U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-341/93016(DRP)

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

Licensee: Detroit Edison Company
2000 Second Avenue
Detroit, MI 48226

Facility Name: Fermi 2

Inspection At: Fermi Site, Newport, Michigan

Inspection Conducted: July 27 through September 9, 1993

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Reactor Projects Section 2B

Inspection Summary

Inspection from July 27 through September 9, 1993
(Report No. 50-341/93016(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of action on previous inspection findings; operational safety verification; engineered safety feature systems; onsite event follow-up; current material condition; housekeeping and plant cleanliness; radiological controls; security; regional requests; safety assessment/quality verification; maintenance activities; surveillance activities; Nuclear Safety Review Group; Information Notice 87-10; sequence of events; reactor core isolation cooling; technical issue report; technical performance improvement plan; gland seal system; main control room panel bulbs; and report review.

Results: Of the twenty-one areas inspected one non-cited violation was identified concerning the record falsification of a fire watch (paragraph 3.a). Three Unresolved Items were identified that pertained to plant tours by firewatches (paragraph 3.a), events associated with the August 13, 1993, reactor trip (paragraph 3.c), and the licensee's assessment of Information Notice 87-10 (paragraph 7.b). Three inspection followup items were also identified that pertained to HPCI pump suction transfer (paragraph 3.c), RCIC high suction pressure (paragraph 7.d), and indicating bulbs on the main control panels (paragraph 7.h).

The following is a summary of the licensee's performance during this inspection period:

Plant Operations

The licensee's performance in this area was mixed. The operator's actions to mitigate the consequences of a degraded General Service Water (GSW) system was very good. The Shift Supervisor's identification of a degraded Modular Power Unit (MPU) during shift turnover was also very good. The teamwork between all the departments in the troubleshooting and repair of the MPU was excellent. The licensee's actions to repair a defective weld on a safety relief line on the 1S feedwater heater was also good. The subsequent actions to return the 1S heater to service were delayed due to personnel safety concerns. The plant tour of a non-licensed operator (NPPO) observed by the inspectors was very good. The shift briefings and plan of the day meetings continue to be of high quality. Material condition and housekeeping were also good.

In contrast, the operators response to the August 13, 1993, reactor trip was less than adequate. The operators failed to recognize the significance of annunciator alarms which could have precluded the loss of the gland seal steam and subsequent loss of condenser vacuum, this was partially due to the multiple distractions that occurred during the response to this trip, including the loss of approximately 100 indication lights. As a result of the loss of the condenser as a heat sink, operators were required to use reactor safety relief valves and the torus to control reactor pressure and remove decay heat. The training of licensed operators on the plant simulator was conducted with the gland seal system in a configuration that did not agree with normal plant operations. The inspectors were concerned that operations did not aggressively pursue the installation of the gland seal modification or establish compensatory action until the modification was installed. The plant tour of a firewatch observed by the inspectors was less than adequate and did not meet the Shift Supervisor's expectations.

Maintenance and Surveillance

The licensee's performance in this area was good. The Quality Assurance (QA) audit of the Technical Specification (TS) surveillance program was a good assessment and performance based. Even though QA rated the TS surveillance program "satisfactory," a potential weakness was identified by the QA organization that resulted in a Management Action Request Deviation Event Report for incorporation of TS amendments into the TS surveillance program. The licensee's critique of maintenance activities that were occurring on Emergency Diesel Generator 11 during the August 13 reactor trip demonstrated good management action to improve performance.

Engineering and Technical Support

The licensee's performance in this area was mixed. The Nuclear Safety Review Group's activities were reviewed and found, in some cases, to exceed the licensee's commitments in this area. The licensee's engineering organization had initiated a Technical Performance Improvement Plan to improve the overall performance of the technical organizations. The plan specifically addressed three general areas that indicate the need for improvement. These areas pertained to the failure of the No. 4 heater extraction steam line and subsequent failure of a temporary instrument connection that caused a reactor trip; the NRC inspection of engineering and technical support that identified an inadequate evaluation of a water hammer and other weaknesses; and the multiple problems associated with the installation of new post accident instrumentation. The engineering organization also issued a Technical Issue Report to aid in the overall understanding of current site technical issues. The testing performed on Emergency Diesel Generator 13 to assess a decrease in jacket water pressure demonstrated good followup on a technical issue. The approach taken by nuclear engineering during the flux tilt testing and the engineering organization's response to a defect in the Sylvania Par Flood lamps used in the control room lighting was also very good.

In contrast, the impact on plant operations with the gland seal system operating in a manual configuration was not adequately assessed by engineering. Engineering and Safety Engineering's review of a possible water hammer event in the residual heat removal system was less than adequate. In addition, the followup to a periodic high suction pressure alarm on the reactor core isolation cooling system was less than adequate.

DETAILS

1. Persons Contacted

Detroit Edison Company

R. McKeon, Plant Manager, Nuclear Production
J. Nolloth, Superintendent, Maintenance
J. Plona, Superintendent, Operations
R. Eberhardt, Superintendent, Radiation Protection
P. Fessler, Technical Manager
L. Goodman, Director, Nuclear Quality Assurance (NQA)
J. Walker, General Director, Plant Engineering
R. Szkotnicki, Supervisor, Inspection & Surveillance
A. Kowalczuk, Director, Plant Support
J. Malaric, Supervisor, Modifications
W. Miller, Director, Nuclear Licensing
G. Pierce, Work Control
J. Tibai, Principal Compliance Engineer
C. Cassise, General Superintendent, Mechanical Maintenance
R. Russell, Training Supervisor
R. Newkirk, Supervisor, Licensing and Risk Analysis

All of the above attended the exit interview conducted on September 9, 1993.

The inspectors also had discussions with other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift supervisors, and electrical, mechanical, and instrument maintenance personnel, and security personnel.

2. Action on Previous Inspection Findings (92701)

(Closed) Unresolved Item (341/93013-02(DRP)): Reportability of EECW manual initiation. On July 26, 1993, the licensee manually initiated the emergency equipment cooling water (EECW) system when general service water (GSW) heat exchanger temperatures increased, resulting in an increase in the drywell pressure and temperature. The licensee initially did not consider the manual initiation of EECW, an ESF system, as a reportable event in accordance with 10 CFR 50.72. The licensee subsequently reported the event after discussions with the NRC approximately 28 hours after the manual initiation of EECW. The manual initiation of an ESF system is a four hour notification per the requirements of 10 CFR 50.72. The inspectors met with licensee management to discuss the reportability aspects of this event. Included in these discussions was what the NRC considers as a pre-planned evolution and the history of those events at FERMI that were not previously reported in accordance with 10 CFR 50.72. Based on information provided by the licensee, the inspectors determined that mixed interpretations had been provided to the licensee in the past by the NRC regarding when a manual initiation of ESF equipment was reportable in accordance with 10 CFR 50.72. Upon realization that the event was considered reportable by NRC, the licensee promptly reported it. Based on this history and the fact that the report was made, this matter is considered closed.

3. Plant Operations

Fermi 2 operated at power levels up to 93 percent until August 13, 1993, when a reactor trip occurred due to a spurious Level 8 reactor water trip signal. The spurious signal was caused by a non-licensed operator removing tape from an instrument valve stem. Details of the event are discussed in paragraph 3.c of this report. The unit was returned to service on August 15, 1993, and operated at power levels up to 93 percent. On August 31, 1993, the unit's power was reduced to 70 percent to take off line the 1 South (1S) and 2 South (2S) Feedwater Heaters to repair a cracked weld on a Sockolet for a relief valve line on the 1S Feedwater Heater. The power was than raised to 93 percent power and the repairs to the weld were completed. The unit has since operated at 93 percent power. However, the return to service of the 1S and 2S Heaters was delayed due to personnel safety considerations that existed during the venting of the heaters. The licensee was concerned that the height of the vent valves and the high temperatures in the area could result in personnel injury if venting occurred while personnel were present.

a. Operational Safety Verification (71707)

The inspectors verified that the facility was being operated in conformance with the license and regulatory requirements, and that the licensee's management control system was effective in ensuring safe operation of the plant.

On a sampling basis, the inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence with procedures and technical specifications; monitored control room indications for abnormalities; verified that electrical power was available; and observed the frequency of plant and control room visits by station management. The inspectors reviewed applicable logs and conducted discussions with control room operators throughout the inspection period. The inspectors observed a number of control room shift turnovers. The turnovers were conducted in a professional manner and included log reviews, panel walkdowns, discussions of maintenance and surveillance activities in progress or planned, and associated LCO time restraints, as applicable. The inspectors identified no concerns in this area.

During a shift turnover at approximately 3:30 p.m. on September 6, 1993, the Shift Supervisor noticed that position indication for several isolation valves were dim. The licensee subsequently discovered low output voltage on Modular Power Unit (MPU) No. 1. The output voltage was measured at 98 Volts with the normal voltage being approximately 130 Volts. Technical Specification (TS) 3.8.3.1.a.1.e required that MPU No. 1, the 120V Division I

Instrumentation & Control Power Supply Unit, be energized. At 8:30 p.m. on September 6, 1993, the licensee declared MPU No. 1 inoperable and entered the appropriate TS Action Statement. The TS Action Statement required MPU No.1 be restored to an operable condition within 8 hours or be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours. The licensee expected the repairs to be completed by 5:30 p.m. on September 7, 1993. However, since repairs could last longer than the time allotted in the TS Action Statement, the licensee requested discretionary enforcement from the NRC. The licensee requested and received from the NRC an additional 9 hours to the 12 hour Action Statement to place the unit in Hot Shutdown. The licensee's repairs were completed and MPU No. 1 was returned to service at 3:09 pm on September 7, 1993, prior to the original time expected and thus negating the need for discretionary enforcement.

The inspectors toured the turbine building with a nuclear power plant operator (NPPO), a non-licensed operator. The inspectors observed the NPPO obtain the required data for logkeeping and monitor overall equipment condition, system status, housekeeping, and material condition of the plant. When the NPPO found water on the floor, the control room and health physics were contacted. The NPPO monitored running equipment by touching motors for vibration and excessive heat; removed discarded tape from piping; and cleaned small oil drips from rotating equipment. The NPPO appeared knowledgeable and conscientious during the performance of the plant tour.

The inspectors performed a tour with a firewatch. The firewatch was required to use a barcode reader to record his entrance into the areas inspected on the tour. The firewatch went from area to area, logging in with the barcode with little observation of the condition of fire equipment, fire barriers, or the general area. Some of the barcodes were located just inside of the access doors to the areas. An example was a division of the control room heating, ventilation, and air conditioning (CCHVAC). The inspectors observed the firewatch log in on the barcode without completely entering the room. When questioned why the CCHVAC room was on the firewatch tour, the firewatch indicated that Thermolag insulation was in the room. The firewatch also stated that he was looking for fire, smoke, fire hazards, and conditions out of the normal. When asked, the firewatch had some difficulty in locating and identifying the Thermolag insulation. After the tour, the shift supervisor related his expectations of the firewatch to the inspectors. The expectations were to look for and report any smoke or fires, fire hazards, damage to fire equipment or barriers, and abnormal plant conditions. The inspectors concluded that the firewatch observed on tour did not meet the shift supervisor's expectations. The adequacy of tours conducted by firewatches is considered an Unresolved Item pending further NRC review (341/93016-01).

The inspectors reviewed the March 11, 1993, event where the licensee identified that a main Halon tank for the computer room above the Main Control Room was disconnected even though the associated records indicated that it had been connected and verified connected. The licensee immediately reconnected the main Halon tank and initiated an investigation into the performance of the work and verification. All CO2 and Halon system actuators were inspected and verified for correct lineup. The licensee also reviewed all fire protection surveillance procedures performed since November 1992 with no discrepancies identified. The licensee's investigation determined that the individual responsible to perform the independent verification during the fire protection surveillance did not verify the main Halon tank was reconnected. The individual signed a surveillance step that indicated he performed the independent verification without leaving his office, and stated that he had intended to perform the surveillance but had forgotten. The licensee promptly reported this information to the NRC and placed the individual on several days of leave without pay and a years probation. The inspectors determined there was no indication of malicious intent by the individual. The inspectors reviewed the circumstances surrounding this violation against the criteria specified in 10 CFR Part 2, Appendix C, Section VII.B, for willful violations and determined that this event qualified for mitigation of enforcement sanctions. Therefore, a Notice of Violation will not be issued.

b. Engineered Safety Feature (ESF) Systems (71710)

During the inspection, the inspectors selected accessible portions of several ESF systems to verify status. Consideration was given to the plant mode, applicable Technical Specifications, Limiting Conditions for Operation requirements, and other applicable requirements.

Through observation, the inspectors verified that the following were acceptable: installation of hangers and supports; housekeeping; freeze protection, if required, was installed and operational; valve position and conditions; no potential ignition sources; and major component labeling, lubrication, cooling, etc. The inspectors also verified that instrumentation was properly installed and functioning and that significant process parameter values were consistent with expected values; that instrumentation was calibrated; that necessary support systems were operational; and that locally and remotely indicated breaker and valve positions agreed.

The following ESF systems were walked down:

- Division I/II Residual Heat Removal/Low Pressure Coolant Injection

- Emergency Diesel Generator 13

No problems were identified.

c. Onsite Event Follow-up (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. The inspectors verified that any required notifications were correct and timely. The inspectors also verified that the licensee initiated prompt and appropriate actions. The specific events were as follows:

- On July 26, 1993, both divisions of the emergency equipment cooling water (EECW) system were manually initiated to decrease drywell pressure and temperature that were rising due to an unexpected increase in general service water (GSW). The licensee subsequently submitted LER 93009 discussing the details of this event and proposed corrective actions. The inspectors review of that LER is discussed in Section 5 of this report.

- On August 13, 1993, at 9:46 a.m. (EST), the turbine and reactor feedwater pumps tripped when a spurious high reactor water level (Level 8) signal was received by the trip circuits. The turbine trip resulted in a reactor trip. Since the spurious high reactor water level resulted in the feedwater pumps tripping, reactor level dropped rapidly and reached a Level 2 which resulted in the automatic initiation of the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Control (RCIC). In accordance with the licensee's procedures, an Unusual Event was declared at 10:15 a.m. (EST) due to injection into the reactor. The licensee terminated the Unusual Event at 7:10 p.m.

  The licensee's investigation determined that the spurious high level signal was caused by a non-licensed Nuclear Power Plant Operator (NPPO) on routine rounds who noticed some tape on an instrument valve stem for a local reactor pressure gauge. The NPPO removed the tape and subsequently tried to remove the tape residue from the valve stem. The attempt to remove the residue resulted in a perturbation on the instrument reference leg that was shared with other instrumentation, including two reactor water level instruments. The perturbation resulted in a spurious high reactor level that tripped the turbine and reactor feed pumps.

  Subsequent to the reactor trip, the gland seal system was not realigned by the operators to the 52 inch manifold.

This resulted in the lost of gland seal and subsequent loss of condenser vacuum. The increased condenser pressure resulted in the automatic closure of the Main Steam Isolation Valves. Due to the loss of the condenser as a heat sink, the operators had to manually cycle the safety relief valves (SRV) to the torus to provide a heat sink for the reactor. The operators took actions to restore condenser vacuum to allow the condenser to be used again as a heat sink. The operators did receive annunciator alarms for low gland steam pressure and later an annunciator for low condenser vacuum approximately 10 minutes after the reactor trip. However, the operators failed to recognize the significance of the alarms and realign the gland seal system to the 52 inch manifold.

Prior to the event, the gland seal system was isolated from the 52 inch manifold and the regulator. Pressure for gland seal steam was being maintained by a bypass valve around the regulator. This configuration was considered to be the "manual mode" of the gland seal system. The as designed configuration of the gland seal system would have a regulator online to automatically dump gland seal steam when gland seal pressure increased to a predetermined setpoint when the unit was at a power level where the turbine was self sealing. Also, two other regulators would be online to the 52 inch manifold to automatically supply steam to the gland steam system to seal the turbine at low power when the turbine was not self sealing. The as designed configuration was considered the automatic mode of the gland seal system. A functional gland seal system in the automatic mode would have supplied the gland seal system with steam from the 52 inch manifold when the turbine tripped and would have precluded the loss of the turbine seal and subsequent loss of the condenser vacuum. The operation of the gland seal system in a manner contrary to the design is further discussed in paragraph 7.g of this report.

Investigation by the residents and the licensee determined that reactor operator training on the simulator has been conducted with the gland seal system in an automatic mode rather than manual, which is contrary to the actual plant configuration.

ECCS systems operated as designed; however, the following equipment problems resulted in operator distractions during the event: momentary failure of Division I Post Accident Instrumentation for drywell pressure; failure of an instrument for jet pump diffuser delta pressure used in the LPCI loop select logic; the failure of a pump to auto start to lower the reactor feedpump turbine seal tank level which resulted in an overflow onto a turbine building floor; annunciator alarm for low pressure in the Emergency Diesel

Generator 13 air receiver; and approximately 100 bulbs on the main control board burned out during the event. The operators handled the distractions in a good manner with other indications being used for the status of equipment with burned out indicating bulbs. The bulb issue is further discussed in paragraph 7.h of this report. The issues related to annunciator response and training contrary to the method of operations are considered an unresolved item (341/93016-02) pending review of the licensee's LER on the same subjects.

- On August 24, 1993, there was an inadvertent closure of B31F016A, the Outboard Reactor Recirculation Pump Seal Purge Isolation Valve. The closure occurred during a planned transfer of power of the reactor protection system "B" bus to the alternate supply. Prior to the transfer jumpers were installed to prevent the closure of Valve B31F016A. Approximately two minutes after the power transfer, a licensed operator noticed a loss of position indication for Valve B31F016A. Investigation determined that a fuse was blown to the normally energized solenoid for the valve. The blown fuse was replaced and Valve B31F016A was reopened. The licensee believes the fuse blew during placement of the jumpers. The inspectors will review the LER for appropriate corrective action.

- On September 6, 1993, at 9:29 a.m. (EST), the HPCI suction automatically transferred from the condensate storage tank (CST) to the torus when one of the torus level instruments that provide a signal to the transfer logic was indicating a torus level of +2.1 inches. The other level instrument that furnishes a signal was indicating a torus level of +1.6 inches. The setpoint for the transfer was +2 inches in the torus with a one out of two logic. At the time of the transfer the licensee was preparing to pump down the torus. The root cause and subsequent corrective actions will be reviewed by the inspectors when the associated LER is issued.

  The inspectors were concerned with the number of HPCI suction transfers that occur when in the torus cooling mode of the residual heat removal system and surveillance testing of HPCI and RCIC. At the start of a LOCA, the normal lineup for the HPCI pump suction was from the condensate storage tank (CST) through Valve E4150F004 with suction being automatically transferred to the torus when the torus level reaches +2 inches. Since the HPCI suction transfer from the CST to the torus has occurred during routine plant evolutions, the inspectors were concerned that these unnecessary challenges to HPCI ESF components could result in a failure of the torus suction valve to open during the transfer under accident conditions. With the torus valve failing to open and the CST suction valve closed, the HPCI pump would have no source of water at the suction until an operator manually opened the HPCI torus suction valve. To date, there has been no failures of these valves during an automatic switchover. The matter of unnecessary challenges to the HPCI suction valves is considered an Inspection Followup Item pending further licensee and NRC review (341/93016-03).

d. Current Material Condition 71707)

The inspectors performed general plant as well as selected system and component walkdowns to assess the general and specific material condition of the plant, to verify that work requests had been initiated for identified equipment problems, and to evaluate housekeeping. Walkdowns included an assessment of the buildings, components, and systems for proper identification and tagging, accessibility, fire and security door integrity, scaffolding, radiological controls, and any unusual conditions. Unusual conditions included but were not limited to water, oil, or other liquids on the floor or equipment; indications of leakage through ceiling, walls, or floors; loose insulation; corrosion; excessive noise; unusual temperatures; and abnormal ventilation and lighting. The inspectors found the material condition of the plant to be good.

e. Housekeeping and Plant Cleanliness

The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter. The housekeeping was considered good during this inspection period.

f. Radiological Controls (71707)

The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc., and randomly examined radiation protection instrumentation for use, operability, and calibration.

g. Security (71707)

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan. The inspectors noted that persons within the protected area displayed proper photo-identification badges, and those individuals requiring escorts were properly escorted.

Additionally, the inspectors also observed that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

No violations or deviations were identified.

4. Regional Request (92701)

a. Temporary Instruction 2500/208, "Employee Concerns Program"

During this inspection period, the inspectors were requested by the Region to conduct a survey of the characteristics of licensee's Employee Concern Program. The completed survey sheet was forwarded to the Regional office and is included as an attachment to this report.

b. Information Notice (IN) 87-10

The Region requested the inspectors to evaluate the licensee's assessment of IN 87-10 that pertained to possible water hammer in residual heat removal systems. The results of the inspectors' review is documented in paragraph 7.b of this report.

5. Safety Assessment/Quality Verification (40500 and 92700)

Through direct observations, discussions with licensee personnel, and review of records, the following Licensee Event Report was reviewed to determine that reportability requirements were fulfilled, that immediate corrective action was accomplished, and that corrective action to prevent recurrence had been or would be accomplished in accordance with Technical Specifications (TS):

(Closed) LER (341/93009): Manual initiation of the emergency equipment cooling water/emergency equipment service water (EECW/EESW) to supplement Reactor Building Closed Cooling Water (RBCCW). On July 26, 1993, the EECW/EESW systems were manually initiated to reverse the increasing drywell pressure and temperature caused by an inadvertent opening of a valve connecting the circulating water (CW) pond and the general service water (GSW) intake. The valve was opened by a painter in the GSW building believing the control switch was an enclosed 120 V electrical outlet. Opening of the valve diverted approximately 95 degree water from the CW pond to the GSW intake (approximately 75 degrees). Since GSW cools the RBCC system, the increased temperature in the GSW intake decreased the cooling capability of the drywell coolers which were cooled by the RBCC system. The operators noted an increase in temperatures on all heat exchangers cooled by GSW and initiated emergency equipment cooling water/emergency equipment service water (EECW/EESW) to supplement Reactor Building Closed Cooling Water (RBCCW). The initiation of EECW/EESW reduced the drywell pressure and temperature until GSW was restored to normal configuration. Valve P41F601 was found open by the system engineer, who had gone to the GSW building to investigate the increased GSW temperatures. The system engineer's involvement contributed to the quick termination of an event. The licensed operators responded well to this event in controlling drywell pressure and temperature. The inspectors reviewed the licensee's corrective actions and have no further questions.

In addition to reviewing the above LER, the inspectors reviewed closed Deviation Event Reports (DER) and DERs the licensee issued during the inspection period. This was done in an effort to monitor the conditions related to plant or personnel performance, potential trends, etc. DERs were also reviewed to ensure that they were generated appropriately and dispositioned in a manner consistent with the applicable procedures. The inspectors' review of the DERs resulted in the following concerns:

- The resolution to DER 93-0033 that pertained to a engineering review of a Nuclear Network Plant Status Report appeared to be inadequate. This DER is discussed in further detail in paragraph 7.b of this report.

- On August 30, 1993, DER 93-0507 was issued to document a problem with opening Mini-Flow Valve, E51F019, for the Reactor Core Isolation Cooling (RCIC) Pump. The RCIC Pump High/Low Suction Pressure Alarm, 1D73, annunciated due to a high pressure condition. The Annunciator Response Procedure (ARP) 1D73 action required opening Valve E51F019 to reduce the pressure. When the licensed operator tried to open Valve E51F019 using the control room open pushbutton on Panel H11-P601, the valve failed to open. Subsequent investigation by the licensee determined that an auxiliary contact block was deficient. The component was replaced and the valve operated on demand. The inspectors contacted the system engineer on September 3, 1993, to determine the cause of the high suction pressure alarm. The results of this discussion with the system engineer is documented in paragraph 7.d of this report.

No violations or deviations were identified.

6. Maintenance/Surveillance (62703 & 61726)

   a. Maintenance Activities (62703)

      Routinely, station maintenance activities were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with technical specifications.

      The following items were also considered during this review: limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; functional testing or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel.

Portions of the following maintenance activities were observed or reviewed:

- 000Z933866 Mini Flow Valve E51F019
- 000Z933744 Repair to 1S Feedwater Heater weld
- 000Z933724 SLC "A" pump run light will not light
- 000Z933936 Troubleshoot MPU No. 1 Regulator
- R121921156 EDG starting air compressor
- 000Z933133 Retorque flange bolts for EDG 11

The teamwork exhibited by all the station's departments to repair Modular Power Unit (MPU) No. 1 was excellent. The coordination between maintenance, work planning, engineering, licensing, and operations resulted in the repairs to the MPU being performed in a safe and expeditious manner.

During the reactor trip event on August 13, 1993, the low pressure annunciator for Emergency Diesel Generator (EDG) 11 alarmed. The licensee performed a maintenance event critique, NPMA 93-04, since this alarm annunciated during a reactor trip event and caused an operator distraction. The inspectors reviewed critique results to ascertain the effectiveness of the licensee's review to identify any lessons learn. The EDG 11 Starting Air Compressor was taken out of service at 9:15 a.m. on August 13, 1993, approximately 30 minutes prior to the reactor trip. Since the setpoint for the EDG 11 Starting Air Pressure Low Annunciator Alarm was 180 psig, the air pressure was verified by the mechanics to be at 245 psig, well above the setpoint, when the compressor was taken out of service. Maintenance started work on the air compressor in accordance with Work Request 000Z933133 at 10:00 a.m. The work was completed at 11:00 a.m. on WR 000Z933133 and the maintenance personnel left the EDG 11 room and returned to the plant. Maintenance personnel did not return to the EDG 11 room until notified by operations that a low air pressure alarm had been received. Maintenance and operations personnel returned to the EDG 11 room and restored the air start system lineup back to normal. Subsequent investigation by the licensee identified that the higher than expected drop in the EDG 11 starting air receiver pressure was caused by excessive leakage past the air receivers blowdown valves. The licensee's lessons learned included:

- Do not assume system/components removed from service will react the same way each time;

- When system parameters need to be monitored during work activities, personnel should be assigned to perform the needed monitoring activities; and

- All jobs on a system, no matter how minor, should be prioritized and worked accordingly.

The licensee has initiated actions to address the lessons learned. The inspectors considered the licensee's critique as good management action to improve performance.

b. Surveillance Activities (61726)

During the inspection period, the inspectors observed Technical Specification required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated. that results conformed with technical specifications and procedure requirements and were reviewed, and that any deficiencies identified during the testing were properly resolved.

The inspectors also witnessed or reviewed portions of the following surveillance:

- 24.204.01 Div. I LPCI and Suppression Pool Cooling/Spray Pump and Valve Operability Test
- 24.307.017 EDG 14 Start and load test.
- 57.000.17 Determination of Defective Fuel Bundle Location Flux Tilt Method.

The inspectors reviewed a quality assurance (QA) audit of the Technical Specification (TS) surveillance program. The audit assessed the TS surveillance program "as satisfactory." However, the audit did identify that past problems in the surveillance program in regards to implementation of TS amendments still existed. As a result, a Deviation Report (DER) 93-0427 was issued for management action. Even though the problems identified did not impact safe and reliable operation of the plant to meet the requirements of the operating license, QA determined that repeated problems with TS amendments warranted management involvement to preclude any future problems which could affect plant operations. The inspectors considered the QA audit of the TS surveillance program an example of a good performance based audit.

No violations or deviations were identified.

7. Engineering & Technical Support (37700)

a. Nuclear Safety Review Group

Fermi's Nuclear Safety Review Group (NSRG) consists of 11 members including a chairman and a vice chairman, which exceeds the TS requirement of nine members. Each of the members had extensive experience and all the required fields were covered by qualified individuals. In all but two of the fields, at least half of the members met or exceeded the minimum of 5 years of experience, providing a strong knowledge base for all fields. Four of the eleven NSRG members were from outside of Fermi's organization and include both senior management members from other utilities and experienced consultants. The qualification of members involves completing required reading and completing a written course examination.

The inspectors reviewed procedure FIO-FMP-01, "Safety Review Group Organizations," and concluded that it met the intent of ANSI N18.7. Items for review were distributed by the NSRG staff engineer via an NSRG Document Transmittal and Comment Form. The NSRG was responsible for review of the areas designated in Fermi TS 6.5.2.7, and the NSRG staff engineer was responsible for maintaining a log of the material reviewed. The results of the reviews were documented on the comment form or attached to the package. Safety evaluations were rated in accordance with Fermi's Safety Evaluation Rating System.

The NSRG was meeting every other month, well in excess of the required once per 6 months. All 11 members were present at the meeting held on July 22, 1993. The meeting was a very open discussion with comments from many of the NSRG members. Two of the main issues addressed were the consistent theme of personnel performance issues and the incorrect installation of the T-50 recorder and the related enforcement conference. NSRG subcommittees provided reports during the meeting which included reports from the Plant Operations Review Subcommittee, the Radiological/Chemistry Subcommittee, the Audit Subcommittee, and the Onsite Safety Review Organization Subcommittee. After the subcommittee reports, Technical Specification changes were presented. Approval to proceed with all the TS changes was provided by the NSRG except for the Performance Based Audit Program TS. Questions arose regarding the changes to the audit frequency. The change was based on greater flexibility to focus audit resources on problem areas. Discussion on this package will continue at the next NSRG meeting. The inspectors also reviewed the meeting minutes for NSRG meeting 93-01 held on January 20 and 21, 1993, and determined that they met the intent of ANSI N18.7.

b. Information Notice (IN) 87-10

IN 87-10 addresses the potential of water hammer in the residual heat removal (RHR) system of BWRs during a design base accident (DBA) coincident with a loss of offsite power (LOOP) if the RHR system is aligned for suppression pool cooling. During the power loss and subsequent valve realignment, portions of the RHR system could void because of the drain down to the suppression pool as a result of elevation differences. A water hammer may occur in the RHR loop that was in the suppression pool cooling mode when the RHR pumps restart after the diesel generators reenergize the buses.

The resident staff reviewed Fermi's assessment of the information notice and found that the licensee's December 1988 assessment did not address the issue of possible water hammer during suppression pool cooling mode when there is a LOCA with a LOOP. The assessment noted that Fermi 2 had not experienced high usage for suppression cooling. The assessment also referred to an evaluation of INPO SER 83-055 which pertained to possible water hammer when there was an interruption of RHR pump operation during suppression pool cooling or drywell spray modes. The licensee's November 1985 assessment of INPO SER 83-055 stated that the procedure for operating RHR required the closure of the RHR discharge valves following shutdown of the RHR pump. The assessment also took credit for the "keep fill" pump to replenish any water that is lost until the discharge valves are closed. The licensee's assessment of the issue defined in IN 87-10 appeared to be inadequate since the "keep fill" system was not sized to replace water lost during an inadvertent draining of RHR piping and power would not be available to run the "keep fill" pump. Also, the operating procedure would not be applicable during a LOCA and LOOP since power would not be immediately available to close valves to terminate the draining of the pipe. In addition, the licensee failed to recognize that with the suppression pool cooling system operating in the crosstie mode, which is required for a LPCI loop select plant, the potential was to drain down <u>both</u> loops of RHR rather than just one.

During the review of the licensee's actions for IN 87-10, the inspectors reviewed DER 93-0033 issued in January 1993. The licensee issued DER 93-0033 to address a morning report pertaining to Washington Nuclear's identification of both trains of RHR being inoperable. The inoperability of RHR was based on the potential of a water hammer event occurring as described in IN 87-10. The licensee reviewed this morning report for applicability to Fermi using the DER. The inspectors reviewed the closed DER and determined that the disposition was inadequate. The licensee's engineering organization stated the probability of a water hammer in the RHR system while in suppression cooling when there is a LOCA concurrent with a LOOP was so low that it was not in the design basis of RHR. This position missed the entire point of the IN and is contrary to the UFSAR. The UFSAR addresses the LOCA with a LOOP along with a description of how RHR can be operated in the test or suppression pool cooling mode. The UFSAR further states that if a LOCA occurred during these modes the RHR valves would realign to the LPCI mode.

Based on the above, the licensee's assessment of possible water hammer in the RHR/LPCI system as described in IN 87-10 and the resolution of DER 93-033 is considered an Unresolved Item pending further licensee and NRC review (341/93016-04).

c. Sequence of Events (SOE)

On August 25 and 26, 1993, the licensee performed SOE 93-03 on Emergency Diesel Generator (EDG) 13 to investigate the reduced jacket water pressure when EDG 13 was operated in the 2500-2600 Kw range. When the EDG was run at 1800 Kw, the jacket coolant system pressure was 32 PSIG. When load was increased to 2550 Kw, jacket coolant pressure decreased to 18-24 PSIG and was erratic (plus or minus 3 PSIG). The licensee believed the decrease in jacket water pressure was caused by a minor exhaust leak into the jacket water system. With the decrease in jacket water pressure the jacket water temperature was still maintained within the acceptance band (150-165°F). SOE 93-03 was reviewed by the inspectors with no concerns being identified. The SOE contained the necessary controls to ensure the test did not impact other EDGs. Based on the results of the test conducted as described in SOE 93-03, the exhaust gas leakage was from the adapter crush gaskets, not through a crack in the liner and that cylinder No. 2 was the primary contributor to the reduction of the jacket coolant pressure.

d. Reactor Core Isolation Cooling (RCIC)

On August 30, 1993, DER 93-0507 was issued to document a problem with opening Mini-Flow Valve E51F019 for the Reactor Core Isolation Cooling (RCIC) pump. The RCIC Pump High/Low Suction Pressure Alarm, 1D73, annunciated due to a high pressure condition. The system engineer was contacted to discuss the alarm. The system engineer stated that the cause of the high suction pressure appeared to be related to the running of the barometric condenser pump. The barometric condenser pump automatically starts on a high level in the RCIC barometric condenser. The system engineer stated that the pump has automatically started about twice a day since August 16, 1993. When the pump auto starts to decrease level in the RCIC barometric condenser, valve E51F004 also auto opens on a high barometric condenser level to allow a flow path for the condenser pump to radwaste. The inspectors reviewed the system engineer's GETARS tracing of the RCIC suction pressure and noted that the pressure continues to increase for approximately 90 seconds once the condenser pump auto starts. The cause of the high RCIC suction pressure alarm had not yet been determined as of August 30. The inspectors do not consider this to be timely follow up to determine the periodic high RCIC suction pressure by engineering. This matter is considered an Inspection Followup Item pending further licensee and NRC review (341/93016-05).

e. Technical Issue Report (TIR)

The inspectors reviewed the licensee's initial issue of the Fermi 2 TIR. This report will be issued monthly and will summarize all those technical issues being addressed by personnel into one comprehensive document. The report will aid in the overall understanding of current site technical issues and provide for progress assessments on a monthly basis. The report will also serve as a quick reference tool for information on current technical issues. The initial issue addressed the high pressure coolant injection reliability program, safety relief valve (SVR) setpoint drift, reactor pressure level water level, and Thermolag barriers, among others. The inspectors consider this report to be a good engineering initiative to provide management overview of current site technical issues.

f. <u>Technical Performance Improvement Plan (TPIP)</u>

The licensee's engineering organization initiated the TPIP to improve the overall performance of the technical organizations. The plan specifically addressed three general areas that indicate the need for performance improvement; namely, the second failure of the No. 4 heater extraction steam line in the condenser and subsequent failure of a temporary instrument connection during restart; the NRC inspection of engineering and technical support that identified an inadequate evaluation of a water hammer event in HPCI and other weaknesses; and the multiple problems associated with the installation of new post accident wide range drywell and suppression chamber pressure recorders that resulted in both divisions of this instrumentation being inoperable for approximately three months.

The inspectors will monitor the licensee's implementation of the TPIP and will meet with the Technical Manager on a periodic basis to discuss progress in management's efforts to improve engineering performance.

g. <u>Gland Seal System</u>

The loss of condenser vacuum due to the failure of the operators to realign the gland seal system to the 52 inch manifold after a reactor trip on August 13, 1993, resulted in the use of the Safety Relief Valves and torus as the heat sink for the reactor's decay heat. The gland seal system for several years has not been operated in the "as designed" configuration due to inherent design problems of using one controller for three pressure regulator valves. The licensee had a modification scheduled for the next refueling outage (Spring 1994) to correct the design problems. However, operating the gland seal system in the manual mode challenged the operators during reactor trips to manually align the gland seal system to the 52 inch manifold to prevent loss of condenser vacuum. Prior to returning the unit to service after the reactor trip on August 13, the licensee performed a loop calibration for the gland seal pressure regulator for the 52 inch manifold that allowed the system to be aligned to the manifold even when the turbine was at power levels when the turbine was self sealing thus ensuring gland seal steam after a reactor trip.

The regulator that controls gland seal pressure when the turbine was self sealing was still isolated with pressure being controlled by the operators with the regulator's bypass valve. As a result of this action, any reactor trips occurring prior to the installation of the gland seal system modification should not require any operator action to maintain gland seal. The inspectors were concerned that the impact on plant operations with the gland seal system operating in a manual configuration contrary to the automatic mode (see paragraph 3.c of this report for explanation of manual and automatic modes) had not been adequately assessed by engineering resulting in the unnecessary challenging of operators during response to a plant transient.

h. Main Control Room Panel Bulbs

During the reactor trip on August 13, 1993, there were approximately 100 bulbs that burned out. The control room has approximately 10,000 bulbs for various equipment status. Approximately 70 percent of the burned out bulbs were associated with the core display. The bulbs gave indication such as: control rod position; pump running; breaker position; and valve position. Some of the equipment status lost was the result of two bulbs burning out. The failure of the bulbs required the operators to use other means to verify the status of equipment that had the burned out bulbs. The number of burned out bulbs during the August 13 reactor trip was unusually high. The licensee's actions to address the bulb failure is considered an Inspection Followup Item pending further licensee and NRC review (341/93016-06).

i. Flood Lamp Failures

On August 26, 1993, the licensee issued Deviation Event Report (DER) 93-0502 to document failures of Sylvania Par 38 Capsylite Flood Lamps in the simulator control room. The lamps in the simulator on seven occasions have had the lens shatter and fall on the floor. The failures occurred in those lamps stamped with a production code 15. The licensee determined through discussion with the manufacturer that there was a defect with production of 15 lamps. Since the plant's main control room could also have this production code installed, the licensee checked the lamps and found lamps installed stamped with production code 15. Even though there had been no failures of the lamps in the plant's main control room, the licensee still replaced those lamps with new lamps provided by the manufacturer.

j. Flux Tilt

On August 8, 1993, the licensee performed a flux tilt test to identify the location of a leaking fuel bundle. The operation was treated as an infrequently performed test or evolution (IPTE). As such, a designated chain of command was established for the evolution and expanded briefings were held to train involved personnel. Shift briefings were held a week in advance to train all operating crews. A briefing was also held immediately prior to commencing the test. All personnel involved in the test (chemistry, radiation protection, operators, and nuclear engineering) were present at the final brief. Items discussed at the briefing included performance of the test itself, possible trouble areas and contingencies, duties and responsibilities of involved individuals, and results of a similar test performed during the prior fuel cycle. The procedure was halted for shift turnover and the oncoming crew thoroughly briefed prior to recommencing the test. The inspectors observed good command and control of the evolution. The inspectors also considered the briefings to be thorough and informative. The licensee was successful in locating the leaking fuel assembly and subsequently changed the operating control rod pattern to suppress the flux around the leaking fuel bundle. At the end of the inspection period, the licensee was still evaluating the long term impact of the leaking bundle and suppressed localized neutron flux, including any possible impact on the next cycle's core load.

No violations or deviations were identified.

8. Report Review

During the inspection period, the inspector reviewed the licensee's Monthly Operating Status Report for July 1993. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.9.1.6 and Regulatory Guide 1.16.

9. Inspection Followup Items

Inspection Followup items are matters which have been discussed with the licensee, which will be reviewed by the inspector, and which involve some action on the part of the NRC or licensee or both. Inspection Followup Items disclosed during the inspection are discussed in paragraphs 3.c, 7.d and 7.h.

10. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during the inspection are discussed in paragraphs 3.a, 3.c, and 7.b.

11. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on September 9, 1993. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

Attachment: Employee Concerns Programs

Attachment

EMPLOYEE CONCERNS PROGRAMS

PLANT NAME: Fermi 2 LICENSEE: Detroit Edison DOCKET #: 50-341

NOTE: Please circle yes or no if applicable and add comments in the space provided.

A. PROGRAM:

1. Does the licensee have an employee concerns program? (Yes or No/Comments)
Ombudsman program is primary means. Also available: Deviation Event Report (DER) program
Employee Assistance Program (EAP)
Employee Complaint Procedure

2. Has NRC inspected the program? Report # N/A
No

B. SCOPE: (Circle all that apply)

1. Is it for:

a. Technical? (Yes, No/Comments)
Ombudsman + DER programs

b. Administrative? (Yes, No/Comments)
Ombudsman + DER programs

c. Personnel issues? (Yes, No/Comments)
Ombudsman + Employee Complaint Procedure

2. Does it cover safety as well as non-safety issues? (Yes or No/Comments)

3. Is it designed for:

a. Nuclear safety? (Yes, No/Comments)
DER

b. Personal safety? (Yes, No/Comments)
Ombudsman, DER

c. Personnel issues - including union grievances? (Yes or No/Comments)
Employee Complaint Procedure (Though union issues are primarily dealt with through the union steward + union process)

4. Does the program apply to all licensee employees? (Yes or No/Comments)
Company wide; however, DER process applies to Fermi only

5. Contractors? (Yes or No/Comments)

6. Does the licensee require its contractors and their subs to have a similar program? (Yes or No/Comments)
Contractors are trained on Fermi Procedure

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns?
   (Yes or No/Comments)
   One of the outprocessing forms asks if they have any concerns

C. INDEPENDENCE:

1. What is the title of the person in charge?
   Ombudsman
2. Who do they report to?
   Senior Vice President, Nuclear Generation
3. Are they independent of line management?
   Yes
4. Does the ECP use third party consultants?
   No off-site 3rd party used; will utilize the QA department to look into certain areas
5. How is a concern about a manager or vice president followed up?
   Ombudsman can go to company CEO with his concerns

D. RESOURCES:

1. What is the size of staff devoted to this program? 1 person
2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)?
   the ombudsman has had the following training; however they are not required for the position
   - Technical staff and manager training
   - Problem Solving and Decision making training

E. REFERRALS:

1. Who has followup on concerns (ECP staff, line management, other)? to the extent possible, concerns are turned over to line management for resolution

F. CONFIDENTIALITY:

1. Are the reports confidential?
   (Yes or No/Comments)
   → Source is confidential
   → report (which contains issue content) goes out to the line organization
2. Who is the identity of the alleger made known to (senior management, ECP staff, line management, other)?
   (Circle, if other explain)
   identity is made known only to the ombudsman

3. Can employees be:

   a. Anonymous? (Yes, No/Comments)

   b. Report by phone? (Yes, No/Comments)

   by procedure concerns can be raised via: written input, face-to-face, or over the phone

G. FEEDBACK:

1. Is feedback given to the alleger upon completion of the followup? (Yes or No - If so, how?)

   → they get a written response

2. Does program reward good ideas?

   can be fed back into PRIDE team

3. Who, or at what level, makes the final decision of resolution?

   line organization will make final resolution, then looked at by QA department or the ombudsman

4. Are the resolutions of anonymous concerns disseminated?

   Yes

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)?

   they try not to publicize in order to protect the confidentiality of the source

H. EFFECTIVENESS:

1. How does the licensee measure the effectiveness of the program?

   N/A

2. Are concerns:

   a. Trended? (Yes or No/Comments)

   b. Used? (Yes or No/Comments)

3. In the last three years how many concerns were raised? ______ Closed? ______ What percentage were substantiated? ≈60%

   formal "ombudsman concerns": 1990 → initiated 6; 1991 → initiated 4; 1992 → initiated 6; 1993 → initiated 5 (through July)

4. How are followup techniques used to measure effectiveness (random survey, interviews, other)?

   ombudsman looks at on a case-by-case basis, see if the problem arises again

5. How frequently are internal audits of the ECP conducted and by whom?

Audited by downtown corporate → every 2 years

I. ADMINISTRATION/TRAINING:

1. Is ECP prescribed by a procedure? (Yes or No/Comments)

FIP-CA1-03, Rev 3

2. How are employees, as well as contractors, made aware of this program (training, newsletter, bulletin board, other)?

newsletter (Moderator), Fermi 2 orientation training handbook, signs and posters located in major buildings

ADDITIONAL COMMENTS: (Including characteristics which make the program especially effective or ineffective.)

The person completing this form please provide the following information to the Regional Office Allegations Coordinator and fax it to Richard Rosano at 301-504-3431.

NAME: Ken Riemer / TITLE: Resident Inspector / PHONE #: 313 586-2098 DATE COMPLETED: 8/30/93