summary (Week of 06/04/2007)

CARD 07-22317: Major Work Removed from 4/30/07 Work Week; April 29, 2007

CARD 07-22378: NRC Question on Defense in Depth Postings; May 1, 2007

CARD 07-22380: NRC Identified Concern Regarding Staging of Equipment on Standby Equipment; May 1, 2007

CDF Risk Profile for the Week of May 7 to May 14

Division 2 Work Week - On-Line Core Damage Risk: Week 2719

Fermi 2 Plan of the Day, Div 2 Week; Thursday, June 07, 2007

Performance Analysis Review Week of April 23, 2007

Performance Analysis Review, Week of June 4, 2007

Schedules Risk Profile Summary, Week of June 4, 2007

Scheduler's Evaluation for Fermi 2: May 21, 2007, 08:00

Scheduler's Evaluation for Fermi 2: June 1, 2007, 08:00

ODMI-07-006: Transformer Cleaning with Air is Not Effective; dated June 20, 2007

### **Section 1R15: Operability Evaluations**

CARD 07-22680: Failed Acceptance Criteria Step in 24.321.12; dated May 15, 2007

CARD 07-21265: RCIC Pump Outboard Seal Leak; dated March 4, 2007

Procedure 35.206.003, Revision 27: RCIC Pump Rotating Assembly Removal and Installation

CARD 02-19948: Incorrect Material Used; dated December 3, 2002

CARD 03-19037: RCIC Pump Maintenance; dated June 30, 2003

CARD 06-23195: RCIC Pump Outboard Seal Leaking After Replacement; dated May 6, 2006

DER 96-1345: Damaged RCIC Pump; dated October 10, 1996

Job 0268070224: Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig; dated March 4, 2007

Job 0268070227: Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig; dated March 7, 2007

WR 000Z061590: RCIC Pump Outboard Seal Leaking; dated May 5, 2006

WR 000Z070642: RCIC Pump Outboard Seal Leak; dated March 7, 2007

### **Section 1R19: Post-Maintenance Testing**

B2100F076A Timeline; dated May 30, 2007

CARD 01-14849: B2100F032A & B, F076A & B; dated May 3, 2001

CARD 01-20102: B2100, Failed LLRT; dated November 3, 2001

CARD 01-20794: B2100/E1100: Classification of Feedwater Check Valves and RHR System Injection Check Valves as a Component (a)(1) Class under the Maintenance Rule; dated November 14, 2001

CARD 03-16598: B2100 LLRT Failure of Feedwater Supply Check Valve; dated April 5, 2003

CARD 04-25869: B2100F076A Fails LLRT Seat Leakage Test; dated November 21, 2004

CARD 07-22216: NRC Concern - Potential Inadequacies of CARD 06-21751; dated April 24, 2007

CARD 07-222279: Clarification of Maintenance Rule Procedures; dated April 26, 2007

CARD 07-22807: NRC Concern - Maintenance Procedure 35.137.005 Needs Measurement Criteria Added; dated May 22, 2007

CARD 07-22909: NRC Identified Work Package Discrepancy During Package Review; dated May 24, 2007

CARD 07-22910: NRC Identified Issue - Procedural Compliance Concern; dated May 24, 2007

CARD 07-23048: NRC Concern - Feedwater Check Valves Inappropriately Returned to (a)(2); dated May 31, 2007

CARD 07-23049: NRC Concern - PM Deferral Processed Without Considering All Internal Operating Experience; dated May 31, 2007  
CARD 07-23180: NRC Concern - Level 2 CARDS 04-25385 and 04-25360 Closed Into Level 1 CARD 01-20794 Without a Clear Link in CARD 01-20794; dated June 7, 2007  
CARD Review Board Meeting Minutes for December 13, 2006  
Deviation Event Report 96-1361: Damaged Soft Seat / Feedwater Check Valve; dated November 11, 1996  
Feedwater and RHR Check Valve Repair History: A7100 made (a)(1) shortly after RF08 Maintenance Rule Conduct Manual, Appendix D: Guidelines for Determining Functional Failures and Maintenance Preventable Functional Failures; Rev 5  
PM Event T210: Disassemble and Inspect - Replace Valve Disc Soft Seat  
PM Deferral Request 1205205: Replace O-Ring/Resilient Seat Per NE-6.6-EQMS.093 and Inspect Per 47.000.13; Version 1 dated October 11, 2004, Version 2 dated March 11, 2005, Version 3 dated March 11, 2005  
PM Deferral Request Approval 1205870  
TMIS-01-0204: dated December 18, 2001  
Work Request 000Z063986, R30NA19A: Part 7 PMT Activity; P1 Instruction; April 26, 2007  
Work Request 000Z070303, R3001S001: Part 7 PMT Activity; P1 Instruction; April 26, 2007  
Work Request F729070100, R3000F062A: Part 7 PMT Activity; P1 Instruction; April 26, 2007  
Work Request G132070100, R3001S001: Part 7 PMT; Activity P1 Instruction; April 26, 2007  
Work Request G793070100, R3001C025: Part 7 PMT Activity; P1 Instruction; April 26, 2007  
Work Request T210040100, B2100F076A: Nuclear Boiler Feedwater Supply Check Valve; dated March 13, 2006  
Work Request T211020100, B2100F076B: Replace O-Rings and Resilient Seat per NE-6.6-EQMS.093 and Inspect Per 47.000.13; dated June 20, 2001  
Work Request Q320050100, Replace Suction and Discharge Valves With New or Refurbished Valves

### **Section 1R22: Surveillance Testing**

CARD 07-22152: Need Engineering evaluation of correct pressure setting for failsafe regulators for G33F152 A/B valves; dated April 20, 2007  
CARD 07-22154: RWCU differential flow indicates downscale following restoration of TWCU from system outage; dated April 20, 2007  
Drawing 4M721-4573, Rev F: LLRT Penetration X-9A, dated December 30, 1997  
DC-4567: RWCU Differential Flow Instrumentation Surveillance Procedure Validation; Volume 1, Revision C  
Leakage Summary Report: RF-10; dated November 30, 2004  
RF-11 Post Outage Report: LLRT Failure Comparison  
Surveillance Performance: Job 0198070427, Perform 42.302.01 4160 V Bus 64B (EDG11) Div 1, Undervoltage Circuits, C/Func.; April 27, 2007  
Surveillance Performance: Job 0382040928, Perform 43.401.303 LLRT for X-9A (Test-1:B2100F010A); dated November 11, 2004  
Surveillance Performance: Job 0548070422, Perform Procedure 44.020.152, NSSSS RWCU Differential Flow Calibration / Functional Test (Partial); dated April 20, 2007  
Surveillance Performance: Job 0548070717, Perform Procedure 44.020.152, NS4 RWCU Differential Flow Cal./Func.; dated April 18, 2007  
Surveillance Performance: Job 0980041022, Perform Procedure 43.401.300, LLRT Type C General; dated November 26, 2004

Surveillance Performance: Job 1383041022, Perform Procedure 43.401.303, LLRT For X-9A (Test-2:B2100F076A,E4150F006)

Surveillance Performance: Job 1383060425, Perform Procedure 43.401.303 LLRT For X-9A (Test-2:B2100F076A, E4150F006) "as left"; dated November 15, 2004

Surveillance Performance: Job 3491041022, Perform Procedure 43.401.511, Sect 6.5 - Bypass Valve Leakage Calculated Total; dated April 27, 2005

Surveillance Performance: Job 0098070629, Perform Procedure 24.307.15, Sect 5.1 - EDG 12 Start and Load Test - Slow Start; dated June 29, 2007

### **Section 1R23: Temporary Plant Modifications**

Drawing 6I721-2322-04: Turbine Tripping Circuits; Rev R, dated May 21, 2007

Temporary Modification 07-0009: Disconnect wire # K7, from Vacuum switch N30N216A, at Terminal Block #2/#3 in H21P254, in order to defeat the switch function in the Main Turbine Protection system '63VX/63VY' vacuum protection relay circuit; dated May 17, 2007

Temporary Modification 07-0010: Temporary Filters for the Main Unit Transformer Coolers; dated June 4, 2007

### **Section 1EP6: Drill Evaluation**

Controller/Evaluator Comment Form; April 11, 2007

Nuclear Plant Event Notification (Drill) Forms, Plant Message Numbers 1, 2, and 3: April 11, 2007, 2132; April 11, 2007, 2206 and April 11, 2007, 2207 respectively.

Nuclear Plant Event Notification (Drill) Forms, Plant Message Numbers 1 and 2: April 12, 2007, 2107, and April 12, 2007, 2126 respectively.

### **Section 4OA1: Performance Indicator Verification**

Selected MSPI Derivation Reports; dated May 21, 2007

### **Section 4OA2: Identification and Resolution of Problems**

Additional Analysis for CARD 07-21198

CARD 01-20101: Failed LLRT; dated November 3, 2001

CARD 03-16592: LLRT Failure of Feedwater Supply Inboard Primary Containment Check Valve

CARD 04-25385: B2100F076B Failed It's Seat Leakage Test. Unable to Pressure Test Volume. Leakage is Through Seat. Primary Containment Program Owner Will Continue to Monitor Overall Containment Leakage and Will Notify SM if  $L_a$  is Exceeded; dated November 10, 2004

CARD 06-21751: LLRT Failure of B2100F076A; dated April 1, 2006

Card Review Board Meeting Agenda: 07-21198 PMT Failure: Abnormal noise and subsequent S/D of South RWCU pump; Wednesday, May 2, 2007;

Deviation Event Report 96-1219: Failure of LLRT Containment Isolation Valves; dated September 28, 1996

Equivalent Replacement Evaluation 31714: Stuffing Box and Bearing Cover Upgrade; dated November 4, 2001

OSRO Meeting Minutes #1037: dated November 29, 2004

Procedure 35.137.005: Exercisable Check Valve B2100-F010A(B) Maintenance; dated October 9, 2006

WR 000Z002032: Contingency - Disassemble and Rework VLV Internals if Valve Fails LLRT Testing; dated November 3, 2001

WR 000Z002033: Contingency - Disassemble and Rework VLV Internals if Valve Fails LLRT Testing; dated April 7, 2003

WR 000Z031251: LLRT Failure of Feedwater Supply Inboard Primary Containment Check Valve; dated April 7, 2003  
WR 000Z031286: B2100F010B Failed to Stroke Properly. This Revision Will Rebuild the Actuator; dated April 12, 2003  
WR B203040100: Replace Valve Seat Per NE-6.6 EQMS .092 and Inspect Per 47.000.13 for Degradation; dated April 1, 2006  
WR T210020100: Replace O-Rings and Resilient Seat Required by NE-6.6-EQMS.093; dated April 21, 2000  
WR T210961026: Replace O-Rings and Resilient Seat Required by NE-6.6-EQMS.093; September 15, 1998  
WR T211040100: Add Rings or Repack Indicator Side Stuffing Box; dated November 20, 2004  
WR Revision T210040100; Added Additional Inspection Requirements; dated April 2, 2006  
CARD 06-20344: Division 1 Control Air Compressor Did Not Unload Resulting in Failed PMT; dated January 25, 2006

**Section 40A5: Other Activities**

3071-128-EZ-03: Electrical Design Instructions Thermal Overload Heaters Sizing; Revision C  
EDG-SIT-054-11-18-06: TOL Sizing Criteria; Revision A  
CARD 06-25253-28: Revise Appropriate Documents to Address the Temperature Compensation Study; dated May 23, 2007

**Section 40A7: Licensee Identified Violation**

Apparent Cause Evaluation: CARD 07-22403, Reactor Building 5<sup>th</sup> Floor Equipment Hatch Missing Hold-down Bolts  
CARD 06-28090: UFSAR Referenced Manholes uncovered, not compensated for; dated December 20, 2006  
CARD 07-22403: Bolts Not Installed Securing Refueling Floor Crane Bay Hatch Cover to the Floor in the Closed Position; dated May 2, 2007

## LIST OF ACRONYMS USED

°C	degrees Celsius
°F	degrees Fahrenheit
CARD	Condition Assessment Resolution Document
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EECW	Emergency Equipment Cooling Water
EESW	Emergency Equipment Service Water
FW	Feedwater
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
kV	Kilovolts
LLRT	Local Leak Rate Test
MCC	Motor Control Center
MSPI	Mitigating System Performance Index
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
PI	Performance Indicator
PM	Preventative Maintenance
PMT	Post-Maintenance Testing
RCE	Root-Cause Evaluation
RCIC	Reactor Core Isolation Cooling
RF	Refueling Outage
RHR	Residual Heat Removal
SBO	Station Blackout
SDP	Significance Determination Process
SSC	Structures, Systems, and Components
SSO	Safety System Outage
TM	Temporary Modifications
TOL	Thermal Overload
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
WR	Work Request