U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-341
License No:	NPF-43
Report No:	50-341/98013(DRP)
Licensee:	Detroit Edison Company
Facility:	Enrico Fermi, Unit 2
Location:	6400 N. Dixie Hwy. Newport, MI 48166
Dates:	July 30 - September 21, 1998
Inspectors:	G. Harris, Senior Resident Inspector S. Campbell, Senior Resident Inspector, Davis-Besse J. Clark, Resident Inspector, Perry
Approved by:	Bruce Burgess, Chief Reactor Projects Branch 6

EXECUTIVE SUMMARY

Enrico Fermi, Unit 2
NRC Inspection Report 50-341/98013(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection.

Operations

- The inspectors identified that administrative controls for protection of normal and emergency power sources were not fully implemented in that placards were not placed on the fence to preclude work in the 120 kV switchyard. Review of activities performed during the time that the emergency diesel generators and the 120 kV switchyard were protected did not identify any work in these two areas. (Section O1.2)

- Adequate documented justification was available for not locking the emergency diesel generator starting air and fuel oil valves. However, the justification conflicted with guidelines that determined which valves should be locked. Licensee management agreed to reassess the issue. (Section O1.4)

- The inspectors confirmed that the licensee appropriately scrammed the plant when power oscillations were observed on average power range monitor channels. The probable cause of the oscillations was attributed to looseness in the actuator linkage for Turbine Control Valve No. 3. (Section O1.5)

- The inspectors concluded that the licensee appropriately performed surveillance procedures within the time period specified by Procedure 20.000.01, "Reactor Scram," following a manual scram. (Section O1.6)

- The probable cause of the inadvertent opening of Emergency Diesel Generator 13 Output Breaker EC4 during breaker logic and emergency diesel generator testing was related to a faulted nonsafety-related offsite frequency relay. The licensee's focus on the relay as the probable cause was appropriate. (Section O1.7)

Maintenance

- The inspectors concluded that the storage of the safety-related batteries on the third floor of the turbine building did not degrade the performance of the batteries. The issue of whether current procedures allowed for the storage and handling of safety-related batteries on the third floor of the turbine building remained unclear. The inspectors also concluded that confusing instructions in the work package contributed to incorrect wiring of a temporary battery charger. The incorrect wiring of the batteries did not cause damage to the batteries. The event resulted in a reset of the error free day clock. (Section M1.2)

- The conduct of the wrong post maintenance test was performed after work on the automatic depressurization system logic circuitry. Contributing to the event were weaknesses in work controls that included work planning. Subsequent multiple reviews of the work packages and work activity failed to detect the error. The error resulted in one automatic depressurization system logic string being administratively inoperable while the other was physically inoperable. At the same time work was performed on divisional residual heat removal components. The licensee's investigation was comprehensive and thorough. (Section M1.3)

- Scheduling a fire protection barrier surveillance during Mode 1 operations contributed to the failure of completing the surveillance before the required surveillance interval expiration date. The failure to complete the surveillance prior to the expiration date caused the inoperability of several fire barriers located mainly in the reactor building steam tunnel. In addition, the lack of familiarity and general understanding of the conduct of the surveillance procedure by fire protection personnel was also a contributor, as well as work control reviews that failed to identify that the procedure would not be done prior to its required completion date. The inspectors determined that the licensee's corrective actions were acceptable. (Section M1.4)

- The inspectors concluded that not documenting an engineering equivalency before interchanging parts on safety-related breakers presented a vulnerability to rework, if the equivalency resulted in a discrepancy. Visual verification of the under-frequency relay part and model numbers for Breakers ED4 and EC3 was acceptable. However, the work request process ensures traceability of model and part numbers during a work request closeout. Corrective actions to strengthen a weak cannibalization program have been established, but not implemented. (Section M1.5)

Engineering

- The inspectors concluded that the safety evaluation that analyzed the use of emergency equipment cooling water in the augmentation mode for reactor building closed cooling water had not been reevaluated and revised to reflect the increased number of starts and longer operating times of the equipment. The safety evaluation was subsequently revised. The inspectors also concluded that no long term degradation of emergency equipment cooling water would result from this mode of operation. (Section E1.1)

- A misinterpretation of the conduit and cable specification by the modification engineer led to installation of a conduit before proper authorization was received. Further, the installation specification used by the plant engineer did not provide flexibility required for an at-risk technical service request. Further, written instructions were not followed for installation of the cables. Inadequacies in work package instructions and nonadherence to station work control guidelines were identified. (Section E8)

Plant Support

- The inspectors identified that two required frisking methods were not being observed by all individuals exiting the radiologically restricted area. The inspectors noted that individuals were not frisking hand-held items separately, and some individuals were receiving multiple personal contamination monitor alarms without contacting health physics personnel. However, the licensee took prompt corrective actions and documented identified frisking errors in their corrective action system. (Section R1.1)

Report Details

Summary of Plant Status

Unit 2 began this inspection period by completing an investigation to determine the cause of unanticipated secondary power oscillations. During this period, the plant operated at 88 percent power with the No. 4 Turbine Control Valve (TCV) closed. On September 4, 1998, while attempting to perform a controlled shutdown of the unit, control room operators initiated a manual scram after identifying a repeat occurrence of power oscillations. The unit remained shutdown for Refueling Outage (RFO) 6.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

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

Extensive observations were conducted of control room activities over the inspection period. The inspectors observed that control room evolutions were handled effectively by control room personnel. Good command and control was observed by the inspectors during observation of control room personnel communications. Operation's control of out-of-service equipment and annunciators was effective. Supervisory oversight of control room evolutions and activities was evident. Plant tours revealed that components were clearly labeled and that despite outage preparation activities, the housekeeping and material condition of plant equipment was good. Specific precautions and localized procedures were clearly posted.

O1.2 Protected Division I Electrical Activities During Division II Electrical Maintenance Activities

a. Inspection Scope (71707)

The inspectors performed walkdowns of emergency diesel generators (EDGs) and the 120 kV Switchyard, reviewed the Defense-In-Depth Plan, plan-of-the-day, Operations Department Instruction 044, Revision 3, "Operations Outage Philosophy," and interviewed operations and work control personnel.

b. Observations and Findings

Following the plant scram, the licensee began maintenance outage activities on Division II equipment. To ensure that emergency backup and offsite electrical sources were maintained, the licensee provided protection for Division I EDGs 11 and 12 by implementing administrative controls including the placement of magnetic placards on the EDG room doors. The placards indicated that operations approval was required prior to work on these components. The licensee also developed a defense-in-depth plan that used minimum required electrical power sources during each division outage. Administrative controls, including the use of placards, were also intended for the 120 kV Switchyard at Fermi Unit 1. The inspectors toured the 120 kV Switchyard at Fermi Unit 1 while the licensee performed maintenance in the Division II 345 kV switchyard. The inspectors verified that no maintenance activities were in progress in the 120 kV Switchyard. However, the inspectors were not able to verify that placards had been placed on the fence surrounding the 120 kV Switchyard. The inspectors discussed the use of administrative controls with the licensee and the licensee agreed to post the placards. The inspectors verified the administrative controls were put in place and that the electrical lineup satisfied the defense-in-depth plan.

c. Conclusions

The inspectors identified that administrative controls for protection of normal and emergency power sources were not fully implemented in that placards were not placed on the fence to preclude work in the 120 kV switchyard. Review of work activities performed during the time that the EDGs and the 120 kV switchyard were protected did not identify any work activities.

O1.3 Verification of Technical Specification (TS) Requirements in Refueling Mode 5

a. Inspection Scope (71707)

The inspector reviewed and verified compliance with TS requirements for Refueling Mode 5.

b. Observations and Findings

While the plant was in the refueling mode, the inspectors reviewed the minimum TS requirements for the source range monitors (SRMs), spent fuel pool and reactor vessel water levels and the reactor mode switch. The inspectors verified that the licensee had calibrated the SRMs within the time limit required by TSs and that the minimum counts per second were indicated on the SRMs. The licensee ensured minimum TS requirements for spent fuel pool and reactor vessel levels through visual verification of weir spillover to the skimmer surge tank. The licensee added a redundant level indicator using a portable computer. The inspectors reviewed control room unit logs and verified that the reactor mode switch was locked within the time limits specified in TS. Also, the inspectors verified that the switch had been maintained locked in the refueling position. The licensee had checklists to verify these parameters at least once per shift and the inspectors verified these checklists were consistent with TS requirements.

c. Conclusions

The inspectors concluded that the licensee was in compliance with TS requirements for Mode 5 refueling operations.

O1.4. EDG Fuel Oil and Starting Air Manual Valves Not Locked

a. Inspection Scope (71707)

The inspectors reviewed Design Calculation (DC) 1959, "Locked Valve Program," DC-4959, "Locked Valve Program," Inspection Report 50-341/91018, Operations Conduct Manual MOP09, "Locked Valve Guidelines," and interviewed operations supervisory personnel.

b. Observations and Findings

During a tour of the EDG 11 and 12 rooms, the inspectors noted that the manual valves for the EDG starting air and fuel oil systems were appropriately aligned but the valves were not locked. Locking the valves in the required position ensured that these valves would not be misaligned. The misalignment of these valves could potentially prevent starting of the diesel. The inspectors reviewed the locked valve program to determine if the licensee had justification for not locking these valves. The inspectors verified that DC 4959 provided justification. The justification was based on the performance of the 31-day EDG TS required surveillance. It had been concluded that this surveillance would reveal a misaligned valve. However, this justification conflicted with the guidelines used to determine which valves required locking. Specifically, the DC required locking manual valves that were located in engineered safety feature (ESF) actuation systems when valve misalignment could defeat the safety function of the system. In addition, the inspectors noted that the valves were accessible and could potentially be inadvertently manipulated. Further, the inspectors noted that Fermi's probabilistic risk assessment indicated that a loss of the EDG was a high risk contributor to core damage frequency. Therefore, it appeared prudent to provided additional administrative controls for the manual valves located in the starting air and fuel oil systems for the EDGs. The inspectors discussed this concern with appropriate licensee personnel who agreed to reassess locking these valves. Subsequent inspection of the manual valves located in the fuel oil and starting air systems did not identify any misaligned valves.

c. Conclusions

Adequate documented justification was available for not locking the emergency diesel generator starting air and fuel oil valves. However, the justification conflicted with guidelines that determined which valves should be locked. Licensee management agreed to reassess the issue. (Section O1.4)

O1.5. Reactor Scram during Plant Shutdown for RFO6

a. Inspection Scope (71707)

The inspectors evaluated the circumstances surrounding a manual scram that was initiated during shutdown of the plant for RFO6. The inspectors also reviewed the strip chart, General Electric Transient Analysis Report System (GETARS), and Scram

Reports 98-002 and 98-003, Operations Conduct Manual MOP03, and interviewed operations personnel.

b. Observations and Findings

On September 4, 1998, during the power reduction in preparation for RFO6, the plant experienced reactor power oscillations in excess of 10 percent peak to peak. Similar power oscillations had occurred on July 19,1994, during the conduct of a control rod sequence exchange. In the July 19, 1994 power oscillation, the root cause was attributed to the identification of looseness in the No. 4 Turbine Control Valve actuator linkage. For the September 4, 1998 power oscillation event, loose linkage was also identified in the actuator associated with the No. 3 Turbine Control Valve. In response to both the July and September power oscillations, control room operators placed the reactor mode switch in "Shutdown" and manually scrammed the plant.

With regard to the September 4 manual scram, the licensee conducted a shift brief for lowering the reactor power for the start of RF06. During the brief, operators discussed the possibility of scramming the plant if the power oscillations were observed on the APRMs. At 5:00 p.m., the operators commenced a plant shutdown. At 5:27 p.m., when reactor power reached approximately 70 percent, the operators observed a 20 percent peak to peak power oscillation on all APRMs. In response to the oscillations, the operators placed the reactor mode switch in "Shutdown" and scrammed the plant. The plant responded as expected with no safety relief valves opening and no ESF equipment actuations. The inspectors verified that operators entered all appropriate emergency operating procedures.

The inspectors interviewed the operator who scrammed the reactor and determined that the reactor mode switch was placed in shutdown after observing the power oscillations on the APRMs. Strip charts and GETARS printouts included in Scram Report 98-003 confirmed that power oscillations of 20 percent peak-to-peak occurred before the plant was scrammed. Moisture separator reheater and main steam system flow indicators also confirmed the power oscillations. The inspectors compared Scram Report 98-002, for the July 19 scram, with Scram Report 98-003 and found similar system responses. Procedures were in place to direct the operators to manually scram the reactor when greater than 10 percent peak-to-peak oscillations were indicated on the APRMs. No violations of TS requirements as a result of the event were identified.

c. Conclusions

The inspectors confirmed that the licensee appropriately scrammed the plant when power oscillations were observed on APRM channels. The probable cause of the oscillations was attributed to looseness in the actuator linkage for TCV No. 3.

O1.6 Post Scram TS Procedures Verified

a. Inspection Scope (71707)

The inspectors verified that the following surveillance procedures were completed within 72 hours after a plant scram as required by Procedure 20.000.21, "Reactor Scram."

b. Observations and Findings

- 44.010.206, Reactor Protection System (RPS) Scram Discharge Volume High Water Level Division I, Channel B Float Switch Functional Test
- 44.010.207 RPS Scram Discharge Volume High Water Level Division II, Channel B Float Switch Functional Test
- 44.010.208 RPS Scram Discharge Volume High Water Level Division I, Channel C Float Switch Functional Test
- 44.010.209 RPS Scram Discharge Volume High Water Level Division II, Channel D Float Switch Functional Test
- 44.070.001 Control Rod Block Scram Discharge Volume High Water Level Float Switch (E and F) Functional Test
- 44.070.003 Control Rod Block Scram Discharge Volume High Water Level Float Switch (G and H) Functional Test

The Surveillance Scheduling and Tracking Report noted that all required surveillances were completed at 12:30 a.m. on September 5, 1998.

c. Conclusions

The inspectors concluded that the licensee appropriately performed surveillance procedures within the time period specified by Procedure 20.000.01, "Reactor Scram," following a manual scram.

O1.7 Inadvertent ESF Actuation During a Division II Simulated Loss of Power Test

a. Inspection Scope (71707)

The inspectors reviewed Procedure, 24.307.12, "EDG 13 Emergency Core Cooling System Start and Load Rejection Test and Logic Functional Test of Bus 65E," Condition Assessment Resolution Document (CARD) 98-16439, Schematic Diagrams 61721-2572-29, "4160 V Engineered Safeguard System (ESS) Buses No. 65E and 65F Load Shedding Strings," 61721N-2572-19, "4160 V ESS Diesel Bus 13EC Load Shedding Strings," and 61721N-2572-21, "4160 V ESS Diesel Bus 13EC POS EC3," and Procedure 24.307.12, "Schematic Diagrams," Technical Specifications, technical documentation, and conducted interviews with engineering and operations personnel.

b. Observations and Findings

On September 8, 1998, the licensee performed Procedure 24.307.12, "EDG 13 Emergency Core Cooling System Start and Load Rejection Test and Logic Functional Test of Bus 65E Breakers." The test required operating EDG 13 with its output breaker (EC3) closed to Bus 13EC. Bus 13EC Supply Breaker E8 was closed to the safety-related 4160 V Bus 65E. Likewise, the test required Bus 65E offsite Supply Breaker E6 to be closed to supply offsite power to the bus. Supply Breaker E12 from Bus 65E to safety-related 480 V Bus 72E was also closed. As part of the test, the licensee simulated a loss of offsite power condition on Bus E65 by opening Supply Breaker E6. When supply breaker E6 was opened, E8 opened as expected but EDG Supply Output Breaker EC3 unexpectedly opened. Since Breaker EC3 opened, a loss of power to 4160 V Safety Bus 65E and 480 V Bus 72E occurred that resulted in 14 group isolations and an actuation of RPS Channel B. Breaker EC3 did not subsequently close and safety loads were not sequenced onto Bus 65E.

Following the inadvertent actuation, the licensee made the appropriate notifications. The event was documented on CARD 98-16439.

During the investigation, the licensee focused on the "ES" and "81" relays that may have caused Breaker EC3 to inadvertently trip. Both relays were removed for testing. The "ES" relay was used for EDG droop/isochronous transfer tested satisfactorily. However, the "81" relay that was used for offsite under frequency protection failed the time delay test. The relay was designed to trip open EC3 when an under frequency condition existed on the offsite bus with Breakers E6 and E3 closed. Based on the failure of the time delay function, the licensee concluded that the most probable cause for an inadvertent trip of Breaker EC3 was a faulty "81" relay. The licensee sent the relay to a vendor for further testing and evaluation. The licensee removed the under frequency relay from EDG 14 Output Breaker circuitry and installed it in EDG 13 Output Breaker circuitry. Subsequently, the surveillance procedure for EDG 13 was completed. The acceptability of replacing the like-for-like relay from EDG 14 to EDG 13 is discussed in Section M1.5.

The inspectors determined that the most probable cause of inadvertent opening of Breaker EC3 was the failure of the "81" under frequency relay and not from a test deficiency. After reviewing TS requirements for EDG logic functional testing, the inspectors determined that the "81" relay was not required to be tested per TSs and that the relay provided a nonessential protective trip. The inspectors determined an open switch (SW-27) isolated the load shed relay string. This prevented the sequencing of safety-related loads onto the 4160 V Bus and also prevented closure of Breaker EC3 after deenergizing the buses. The licensee stated that the test intentionally isolated this string. The inspectors questioned whether a periodic calibration of the "81" relay had been conducted. As of the end of the inspection, the licensee had not confirmed whether or not a relay calibration of the "81" relay had been conducted.

c. Conclusions

The probable cause of the inadvertent opening of Emergency Diesel Generator 13 Output Breaker EC4 during breaker logic and emergency diesel generator testing was related to a faulted nonsafety-related offsite frequency relay. The licensee's focus on the relay as the probable cause was appropriate. (Section O1.7)

O2 Operational Status of Facilities and Equipment

O2.1 ESF System Walkdowns (71707)

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

- Non Interruptible Air Supply
- EDG Nos. 13 and 14
- Control Center Heating Ventilation and Air Conditioning

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 inspectors identified no substantive concerns as a result of these.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- 24.000.02 Shiftly, Daily, and Weekly Surveillances
- 24.207.08 Emergency Equipment Cooling Water (EECW) Pump and Valve Operability Test
- 24.307.15 EDG No. 12 Start and Load Test
- 24.307.17 EDG No. 14 Start and Load Test
- 24.404.04 Division II Standby Gas Treatment System Filter and Secondary Containment Isolation Damper Operability Test
- 24.408.03 Division I Primary Containment Monitoring System Valve Operability and Position Indication Verification Test
- 24.413.03 Control Room Emergency filter Auto Transformer Test
- 24.416 Drywell Cooling Fan 1 and 2 Operability Test
- 28.505.02 Fire Detection Zone Operability Test Reactor Building
- 28.507.001 Fire Barrier Inspection
- 44.020.236 Nuclear Steam Supply System - Reactor Core Isolation Cooling System Steam Line Pressure, Division I Functional Test

- 44.020.240 Nuclear Steam Supply System - Reactor Core Isolation Cooling System Steam Line Pressure, Division II Channel A Calibration
- 44.210.051 Reactor Coolant System Interface Valve Leakage Pressure Monitor Low Pressure coolant Injection of Shutdown Cooling Test
- 64.080.303 Area Radiation Monitoring system Channel Calibration

M1.2 Lack of Administrative Controls for Temporary Storage Replacement Batteries and Wiring Error

a. Inspection Scope (71707)

The inspectors reviewed Materials Management Conduct Manual (MMM) Procedure 07, "Material Issue, Control, Return and Delivery Offsite," MMM08, "Material Shipping, Handling and Storage," technical documentation, vendor documentation, Updated Final Safety Analysis Report (UFSAR), and TS. The inspectors also performed a walkdown of battery storage areas and interviewed engineering and material management personnel.

b. Observations and Findings

The inspectors performed an physical inspection of Division II Station Batteries stored on the third floor of the Turbine Building. The batteries were being stored for later installation during the RF06 outage. The inspectors questioned whether storing the batteries on the Turbine Building third floor was appropriate. The inspectors reviewed Procedure MMM08, "Material Shipping, Handling and Storage." The procedure identified that in general batteries required Class B storage. According to station procedures, Class B items were to be stored in controlled areas (i.e., fire protection and adequate ventilation). In addition, the procedure stated that the items should not be subject to potential flooding conditions. The storage area should also be uniformly heated and temperature controlled to prevent condensation and corrosion. In addition, the items stored as Class B according to station procedures should be placed on pallets or shoring. The inspectors were not certain given these requirements whether the storage location of the safety-related batteries on the Turbine Building Floor was appropriate. Specifically, the inspectors questioned the apparent lack of environmental controls, specific tagging of materials, and lack of foreign material or protection of the batteries from damage. During the approximately 2-month storage period on the Turbine Building floor, the safety-related batteries were exposed to elevated temperatures, in part, as a result of a Turbine Building Heating Ventilation and Air Conditioning outage. Elevated temperature effect on the safety-related batteries was not a consideration during Turbine Building Heating Ventilation and Air Conditioning outage planning. Station procedures stated that the limit on temperature for Class B items (i.e., safety-related batteries) was from 40°F to 140°F. The inspectors verified that these temperatures had not been exceeded. The inspectors reviewed Procedure MMM07, "Material Issue, Control, Return and Delivery Offsite." The inspectors could not locate specific instructions in the procedure that addressed storage of safety-related equipment in this manner. The Division II Safety-Related Batteries were later installed and tested with no observed deficiencies.

During a wiring inspection for a temporary battery charger that had been connected to new Division II batteries, it was determined that the charger had been installed in series instead of a parallel configuration. A WR had been written to place an equalizing charge on the replacement Division II batteries. This was to be accomplished by dividing the 260 V Battery Bank into two 130 V banks and then using a jumper to install the charger in parallel with the battery banks. After reviewing the work package, maintenance personnel were confused as to whether a jumper should or should not have been installed. Following discussions with field engineering personnel, it was decided that the batteries should be connected as described in the WR and as shown on a reference drawing. The battery charger was later energized. Maintenance personnel noted that a voltmeter on the battery charger read approximately 170 volts and the charger output voltage was minimal as it was programmed for 130 volts. All work was immediately stopped. Discussions with supervisory personnel revealed that the jumper between the battery banks should not have been installed. The inspectors reviewed the licensee's corrective action for the event and determined that it was adequate. No damage to the batteries occurred as a result of this event. The event resulted in a reset of the error free day clock.

c. Conclusions

The inspectors concluded that the storage of the safety-related batteries on the third floor of the Turbine Building did not degrade the performance of the batteries. The issue of whether current procedures allowed for the storage and handling of safety-related batteries on the third floor of the Turbine Building remained unclear. The inspectors also concluded that confusing instructions in the work package contributed to incorrectly wiring a temporary battery charger. The incorrect wiring of the battery charger did not cause damage to the safety-related batteries. The event resulted in a reset of the error free day clock.

M1.3 Wrong Post Maintenance Testing (PMT) Used for Automatic Depressurization System (ADS) Logic Testing

a. Inspection Scope (71707)

The inspectors reviewed CARDs 98-13972 and 98-16321, TS, UFSAR, WR 000Z981963, Procedure MOPO4, "Event and Casual Factor Chart with Barrier Trace," Surveillance Procedure 44.030.291," ADS Channel 1 Logic Functional Test," Surveillance Procedure 44.030.292, "ADS Channel 1 Logic Functional Test," and operations and work control supervisory personnel were interviewed.

b. Observations and Findings

The inspectors reviewed CARD 98-16321 and noted that the wrong PMT had been performed on power supply relays associated with the ADS actuation circuitry. Condition Assessment Resolution Document 98-13972, had been written due to a previous alarm that indicated the potential for a failure of an ADS/safety relief valve power supply. As a result, WRs 000Z981963 and 000Z982512 were prepared and scheduled. The work packages required the relays to be bench tested to determine if pickup and drop out voltages were correct. The electrical planner prepared one work package to be performed on two different ADS logic strings. This was based on the assumption that the logic strings were of the same division but different channels. The electrical planner assumed that a single surveillance could serve as a PMT for both relays. Therefore, the planner specified one surveillance for both relays. However, the existing surveillance procedures tested Logic String A and B separately. The planner's PMT decision resulted in the surveillance procedure for Logic Strip A to be assigned to the WR for the B relay. The operation's work control NSO reviewed the work packages and instructed the planner to separate the package into two distinct work packages. However, the same surveillance (i.e., PMT) continued to be specified in both work packages despite reviews by operation's work control personnel, the work week manager and the plan-of-the-day coordinator.

An operation's work control NSO reviewed the new ADS work packages and corrected the impact statement to reflect work on Logic String B instead of A. Following this review, further evaluation of the package was conducted at the 3-week plan-of-the-day meeting and by the work control nuclear assistant shift supervisor (NASS). A review of the package by the work group supervisor also failed to detect the error. Later it was decided that the work on the relays could be combined with the Residual Heat Removal (RHR) outage. This required further reviews of the logic relay work activity by the work week manager and work control NASS, but the surveillance PMT error was not detected. Some concern was expressed with the RHR outage being performed in conjunction with the relay testing. However, the work control NASS stated that the configuration had been reviewed and that equipment would be positioned to have ADS operable.

Operations entered Limiting Condition for Operations 98-007 for ADS Logic "B" WR 000Z981963. Operations hung Safety Tagging Record 98-781 for ADS logic work and removed fuses in Relay Room Panel H11P628. Removing the fuses caused Alarm Window 1D27 to energize. The work control NASS released WR 000Z981963 to be performed.

Following completion of work activities, operations personnel reinstalled fuses and Alarm Window D57 cleared. After a briefing by instrumentation and control supervisory personnel and the release of the surveillance by the control room NSO, the technicians performed the surveillance. At this time Trip System "B" became administratively inoperable. Moreover, at the same time Trip System "A" was inoperable because of the physical performance of the surveillance. Shortly after completion the surveillance was reviewed by the shift technical advisor. The shift technical advisor determined that the incorrect surveillance had been performed.

The work control NASS left the control room to discuss the issue with the instrumentation and control foreman concerning the proper PMT for WR 000Z981963. The correct PMT for the logic string was determined to be removal of power supply logic fuses, verifying 1D57 as energized and that backup power restored power to the circuit. This PMT was performed satisfactorily.

Operations personnel discussed the TS implications of ADS Logic B being administratively inoperable while performing the surveillance procedure on ADS Logic A.

The licensee determined that no violations of TS requirements because at the point of discovery of the "A" system had passed its surveillance test.

c. Conclusions

The conduct of the wrong post maintenance test was performed after work on the automatic depressurization system logic circuitry. Contributing to the event were weaknesses in work controls that included work planning. Subsequent multiple reviews of the work packages and work activity failed to detect the error. The error resulted in one automatic depressurization system logic string being administratively inoperable while the other was physically inoperable. At the same time work was performed on divisional residual heat removal components. The licensee's investigation was comprehensive and thorough. (Section M1.3)

M1.4 Fire Protection Barrier Surveillance Procedure

a. Inspection Scope (62703)

The inspectors reviewed Procedure 28.507.001, "Fire Barrier Inspection," UFSAR, Work Control Conduct Manual, Chapter 3, "Surveillance/Performance Package Control," performed a walkdown of fire barriers and interviewed fire protection supervisory personnel.

b. Observations and Findings

The inspectors reviewed Surveillance Procedure 28.507.001, "Fire Barrier Inspection." The Updated Final Safety Analysis Report, Section 9A.6.8.2.1, required fire barriers to be inspected every 18 months to ensure integrity. The inspectors noted that the surveillance had not been completed due to lack of access to certain areas of the plant, including the Reactor Building steam tunnel. The surveillance procedure contained entries that revealed that the remaining areas would be completed during the RF06 outage. The inspectors reviewed the procedure and noted that the desired completion date had been exceeded. In addition, the inspectors noted that the remaining activities could not be performed before the expiration of the required completion date. The inspectors questioned the surveillance work control personnel and verified that the required completion date included the 25 percent surveillance grace period. The inspectors later discussed the issue with shift supervisory personnel who had reviewed the surveillance and also determined that the surveillance could not be met prior to the required completion date. The inspectors concluded that not completing the surveillance prior to the required completion date would require that the fire barriers be declared inoperable.

The inspectors discussed the issue with fire protection supervisory personnel. The surveillance was scheduled for performance during Mode 1 operations. This did not give proper consideration to portions of the surveillance that could not be performed during normal power operations. For example, there have been at least two plant shutdowns since expiration of the desired completion date that would have allowed access to the Reactor Building steam tunnel areas. In addition, contributors to the event were a lack of familiarity with the conduct of the surveillance and a lack of a general understanding of the completion date requirements. In addition, work control reviews failed to identify that the procedure would not be done prior to its required completion date. The licensee's corrective action included devising a plan to implement compensatory measures for the uninspected fire barriers. The inspectors reviewed the plan and determined that it was adequate. The inspectors walked down the affected locations and noted no discrepancies. In addition, the licensee removed the inspection requirements for those fire barriers that could only be inspected while the plant is in a shutdown condition and placed the requirements in a separate procedure. The inspectors concluded that the licensee's corrective actions were adequate.

c. Conclusions

Scheduling a fire protection barrier surveillance during Mode 1 operations contributed to the failure of completing the surveillance before the required surveillance interval expiration date. The failure to complete the surveillance prior to the expiration date caused the inoperability of several fire barriers located mainly in the reactor building steam tunnel. In addition, the lack of familiarity and general understanding of the conduct of the surveillance procedure by fire protection personnel was also a contributor, as well as work control reviews that failed to identify that the procedure would not be done prior to its required completion date. The inspectors determined that the licensee's corrective actions were acceptable. (Section M1.4)

M1.5 Acceptability of Replacing EDG 13 Under Frequency Relay With EDG 14 Under Frequency Relay

a. Inspection Scope (62703)

The inspectors noted that the licensee interchanged the under frequency relays for the output breakers on EDG 14 and 13 without the appropriate documentation and followed up its acceptability.

b. Observations and Findings

The inspectors interviewed the work control superintendent and the materials engineering supervisor regarding the engineering equivalency of installing the under frequency relay from EDG 14 Output Breaker ED4 into EDG 13 Output Breaker EC3. Also, the inspectors determined that the licensee had an engineering equivalency checklist on an internal requisition, but did not use it. The inspectors found that the licensee visually confirmed equivalent model and part numbers on the relays but did not document the results of this equivalency. Work Conduct Manual Procedure 02, Revision 12, "Work Control Manual," required that applicable stock code numbers and serial numbers be listed in the parts requirement section of the WR during a WR closeout. Since the WR closeout had not been completed, the documentation was not completed before interchanging the relays. The inspectors determined that the licensee was vulnerable to rework systems where the engineering equivalency checklists were not completed before performing the work.

The licensee had recognized that the cannibalization process was weak in early 1998. For example, CARD 98-10397, was written to document fuse disconnects from one motor control center into a different motor control center. The corrective actions to this CARD had not been completed and, therefore, the process was not updated to complete the required documentation before cannibalization parts from safety-related systems.

c. Conclusions

The inspectors concluded that not documenting an engineering equivalency before interchanging parts on safety-related breakers presented a vulnerability to rework, if the equivalency resulted in a discrepancy. Visual verification of the under-frequency relay part and model numbers for Breakers ED4 and EC3 was acceptable. However, the work request process ensures traceability of model and part numbers during a work request closeout. Corrective actions to strengthen a weak cannibalization program have been established, but not implemented. (Section M1.5)

III. Engineering

E1 Conduct of Engineering

E1.1 Safety Evaluation for Reactor Building Closed Cooling Water (RBCCW) Augmentation Mode of Operation

a. Inspection Scope (92903)

The inspectors review SE 95-0036, "Manual Operations of Emergency Equipment Cooling Water (EECW)," design basis documentation, TSs, control room logs, and the UFSAR. The inspectors also conducted interviews of licensing and system engineering personnel.

b. Observations and Findings

The inspectors reviewed SE 95-0036, "Manual Operation of EECW system." The SE considered procedural changes that would permit one or both divisions of EECW to be used on an intermittent basis to augment RBCCW cooling capability. This mode of EECW operation would be used to allow single RBCCW pump and heat exchanger operation. The SE specifically stated that the use of the RBCCW augmentation mode was for cleaning of the RBCCW heat exchangers following Clamtrol treatment or to augment Drywell cooling to maintain the Drywell temperatures below the TS maximum of 145°F during periods of unseasonably high lake temperatures.

The inspectors reviewed the SE and noted that the use of the augmentation mode of RBCCW would be infrequent. In addition, the SE stated that alignment would only be in effect for a short period of time.

The inspectors noted that Drywell temperatures frequently approached TS values requiring the use of the EECW system in the argumentation mode. This was due, in part, to the accumulation of Zebra Mussels, caused by a lack of Clamtrol treatment in the General Service Water system. The presence of the Zebra Mussels required the

RBCCW heat exchangers to be frequently cleaned. In addition, control room logs showed that the EECW system running in the argumentation mode of operation for longer periods of time than had been anticipated. The inspectors noted that although lake temperatures were slightly above the values noted in recent years, the temperatures did not reach previous highs or exceed record values in addition, UFSAR general service water temperature requirements for RBCCW heat exchanger performance were not approached.

The inspectors noted that running the EECW pump for longer durations may result in some increased wear to internal components. The majority of the degradation would be associated with starting the equipment. The SE further stated that the frequency of starts would not be greater than the expected number of normal starts. However, the number of expected starts increased due to frequent approaches of Drywell temperature to TS limits. The inspectors were concerned that the current mode of operation of the EECW system requiring more starts and longer operating times had not been evaluated and recognized in the current version of the SE. The inspectors agreed that the increased number of starts may not have affected long term operation of the pump. However, the SE was reevaluated and revised to reflect the current conditions requiring frequent EECW pump starts and longer operating times.

c. Conclusions

The inspectors concluded that the safety evaluation that analyzed the use of emergency equipment cooling water in the augmentation mode for reactor building closed cooling water had not been reevaluated and revised to reflect the increased number of starts and longer operating times of the equipment. The safety evaluation was subsequently revised. The inspectors also concluded that no long term degradation of emergency equipment cooling water would result from this mode of operation. (Section E1.1)

E8 Miscellaneous Issues

During the performance of the At-Risk Technical Service Requirement (TSR) 27421, maintenance personnel installed an unauthorized conduit and hanger between the relay room and cable spread room with the verbal approval of the modification's engineer and without proper written authorization. The TSR involved opening a penetration between the two rooms to install cabling for the APRM modification. Maintenance personnel were informed that the At-Risk TSR authorized the installation of the conduit and that Design Specification 3071-128 covered the hanger and conduit design. Further, since plant support engineering personnel were involved in the discussions, the engineering design package covering the modification was supposed to be appropriately modified. Moreover, it was believed that the modification would not be in place until the revised engineering design package was issued. Contrary to station requirements, work proceeded without any written direction in the work package. The inspectors reviewed the At-Risk TSR. The following statement was included, "the cables shall be pulled per attached cable card." The cable cards, however, did not authorize the installation of a conduit or hanger. Further reviews showed that the WR was incomplete as written and did not contain specific instructions for field verification of the final installation by a nuclear shift supervisor or delegate. In addition, it did not contain a cable sign off for the maintenance supervision or modification field engineer to verify the completion of a turnover checklist. Once the error was discovered, all work in the field was immediately stopped and the work package was removed from the field. The inspectors concluded that installation of the conduit and hanger did not degrade existing equipment or structures.

c. Conclusions

A misinterpretation of the conduit and cable specification by the modification engineer led to installation of a conduit before proper authorization was received. Further, the installation specification used by the plant engineer did not provide flexibility required for an at-risk technical service request. Further, written instructions were not followed for installation of the cables. Inadequacies in work package instructions and nonadherence to station work control guidelines were identified. (Section E8)

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Improper Frisking Practices

a. Inspection Scope (71750)

The inspectors observed the access control point for entering and exiting the Radiologically Restricted Area (RRA) for use of proper radiological control practices.

b. Observations and Findings

On September 1, 1998, the inspectors observed several individuals exit the RRA without properly following the station's radiological control procedures. The inspectors observed two contractor personnel with clipboards pass the equipment friskers and enter personal contamination monitors (PCM). Additionally, three contractors were observed to receive multiple alarms on the PCMs before receiving a "clear to pass" message. Specifically, two individuals received two alarms before receiving a "clear to pass" acknowledgment on a PCM. Another individual received two alarms on one PCM and an additional alarm on a second PCM before receiving a clear reading on his fourth attempt. The inspectors observed that health physics (HP) personnel at the RRA desk were not notified by the personnel of the repeat alarms. Additionally, the inspectors noted that the HP personnel at the desk did not observe or respond to these repeat alarms due to confusion caused by a large volume of personnel entering and exiting the area at the same time.

The inspectors did not observe an uncontrolled release of radioactive material in any of the observed cases. The hand-held items were in close proximity to the PCM during frisking, and did not cause an alarm. The individuals that caused the two or more PCM alarms received "clear" readings on the last attempt. The inspectors discussed these observations with the radiological protection manager (RPM). The RPM stated that immediate corrective actions were put in place, including an HP technician to continually observe frisking practices at the RRA exit, and discussions with contractor personnel. On September 3, 1998, the inspectors had follow up discussions with the RPM. The RPM indicated that the corrective actions for PCM frisking appeared at first to be fully effective. However, another individual was observed to not properly use the PCM wile exiting the third floor Turbine Building area. This observation is documented in Inspection Report 50-341/98016. However, the RPM indicated that there were still approximately two percent of individuals with hand-held items passing by the equipment friskers, before being stopped by the HP technician. No violations of regulatory requirements were identified.

c. Conclusions

The inspectors identified that two required frisking methods were not being observed by all individuals exiting the RRA. The inspectors noted that individuals were not frisking hand-held items separately, and some individuals were receiving multiple PCM alarms without contacting HP personnel. However, the licensee took prompt corrective actions and documented identified frisking errors in their corrective action system.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 22, 1998. The licensee acknowledged the findings presented. The inspectors 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

D. Cobb, Operations Superintendent
P. Fessler, Plant Manager
R. Gaston, Supervisor, Compliance
J. Green, Maintenance
T. Haberland, Superintendent, Work Control
K. Howard, Director, PSE
J. Moyers, Director, Quality Assurance
W. O'Connor, Manager of Nuclear Assessment
S. Peterman, Engineer, Operations
N. Peterson, Acting Director, Nuclear Licensing
J. Plona, Technical Director
L. Sanders, Training, Operations
B. Sheffel, Director, ISI/PEP
K. Snyder, Nuclear Shift Supervisor
S. Stasek, Supervisor, Independent Safety Engineering Group
W. Tucker, Director, Nuclear Engineering

Nuclear Regulatory Commission

G. Harris, Senior Resident Inspector, Fermi 2
A. Kugler, Project Manager, NRR

INSPECTION PROCEDURES USED

IP 62703:	Maintenance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92903:	Followup Engineering

LIST OF ACRONYMS USED

ADS	Automatic Depressurization System
APRM	Average Power Range Monitor
CARD	Condition Assessment Resolution Document
DC	Design Calculation
EDG	Emergency Diesel Generator
EECW	Emergency Equipment Cooling Water
ESF	Engineered Safety Feature
ESS	Engineered Safeguard System
GETARS	General Electric Transient Analysis Report System
HP	Health Physics
MMM	Material Management Conduct Manual
MOP	Manual of Operations Conduct Procedure
NASS	Nuclear Assistant Shift Supervisor
NSO	Nuclear Supervising Operator
PCM	Personal Contamination Monitor
PMT	Post Maintenance Testing
RBCCW	Reactor Building Closed Cooling Water
RFO	Refueling Outage
RHR	Residual Heat Removal
RPM	Radiological Protection Manager
RPS	Reactor Protection System
RRA	Radiologically Restricted Area
SE	Safety Evaluation
SRM	Source Range Monitor
TCV	Turbine Control Valve
TS	Technical Specification
TSR	Technical Service Request
UFSAR	Updated Final Safety Analysis Report
WR	Work Request