U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-341/89018(DRP)

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

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

Facility Name: Fermi 2

Inspection At: Fermi Site, Newport, Michigan

Inspection Conducted: June 6 through July 24, 1989

Inspectors: W. G. Rogers

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Mark A. Ring, Chief
Reactor Projects Section 3B

Date 8/14/89

Inspection Summary

Inspection on June 6 through July 24, 1989 (Report No. 50-341/89018(DRP))
Areas Inspected: Action on previous inspection findings; follow-up of events; operational safety; maintenance; surveillance; LER follow-up; allegation follow-up; DET review; preparations for refueling; regional requests; and management meetings.
Results: Additional examples of construction deficiencies were identified during the inspection period reinforcing the need for a systematic review of all important-to-safety (ITS) equipment/functions. Also, production

organization personnel made inappropriate decisions on ITS equipment due to a lack of design bases knowledge emphasizing the need for a broad dissemination of the ITS systematic review. During the inspection period, operations personnel handled all transient events in a professional manner, but some minor deficiencies in handling routine administrative functions were noted. Fuel receipt inspection was generally handled well. Continued examples of untimelyresolution of deviation event reports were observed. The present drawing control system places a significant burden on the production organization to maintain the as-built status. This burden increases the likelihood of using an out-of-date drawing. Two unresolved items were identified (Paragraph 3) and seven open items were identified (Paragraphs 3, 6 and 7).

DETAILS

1. Persons Contacted

a. Detroit Edison Company

*P. Anthony, Licensing
*#S. Catola, Vice President, Nuclear Engineering and Services
@#G. Cranston, General Director, Nuclear Engineering
*D. Gipson, Plant Manager
*@#L. Goodman, Licensing
@#P. Marquardt, General Attorney
*R. Matthews, Maintenance Superintendent
*R. McKeon, Operations Superintendent
*@#W. Orser, Vice President, Nuclear Operations
G. Overbeck, Director, Nuclear Training
J. Pendergast, Compliance Engineer
*T. Riley, Compliance Supervisor
*A. Settles, Technical Engineering Superintendent
*R. Stafford, Quality Assurance Director
@*F. Svetkovich, Assistant to the Plant Manager
*@#B. R. Sylvia, Senior Vice President, Nuclear Operations
W. Tucker, Assistant to the Vice President
*J. Walker, Nuclear Engineering Supervisor

b. U.S. Nuclear Regulatory Commission

*@#W. Rogers, Senior Resident Inspector
*S. Stasek, Resident Inspector
#B. Berson, Region III
#R. Ewing, Intern, DRP Branch 2
#W. Forney, Deputy Director, DRP, RIII
@#J. Grobe, Director, EICS, RIII
@#R. Knop, Chief, DRP Branch 3
@#C. Paperiello, Deputy Regional Administrator, RIII
#C. Pederson, Reactor Engineer, RIII
@#P. Pelke, Project Inspector
#M. Phillips, Chief, OPS
@#M. Ring, Chief, DRP Section 3B
#J. Stang, Project Manager, NRR

*Denotes those attending the exit meeting on July 27, 1989.
#Denotes those attending the Enforcement Conference on June 9, 1989.
@Denotes those attending Part 2 of the Enforcement Conference on June 27, 1989.

The inspectors also interviewed others of the licensee's staff during this inspection.

2. Action on Previous Inspection Findings (92701)

a. (Closed) Violation (341/89002-02(DRP)): Improper storage of emergency diesel generator (EDG) parts. The inspector reviewed

the uncontrolled area and noted that all EDG parts had been removed from the area. The inspector also reviewed a memorandum from the maintenance and modification superintendent to all maintenance staff, NP-MA-89-0134, which discussed this situation and the necessity for proper storage of material. The inspector reviewed training records that indicated that all maintenance supervision had been trained on proper material storage procedures. The inspector noted that a maintenance news letter item had been generated that discussed proper storage of material. Based upon the inspector's observation of the uncontrolled storage area and the training records this matter is considered closed.

b. (Open) Unresolved Item (341/88003-02(DRP)): Inservice test requirement for RHR service water discharge valve. On June 26, 1989, the licensee informed the inspector that there would be a meeting between the licensee and NRR to discuss the applicability of this valve to the Inservice Test Program. The meeting was scheduled for late July.

c. (Open) Violation (341/89007-02(DRP)): Inadequate corrective actions to the utilization of an improper head correction factor on a HPCI flow transmitter. The response to the violation was unclear to the inspector as to what procedures would be changed.

In a meeting on June 5, 1989, the inspector informed the licensee of this condition and requested that the information be provided. Once received this information would be documented in an inspection report to provide adequate documentation for the NOV response. In subsequent meetings with the licensee on July 10, 17 and 24, the inspector continued to request the information. The licensee indicated that the information was being prepared.

d. (Closed) Violation (341/87038-02(DRP)): Failure to verify closed and locked valves as required by Technical Specification 4.6.1.1.b. Following a walkdown and review of the core spray system, the inspector initially identified two drain valves not included in procedure NPP 24.425.01, "Primary Containment Integrity Verification," and in a subsequent review of the HPCI and RCIC systems, identified eight other valves not included in the procedure. The subject procedure implemented Technical Specification 4.6.1.1.b which requires monthly verification that primary containment penetration valves not capable of being automatically closed are closed and capped where required. The procedure also required the verification of correct valve positions of the automatic isolation valves. These findings indicated that further review into other systems was required and the subsequent review by the licensee identified 76 test, vent and drain (TVD) valves outside containment, six TVD valves inside containment, and five bonnet taps that were not included in the surveillance procedures. An inspection of the above omissions showed that the valves were properly positioned by standard operating procedures and no violation of primary containment had occurred. Procedures NPP 24.425.01 and NPP 24.425.03, "Primary Containment Integrity Verification for Equipment Inside Containment,"

were revised to include the above TVDs and bonnet taps and the procedures were performed. In addition, a surveillance improvement plan was undertaken in 1988 to upgrade the licensee's overall performance in this area. The inspector reviewed the Technical Specification Improvement Package for Technical Specification 4.6.1.1, "Primary Containment Integrity," and the revised procedures NPP 47.000.77, "Test, Vent and Drain Valve Cap and Plug Verification," NPP 24.425.01 and NPP 24.425.03. The review included a 100 percent examination of TVDs by comparing those valves on functional operating sketches (FOS) with those in the revised procedure, NPP 47.000.77, using the criteria for pipe cap/plugs established by the licensee in letter NE-NS-85-0118, dated December 2, 1985. A random examination of the valves, caps and plugs in Procedures NPP 24.425.01 and .03 was also performed. A hands on inspection of selected valves for correct positions and cap installations was also performed. The inspected valves were found to be correctly positioned with properly identified caps, where required.

The inspector reviewed the last scheduled surveillance procedure checklists for the above procedures and found them to be properly completed.

In the course of the above procedure reviews using the UFSAR and the FOSs, several minor errors were found, two in the UFSAR and four in various FOSs. These were reported to the licensee and corrections were initiated.

e. (Closed) Violation (341/87040-03(DRP)): Failure to maintain Primary Containment Integrity on the Primary Containment Radiation Monitoring System (PCRMS). In January 1984, the licensee determined that the PCRMS did not comply with the UFSAR. The requirements allowed single remote manual isolation valves on essential closed loop systems outside primary containment. However, the PCRMS was not qualified to containment design accident pressure and portions of the system were not seismically or materially qualified. Therefore, the PCRMS was not essential following a LOCA and the system would automatically isolate upon receipt of a LOCA signal (high drywell pressure). To confirm the requirements for a non-essential closed loop system automatic isolation valves were added, but the UFSAR was not updated nor were the Technical Specifications amended to included these valves. In addition, the modification to install the valves did not provide for the inclusion of these valves in the Fermi testing program, i.e. functional testing, logic testing, position indication check, or local leak rate testing.

On October 17, 1987, during implementation of another modification of the PCRMS, the use of these valves for system isolation was questioned since they were not included in the UFSAR or Technical Specifications and had been left open during the modification. In addition the valves were not properly qualified. This violation of primary containment integrity was immediately reported on the ENS and by LER 341/87-52 on November 14, 1987. This violation resulted

in the imposition of a Civil Penalty, issued via letter dated June 16, 1988, for failure to determine that the 1984 modification was not an acceptable alternative to 10 CFR 50, Appendix A, General Design Criteria 56, that a Technical Specification Amendment was not processed and that procedures were not put in place to periodically test the valves in accordance with 10 CFR 50, Appendix J, and other testing requirements.

Following the detection of the violation, the licensee applied for and was granted a temporary exemption from the GDC 56 requirement for the PCRMS on November 13, 1987. In the interim, until March 29, 1988, when the NRC approved a Technical Specification Amendment accepting a permanent PCRMS design configuration as an acceptable alternative to GDC 56, the licensee tested the in place valves in accordance with Technical Specifications. Daily inspections of the valves and associated piping were also made. The Emergency Operating Procedures were revised to included actions for isolation of the PCRMS and training was provided to all licensed operators on these changes.

The 1984 modification on the PCRMS took place before the operating license was issued. Subsequently, the program to make and verify design modifications has been formalized, strengthened and includes various reviews of the design adequacy as well as review of previous commitments made to the NRC (UFSAR, TS, NUREG, IB, etc.). In addition, the licensee has improved the safety evaluation program and provided training in this program to appropriate employees.

f. (Open) Open Item (341/89008-03(DRP)): Determination of the cause of CCHVAC Division 2 fan motor failure.

On July 13, 1989, the engineering research department (ERD) report on the failure of the fan was received by the inspector. Upon initial review the inspector noted that the report was dated June 20, 1989, and questioned the timeliness of the report distribution. After additional interviews with licensee personnel the inspector ascertained that the original draft was completed on June 20 and additional concurrences within ERD were required prior report submittal to the site. The report probably reached the site on July 10 or 11. However, the inspector commented to licensee management that issuance of the report was untimely especially since the verbal evaluation of the motor failure was provided to the cognizant system engineer during the week of June 5.

Upon review of the report the inspector noted the documented cause of the motor failure was not consistent with the system engineer's understanding of failure based upon the ERD verbal report. The ERD report stated, "The cause of high vibration appears to be attributable to a failure of the bearing. The lubricant appeared to be contaminated with water which accelerates pitting type failure . . . " Unfortunately, the bearings were degreased prior to transportation to ERD so no analysis of the grease could be performed. The inspector immediately contacted the system engineer

as to the source of the water. No definite source of water had been ascertained.

Following the failure of the Division 2 fan in February 1989, the inspector inquired as to what actions the licensee intended to take with the Division 1 fan. Originally, licensee personnel had decided to inspect the bearings at the earliest system outage. However, subsequent determination was made that the motor vibration could be monitored and if vibration increases were observed the inspection would be accomplished. This reduced manpower constraints and the inspector considered the monitoring a viable alternative. The first set of vibration data revealed acceptable results.

When the written report was issued by ERD, the inspector inquired as to the status of the Division 1 fan. At this time the engineer informed the inspector that another set of vibration readings had been taken and indicated increased vibration, but not into the action level. The engineer also stated that the work request to inspect the motor bearings would be scheduled for the upcoming CCHVAC Division 1 outage on July 17.

On July 20, the inspector inquired of maintenance craft personnel as to the results of the motor inspection. Craft personnel responded that no motor/bearing inspection was performed or was scheduled to be performed.

The inspector immediately contacted the cognizant engineer, scheduler, planner and appropriate supervision to confirm that the bearing inspection had not been accomplished. From these interviews the inspector confirmed the craft statements. The reason for the cancellation of the inspection was lack of an available spare motor.

A week to two weeks prior to ERD report issuance the system engineer and planner had discussed the bearing inspection and the system engineer considered the inspection conditional upon availability of a spare motor. The planner checked that the purchasing department had a buyer's worksheet for the motor. The inspection was added to the scope of the upcoming CCHVAC outage on July 17.

The Thursday (July 13th) prior to the scheduled CCHVAC outage, maintenance and planning personnel reviewed the work to be performed and the bearing inspection was cancelled since the spare motor had not been received. The ERD report had been received a few days earlier, but the systems engineer had not contacted the planner to specify eliminating the need for the spare motor to perform the inspection. The systems engineer was unaware of the cancellation until informed by the inspector on July 20.

The inspector inquired as to whether the operating authority had been informed of the bearing vibration condition. The technical staff personnel responded that operations had not been notified. Also, the inspector inquired as to whether the motor inspection still could be accomplished during the present system outage. The licensee

responded that with system restoration already in progress, the inspection could not take place.

In a meeting on July 24, 1989, the inspector asked what actions the licensee intended to take with the Division I CCHVAC fan. The licensee responded that additional vibration readings would be taken and motor inspection would be accomplished in mid-August during another CCHVAC outage.

The inspector began an additional review into why it was taking so long to procure a replacement motor. The inspector ascertained that the DECo procurement system uses an automatic buy mechanism on components below a certain dollar amount. If the cost of the item was greater than this amount or the item was repairable an internal review must be accomplished before purchasing. The internal review is accomplished by the use of an Internal Dispersment Review Form (IDRF). This motor fell into the review category. Therefore, a review and notification to the purchasing department was required prior to issuance of the buyer's worksheet. The buyer's worksheet is reviewed by the materials engineering group and quality assurance and returned to the purchasing department. A purchase order is then generated by purchasing.

On February 10, 1989, the last CCHVAC motor in stock was used to repair the Division 2 fan. On February 14th the IDRF was generated by the computer in downtown Detroit. The IDRF was sent to the warehouse who forwarded the IDRF to the requisitioner of the motor just removed from stock on March 1st. Evidently, the IDRF ended up with the spare parts expediting group in the maintenance department. For reasons that are presently unclear to the inspector, the IDRF did not come to the requisitioner until mid-May. On May 16th the IDRF was signed and submitted to the warehouse. On May 26th the warehouse entered the results of IDRF stating that a new motor must be purchased. On June 2, 1989, a buyer's worksheet was generated by the computer in downtown Detroit and was sent to purchasing onsite. On June 12, 1989, the buyer's worksheet was sent to the materials engineering group (MEG) for technical review. The MEG review was completed on July 18th and provided to purchasing to issue a purchase order. This was one day after the commencement of the CCHVAC outage. Presently, the new motor has an estimated delivery date of 16 to 20 weeks.

The inspector will continue to evaluate licensee actions with this fan and why purchasing activities took so long for the spare motor.

g. (Open) Open Item (341/88037-15(DRP)): Performance Enhancement Program (PEP) development. Subsequent to the curtailed licensee presentation on this program in the monthly management meeting on June 29, 1989, the inspector met with the supervisor in charge of PEP development. Based upon the presentation and interview the inspector noted that progress is being made in this area but closure of this item would be premature.

h. (Open) Violation (341/88021-02(DRP)): Improper setting of HPCI and RCIC flow controllers. DECo responded to the notice of violation through correspondence dated December 2, 1988, and January 25, 1989. The licensee's conclusion was that no violation had occurred. The NRC reviewed the material provided and submitted a letter dated June 27, 1989. In this letter the licensee was requested to provide certain information on the core spray and LPCI systems within 60 days. This matter will be considered open pending submittal of the information and subsequent NRC review.

i. (Open) Unresolved Item (341/89015-02(DRP)): Use of a Potential Design Change (PDC) to identify a lead design document discrepancy. During the week of June 8 through 16, the licensee Quality Assurance Department conducted Surveillance 89-0174 into the inspector's concern. Six PDCs, including the one identified by the inspector, were reviewed by Quality Assurance (QA). QA concluded that the PDC identified by the inspector, 10153, would have been more appropriately documented on a DER, but the PDC rectified the situation in a controlled manner. The other five PDCs should not have been DERs. The inspector reviewed the surveillance and concluded that a DER was required for 10153 and that the other five PDCs did not require a DER.

The inspector met with cognizant QA personnel on July 14, 1989, and discussed the surveillance report. During the meeting the licensee identified that one DER has been issued to capture and trend CECO errors. At the end of 1989 the DER will be reviewed to ascertain whether the CECO error rate is sufficiently low. QA personnel stated that they would contact Technical Engineering to reiterate that as-found discrepancies warranted a DER.

j. (Open) Open Item (341/87020-01(DRP)): Implementation of Exo-Sensor action plan. PDC 7081 Revision A was issued on June 30, 1989. The PDC provides direction to return the functional and calibration test to their original frequency, extend sensor change out to 3 years and establish shelf life controls on the sensors consistent with the Whittaker Corporation, present owners of Exo-Sensor, letter of June 12, 1989. Closure of this item is conditional upon implementation of this PDC by the licensee.

k. (Closed) Violation (341/88033-01(DRP)): Administrative closure of deviation event reports. The inspector follow-up activities associated with this matter in IR 341/88033 were sufficient to assure corrective actions had been implemented. This matter is considered closed.

l. (Closed) Violation (341/89011-04(DRP)): Periodic procedure review requirements exceeded. Inspection efforts during IR 341/89011 were adequate to assess the licensee's corrective actions.

m. (Closed) Violation (341/89011-05(DRP)): OSRO review of Technical Specification violations. Inspection efforts during IR 341/89011 were adequate to assess the licensee's corrective actions.

n. (Closed) Violation (341/88006-01(DRP)): Core Spray System differential pressure not determined within the required 12 hour periodicity on nine occasions. Root cause of this violation was determined to be an incorrect application of Technical Specification 4.0.2 which allows for 25 percent extension to periodicities on routine surveillances. In this case the core spray differential pressure was to be checked at least once every 12 hours in accordance with a Technical Specification Section 3 Action Statement, not a Section 4 periodic surveillance. In response, the licensee issued Urgent Required Reading No. 88-4-6 which clarified the differences and included presentation of an additional note in Procedure 24.000.02, Attachment 10 specifying that the 25 percent "grace period" does not apply to situation required surveillances. (Subsequently, Procedure 24.000.01, "Situational Surveillances," was issued and all requirements for the subject area were transferred from 24.000.02). Additionally, discussion of this topic has been included in operator training under Training Lesson Plan LP-OP-802-102, "Plant Administrative Procedures." The inspector verified all operators had reviewed URR 88-4-6, Procedure 24.000.02, Attachment 10 as revised, and that the training lesson plan explicitly included the subject topic (reference Training Change Request I-89-0567). This item is closed.

o. (Closed) Violation (341/88030-02(DRP)): Failure to deenergize containment lighting circuits in accordance with Technical Specifications 3.8.4.1 and 3.0.4. The licensee subsequently determined the cause to be personnel error in performance of the drywell closeout evolution as well as an unclear procedure as to the requirements governing the closeout. An accountability meeting (No. 88-034) was held between management and all involved personnel, and those involved in the failure to deenergize the circuits as well as those who authorized ascension in power were counselled and/or disciplined. Additionally, Procedure 23.425.01, "Primary Containment Procedures," was revised to clearly specify the Technical Specification requirements to deenergize the subject circuits, and a Lessons Learned (Document No. 88-015) was issued on the event (which was included as required reading for all operators). The inspector reviewed licensee corrective actions and found them acceptable. This item is closed.

p. (Closed) Violation (341/88030-03(DRP)): Failure to verify containment lighting circuits deenergized at least once per 24 hours in accordance with Technical Specifications. In addition to those actions taken as described in Item 2.o above, personnel responsible for failing to verify proper circuit configuration were counselled/disciplined. One licensed operator was dismissed for his actions per Detroit Edison Company Policy. Additionally, a memorandum from the plant manager to all site personnel was issued on November 9, 1988, reiterating the Fermi 2 management position on the subject of dishonesty and falsification of records. This item is closed.

q. (Open) Open Item (341/89011-07(DRP)): Implementation of the lubrication program action plan. Since the last review of this item, the licensee has added Items 19 and 20 to the action plan; (19) evaluate the use of the Turbine Building 2nd floor lubrication issue area to determine if improvements can be made, and (20) evaluate the use of lubrication extension tubes (external from housing to bearing) for grease degradation over time. The inspector determined that two of the 20 items are complete as follows:

Item 4: Lubrication identified in CECO differs from that specified in vendor manuals. Provide documented evidence that proves equivalency for lubricants used in safety-related applications. The inspector reviewed DECo Engineering Research Report No. 89B73-8, Revision 1, "Comparison of Lubricants in the Fermi 2 Lubrication Manual and the Manufacturer's Maintenance Manual," issued May 10, 1989. The report documented that in every instance where the lube manual differed from the manufacturer's (vendor) manual the quality of the lubricants recommended were equal to or superior to the products recommended by the manufacturer.

Item 9: During the performance of corrective or preventative maintenance activities, when lubricants are found not in compliance with CECO, they shall be changed out at that time. These situations shall be documented on a DER. The licensee's position on this issue is to document each discrepancy on a DER and evaluate each on a case by case basis. Region III will continue to monitor the disposition of any future DERs involving lubrication issues.

The following are inspector comments regarding items which are partially complete:

Item 3.a: Verify by sampling the technical accuracy and thoroughness of CECO compared to Revision 8 of the Lubrication Manual. This item is being performed to ensure that incorrect data was not entered into the new computerized CECO database during the changeover from the hard copy lube manual. QA took a sample and identified 17 discrepancies. Fifteen discrepancies involved Dolium S being specified in the hard copy lube manual while the correct Dolium R was specified in the CECO database. Dolium R was incorrectly changed to Dolium S in the hard copy lube manual by the site lubrication engineer when he learned that Dolium S was an improved product over Dolium R but had not yet been marketed and distributed by Shell. Subsequently, the product was never distributed due to test results. This example highlights the ease with which the lube program could be changed without independent review.

Item 3.d: Assess user friendliness of CECO relative to lubrication requirements. Initiate CSRs to Computer Systems accordingly. Provide information and/or training on the use of CECO, PM and EQ for lubrication requirements. The licensee has

modified the CECO lubrication screen such that subcomponent lubrications are now displayed when the component lubrication screen is viewed. No further modifications have been made to the software. Training will be conducted after all software changes have been made.

Item 4.f: Revise procedures to designate CECO as the Lead Design Document for lubrication and communicate the same. Maintenance Procedure 35.000.217 has been changed, however, the licensee's Lead Design Document Index procedure has not been changed.

Item 10.a: How lubricants are purchased. Lubricants are purchased as nonsafety-related (NQ), important to safety (NX), and safety-related (CQ). Testing is performed on CQ lubricants by Plant Chemistry upon receipt. Purchase requisitions for additional lubricants which are not stocked are subject to a technical review by the Material Engineering Group (MEG) to identify the intended use and procurement code. If maintenance finds it necessary to use an NQ lubricant in a safety-related application, MEG must perform a commercial grade dedication of the NQ lubricant.

Item 16: Reevaluate all responses/evaluations to OERs related to lubrication, grease, oil and bearings. The review is complete. Some minor changes to the licensee's response to the OERs are required.

The inspector reviewed the status of the 20 DERs related to the lubrication program. Five of the twenty are closed. Additionally, the inspector determined that the site lubrication engineer was working on two new related DERs, 89-0490 and 89-0647. DER 89-0490 discussed a Toledo Edison Part 21 concern of using Molykote on the valve stem/stem nut area of Velan rising stem valves with motor operators. DER 89-0647 discussed a Namco Controls Part 21 on grease changes for Namco EA740 and EA750 Series Limit Switches.

r. (Open) Unresolved Item (341/88037-09(DRS)) RCIC Valve Testing: RCIC valve tests did not confirm UFSAR performance requirements. The licensee maintains that the section of the UFSAR from which these "Performance Requirements" were taken contains only design requirements for the RCIC valves and that such requirements do not constitute test commitments. The NRC inspector confirmed that the performance requirements were located in the design section of the UFSAR.

The licensee is developing a matrix including all of the RCIC valves on which the Diagnostic Evaluation Team (DET) had commented. In this matrix, each individual valve is listed along with seven columns. The first column identifies the DET concern. The second shows whether the valve has been or will be tested by the Motor Operated Valve Analysis and Test System (MOVATS) employed by Detroit Edison. The MOVATS system provides a record of the motor operated valves'

motor current, stem thrust, limit switch operation and torque switch operation. Records are made in both the open and the closed directions. The third column identifies UFSAR requirements. The fourth lists the type of testing performed on similar valves in the HPCI system. The fifth column lists IST Program requirements for those RCIC valves already in the IST Program and the sixth column identifies current testing performed on the RCIC valves. The final column provides miscellaneous information.

When this matrix is completed (scheduled date: September 1, 1989), it will be included in the resolution of DER 89-0205, which will be submitted to the NRC resident inspector. It will be examined at that time to determine if the proposed testing for each valve will assure that the valve will fulfill its safety function. Meanwhile, the Unresolved Item remains open.

s. (Closed) Unresolved Item (341/88037-10(DRS)) RCIC Turbine Testing: No testing of the RCIC turbine mechanical or electrical overspeed trip functions was apparently being done.

DER 88-0279 documented deficiencies in RCIC turbine maintenance procedures and indicated that no procedures existed for overspeed testing. The NRC inspector examined the licensee's completed preoperational test PRET.E5100.001, Revision 1, and confirmed mechanical overspeed trip of the RCIC turbine to be 5625 rpm +/- 2 percent for three consecutive trips on February 10, 1984. The licensee indicated that the electrical overspeed trip was an option which was not procured for the RCIC turbine, therefore it could not be tested. The inspector reviewed pertinent sections of the UFSAR and confirmed that it referred only to the mechanical overspeed trip. Overspeed trip testing was done in 1984.

The writing of the procedure for overspeed testing is currently scheduled to be completed before the completion of the first refueling outage (tentatively November 20, 1989). There was no violation of nor deviation from the license requirements. This item is closed.

t. (Closed) Unresolved Item (341/88037-11(DRS)) (DET Section 3.4.2.2): The licensee appeared to have no mechanism to systematically identify UFSAR commitments that warranted periodic testing or to ensure the timely development and implementation of such testing. The NRC inspector reviewed a portion of the licensee's Regulatory Action Commitment Tracking System (RACTS) and found that it included UFSAR commitments as interpreted by the licensee's staff. Deviation Event Report (DER) 89-0228, which was written to cover the subject Unresolved Item, indicates that a previous DER (87-172) required a review of all test procedures listed as implementing the testing covered in the UFSAR.

Further refinement of the system will occur as a result of the training program now in effect for system engineers. As part of current training, each system engineer will review testing prescribed for the system for which he is responsible, starting with the UFSAR.

Included in that review will be a determination if any changes should be made in the prescribed testing.

Although evolution of the existing mechanism for identifying UFSAR testing commitments is anticipated, it is fully operational at this time. This item is closed.

u. (Closed) Open Item (341/88037-18(DRS)) (DET Section 3.4.2.2): No Program for Testing Relief Valves That Were Not In The Section XI IST Program: The licensee generated DER No. 89-0221 to deal with this item. This was combined with DER No. 88-0046, in which American Nuclear Insurers requested that such a program be developed. The combined document, identified as DER 88-0046, scheduled the start of implementation of the BOP Relief Valve Testing Program for the first refueling outage and completion of all relief valves within a period of ten years. Detroit Edison Letter 0801.01.21 dated May 24, 1989, identifies 26 valves to be tested during the first outage.

The NRC inspector established that the program for testing relief valves other than in ASME Section XI is now in effect and the inspection period is compatible with the testing schedule for Classes 2 and 3 Pressure Relief Valves as prescribed in Table 2 of ASME/ANSI OM-1987, Part 1, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices." This item is closed.

v. (Closed) Violation (341/85040-11(DRP)): Primary Containment Valve left open. On September 2, 1985, during startup testing, a 3/4 inch Primary Containment Monitoring System (PCMS) test penetration valve was found open with its cap removed. The valve (T50-F071A) was in the open position and uncapped for approximately 60 days. The cause of this violation was not conclusively determined; however, it was determined that several factors contributed to the valve being left open. The valve was installed along with several others to facilitate leak rate testing and the Engineering Design Package (EDP) for the installation did not ensure that affected procedures and drawings were updated to ensure proper valve lineup. The work order to install the valves did not require a leak test following installation nor did it require a sign off that work was completed. Corrective actions taken included immediately closing the valve and installing its cap. All other primary containment penetrations were examined for proper alignment. All procedures were revised to ensure test, vent and drain valves (TVDs) were specified to be closed and capped. In addition, the work order procedure at the time, 12.000.15, was revised to require post maintenance or modification testing and foreman signoff that the work and testing are completed. This procedure and the procedure for EDPs, 12.000.64 (now NPP-CMI-01), were also revised to ensure that drawings and procedures are revised to reflect the modifications prior to the work being accepted for service. An EDP was also issued to paint primary containment TVD caps orange to uniquely identify them.

No violations or deviations were identified.

3. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the period from June 6 to July 16, 1989. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the reactor building and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the following systems to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved and functioning.

- Diesel Fire Pump
- Electric Fire Pump
- Noninterruptible Air System-Divisions I and II
- 130/260 VDC Batteries-Divisions I and II
- High Pressure Coolant Injection

The inspectors also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures. During these reviews the inspector's observations or findings were:

a. During the inspection period the inspector asked what types of as-built controls had been placed on drawings utilized in the Technical Support Center (TSC) and the Emergency Operations Facility (EOF). The licensee responded that drawings associated with those areas were handled under the normal drawing control process. The only drawings that received red-lining were the drawings in the control room. The licensee expressed the same concern as to the merits of maintaining drawings associated with the TSC and EOF in an as-built condition. Also, there were other problems that had been generated as a result of weaknesses in the drawing control program. In a meeting on July 3, 1989, the licensee indicated the existence

a drawing control task force to improve the timeframe it takes an engineering design change to be implemented until the drawing is completely updated. The root cause of the issue with the EOF and TSC drawings is lodged in this turn-around time between implementation of the design change and updating the drawings. The inspector will continue to follow the licensee's progress under the drawing control task force as an Open Item (341/89018-01(DRP)).

b. During the walkdown of the non-interruptible air system the inspector noted that both divisions of the NIAS were color coded orange for the compressor, the dryer, and other major components. In a meeting on July 3, 1989, the inspector requested the licensee review the color code scheme on the two divisions to determine whether it was consistent with plant requirements. Subsequently, the licensee responded in a meeting on July 17, 1989, that there were no requirements for color coding major mechanical components, only electrical divisions. The inspector informed the licensee that with having both divisions of NIAS orange, the electrical color code for Division I, the chance of a wrong train equipment manipulation was increased, especially since both divisions are in the same room. The licensee committed to write a PDC on the condition and evaluate its merits. This matter is considered an Open Item (341/89018-02(DRP)).

c. During the week of June 26, 1989, the inspector noted an outstanding work request on nitrogen cylinders to a mechanical brake on a RHR mechanical draft cooling fan. Inspector follow-up of this matter is considered an unresolved Item (341/89018-03(DRP)) and will be documented in a future special safety inspection report.

d. During the inspection period the inspector noted that one of the drain pot valves off of the HPCI steam supply system was malfunctioning. Further review with the operating authority identified that failure of either or both drain pot valves would not cause the licensee to enter into a Technical Specification limiting condition for operation. The licensee's rationale was based upon the fact that the system would continue to provide sufficient flow at the designated required steam pressures to meet the requisite Technical Specifications. Also, the valves in question were not designated primary containment isolation valves and, as such, their failure did not affect primary containment isolation or integrity.

The inspector further pursued whether any requirements were applicable to the drain pot valves. In the original SER these valves were questioned as to whether they should be taken into account as part of the 4 percent secondary containment bypass leakage limit. However, in a subsequent SER supplement the main HPCI steam supply valves were taken credit for in that any leakage past those valves would be factored into secondary containment bypass leakage. As such, the inspector did not understand fully what the ramifications would be in a small break LOCA condition with the HPCI steam supply valves open. This matter is considered Open (341/89018-04(DRP)) pending additional review by the inspector on the function of these valves and how they interface with bypass leakage to secondary containment in a small break LOCA situation.

e. During the inspection period a RHR service water pump discharge check valve failed its inservice test requirements. Subsequently, the licensee isolated that RHR service water pump and entered into the 30 day Limiting Condition for Operation (LCO) as required by Technical Specification 3.7.1.1. As a result of this condition the inspector inquired as to whether that division of RHR service water was still capable of performing its safety function with one pump out of service. In a meeting on June 12, 1989, the engineering authority informed the inspector that the mechanical stability of the heat exchanger and RHR service water configuration would not be impaired by utilization of one pump. The inspector further inquired as to whether the one pump configuration would meet the necessary LOCA heat load rejection requirements. The engineering authority responded that two pumps were required to meet all the FSAR assumptions. Inclusive in those assumptions were very restrictive tube fouling allowances associated with the efficiency of the heat exchangers. Through review of FSAR figures it was ascertained that with one RHRSW pump out of service in each train, somewhere between three and 30 hours into the post accident scenario, the necessary net positive suction head for all the low head ECCS pumps would be lost rendering those pumps inoperable.

The RHR service water system is a support system for adequate completion of the ECCS function. Loss of a LPCI division is a seven day LCO. Seven days appears to be more consistent than the 30 days of Action 3.7.1.1.a.1. Also, Action 3.7.1.1.a.3 allows one pump in each subsystem of RHRSW to be inoperable for seven days. However, only through the operation of both RHRSW pumps can the safety function be accomplished. Based upon this information the inspector will submit a request for NRC review of the appropriateness of the 30 day LCO associated with LCO Action 3.7.1.1.a.1 and seven days for 3.7.1.1.a.3.

f. During the last week of June the licensee informed the resident inspector that the drain pot for one division of the Non-interruptible Air System (NIAS) was not fully qualified. The ensuing licensee and inspector followup of this situation is considered an Unresolved Item (341/89018-05(DRP)) and will be documented in a future special safety inspection report.

g. During control room panel walkdowns the inspector observed the flow indication for emergency equipment service water (EESW) reading 10% with the pump off. The inspector brought the condition to the control room operator's attention, who placed a control room information system (CRIS) dot on the indicator. During the inspection period a number of minor equipment malfunctions were brought to the attention of control room operators where no CRIS dots had been placed. The inspector discussed this matter with the operating authority so that the matter could be rectified. Later in the inspection period the inspector noted more vigilance on the part of control room personnel in CRIS dot application. The inspectors will continue to observe operator performance in this area.

This EESW flow indication condition has been observed on numerous occasions in the past. The inspector ascertained that the problem is a design deficiency in the flow transmitter reference leg location which drains following pump operation. A potential design change, PDC 9487, has been written to correct the problem. Implementation of the PDC is considered an Open Item (341/89018-06(DRP)).

h. On July 7, 1989, the inspector observed that the licensee had entered into a seven day limiting condition for operation action statement for the diesel fire pump. Following a surveillance run of the diesel, the fuel oil tank level had decreased to less than that allowed by the Technical Specifications. The inspector questioned control room personnel as to why tank level had not been checked following the last run of the diesel prior to the surveillance test and additional oil procured. Personnel responded that maintenance activities had occurred earlier that week and the level was not checked at the end of post maintenance testing. The inspector informed plant management that entrance into this action statement could have been avoided by proactive performance of personnel at the conclusion of the maintenance activities. The licensee agreed and as of the end of the inspection period is contemplating procedural changes to correct the matter.

i. During walkdowns of the control room panels the inspector observed Annunciator 2D96, "Drywell Equipment Sump Leakage High," illuminated. The condition was brought to the attention of the control room operators who responded that this was a normal condition when the sump was in a recirculation mode and not indicative of excessive leakage. The inspector reviewed the Alarm Response Procedure (ARP) for this annunciator and noted that the recirculation condition was not described as a reason for the alarm. This was brought to the operator's attention also. Subsequently, a memorandum was submitted to the operations support group to revise the ARP. Completion of the ARP revision is considered an Open Item (341/89018-07(DRP)).

j. During walkdowns of the control room panels the inspector noted that the recorder scale for Division II hydrogen/oxygen concentration was illegible. By comparison with the Division I scale the inspector determined that hydrogen concentration was indicating 1.3 percent. This is the upper most acceptance limit for the channel check of this instrument. The situation was brought to the attention of the operators who stated that they were aware of the situation and indicated a circuit board replacement was needed to remove the offset. The inspector ascertained that maintenance was scheduled and the offset was eliminated by the end of the inspection period. The scale condition was brought to the operating authority's attention and a new scale was installed by the end of the inspection period.

k. On June 23, 1989, while operators were performing a surveillance on the High Pressure Coolant Injection (HPCI) System, Annunicator 1D61 "SRV Open" was received. Operators immediately verified from observation of safety relief valve (SRV) position indication on the

control room panels that all SRVs remained closed. A check of the SRV tailpipe temperature recorder located in the relay room revealed that K SRV was indicating approximately 220 degrees fahrenheit, the annunciator setpoint. When questioned by the inspector, operators initially indicated that the K SRV tailpipe temperatures normally ran almost at the annunciator setpoint and due to the proximity of the tailpipe to the HPCI piping, sufficient heat was transferred during the HPCI run so the tailpipe temperature eventually reached its setpoint. However, when HPCI was subsequently shutdown, the annunciator did not clear. Additionally during a power reduction on June 24, the annunciator cleared, and subsequently returned during the following power ramp-up. An investigation was then initiated to determine if K SRV was "weeping." The licensee eventually determined that the SRV was experiencing a small amount of leakage which had existed since approximately December 1988. Internally, and with General Electric assistance, the licensee determined that this was a low significance condition; catastrophic valve failure or uncontrolled opening would not result and unit operation could continue. The inspector questioned operations personnel whether longterm trending was performed on parameters such as these. The response was that no longterm trends were done but that the indication was reviewed for short term (step change) trends and that conservatism of the annunciator setpoints, as well as redundant indications in most cases, minimized concerns for such longterm trending. The inspector agreed with the licensee's determination of significance in this case, however, believed that cognizance of potential longterm degradation has benefit. The inspectors will continue to review trends of this type as part of the routine inspection program.

No violations or deviations were identified in this area.

4. Monthly Maintenance Observation (62703)

Station maintenance activities on safety-related systems and components listed below were observed 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 considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were observed:

- WR 006CB90620 RHR Relay Contacts with High Resistance.
- WR 001C890624 Repair Center Station Air Compressor/Install Temporary Compressor.
- WR 001C890710 SGTS Division I Room Cooler Ammeter Flashing.
- WR 015C890612 EDG No. 13 Troubleshoot/Adjust Governor.

Following completion of maintenance on Emergency Diesel Generator No. 13, the inspectors verified that this system had been returned to service properly.

No violations or deviations were identified in this area.

5. Monthly Surveillance Observation (61726)

The inspectors observed the offsite power source verification surveillance test required by Technical Specifications and verified that: testing was performed in accordance with adequate procedures, test instrumentation was calibrated, limiting conditions for operation were met, removal and restoration of the affected components were accomplished, test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors also witnessed portions of the following test activities:

- 24.202.01 HPCI Pump Time Response and Operability Test
- 24.307.15 Emergency Diesel Generator No. 12 - Start and Load Test
- 27.106.04 Control Rod Drive Withdrawal Stall Flow Measurements
- 46.601.01 Racon Model 13000 Microwave Intrusion Detector Calibration

During the performance of 24.202.01, it was noted that E41-F029, HPCI steamline drain pot isolation valve, stroked approximately 40 percent in the closed direction rather than closing completely as required when HPCI was started. The redundant valve (E41-F028) in series with E41-F029 operated correctly. Therefore, the drainline isolation function was maintained. Further, when the system was shutdown, E41-F029 did not stroke open as required to restore the drain path from the drain pot. This is an example of the inspector concern discussed in paragraph 3.d. of this report.

The inspectors performed a records review of completed surveillance tests. The review was to determine that the test was accomplished within the required Technical Specification time interval, procedural steps were

properly initiated, the procedure acceptance criteria were met, independent verifications were accomplished by people other than those performing the test, and the tests were signed in and out of the control room surveillance log book. The surveillance tests reviewed were:

- 24.000.002 Attachment 9 Shiftly, Daily, Weekly and Situation Required Surveillances.
- 64.713.019 Attachment 2 Radiological Effluents Routine Surveillances.
- 74.000.018 Attachment 2 Chemistry Shiftly, 72 Hour and Situation Surveillances.

No violations or deviations were identified in this area.

6. Followup of Events (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. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements and that corrective actions would prevent future recurrence. The specific events were as follows:

- June 8, 1989 - HPCI Level 8 Trip Unit Found Outside Allowable Value During Surveillance - Retracted as a Reportable Occurrence. The licensee evaluated this condition and determined that though the Level 8 trip was degraded, it still would have performed its safety function. The safety function is tripping the HPCI turbine prior to water filling the steam lines. This particular circuit utilizes a two-out-of-two logic. Therefore, failure of one of the level inputs is required to render the trip function inoperable. In this the function was available but incorrectly set. The licensee provided a letter dated June 2, 1989, from General Electric to support their position. The inspector reviewed the licensee's rational and concluded that the situation fell within engineering judgement, barring additional input from AEOD on this matter.

  Within the last quarter this same condition was noted on a RCIC Level 8 trip unit. RCIC utilizes this same logic configuration. The licensee had used the same rationale for not reporting that situation. The inspector expressed concern as to whether there was a generic drift condition being exhibited on the Level 8 transmitters. Of special concern to the inspector was the third Level 8 trip system for the feedwater turbines and main turbine. The Level 8 trip system is the one taken credit for in the accident analysis. The licensee evaluated the calibration data and reported that they could not identify a similar problem with this trip system or any problems with the other Level 8 transmitters.

- June 15, 1989 - Unusual Event Declared. No. 13 Emergency Diesel Generator Inoperable Longer Than the Allowable 72 Hours.

- June 24, 1989 - Trip of RBHVAC and Auto Start of SGTS Division I. This unplanned ESF actuation occurred previously due to the same root cause, inaccessability to the terminal point. LER 87054 designated implementation of EDP 1076, Star Lug Installation (Open Item 341/88026-03(DRP)), as the long term corrective action to the situation. Presently, star lug installation is underway but had not been implemented on this terminal point. This actuation appears to have been avoidable had the long term corrective action had been more timely.

- June 30, 1989 - Failure of numerous sirens during routine testing. The sirens were reported as repaired and retested on July 20th. A full retest of the system was scheduled for July 28th.

- July 7, 1989 - Loss of RPS Bus A Due to EPA Breaker Trip on Over Voltage. The cause was attributed to an erroneous reading voltmeter. An operator noted low voltage as indicated on the voltmeter and adjusted the voltage upward. The voltage increase was enough to actuate the overvoltage trip.

- July 9, 1989 - Station Air Compressor Failure. During the afternoon with two air compressors out of service, another at diminished capacity and a temporary compressor in-service, the temporary compressor failed. The air header pressure dropped to 80 psi causing automatic initiation of the two non-interruptible air system (NIAS) compressors before the diminished capacity compressor could be placed into service. None of the air users exhibited degraded performance and operators dealt with the situation in a controlled and professional manner. Subsequently, the temporary compressor was restored to service. The inspector reviewed whether this situation, automatic initiation of the safety-related air compressors, was reportable as an engineered safety features (ESF) actuation. The inspector concluded that the UFSAR and the SER did not identify NIAS as an engineered safety feature and therefore reporting under 10 CFR 50.72 or 10 CFR 50.73 was not required.

  However, automatic initiation of NIAS does meet the spirit of the reporting requirements. NIAS is a standby power system much akin to the emergency diesel generators (EDGs). The EDGs receive automatic initiation signals on loss/degradation of the incoming nonsafety related power source (voltage) as well as on a LOCA signal. The NIAS compressors also receive automatic initiation signals on loss/degradation of the nonsafety-related power source (air) and on a LOCA signal. Without the NIAS compressors in service during a design basis LOCA, numerous systems necessary to mitigate the accident would not function just as is the case for the EDGs. The inspector requested the licensee to review this situation under the voluntary reporting aspects of the LER system. The inspector suggested the licensee consider reclassification of the NIAS as an ESF. In addition, the inspector will pursue reclassification of the NIAS as an ESF through appropriate internal regulatory avenues.

- July 13, 1989 - Notification to MDNR of Residual Chlorine Discharge to EF-1 Overflow Canal During GSW Chlorination.

- July 14, 1989 - Reactor Power Reduction. At 2200 on July 13, 1989, the No. 2 turbine intercept valve went closed unexpectedly. This event coupled with the power reduction to reduce radiation levels in the area of the failed valve caused feedwater level perturbations. At 0800 operators lowered the level in the reheater seal tank to stabilize the level problem. Stabilization was achieved at 67% power but increased the feedwater temperature to the reactor vessel to in excess of the limit established in Procedure 22.000.02. Later that day the inspector met with operations, General Electric and engineering personnel to discuss the ramifications of the higher feedwater temperature. The licensee explained that the upper temperature limit was for optimum heat balance considerations up until the 100% power temperature limit. The temperature at 67% power was not greater than the 100% power limit. The inspector inquired as to the ramifications on feedwater nozzle qualification, soft seat check valves and any other piping component should this increased feedwater transient should have happened at 100% power. The licensee agreed to review this matter. Review of the licensee's analysis is considered an Open Item (341/89018-08(DRP)).

- July 18, 1989 - Loss of RPS Bus A Due to EPA Breakers Trip on Over Voltage. As of the end of the inspection period the licensee had not determined a root cause of the trip.

- July 18, 1989 - Deceased Person Washed Up on Shore.

No violations or deviations were identified in this area.

7. Licensee Event Report Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with technical specifications.

a. (Closed) LER 85073 and Revision 1, Reactor scram due to instrument valving error. Implementation of the corrective actions to Violation 341/86032-02 during the first refueling outage will resolve instrument valving errors of this nature.

b. (Closed) LER 86033, Reactor scram and ECCS injection during instrument valving evolution. Implementation of the corrective actions to Violation 341/86032-02 during the first refueling outage will resolve instrument valving problems of this nature.

c. (Closed) LER 87010 and Revision 1, Operator requalification training deficiencies.

d. (Closed) LER 87031 Revision 1, False high turbine bearing vibration turbine trip and reactor scram.

e. (Closed) LER 87040 Revision 1, Loss of RPS Bus A on EPA breaker overvoltage trip. The licensee LER investigative activities were never able to establish a root cause for the overvoltage trip. Subsequently, two more breaker trips occurred during this inspection period. Any further followup into EPA overvoltage breaker trips will be documented under these new LERs.

f. (Closed) LER 87044, Failure to verify closed and locked valves as required by Technical Specification 4.6.1.1.b. See the event description and corrective actions taken in response to Violation 341/87038-03, as discussed in Paragraph 2.d above.

g. (Closed) LER 87052, Failure to maintain Primary Containment Integrity on the PCRMS. See the description and corrective actions taken in response to Violation 341/87040.03, Paragraph 2.e above.

h. (Closed) LER 88009 Revision 1, Pressure test failure of safety relief valves.

i. (Closed) LER 89012, Unplanned ESF actuation due to inadequate procedure change. Upon receipt of the LER the inspector reviewed its contents and began interviewing personnel as to the corrective actions taken. The LER indicated that an accountability meeting had been held, additional reviews would be performed on those surveillances being utilized for star lug installation, a lessons learned document developed and required reading on the lessons learned would be completed by July 1989. The inspector verified that the accountability meeting occurred and an additional I&C staff individual was assigned to review the star lug procedure changes in addition to the normal required reviews. However, when interviewing the individual assigned development of the lessons learned document, he stated that the document had not been developed. The inspector contacted licensing personnel informing them of the discrepancy in the LER. In a meeting with licensing personnel on July 10, 1989, the inspector was informed that a communication problem had occurred in preparing the LER and the LER would be revised. Also, plant staff could not support the end of July to complete the required reading and the revised LER would include an end of August date to complete the required reading. At the conclusion of the meeting the inspector stressed the importance of accuracy in the contents of the LER. This same message had been presented to plant management in an earlier meeting on July 10. Verification of completion of the required reading will be performed in follow-up to the LER revision.

j. (Open) LER 89012 Revision 1, Unplanned ESF actuation due to inadequate procedure change. The LER revision was issued to the NRC on July 17, 1989. As stated above, closure is contingent upon future licensee corrective actions.

k. (Closed) LER 89011, Failure of Backup Manual Scram Breaker to Trip. Further review of this reportable event will be performed under Open Item 341/89011-08. Also, the permanent solution to the backup

manual scram breaker is implementation of EDP 10127 at the upcoming refueling outage. Implementation of this EDP is considered an Open Item (341/89018-09(DRP)).

l. (Closed) LER 88036, Failure to Properly Perform Startup Checklist and Daily Plant Surveillances. This event resulted in a violation of Technical Specification requirements 3.8.4.1 and 3.0.4. NRC notice of Violations 341/88030-02 and 341/88030-03 were issued in response to the event. Follow-up of those items is further discussed in Paragraphs 2.o and 2.p of this report. The inspector verified all corrective actions as described in the LER have been completed. This item is closed.

m. (Closed) LER 85060, Revision 1 and Revision 2, Primary Containment Valve Left Open. See event description and corrective action for Violation 85040-11, Paragraph 2.v.

n. (Open) LER 89014, Inadequate Surveillance of Rod Block Monitor (RBM) Bypass Function. On June 7, 1989, while performing surveillance activities, I&C personnel identified that RBM B reference downscale trip setpoint was outside the tolerance of Procedure 44.010.152 and wrote DER 89-0663. On June 8, the inspector reviewed the DER and contacted the I&C supervisor as to the ramifications of the DER. The supervisor indicated that there had been a change to the reference downscale setpoint in the procedure and performance of this test was a part of changing the setpoint to be consistent with calculations/analysis. Since the downscale trip setpoint establishes the lowest power level at which the RBM system begins to enforce, the inspector inquired whether this change was conservative or non-conservative. The supervisor's impression was that the change was conservative but would check again. If non-conservative, the inspector requested the status of RBM A.

No other conversations took place on this matter until June 19, 1989, when the assistant to the plant manager informed the SRI that both channels of the RBM did not begin enforcing at 30 percent power, the Technical Specification required value, but at 31 percent power. The day before, surveillance activities on RBM B had identified the same situation as that on RBM A and DER 89-0709 had been initiated.

Through the next week the licensee explained the history behind how the RBM downscale setpoint had been derived and tested. That explanation is documented in the text of the LER. To summarize the text; the Technical Specification Improvement Program (TSIP) identified the lack of procedural requirements for testing of the downscale trip setpoint, the procedures were inadequately revised to test the setpoint, subsequent TSIP review of the procedure identified the inadequacy, the procedures were revised again, at which time the discrepancies between the procedures and the plant configuration were identified.

The inspector evaluated the violation of Technical Specification 3.1.4.3 which requires an operable RBM when the

thermal power is greater than or equal to 30% of rated thermal power against 10 CFR 2, Appendix C.G.1, "Exercise of Discretion," criteria. The inspector's assessment against the criteria is provided below:

(1) The violation was identified by the licensee.

(2) Operation of the RBM at 30% versus 31% power has minimal safety significance and fits Supplement I.D.1. examples for a Severity Level IV violation as a less significant violation of a Technical Specification Limiting Condition for Operation.

(3) The violation was reported in accordance with 10 CFR 50.73 within the 30 day timeframe and the report was complete.

(4) The corrective actions documented in the LER appear adequate and timely.

(5) Corrective action to a previously identified violation was the mechanism by which this violation was identified.

The inspector concluded that this violation should be considered a licensee identified violation and no notice of violation issued. However, the inspector did note that more aggressive action should have been taken by the licensee following the first RBM DER. The inspector will assure that the corrective actions stated in the LER are appropriately implemented under LER follow-up inspection activities.

No violations or deviations were identified in this area.

8. Allegation Followup

(Closed) Allegation No. RIII-89-A-0090: On June 14, 1989, while in the Fermi resident office, the inspector received a phone call from an alleger. Subsequently, a second phone call was received regarding the same matter. The alleger's concerns can be summarized as follows:

(a) The certified fuel inspectors are not qualified to use the torque wrench for tightening the capscrew of the channel fastener during the channeling of the new fuel.

(b) Since the certified fuel inspectors are members of the QC organization, how can QC perform a truly independent verification of the torque applied during channeling.

The alleger also stated that he had previously informed the licensee of his concerns. The inspector performed a review of the licensee's process for channeling of the new fuel. The torque wrench was supplied by GE Wilmington and, therefore, was not checked out of the licensee's M&TE inventory. The torque wrench (Serial No. W10278 B302, 75 inch-pounds), had a GE No. 47 calibration sticker with a blue background. The inspector reviewed a letter from GE stating that the torque wrench was calibrated at the GE meteorology lab in Wilmington and that the standards used for

the calibration are traceable to the National Bureau of Standards. The calibration due date for the wrench is the 47th fiscal week of 1989 based on the attached sticker. The inspector reviewed licensee Receiving Inspection Report No. 9-727177 dated May 24, 1989, which accepted the torque wrench along with other gauges supplied by GE. The GE torque wrench was used because it is "safer" in that there is no dial indicator and it slips at the required torque value. The licensee performed a vendor fuel fabrication audit, including meteorological aspects, at GE in May 1989. No concerns were identified in the calibration of equipment area during the audit.

All of the certified fuel inspectors are certified as Level I or Level II inspectors by a GE Level III inspector. Use of the torque wrench was included in the training program for the fuel inspectors. The NRC inspector had previously observed portions of the certification training activities and new fuel receipt inspection activities. In both cases the inspector observed close supervision by the GE Level III representative. Additionally, the inspector determined that independent verification is not required for the torquing of the channel fasteners. New fuel receipt inspection and channeling activities are controlled by Procedures NPP-82.000.01, Revision 21 and NPP-82.000.02, Revision 21.

The inspector concluded that the procedures and documentation were appropriate to the circumstances. Training was sufficient to assure that the fuel inspectors have suitable proficiency in using the torque wrench. This allegation was not substantiated and is considered closed.

9. Review of the Diagnostic Evaluation Team (DET) Report

a. A concern was identified in the DET Report regarding OSRO meetings and is summarized as follows:

Approval of changes tended to be silent votes of approval with no dissensions expressed rather than a positive statement or action by individual OSRO members signifying approval of each change discussed and considered at the meeting . . . procedure provided no assurance that OSRO members voting approval of changes had, in fact, reviewed the specific changes prior to voting. This same concern was also documented in QA Audit 88-0037 as Observation 2 . . .

The inspector reviewed QA Audit 89-0125 of the Safety Review and Evaluation Program which closed Audit 88-0037, Observation 2. The audit was conducted in April 1989. The auditors determined that no similar situations were identified where OSRO members conducting reviews were not familiar with the details required for evaluating the event. The inspector determined that Order FIO-FMP-01, Safety Review Group Organizations, Revision 3 (March 1989) requires distribution of documents to be reviewed at a scheduled OSRO meeting five days in advance. The OSRO stenographer confirmed that distribution was being made. The OSRO Chairman now queries each voting member when reviewing a document for OSRO approval. If there are any dissenting votes, the document is not approved. This issued is considered closed.

b. A concern was identified in the DET Report regarding visual observation of valve testing on Page 72, and is summarized as follows:

Valves were not being routinely observed during testing for indication of excessive valve vibration, jerky valve motion, binding, unusual noise, overheating or other erratic problems.

The Executive Director for Operations (EDO) gave the Office of Analysis and Evaluation of Operational Data (AEOD) the task of evaluating this item to assess whether or not there was sufficient evidence to warrant a generic communication extending such visual observation to valve testing at other plants. AEOD recommended that local observation during MOV stroke timing tests should not be required more frequently than already stated in Section XI of the ASME Code. The licensee has committed to continue to conform to this requirement and the NRC inspector confirmed that the licensee had met this commitment in the past. This item is considered closed.

No violations or deviations were identified.

10. Preparation for Refueling (60705)

The inspector observed new fuel receipt and inspection activities during the inspection period. Approximately 10 percent of the 220 bundles received were viewed to ensure proper handling, control and inspection, and that personnel were properly trained to safely and adequately perform their assigned tasks. Associated activities observed included truck inprocessing into the protected area, radiation protection surveying, container offloading, bundle inspection and channeling, and assembly placement in the spent fuel pool. The first shipment arrived onsite June 12, consisting of 24 bundles. Subsequent shipments arrived approximately two per week with the last arriving June 29.

During the inspection of bundle 04-33, a blemish on the clad was identified on rod H-7 between the fourth and fifth spacers. The licensee contacted General Electric for resolution/disposition. Subsequently, GE concurred that the bundle could be used as-is.

While placing bundle LYS 486 (27-54) on the fuel inspection stand, a portion of the top spacer near the outside corner was bent upon contact with the stand's top securing ring. GE recommended replacing the spacer with the work to be done onsite by DECo personnel under the supervision of a GE representative. This necessitated disassembly and reassembly of the bundle. The inspector witnessed the disassembly, spacer replacement and reassembly operations and observed no weaknesses in their conduct. The work was performed in accordance with a Fermi approved Procedure 82.000.17, "Disassembly and Reassembly of Unirradiated Fuel." Tools were supplied by GE and were approved for their application. Further, the GE representative supervising the operation was very knowledgeable of the work to be performed.

11. Regional Requests

On July 6, 1989, regional management requested the inspector provide the Technical Specification limits and any licensee internal limits for reactor coolant leakage. The information was provided to regional management on July 13, 1989.

12. Management Meetings

a. On June 9, 1989, an enforcement conference between DECo and NRC Region III took place. The subject of the conference dealt with the original design inadequacies of the reactor building railcar door airlock as discussed in IR 341/89006. Opening remarks were made by the DRP Deputy Division Director followed by presentations by the SRI and DECo and the conference was concluded by closing remarks from the Deputy Regional Administrator.

At the end of the meeting some additional information was required for the NRC to complete their assessment of the situation. This information included:

- The quantitative results of the secondary containment drawdown tests with deflated seals.
- Postulated radiological results of the deflated seal condition compared to 10 CFR 100 limits.
- Design document reconciliation program schedule and prioritization philosophy for selecting systems.
- Flood test results.

b. On June 27, 1989, a continuation of the June 9th enforcement conference was held in Region III offices between Detroit Edison and NRC Region III.

The meeting began with a recount by the section chief of those areas where the NRC considered additional information from the licensee was necessary. The Senior Vice President of DECo presented the conclusions that no Part 100 limit would be exceeded and the original evaluation on flooding was conservative. The head of the engineering organization provided a chronology of the events reiterating the safety significance conclusion that no Part 100 limit would be exceeded even without secondary containment integrity, using the most current Standard Review Plan guidelines, and that the original analysis was conservative. In addition he provided the difference between the more conservative UFSAR flood height limits and the Corps of Engineers height limits.

The licensee provided a discussion of the design basis document program. During the discussion the licensee stated that there would be an accelerated review of 10 systems. These 10 systems were rated

as having the highest safety significance. The review for these 10 systems is scheduled to be completed by April 1990.

c. On June 29, 1989, a Monthly Management Meeting was conducted in Detroit Edison's Nuclear Operations Center. The topics are stated below along with a short synopsis of what was provided.

Plant Status

The plant was at 100 percent power. Three of the five circulating water pumps were inservice. The other two were out of service due to local vortexing causing impeller and shaft damage. The unit was at power all of June with four LER reportable events occurring. Presently fuel receipt inspection was under way with minimal problems noted with the fuel.

Refueling Preparation Milestones

The licensee presented the milestones with special emphasis on those that had been missed. Originally, the licensee had scheduled all contracts for the refueling outage to be awarded by May 8, 1989. As of the meeting, 10 of the 25 total contracts had been awarded with the remainder to be awarded by July 28. Also, the engineering design effort was to be completed by June 1. Of the original 55 engineering design packages that were to be completed 32 were complete. Eight temporary modifications had been added that will be turned into engineering design packages. Of the 23 remaining to be completed, 15 were scheduled to be completed the following week.

Performance Indicators

The licensee provided a summary of the performance indicators from the second quarter of 1988 through May of 1989. All indicators were generally favorable. The licensee did indicate that the number of reportable events or LERs would increase in the next monthly period. The majority of these events were characterized by the licensee as in the I&C area.

Following the discussion on these LERs the NRC entered into a discussion on LER 89009 as described in the licensee's monthly performance monitoring report. The NRC commented that the information provided under root cause did not describe the root cause. The licensee elaborated upon this matter and the NRC had a better appreciation of the root cause as the licensee understood it.

The licensee commented that, based upon the indicator results, further emphasis needed to be applied to improving the material condition of the plant. To improve the material conditions of the plant the licensee indicated that there were 40 maintenance workers that were presently in training who would be ready for the outage and that this additional manpower would be helpful in improving the condition of the plant. Also, an organization change had taken place in the maintenance department to reduce the number of management levels.

The Senior Resident commented as to whether the licensee had a method of tracking rework in the maintenance area. The licensee responded that they presently do not but after the refueling outage they will be taking steps to initiate such a program. Performance indicators in the material control area were provided. These indicators generally showed improvement in the ability of the warehousing personnel to provide material on request to the maintenance organization.

Lubrication Corrective Action Program

The licensee discussed problems that had been noted in the lubrication area. The licensee indicated that there appeared to be five main areas into which these problems could be categorized.

The first dealt with overgreasing the motors. The cause appeared to be greasing of bearings that were sealed bearings while the machinery was running. The fix was not to grease them with the machinery running.

The second area was mixed grease. It appeared that the major cause of this problem was that the original manufacturer supplied grease was not consistent with the DECo specified grease. Therefore, subsequent corrective maintenance activities may have caused grease mixing. None of the mixed grease situations had resulted in equipment degradation.

The third area was wrong grease. Five instances of wrong grease were noted in rotating machinery. These occurred due to problems in the selection of the appropriate grease tube for the grease gun and the identification deficiencies of the appropriate grease through the Lube Manual/CECO data base system.

The fourth area was no lubrication. Two motor operated valves were identified as having no grease installed. They were subsequently lubricated and their inspection frequency increased to try to identify why there was no lubrication found installed in the valves.

The fifth area dealt with administrative controls (specifically, the utilization of the lubrication manual versus the CECO data base). Originally, the lubrication manual was the document used for lubrication. However, there was a transition to the CECO data base which is a computer generated system. The computer generated system had some interfaces that were not user-friendly for identifying the appropriate grease. In the interim a red-lined lubrication manual was provided to the shift supervisor for his understanding of what is the correct lubrication.

Following the identification of these five areas, the inspector requested the licensee to explain how the CCHVAC fan failure fit into these five main categories. The licensee responded that the fan failure was a potential sixth lubrication problem area.

Detailed Control Room Design Review Human Evaluation Deficiencies

In a letter to the Commission the licensee made a request to extend the time frame in which to complete a number of human evaluation deficiencies (HEDs). The licensee provided a status of the priority 1 and 2 HEDs. In total there are 166 of these items, 96 of which have been resolved. Eight require work at the refueling outage and 62 do not need a refueling outage to complete. Those that require engineering design packages constitute 26, 23 of which have been completed by the engineering personnel and are ready for issuance to the field. The licensee explained that the original task force for these items was still in effect.

Corrective Action Audit Findings

The licensee provided a trend from June of 1988 to present as to the status of delinquent audit findings in excess of 90 days. From the graph it was apparent that the licensee had reduced the number of audit findings greater than 90 days old to one. This reduction from 13 in June of 1988 is commendable. Also, to fully understand the audit findings the licensee stated that there were 11 audit findings whose extensions had been authorized by the Senior Vice President. These 11 findings represent items that required major programmatic or long term corrective actions for completion.

Preventative Maintenance Corrective Action

Presently the mechanical and electrical efforts are in Phase II which encompasses 2700 events, 50 percent of which are complete. This effort will be completed August 1, 1989. With regards to the instrument and control area the Technical Specification instrument review is complete. The review of Q1 and Q1M instruments will be completed in November 1989, and the balance of plant (BOP) instruments will be completed in December 1990. Presently, the licensee is targeting generation of specific procedures for the Q1 and Q1M instruments in 1991. The senior resident inspector inquired as to whether the BOP review and the Q1/Q1M procedure generation could be paralleled. The licensee stated that manpower constraints might limit such actions.

Other Plant Problems

Following the presentation of the preventative maintenance program, the Section Chief requested information on the station air compressor and condensate demineralizer systems at the facility. The Plant Manager responded that one compressor has a blown head gasket and one was operating at 75 percent capacity. Efforts were being made to acquire a backup air compressor and to repair compressors that were out of service. The NRC commented that given the level of preventative maintenance on this equipment, which is fairly high, that a root cause analysis as to why the compressors failed and to determine what program changes need to be accomplished to improve reliability was warranted. With regards to the condensate

demineralizers, presently the demineralizers require change out once every 30 hours versus once every 5 to 6 days. It appears that the filter units are not getting proper back flush to clean the filters. An ultrasonic cleaner has been installed and is being prepared for use to improve the time and service of condensate demineralizers.

d. On July 12, 1989, a meeting was held at the nuclear operations center between NRC Region III and DECo. The subject of the meeting was to share lessons learned from recent refueling outages at other midwest facilities and ascertain DECo progress in preparing for the refueling outage.

13. 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.c and 3.f.

14. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraphs 3.a, 3.b, 3.d, 3.g, 3.i, 6, and 7.k.

15. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on July 27, 1989, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.