U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Detroit Edison Company
Facility:	Enrico Fermi, Unit 2
Location:	6400 N. Dixie Hwy. Newport, MI 48166
Dates:	June 19 through August 3, 1998
Inspector:	G. Harris, Senior Resident Inspector
Approved by:	Bruce Burgess, Chief Reactor Projects Branch 6

EXECUTIVE SUMMARY

Enrico Fermi, Unit 2
NRC Inspection Report 50-341/98012(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The fouling of the Reactor Building and Main Turbine Generator Lower Lube Oil Cooler heat exchangers due to Zebra Mussel infestation had an impact on plant operations. In some cases, heat exchanger fouling due to Zebra Mussel infestation caused Technical Specification limits to be approached. The licensee's corrective actions included cleaning the heat exchangers, reducing service water flow, and use of a chemical treatment. Also, flushing of a post accident sampling system line caused some changes to occur in reactor system parameters. Control room operators did not identify the reasons for the changes in reactor system parameters due, in part, to a lack of sufficient procedural information and inadequate communications between chemistry personnel and the operations shift crew. In addition, not all the operators were trained to recognize the changes to reactor system parameters when a post accident sample was in progress. (Section O1.1)

- Control room operators were quick to respond to an unexpected power transient caused by a secondary plant oscillation. An operator manually scrammed the reactor following an unexpected power transient. Operator response was good and all systems responded as expected. The cause of the transient was determined to be a loose muffler in the No. 4 turbine throttle control valve. Station managements' decision to operate with the No. 4 turbine throttle control valve closed was appropriate. (Section O1.2)

- The inspector concluded that operators in the control room did not perform a required surveillance to verify offsite power supply availability within 1 hour subsequent to declaring Combustion Turbine Generator (CTG) 11 inoperable. Specifically, Surveillance Requirement 4.8.1.1.1 requires operators to check the availability of other offsite power sources within one hour when either an Emergency Diesel Generator or CTG 11 are declared inoperable. Instead, after control room operators repositioned the CTG local Mark V controller to the AUTO position, rendering the CTG 11 auto-start feature inoperable from the control room and the remote shutdown panel, Surveillance Requirement 4.8.1.1.1 was not performed for a 90 minute period. Several personnel errors were contributors to this event. These errors included the failure to log the surveillance such that an automatic timing feature was not used and the failure to perform a peer check. Of particular concern was the lack of team work in the control room to ensure that the appropriate Technical Specification actions were performed. This is the third failure to conduct the Surveillance Requirement 4.8.1.1.1 within a one year period. This repetitive failure is considered a violation of 10 CFR 50, Appendix B, Criterion 16, "Corrective Action." However, because the licensee was in the process of determining appropriate actions to address this violation at the end of the inspection period, this item is being tracked as an EEI. (Section O1.3)

- The inspector concluded that current station procedures, in some cases, contained insufficient information and inconsistencies that precluded operators from verifying proper emergency diesel generator (EDG) fuel oil system operation. Further evaluation is needed to determine the appropriate method to verify proper EDG fuel oil system operation. (Section O8)

Maintenance

- The inspector concluded that maintenance on the EDGs was conducted in an appropriate manner. Good oversight was provided by station management, supervisory, and quality assurance personnel. Coordination with station work groups including engineering was good. Infrequently performed maintenance tasks were performed well. Emergent items were handled in an efficient manner. A trip of the EDG was caused by a loss of field during post maintenance testing of EDG-13. During post maintenance testing runs following removal and replacement of the governor actuator, problems with controlling EDG frequency and speed were observed. Corrective action included replacement of the governor actuator assembly (EG-B) and the electronic control box (EG-A). (Section M1.2)

- The surveillance procedures used to test fire door alarm functions and safety-related batteries contained insufficient information and inconsistencies. However, no adverse impact was identified as a result of the procedure discrepancies. (Section M3.1)

- The inspector concluded that adequate controls were in place to ensure the proper storage of materials that could be used in safety-related applications. Monthly walkdowns were not thorough enough to identify discrepancies in foreign material exclusion control. (Section M8)

Engineering

- Replacement motor control center compartments containing thermal overload relays were installed in safety-related applications for the residual heat removal service water system. The vendor's acceptance testing method for the thermal overload heater relays was questioned and determined to be acceptable. The licensee's decision to require that other motor control centers be tested using station procedures was conservative. (Section E1.1)

- Fuel receipt activities were conducted in an efficient manner. Overall, the planning and execution of fuel receipt inspections was good. Fuel receipt activities were well-coordinated requiring the cooperation of several station groups. Fuel receipt activities involved inspections of multiple fuel shipments over an extended period of time and were conducted in accordance with established procedures. Emergent equipment issues were handled in an effective manner. Corrective actions for previously identified fuel handling issues were effectively implemented. (Section E2.1)

Plant Support

- The licensee's corrective actions were broad and comprehensive to an event that resulted in the release of a contaminated tool bag to the owner controlled area. Identification, reporting, and the investigation of the event were prompt and thorough. (Section R1.1)

- The inadvertent drop of contaminated metal from an elevated low surface activity container was caused by a shift in the center of gravity of the contents. The incident was of concern due to potential radiological and personnel safety consequences. Contributing to the event was less than adequate rigging and lack of specific training on the H style beam assembly. (Section E8).

- Security personnel did not open doors to the Fermi 1 facility in a timely manner prohibiting station personnel in the area from immediately obtaining shelter during a severe weather event. Contributing to the event was a lack of training on the task to open doors remotely using the Owner Control Area security system. (Section P8)

Report Details

Summary of Plant Status

Unit 2 began this inspection period at 96 percent power. On July 7, 1998, reactor power was reduced briefly to 80 percent primarily due to problems with the No. 1 Low Pressure Intercept Valve. On July 19, operators manually scrammed the reactor when a significant power oscillation occurred during a rod pattern adjustment. On July 30, the unit was returned to 87 percent power following completion of an investigation to determine the cause of the power oscillations.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations. Specific events and noteworthy observations are detailed in the sections below.

a. On July 2, control room operators observed increases in jet pump total flow and core plate differential pressure. These abnormalities were also noted in Jet Pump D loop flow and Jet Pump No. 5 differential pressure. No changes were observed in reactor power or reactor recirculation loop flow and pump speed. The unanticipated changes to these parameters were caused by flushing of a post accident sampling system (PASS) line for a post maintenance test. Procedure 78.000.12," Post Accident Sampling and Transport, Precautions and Limitations," Step 5.1.3 states that the control room should be notified that withdrawing a reactor water sample from a jet pump would cause variations in flow indications for the affected jet pump (for example, samples from the No. 5 or No. 15 jet pumps). The inspector interviewed personnel who were in the control room at the time the PASS sample was being taken and was told that a control room operator was notified of the sampling evolution but did not understand that the jet pump abnormal readings were caused by the PASS sample. In response to these readings, the shift crew conducted an investigation that included reviewing the General Electric Transient Analysis Recorder System traces and control room recorders. The investigation also included a walkdown of the relay room and interviews with control room and system engineering personnel.

The inspector reviewed the PASS sample procedure and noted that it did not provide sufficient information to alert the operators to the changes that would occur to jet pump total flow and core plate differential pressure indications during a PASS sample. However, chemistry personnel were aware of the change in these parameters, yet this information was not communicated to the control room when the operator was notified that a pass sample was to be taken. The inspector concluded that although the control room personnel were notified of the sample, there was insufficient communication between operations personnel and chemistry personnel concerning the changes to reactor system parameters during the performance of a PASS sample. In addition, control room operators did not have a full understanding of the plant parameter changes that would occur during a pass sample. Also, the inspector determined that operators did not receive specific training on the impact of a PASS sample on specific reactor system parameters. In earlier discussions with the licensee, the inspector had expressed a concern with the amount of time that elapsed between the notification of control room personnel that a PASS sample would be taken and the actual performance of the sampling evolution. A longer period of time between these activities would allow operators to evaluate the changes that should occur during the performance of the PASS sample evolution and avoid responding to what appears to be abnormal reactor system indications in the control room.

b. The infestation of Zebra Mussels in the service water side of the Reactor Building Closed Cooling Water (RBCCW) and main turbine lube oil cooler heat exchangers resulted in reduced heat exchanger performance and impacted plant operation. Reactor building closed cooling water heat exchanger performance was reduced by Zebra Mussel infestation causing drywell temperatures to approach Technical Specification (TS) values. As a result, increased use of the emergency equipment cooling water (EECW) system was required to augment RBCCW in maintaining drywell temperatures below TS limits. The RBCCW heat exchangers were cleaned periodically to reduce Zebra Mussel accumulations and improve heat exchanger performance. In addition, Zebra Mussel infestation in the main condenser caused hotwell water box level to increase and approach the elevation of turbine bypass valves. Water intrusion into the turbine bypass valves had the potential to cause a water hammer if steam entered the valves during a transient condition. This condition was recognized by the operators and the water level lowered to normal levels. A sulfuric acid treatment was used in an effective manner to reduce Zebra Mussel infestation in the main condenser. The lower main lube oil cooler for the main turbine required frequent cleaning to reduce the flow restrictions caused by Zebra Mussel infestation. The licensee's corrective actions for degraded heat exchanger performance included cleaning the heat exchangers, reducing service water flow, and the use of chemical treatment.

A biocide treatment, used to reduce the Zebra Mussel population, had not been applied to the general service water (GSW) system since November 1996. The treatment was not permitted due to potential back leakage from the GSW system, potentially resulting in an inadvertent introduction of the biocide into Lake Erie. Further complicating solutions for degraded heat exchanger performance due to Zebra Mussel infestation, was the delay in generating a safety evaluation to allow the use of EECW while cleaning the RBCCW heat exchangers and the use of EECW during periods when lake temperatures are elevated above nominal values. Implementation of a modification to provide supplemental cooling to the torus had also been delayed. A biocide treatment was planned to be implemented during Refueling Outage (RF) 06 scheduled to start on September 3. The inspector noted that the licensee planned to implement modifications to the GSW system that would allow for the introduction of the biocide directly into the system intake in 1999.

c. Conclusions

The fouling of the Reactor Building and Main Turbine Generator Lower Lube Oil Cooler heat exchangers due to Zebra Mussel infestation had an impact on plant operations. In some cases, heat exchanger fouling due to Zebra Mussel infestation caused TS limits to be approached. The licensee's corrective actions included cleaning the heat exchangers, reducing service water flow, and use of a chemical treatment. Also, flushing of a post accident sampling system line caused some changes to occur in reactor system parameters. Control room operators did not identify the reasons for the changes in reactor system parameters due, in part, to a lack of sufficient procedural information and inadequate communications between chemistry personnel and the operations shift crew. In addition, not all the operators were trained to recognize the changes to reactor system parameters when a post accident sample was in progress.

O1.2 Manual Scram from Full Power Due to Power Oscillations

a. Inspection Scope (71707, 71711)

The inspector reviewed control room unit logs, control room recorder information, sequence of events logs, TS, the scram report, emergency operating and abnormal procedures, and performed control panel walkdowns. The inspector also conducted interviews with control room operations personnel and systems and component engineers.

b. Observations and Findings

On July 19, control room personnel observed several reactor power oscillations while at 64 percent power. Control room operators had lowered power to perform turbine bypass valve testing, a control rod pattern adjustment and other maintenance activities. Two power oscillations were observed. The first oscillation occurred while the licensee was investigating problems with the feedwater heater level control system. The oscillation caused changes in both reactor and balance-of-plant parameters (i.e., moisture separator reheater (MSR) flow, feedwater heater level, turbine valve summation indication, feedflow, and steamflow). Reactor power was observed to fluctuate by approximately 3 percent. Similar power oscillations had occurred on May 31, as documented in Inspection Report 50-341/98008. Control room operators noticed a sharp increase in indicated main steam flow to the MSRs. However, the power oscillations stopped immediately when control room operators placed the controller for the north and south heater drain pumps in manual. Following this initial event, the licensee performed several secondary system activities successfully, including turbine bypass valve testing.

Given the recent reactor power oscillations, the resident inspector discussed concerns regarding the performance of a control rod pattern adjustment with licensee personnel and regional management. Following discussions with station senior management, control room supervisory personnel, and reactor and system engineering personnel, the licensee decided to proceed with the control rod pattern adjustment. The basis for the decision included an analysis of the secondary and reactor power oscillations by engineering personnel. To reduce the magnitude of secondary plant oscillations, plant operators maintained the heater drain pump controllers in manual. After six rods were adjusted, a small transient in reactor pressure and power as well as MSR flow was observed. Approximately 10 minutes after the transient, an additional rod was selected and withdrawn. A short time after rod withdrawal, reactor power was observed to decrease abruptly to 50 percent power then increase sharply to 75 percent power and decrease back to 50 percent. Indicated MSR steam flow increased from 0 percent to 100 percent. The control room operator at the reactor controls observed the reactor power transient and appropriately scrammed the reactor by taking the mode switch to shutdown.

Following the reactor scram, all control rods were verified to be fully inserted. All safety systems responded as expected. Reactor water level decreased to nominal values and all appropriate isolations occurred. The inspector verified that control room operators followed all emergency and abnormal operating procedures.

The licensee formed a solution team to determine the apparent cause of the large power oscillation. Based on an evaluation of data, the licensee concluded that the cause of the power oscillation may have been related to a loose internal component of the No. 4 Throttle Control Valve (TCV). This component may have partially obstructed steam flow through the TCV. The obstruction of steam flow was confirmed by a review of data that showed a step change occurred in the position of the TCV during an oscillation on May 31, and occurred twice on July 19, with no observed increase in electrical power output. In addition, on line monitoring showed an increase in vibration levels for the No. 4 Valve. Further evidence obtained from recent surveillance testing revealed sluggish movement of the TCV. Other data related to the valve included some abnormalities in first stage pressure and steam manifold pressure for a given TCV position. Recent measurements also showed an unexplained increase in TCV stroke length. After evaluating this data, the licensee concluded that internal damage had occurred to the TCV. The licensee concluded that the damage allowed an internal component (believed to be a component called the muffler) to obstruct steam flow causing oscillations in both primary and secondary parameters.

Due to the potential internal damage of the No. 4 TCV, engineering personnel performed a safety evaluation to operate the unit with the No. 4 TCV closed. The safety evaluation initially required monitoring throttle valve position, reactor power, and manifold pressure against established limits. Monitoring these parameters provided for operation with only three TCV's open and bounded this mode of operation. The inspector independently reviewed the safety evaluation and did not identify any concerns. Further analysis of the event and observation of TCV operation revealed play in the valve actuator linkage for the No.3 TCV. The licensee concluded that play in the No. 3 TCV actuator linkage was caused by a damaged threaded connection and that this could have caused the previous two secondary power oscillation events.

The inspector expressed concern with the restart of the unit and the possibility of further power oscillations. Discussions were held between station and regional management and the resident inspector. The licensee decided to restart the unit. The decision was based, in part, on the fact that the play in the No. 3 TCV linkage was not as extensive as the increased stroke length for the No. 4 TCV, and measured valve internal vibrations were also not as severe. Also, additional valve degradation would be evident by an increase in measured vibration. Following startup of the unit and a subsequent power increase, another oscillation occurred at approximately 69 percent power. The licensee concluded that this oscillation was caused by the previously described play in the No. 3 TCV actuator assembly. The licensee decided to increase reactor power to 87 percent. This decision was based on an evaluation of the cause of the oscillation, an engineering evaluation of the oscillation event, and on previous experience that showed the effects of obstructing steam flow due to movement of the valve internals was not as likely at higher power levels. At higher power levels, the valve actuator would open the valve fully, allowing steam flow and pressure to maintain the internals to the valve in the fully open position. No further power oscillations have been noted since obtaining this power level. The licensee plans to inspect the TCVs during RF 06.

c. Conclusions

Control room operators were quick to respond to an unexpected power transient caused by a secondary plant oscillation. An operator manually scrammed the reactor following an unexpected power transient. Operator response was good and all systems responded as expected. The cause of the transient was determined to be a loose muffler in the No. 4 turbine throttle control valve. Station managements' decision to operate with the No. 4 turbine throttle control valve closed and to continue plant operation with the degradation observed in the No. 3 turbine throttle control valve was appropriate.

O1.3 Failure to Comply With TS Requirements for Combustion Turbine Generator (CTG) 11-1

a. Inspection Scope (71707)

The inspector reviewed control room logs, TSs, surveillance logs, Procedure 24.324.01, "CTG No. 11, Unit Monthly Operability Check," limiting conditions for operations (LCO) logs, the UFSAR, Inspection Reports 50-341/97014 and 50-341/97007, and interviewed control room operators and shift supervisory personnel.

b. Observations and Findings

On June 23, control room operators performed the CTG monthly surveillance test. The test was being performed in accordance with Procedure 24.324.01, "CTG No. 11, Unit 1 Monthly Operability Check." The test was performed to verify system operability by starting and supplying load to the associated electrical bus. The test was conducted in accordance with Section 5.1, "Operating CTG 11, Unit 1 from CTG 11-1 Control Center." The inspector reviewed Section 2.0, "Precaution and Limitations." Step 2.4 stated that CTG 11-1, Unit 1 was inoperable when the CTG 11-1, Unit 1 local Mark V controller was placed in the AUTO position. The precaution further stated that selecting the AUTO position places the unit in the local control mode only and prevents remote operation from the main control board and shutdown panel. In addition, a recent revision to Procedure 24.324.01, "CTG No. 11, Unit 1 Monthly Operability Check," Enclosure E, similarly states that CTG 11-1 was inoperable when the local Mark V controller was placed in the AUTO position. Technical Specification 3.7.11 states that with CTG 11, Unit 1 inoperable, control room operators are required to verify within 1 hour that the 120 KV bus was available by performing Surveillance Requirement (SR) 4.8.1.1.1. Surveillance Requirement 4.8.1.1.1 stated that each of the required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be determined operable at least once per 7 days by verifying breaker alignment and indicated power availability. Despite the statements in procedures, control room operators failed to perform the required surveillance for a 90 minute period. After recognizing the error, the control room staff declared the unit inoperable and entered the appropriate LCO action statement requiring the unit to be in at least hot shutdown within the next 12 hours and in cold shutdown within the next 24 hours. Operators then immediately performed the surveillance test with no discrepancies noted, exiting the LCO.

The inspector noted that typically, Section 5.1 was performed from the control room. However, a decision was made to allow the operators to start the unit locally. The inspector noted that although Section 5.1 was infrequently performed, control room personnel did not perform the expected peer check prior to making a determination of TS impact. Operations Department Instruction No 51, "Peer Checking," provides guidelines that suggest that a peer check be conducted for activities that are infrequently performed and if performed improperly would have adverse consequences or that could result in an immediate threat to safe and reliable plant operation. In addition, the surveillance was not entered in the unit log prior to the start of the surveillance activity. This prevented the start of an automatic computer timer, initiated when the log entry is made, from warning the control room crew before the required action was missed. Two other similar instances of not performing TS required surveillance activities when equipment was declared inoperable are documented in Inspection Reports 50-341/97014 and 50-341/97007. All three instances of missed TS actions occurred within a 1 year period. Of particular concern was the fact that the operators in the control room did not work together as a team to ensure that the required TS actions were appropriately performed within the allowed time frame.

The licensee's immediate corrective action included retraining on management expectations for peer checks to determine TS impact. The inspector concluded that the repetitive failure to perform the surveillance test per the requirements of SR 4.8.1.1.1 within 1 hour was a condition adverse to quality. This violation was similar to two others as documented in Inspection Reports 97007 and 97014. The inspector concluded that several personnel errors contributed to this violation and that the corrective actions developed from the two previous events should have prevented reoccurrence of this violation. The repeat occurrence of this violation is considered a condition adverse to quality and a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." However, the TS violation was identified by the licensee and corrective actions to the repetitive violation were not available at the end of the report. This item is being tracked as an EEI pending NRC review of proposed corrective actions. (50-341/98012-EEI-01)

c. Conclusions

The inspector concluded that operators in the control room did not perform a required surveillance to verify offsite power supply availability within 1 hour subsequent to declaring CTG 11 inoperable. Specifically, Surveillance Requirement 4.8.1.1.1 requires operators to check the availability of other offsite power sources within one hour when either an Emergency Diesel Generator or CTG 11 are declared inoperable. Instead, after control room operators repositioned the CTG local Mark V controller to the AUTO position, rendering the CTG 11 auto-start feature inoperable from the control room and the remote shutdown panel, Surveillance Requirement 4.8.1.1.1 was not performed for a 90 minute period. Several personnel errors were contributors to this event. These errors included the failure to log the surveillance such that an automatic timing feature was not used and the failure to perform a peer check. Of particular concern was the lack of team work in the control room to ensure that the appropriate TS actions were performed. This is the third failure to conduct the Surveillance Requirement 4.8.1.1.1 within a 1 year period. This repetitive failure is considered a violation of 10 CFR 50, Appendix B, Criterion 16, "Corrective Action." However, because the licensee was in the process of determining appropriate actions to address this violation at the end of the inspection period, this item is being tracked as an EEI.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System (ESF) Walkdowns (71707)

The inspector used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems:

- RBCCW
- EECW Systems
- Emergency Diesel Generator (EDG) No. 11 and support systems
- EDG No. 13 and support systems
- 130/260 VDC Battery Divisions 1 and 2
- Residual Heat Removal System Service Water (RHRSW) system
- Emergency Equipment Service Water system

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. The inspector identified no substantive concerns as a result of these walkdowns. Equipment operability was verified through system and valve lineup and parameter verification.

O8 Miscellaneous Operations Issues (92700)

During the conduct of post maintenance testing (PMT) for EDG-13, the inspector identified that System Operating Procedure (SOP) 23.307, "Emergency Diesel Generators," Step 5.4.2.4.b, stated that fuel oil pressure should be stabilized above 25 psig as indicated on R30RA08A(B,C,D) Fuel Oil Indicator after starting the standby fuel oil pump. The pressure was required to be verified to ensure proper fuel oil system performance prior to starting the EDG. The inspector identified that the indicator used by operations personnel to verify this parameter during the PMT was not labeled as a fuel oil pressure gauge but instead as a duplex filter differential pressure indicator. In addition, the installed indicator had dual indication (red and black pointers) and was used to measure differential pressure across a fuel filter and did not provide an absolute pressure reading. Moreover, the procedure did not describe which of the two indicators should be used. The inspector reviewed portions of similar procedures for the other EDGs and identified additional discrepancies. For example, the inspector reviewed the SOP 23.307 for EDG 11, Attachment 2, "Operating Log," and noted that the fuel oil pressure acceptance reading was 20 psig. Further, in contrast to these requirements, SOP 23.307, Enclosure C, required a fuel oil pressure reading of 10 psig.

As a result of the inspector identified discrepancies, the licensee reviewed surveillance procedures and identified additional similar discrepancies. For example, Surveillance Procedure 24.307.14, "EDG 11 Start and Load Test," Step 5.1.14, stated a similar 25 psig minimum requirement for fuel oil pressure. The inspector noted that Attachment 2, "Operating Log," required a 20 psig minimum reading for fuel oil pressure be taken from the black pointer. However, the use of the black pointer was not in agreement with SOP 23.307, that stated a red pointer should be used to obtain a fuel oil pressure reading. The operation and safety function of the EDG appeared not to be impacted as evidenced by the successful completion of several surveillance tests.

The inspector concluded that current station procedures, in some cases, contained insufficient information and inconsistencies that precluded operators from verifying proper emergency diesel generator (EDG) fuel oil system operation. Further evaluation was needed to determine the appropriate method to verify proper EDG fuel oil system operation.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspector observed all or portions of the following work activities:

- Division 1 RHRSW Service Water Pump and Valve Operability Test
- EECW Valve Operability Test
- EECW Pump and Valve Operability Test
- EDG 13 - Fast Start and Load Rejection Test
- Mechanical Vacuum Pump Run Test
- Turbine Bypass Valve Operability Test
- Division 1 and 2 Control Center Chilled Water Pump and Valve Operability Test
- Control Room Emergency Filter Monthly Operability Test
- Division 1 and 2 Weekly 130/260 VDC Battery Check
- Division 2 18-month 130/260 VDC Battery Check
- Division 1 Alternate Supply Reactor Protection System Electrical Protection Assembly Calibration/Functional Test
- 18-month Emergency Lighting Performance Evaluation
- Division 1 Thermal Hydrogen Recombiner Heater Integrity Test and Visual Inspection
- EDG 11 Start and Load Test
- CTG 11 Unit 1 Monthly Operability Check
- Division 1 Standby Gas Treatment System Filter and Secondary Containment Isolation Damper Operability Test
- Division 2 Standby Gas Treatment System Filter and Secondary Containment Isolation Damper Operability Integrity Test

M1.2 EDGs 11 and 13 Preventive Maintenance

a. Inspection Scope (62707)

The inspector reviewed Procedure 34.307.001, "EDG Inspection and Preventive Maintenance," Procedure 24.307.47, "EDG 13-Fast Start and Load," Procedure 35.307.010, "Emergency Diesel Fuel Injector Maintenance," Procedure 35.319.001, "Electric Space Heater Preventive Maintenance," Procedure 35.000.229, "Non -ASME Section XI Relief Valve Setpoint Test," Procedure 23.307, "EDG," work orders, TSs, and the configuration management risk matrix. The inspector also conducted interviews with maintenance, system, and component engineering personnel.

b. <u>Observations and Findings</u>

The inspector observed work performed during the recent EDG outages, including the performance of an 18-month preventive maintenance task. A recent change to the TS extended the LCO outage time for the EDGs from 72 hours to 7 days and allowed the 18-month preventive maintenance task to be performed during normal plant operations. As a result of this change, the licensee's TSs were modified to include the requirement for the implementation of a configuration risk management program. The program required a risk assessment of emergent and planned maintenance. In addition, the station's blackout CTG was required to remain operable by TS. The inspector verified the licensee's risk assessment of emergent work items. The inspector also verified that CTG 11-1 remained operable.

The inspector noted that the work performed on both diesels was being conducted in accordance with 34.307.001, "EDG Inspection and Preventive Maintenance." The inspector noted that work performed was within the scope of work packages. Maintenance workers were very knowledgeable of diesel components and support systems. Operations personnel continuously supported maintenance workers when necessary, avoiding delays. For example, both EDGs were properly safety-tagged prior to the conduct of work. The work required the support of a number of station groups including engineering. Overall efforts among the groups were well coordinated. Supervisory personnel were continuously present providing guidance and in-field oversight where necessary. The scope of the work was well managed. Emergent items were handled expeditiously and did not impact the overall outage schedule.

The conduct of work activities was good. The inspector reviewed sections of the appropriate preventive maintenance procedure and noted that maintenance personnel actions were in accordance with established instructions. The inspector verified that all measuring and test equipment was calibrated and used in an appropriate manner to gather data and other appropriate readings. Tools were used appropriately and for the correct application. Some seldom conducted evolutions went well, such as the removal and refurbishment of the vertical drive spring pack assembly. Foreign material exclusion controls were observed to be implemented and were appropriate for the activities. Quality assurance personnel were present to provide additional oversight. Other senior station management reviewed work activities to ensure station expectations and standards were met. Housekeeping and cleanliness standards were maintained during the work activities.

During a post maintenance test (PMT), EDG 13 tripped on a loss of generator field caused by an improper adjustment of the voltage regulator circuitry. During subsequent PMTs, problems were encountered with the EDG speed/load control circuitry or governor. The EG-B , governor actuator assembly, had been removed and replaced to facilitate maintenance on the lower torsional dampers. After extensive troubleshooting by engineering, including other PMT runs, a decision was made to replace the electronic control box (EG-A) and the governor actuator assembly (EG-B). The decision was based, in part, on continuing problems with speed and frequency control during PMT runs and on vendor recommendations. A root cause investigation was currently being conducted by the vendor to determine the actual failure mechanism. The inspector witnessed both post maintenance and surveillance tests.

c. Conclusions

The inspector concluded that maintenance on the EDGs was conducted in an appropriate manner. Good oversight was provided by station management, supervisory, and quality assurance personnel. Coordination with station work groups including engineering was good. Infrequently performed maintenance tasks were performed well. Emergent items were handled in an efficient manner. A trip was caused by a loss of generator field during post maintenance testing of EDG-13. During post maintenance testing runs following removal and replacement of the governor actuator, problems with controlling EDG frequency and speed were observed. Corrective action included replacement of the governor actuator assembly (EG-B) and the electronic control box (EG-A).

M3 Maintenance Procedures and Documentation

M3.1 Fire Protection and ESF Battery Surveillance Procedure Deficiencies

a. Inspection Scope (92902)

The inspector observed the conduct of the following surveillances, Procedure 28.507.02, "Fire Protection Door Functional Test," and; Procedure 42.309.01, "130/260 VDC ESF Battery Weekly Functional Test." The inspector reviewed TSs, and the UFSAR, and interviewed fire protection supervisory personnel, specialist and component engineering personnel.

b. Observations and Findings

Selected surveillance tests for fire protection were observed that included fire door functional tests. The UFSAR, Section 9A.6.8.2.2, requires verifying the operability of the fire door supervisory system for each electronically supervised fire door by performing a channel function test at least once per 31 days. The inspector reviewed the procedure and identified an instruction that contained a note requiring the alarm function to actuate in 5.0 minutes. However, the step following the note stated that the fire technician should declare the door inoperable after 5.5 minutes, inform the Nuclear Shift Supervisor (NSS), and close the door. Based on discussions with fire protection technicians and supervisory personnel, the NSS and Nuclear Assistant Shift Supervisor, the inspector determined that the 5-minute limit should be used when evaluating alarm function/door operability. The licensee plans to revise the procedure to ensure that alarm limits are appropriately established and that required actions are taken.

The inspector observed the performance of Division ½ Weekly 130/260 VDC Battery Check. The surveillance was used to verify battery operability in accordance with TS requirements and was performed every 7 days. The surveillance was used to review the performance of pilot cells (i.e. specific gravity and individual cell voltage). The inspector reviewed the procedure and noted an instrument, DMA-35 Density Meter, provided temperature corrected specific gravity readings. The procedure further stated that to use DMA-35, the ambient temperature must be within the range of 20° C and

30° C (68° to 86° F) and the battery cell temperature must be within 3° C of the ambient temperature. If these conditions could not be met, the surveillance procedure required that a standard bulb hydrometer and alcohol thermometer be used to measure specific gravity and temperature, followed by a temperature correction that is performed manually. Step 6.1.1 instructed maintenance personnel to use an alcohol thermometer or equivalent to record ambient temperature at the surface of the battery. The inspector noted that the technician measured ambient temperature at an elevated position 3 feet above the level of the battery. A similar ambient temperature measurement was taken for Division 2 batteries. However, the inspector noted that the procedure for Division 2 was inconsistent in that the same Step 6.1.1 does not instruct the technician to perform the measurement at the surface of the battery. The inspector also observed that the thermometer readings of the DMA-35 and battery cell temperature readings were recorded differently (Celsius vs Fahrenheit). This did not allow for a direct comparison of temperatures to ensure readings were within acceptable limits without conversion. The inspector observed the technician taking the Division 2 battery room ambient temperature readings recorded the readings similar to the practice for Division 1. The inspector discussed his observations with the NSS. The NSS then informed electrical supervisory personnel to instruct technicians to repeat the test in the correct manner to ensure battery operability. The test was repeated in a satisfactory manner.

c. Conclusions

The surveillance procedures used to test fire door alarm functions and safety-related batteries contained insufficient information and inconsistencies. However, no adverse impact was identified as a result of the procedure discrepancies. (Section M3.1)

M8 Miscellaneous Maintenance Issues (92902)

The inspector conducted a materials management inspection and reviewed the control of safety-related components stored in a warehouse storage facility. The inspector reviewed Station Procedure, MMM08, Revision 3, "Material Shipping, Handling, and Storage." The inspector conducted walkdowns of the Warehouse B storage locations and verified that stored materials were properly identified and marked. Coatings, preservatives, descants and inert gas blankets were properly established. In addition, physical damage was identified and corrected, and cleanliness levels were maintained. The inspector determined that for the areas assessed, materials were stored in accordance with established station procedures. Several stored materials that could be used in safety-related applications, including copper tubing, manual valves, carbon and stainless steel piping, were not sealed or covered to prevent entry of foreign material. Monthly walkdowns required by the station's procedures had not identified these discrepancies. The inspector observed numerous motors of various sizes and applications and determined that some were not tagged indicating that the required preventive maintenance was performed. The inspector questioned warehouse personnel who verified that preventive maintenance activities had been performed. In addition, the shelf life was verified for numerous stored materials. All items were appropriately stored in such a manner as to permit access for inspections, and were stacked and arranged so that racks, cribbing, or crates were bearing full weight without distortion. The implementation of cleanliness and housekeeping practices was evident. The inspector verified that temperature requirements for the various categories of stored equipment and parts met regulatory requirements and industry standards. The inspector also verified that hazardous chemicals, paints, and solvents were not stored near safety-related equipment.

The inspector concluded that adequate controls were in place to ensure the proper storage of materials that could be used in safety-related applications. Monthly walkdowns were not thorough enough to identify discrepancies in foreign material exclusion control.

III. Engineering

E1 Conduct of Engineering

E1.1 Insufficient Testing of Thermal Overload Relays

a. Inspection Scope (92903)

The inspector reviewed corrective action resolution documents; "TSs;" the Technical Requirements Manual; the Engineering Support Conduct Manual; MES 27, "Thermal Overload Protection;" Procedure 23.208, "RHRSW Standby;" Reg Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor Operated Valves;" Spectrum Surveillance Test Procedure 42.000.02, "Thermal Overload Relay Calibration;" Design Specification 3071-R00-PUR-133, Rev A, Section 5.1.3, "Testing Requirements;" Purchase Order NR-329515; Design Specification 3071-128-EZ-03 "Thermal Overload Heater Sizing;" Design Basis Documentation; Spectrum Generic Test Procedure for Acceptance and Dedication of Thermal Overload Relays and Heaters; and conducted interviews with operations and system engineering personnel.

b. Observations and Findings

The component engineer questioned whether adequate testing had been conducted on thermal overload relays for replacement motor control centers (MCC). The replacement MCCs were installed for three valves in the RHRSW system. The inspector reviewed TS and identified a requirement to perform testing on thermal overload relays. Technical Specification 3.8.4.3 stated that thermal overload protection of each valve used in safety systems shall be operable. Surveillance Requirement 4.8.4.3 also stated that thermal overload protection for required valves shall be demonstrated operable at least once per 18 months by the performance of a channel calibration of a representative sample of at least 25 percent of all thermal overloads following maintenance on the motor starters. Similarly, the vendor had performed testing using a method that did not test each thermal overload relay to determine if the thermal overload relays were acceptable. The engineer questioned whether this method met the TS requirement to verify operability of the thermal overload protection for each valve used in a safety system.

In response, the licensee elected to perform an operability evaluation to address the engineer's question. While the licensee was conducting the operability evaluation, the three valves were placed in their safety position. Operations Procedure 23.208, "RHRSW Standby Valve Lineup," Attachment B, required that the bypass valve (E1150F603B) be closed, and the cooling tower shutoff valves (E1150F604B and E1150F605B) be opened. The inspector reviewed the lineup and determined it was proper for emergency operation when the RHRSW, diesel generator service water, and emergency equipment service water systems would be discharging water to the residual heat removal mechanical draft cooling towers. The three RHRSW valves were primarily used during cold weather operations. During the summer season, it is unlikely that the outdoor ambient temperature would fall below 35° F, nor would the service water return temperature fall below 60° F. Plant management stated that due to the relatively low safety impact, these valves were chosen to have their associated MCC replaced.

General Electric thermal overload relays and heaters contained in the replacement MCC compartments were supplied by Spectrum Technologies and were tested under Spectrum Generic Test Procedure for Acceptance and Dedication of Overload Relays and Heaters. Section 5.0 of the Spectrum Test Procedure describes the acceptance test steps for both the thermal overload relay and heater. The subject procedures were reviewed and approved by Fermi plant support engineering personnel. Each relay was megger tested at 1000 VDC to 1.0 megohms. Section 5.5 of the Spectrum Test Procedure details the heater tests. Section 5.5.1 stated that the resistance of each overload relay heater was to be measured and recorded. The Spectrum thermal overload heater acceptance test verified the acceptability of two heaters of the same group having the lowest and highest resistance measurement. The tests established the trip time response boundary for all other heaters in the same group or lot. The vendor stated that this test method was acceptable since the remaining heaters from this lot would be assumed to meet the acceptable response time. Engineering personnel reviewed the thermal overload relay/heater method described and determined that the relays were operable using the Spectrum method. Regional specialists reviewed the operability determination and agreed with the licensee's conclusion.

The licensee decided to proceed with testing of the installed thermal overload relays in accordance with Surveillance Procedure 42.000.02, "Thermal Overload Relay Calibration." In addition, the licensee further stated those MCC compartments already supplied by Spectrum Technologies would be tested in accordance with Surveillance Procedure 42.000.02, Rev 29, prior to installation and that Spectrum Technologies would change their thermal overload testing procedure to be identical to the Fermi 2 Surveillance Procedure 42.000.02, Rev 29.

The inspector reviewed Purchase Order NR-329515. The requirements to test all MCCs were supplied to Spectrum and were listed in Design Specification 3071-R00-PUR-133, REV A, Section 5.1.3, "Testing Requirements," and were consistent with the Detroit Edison approved vendor test procedures. The inspector also reviewed Design Specification 3071-128-EZ-03, "Design Instruction Thermal Overload Heater Sizing," Attachment 2, "Multiples of Overload Relay Current Element Rating," in which the test requirements for thermal overload relays are described.

The inspector concluded that the Spectrum method of testing the thermal overload relays was acceptable. No violations of TS requirements were identified.

c. Conclusions

Replacement MCC compartments containing thermal overload relays were installed in safety-related applications for the RHRSW system. The vendor's acceptance testing method for the thermal overload heater relays was questioned and determined to be acceptable. The licensee decision to require that other MCCs be tested using station procedures was conservative.

E2 Engineering Support of Facilities and Equipment

E2.1 Fuel Receipt Inspection Activities

a. Inspection Scope (92903)

The inspector reviewed applicable fuel handling procedures, Procedure 82.00.01, "Receive, Inspect, Channel and Handle New Fuel," Maintenance/Operations Procedure (MOP) 16, "Conduct of Refuel Floor Activities (Non Outage)," Procedure 23.710, "Fuel Handling System," Procedure 23.711, "Fuel Pool Cooling and Cleanup System," daily status checklists, TSs, the UFSAR, control room logs, and access control logs. The inspector also conducted interviews with reactor engineering, radiation protection, operations and system engineering personnel.

b. Observations and Findings

From June 16 through July 18, the inspector observed portions of the receipt of 8 shipments of new fuel assemblies totaling 220 bundles. The bundles were scheduled for installation into the reactor core during RF06. The receipt inspection was conducted in accordance with Procedure 82.000.01, "Receive, Inspect, Channel and Handle New Fuel," and MOP 16, "Conduct of Refuel Floor Activities (Non Outage)." To facilitate the receipt of fuel, the licensee effectively organized several station groups that included vendor, radiation protection, reactor engineering, training, radwaste, warehouse, security, quality assurance, and work control personnel. A team building orientation session was conducted to ensure personnel were knowledgeable of specific topics that included; As-Low As Reasonably Achievable guidelines; procedural precautions and limitations; industry events; and criticality monitoring.

The inspector verified that the refueling bridge pre-operational checklist had been performed in accordance with Procedure 23.710, "Fuel Handling System." In addition, the inspector verified that the fuel pool cooling and cleanup system was operational in accordance with Procedure 23.708, "Fuel Pool Cooling and Cleanup System." The inspector verified refueling floor radiation monitor operation and refuel floor access controls were established. Permission to begin work on the refuel floor was authorized by the NSS. Appropriate log entries were made in the unit log to track refueling floor activities. The inspector verified that the control room NSS and Nuclear Assistant Shift Supervisor were aware of fuel movement activities. Tagboard items were updated to reflect actual location of new fuel assemblies. Some minor equipment problems were encountered; however, repairs were made in an efficient manner. Channeling, handling, and inspection activities were conducted in accordance with established procedures. The inspector concluded that corrective actions for previously identified fuel handling issues were being effectively implemented.

c. Conclusions

Fuel receipt activities were conducted in an efficient manner. Overall, the planning and execution of fuel receipt inspections was good. Fuel receipt activities were well-coordinated requiring the cooperation of several station groups. Fuel receipt activities involved inspections of multiple fuel shipments over an extended period of time and were conducted in accordance with established procedures. Emergent equipment issues were handled in an effective manner. Corrective actions for previously identified fuel handling issues were effectively implemented.

IV. Plant Support

R. Radiological Protection and Chemistry Controls

R1.1 Radioactive Material Inadvertently Transported Outside of Radiological Restricted Area

a. Inspection Scope (71750)

The inspector reviewed corrective action resolution documents and radiation protection procedures, and interviewed maintenance and radiation protection personnel.

b. Observations and Findings

On July 2, maintenance workers were re-entering the plant following the performance of maintenance activities in the circulating water pump house. While the workers were passing through the radiation portal monitor the alarm was actuated. A second attempt was made to pass through the detector but again the alarm was actuated. Radiological surveys performed by radiation protection personnel revealed a contaminated tool bag. Maintenance workers had previously passed through the gamma 60 detectors with the tool bag without actuating any alarms.

A company truck was used to transport personnel to the circulating water pump house. Some intermediate stops were made at a warehouse to obtain gasket material. The workers returned to the Primary Access Portal, where one worker carrying the bag of tools actuated the detectors.

Radiation protection personnel were informed of the portal monitor activation in a timely manner by both security and maintenance personnel. The bag was retrieved and immediately surveyed revealing a 200 cpm spot on the inside of the bag. Tools and other materials surveyed did not yield any detectable levels of contamination. Later, the tool bag was resurveyed and found to be contaminated at 400 cpm. Intrinsic analysis performed on the tool bag revealed that the contamination was primarily Cobalt 60

Radiation protection personnel surveyed vehicles, warehouse locations, personal clothing, the circulating water pump work area and the clean tool area. No additional contamination was detected.

The licensee's corrective actions included personal interviews with maintenance workers and the conduct of extensive surveys of the contaminated tool bag, cold tool crib and bag storage area, Warehouse B, circulating water pump house area, tools, gloves, trash cans, and personal and company vehicles. In addition, the calibration of gamma 60 portal monitors was verified. No detectable levels of radiation were identified.

c. Conclusions

The licensee's corrective actions were broad and comprehensive to an event that resulted in the release of a contaminated tool bag to the owner controlled area. Identification, reporting, and the investigation of the event were prompt and thorough.

E8 Miscellaneous R.&C Issues

a. Inspection Scope (71750

The inspector reviewed the circumstances associated with the dropping of a large metal container posted with a low surface activity (L.A.) sign and containing contaminated metal.

b. Observations and Inspection Findings

On June 29, a large metal L.A. container containing contaminated metal was dropped from an elevated position in the Onsite Storage Facility (OSF). The metal was the result of the disassembly of laundry equipment. The L.A. box (No. 18168) weighing approximately 2000 pounds, was being moved from Bay 2 in the OSF to the OSF truck bay. The L.A. container was dropped approximately 30 feet onto another metal container filled with contaminated materials, crushing it and releasing the contents of the container to the OSF bay area. The containers were filled with low level radioactive components. A review of the loading configuration of the L.A. container showed that it was suspended by two synthetic slings, each in a basket configuration attached to an H type lifting beam. Several attempts had been made to ensure the lift was level. The inspector determined that no significant radiological hazards, contamination, or personnel injuries resulted from the event. The inspector concluded that the event was a near miss with a high potential for both radiological and personal injury. The inspector verified the integrity of the rigging equipment and determined that the overhead crane was operated appropriately and that crane operability remained unaffected. The inspector concluded that the inadvertent drop of contaminated metal from an elevated L.A. was caused by a shift in the center of gravity of the contents. Contributing to the incident was less than adequate rigging and lack of training on the H style beam assembly. The licensee's corrective actions included retraining on rigging techniques and use of the H beam assembly, monitoring of crane operations by Detroit Edison supervision, performing a contamination survey, and briefing the Radwaste crew on the incident. The inspector reviewed the licensee's corrective actions and determined them to be acceptable.

c. Conclusions

The inspector concluded that the inadvertent drop of contaminated metal from an elevated L.A. container was caused by a shift in the center of gravity of the contents. The incident was of concern due to potential radiological and personnel safety consequences. Contributing to the event was less than adequate rigging and lack of specific training on the H style beam assembly.

P8 **Miscellaneous Emergency Preparedness Issues**

On July 5, control room personnel were notified that a tornado warning was in effect for Monroe County. The tornado warning occurred on the weekend. Following the announcement of a tornado warning, station personnel were asked to immediately proceed to assigned tornado shelters. The inspector was told by licensee personnel that workers in the Technical Assistance Center building were required to seek shelter at the Fermi Unit 1 facility. Workers attempted to enter the appropriate building; however, the Unit 1 facility was locked and could not be opened with the workers' key cards. The workers contacted plant security who instructed them to proceed to a shelter in the Technical Support Center. Security personnel had failed to remotely open doors at the Fermi 1 facility. The inspector reviewed posted instructions for the Owner Controlled Area security system to determine actions that should have been taken by security personnel. These instructions guided security personnel through a series of computer tasks to remotely open doors at the Fermi 1 facility. The instructions were not contained in a procedure and were uncontrolled. In addition, the instructions only listed doors to be opened at Fermi 1 and did not include the doors at the Nuclear Operations Center facility that were also required to be remotely opened in a severe weather event. A recent tornado that struck the Davis-Besse Nuclear Plant was observed with only 10 minutes warning.

The apparent cause of the event was lack of training of security personnel. The licensee updated the instructions to include all doors to be opened remotely during a severe weather event. The licensee further plans to incorporate these instructions into a procedure. The licensee's corrective actions included required reading for security personnel on the operation of the Owner Controlled Area security door system.

V. Management Meetings

X1 **Exit Meeting Summary**

The inspector presented the inspection results to members of licensee management at the conclusion of the inspection on August 3. The licensee acknowledged the findings presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Booker, Maintenance Superintendent
D. Cobb, Operations Superintendent
R. Cook, Compliance Supervisor, Nuclear Licensing
R. DeLong, Superintendent, System Engineering
R. Eberhardt, Superintendent, Outage Management
P. Fessler, Plant Manager
E. Heitzenrater, NS, Operations
K. Hlavaty, Assistant Superintendent, Operations
T. Hsieh, Nuclear Fuels Supervisor
W. O'Connor, Manager of Nuclear Assessment
N. Peterson, Acting Director, Nuclear Licensing
J. Plona, Technical Director
T. Schehr, Operating Engineer
S. Stasek, Supervisor, Independent Safety Engineering Group
J. Thorson, Nuclear Engineering Supervisor
W. Tucker, Supervisor Nuclear Fuels and Reactor Engineering Group

INSPECTION PROCEDURES USED

IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71711:	Plant Startup From Refueling
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance

ITEMS OPENED

50-341/98012-01	EEI	Failure to Perform Required SR within 1 Hour

LIST OF ACRONYMS USED

CTG	Combustion Turbine Generator
EDG	Emergency Diesel Generator
EECW	Emergency Equipment Cooling Water
ESF	Engineered Safety Feature
GSW	General Service Water
LCO	Limiting Condition for Operation
L.A.	Low Surface Activity
MCC	Motor Control Center
MSR	Moisture Separator Reheater
NSS	Nuclear Shift Supervisor
OSF	Onsite Storage Facility
PASS	Post Accident Sampling System
PMT	Post Maintenance Testing
RBCCW	Reactor Building Closed Cooling Water
RF	Refueling Outage
RHRSW	Residual Heat Removal Service Water
SOP	System Operating Procedure
SR	Surveillance Requirement
TCV	Throttle Control Valve
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation