U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-341/90005(DRP)

Docket No. 50-341

Operating License No. NPF-43

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

Facility Name: Fermi 2

Inspection At: Fermi Site, Newport, MI

Inspection Conducted: February 16 through March 30, 1990

Inspectors: W. G. Rogers
S. Stasek
M. Farber

Approved By: RW DeFayette
R. W. DeFayette, Chief
Reactor Projects Section 2B

4/26/90
Date

Inspection Summary

Inspection on February 16 to March 30, 1990 (Report No. 50-341/90005(DRP))

Areas Inspected: Action on previous inspection findings; operational safety; maintenance; surveillance; event followup; temporary modifications; LER followup; information notice followup; generic letter followup; regional requests and followup of inaccurate information.

Results: Overall, the licensee continued to exhibit many of the same strengths and weaknesses as documented in the most recent SALP report. On shift operators continue to exhibit appropriate, conservative actions to off-normal conditions. Improvement was noted in the implementation of limiting conditions for operations administrative controls. However, occasional deficiencies in implementation of administrative controls were evident in other aspects of plant operations (temporary change process, procedure adherence, surveillance results review, identification of deficient equipment). The root cause of many of these deficiencies was inattention to detail. The lack of timely, effective resolution to previously identified problems significantly detracted from the implementation of the deficiency identification system. This, coupled with occasional maintenance planning and scheduling deficiencies, reduced safety system availability. Implementation of the temporary modification program continued to be occasionally deficient with a significant contributor to the problem being the excessive length of time many of these temporary modifications have been active. Three violations were identified (Paragraphs 5.a, 5.b and 7.d) and for two of the violations Notices of Violation were not issued. Three open items were identified (Paragraphs 4.g, 6.a and 6.c). NUREG 0737 (TMI Item) II.E.4.2. was closed.

DETAILS

1. Persons Contacted

   a. Detroit Edison Company

   *P. Anthony, Licensing
   # R. Ballis, Supervisor, I&C Engineering
   #@ S. Catola, Vice President, Nuclear Engineering and Services
   # *G. Cranston, General Supervisor, Engineering
   # M. Deora, Nuclear Engineer
   @ R. Eberhardt, Superintendent, Radiation Protection
   @ R. Giaier, Investor Relations
   @ D. Gipson, Plant Manager
   # G. Givens, Nuclear Engineer
   # L. Goodman, Director of Licensing
   *K. Howard, Supervisor, Plant Systems
   # J. Hughes, Senior Engineer, Maintenance
   # A. Kowalczuk, Superintendent, Maintenance and Modifications
   @ J. Lobbia, President
   @ W. McCarthy, Chairman and CEO
   *R. Mckeon, Superintendent, Operations
   # W. Miller, Director, Plant Safety
   @ C. Naegeli, Supervisor, Nuclear Information/Public Affairs
   @ D. Ockerman, Manager, Nuclear Services
   G. Ohlemacher, Principal Engineer, Licensing
   #@ W. Orser, Vice President, Nuclear Operations
   J. Pendergast, Compliance Engineer
   *J. Plona, Operations Engineer
   @*T. Riley, Supervisor, Compliance
   *T. Schehr, Nuclear Shift Supervisor
   *A. Settles, Assistant to the Plant Manager
   B. Sheffel, Nuclear Production, Technical Engineering ISI
   @ B. Siemasz, Compliance Engineering
   *F. Svetkovich, Operations Support Engineer
   #@*B. R. Sylvia, Senior Vice President, Nuclear Operations
   @*R. Stafford, Director, Quality Assurance
   # J. Tibai, Staff Engineer, NSRG
   W. Tucker, Assistant to the Vice President
   *J. Walker, General Supervisor, Plant Engineering
   @ D. Wolf, Community & Government Affairs

   b. U. S. Nuclear Regulatory Commission

   # R. Axelson, Chief, Branch 2, DRP
   # B. Clayton, Chief, Projects Section 1A, DRP
   #@ R. Cooper, Engineering Branch Chief, DRS
   #@ R. DeFayette, Section Chief, DRP
   # M. Farber, Project Engineer, DRP
   #@ E. Greenman, Director, DRP
   #@ L. Paperiello, Deputy Regional Administrator, RIII
   # M. Phillips, Chief, Operational Programs, DRS

#@*W. Rogers, Senior Resident Inspector
@ J. Stang, Project Manager, NRR
@*S. Stasek, Resident Inspector
@ J. Thoma, Project Director, NRR

*Denotes those attending the exit meeting on April 4, 1990.
@Denotes those attending the SALP 11 meeting on March 27, 1990.
#Denotes those attending the monthly management meeting on February 17, 1990
The inspectors also interviewed others of the licensee's staff during this inspection.

2. Action on Previous Inspection Findings)92701)

a. (Open) Open Item (341/89201-05(DRP)): Installation of drywell level indication. Following discussion with production personnel, in January 1990, the licensee issued engineering design package (EDP) 10714, which divided the installation of the drywell level indication into 2 separate packages. The first, revision 0, involved conduit runs for instrument cables to allow production personnel to erect scaffolding and begin cable pulls which made up the majority of the implementation time for the EDP. As a result, on January 31, 1990, revision 0 was issued and scaffolding efforts began on February 24, 1990. Subsequently, revision A was issued to provide all the other installation details. All equipment necessary to complete the EDP arrived by March 4, 1990. However, due to discussions with NRR over the normal position for valve T50-F458 (a new remote manual valve for containment isolation being installed due to the modification) the EDP was not completed by March 31. In a letter dated March 27, 1990, Detroit Edison provided its position as to why the valve should be left normally open versus the NRC staff contention of normally closed. EDP implementation cannot be completed until this matter is resolved.

b. (Open) Open Item (341/89201-09(DRP)): Reinitiation of drywell cooling guidelines. Calculations to determine the guidelines are targeted to be completed by June 15, 1990.

c. (Closed) Open Item (341/89030-03(DRP)): Snubber lockup analysis. The licensee completed evaluation of the ramifications of snubber E11-31540-G13 being in the lockup position. The results of the analysis showed that no maximum code allowable stress would have been exceeded in the design basis condition.

d. (Open) Open Item (341/89018-02(DRP)): Noninterruptible air system color coding. During this inspection, the licensee began painting efforts to eliminate the discrepancy.

e. (Closed) Violation (341/87028-04(DRP)): Not defining "safety-related" on work requests. The inspector performed a random review of equipment identification numbers and determined that the appropriate safety level had been established for equipment used in Technical Specification surveillance activities. In addition, the inspector reviewed the completed product of the Technical Specification improvement program review that identified instruments used in surveillances. Based upon of the results of the review, the inspector considers this matter satisfactorily resolved.

f. (Closed) Open Item (341/86007-02(DRP)): Verification of remote position indication for valves mimicked on the remote shutdown panel. Procedure 24.630.01, "Remote Shutdown Panel Control Circuit Switch Test," designated the appropriate remote position indication verification on an 18 month time interval. This is within the 2 year time frame of the ASME Code, Section XI.

g. (Open) Open Item (341/89008-15(DRP)): Reactor water cleanup enhancement. There were three EDPs and one PDC to be completed to close this item. EDP 7819, "Replacement of Reactor Water Cleanup Heat Exchanger Diaphragm," was completed during refueling outage 01. One of the other EDPs, EDP 4885, "Relocation of Reactor Water Cleanup Blowdown Flow Control Valve Downstream of the Blowdown Flow Element," is scheduled for implementation during refueling outage 02. The design package target date for completion is June 30, 1990. The status of the other EDP and PDC will be provided in a future inspection.

h. (Closed) Open Item (341/89020-01(DRS)): The licensee indicated that additional review of the installation of plant watertight seals, pursuant to Information Notice 88-60, would be performed from the standpoint of assuring that fire fighting waterhose streams will not cause loss of required safe shutdown trains when these trains are separated by wall and floor assemblies. This issue had been identified by the Nuclear Engineering Department in Deviation Event Report 89-1012. The engineering review indicated the following:

   1. The NRC Safe Shutdown Report Supplement No. 5 found acceptable several fire zone boundaries with open stairways; hatches, pipes, etc. These zone boundaries do not utilize fire rated penetration seals or water tight seals exclusively and the fire hazard analyses indicated safe shutdown could be maintained.

   2. The remaining fire rated barriers do, however, use fire rated seals. The fire hazards analysis for each rea/zone, bounded by barriers, identified how post-fire safe shu down was achieved, assuming a fire, and the fire fighting capabilities including hoses in the area.

      a. The testing requirements for several of the fire rated wall and floor penetration seals included consideration of water passage/water tightness.

      b. The fire rated seal designs not indicated as acceptable for water tightness were reviewed. Considering plant configuration, specific to each design and other favorable features, the design was found to provide reasonable assurance of withholding water passage due to fire fighting activities.

i. (Open) Open Item (341/89008-16(DRP)): SRV improvement. In a recent BWR Owners Group Meeting on SRV performance, the Owners Group retracted the recommendation for installation of the PH13-8MO steel for the seat. Presently, there are no new recommendations as to what materials to use. However, the PH13-8MO appears to actually increase the potential for leakage. The inspector will continue to follow licensee activities in this area, especially plans for removal of the PH13-8MO material from the present valves.

j. (Closed) Open Item (341/88026-03(DRP)): Starlug installation controls. Procedure NPP-46.000.199, "Starlug Installation and Removal," was issued by the licensee to control starlug installation and removal. In addition, the administrative procedure controlling procedure changes is being revised to assure that starlug installation and removal is considered when procedures are changed.

k. (Closed) Open Item (341/89021-03(DRP)): Operation of the Torus Water Management System (TWMS). To eliminate lifting of the TWMS discharge relief valve, procedure NPP-23.144, "Torus Water Management System" was revised to incorporate a time delay after startup of the first pump before initiating a start on the second pump.

l. (Closed) Open Item (341/89200-02(DRP)): Revise subject setpoint calculations to include appropriate temperature inputs to reflect actual drywell temperatures during normal operations. The licensee revised Design Calculations DC-4522, "Reactor Dome Pressure;" DC-4523, "Wide Range Level Indication;" DC-4528, "Narrow Range Level Indication;" DC-4556, "Remote Shutdown-Reactor Pressure;" DC-4573, "Alternate Shutdown-Reactor Pressure;" and DC-4579, "Accident Monitoring-Reactor Pressure."

m. (Closed) Unresolved Item (341/89034-01(DRP)): Debris found in inlet valve to Standby Gas Treatment System. The licensee determined that cloth strips were placed during the depressurization phase of the Integrated Leakrate Test (ILRT). Procedure NPP-43.401.100, "Integrated Leak Rate Test-Type A-General," was revised to delineate placement of the strips as well as their removal. Additionally, an independent verification of the removal of the cloth strips was included.

n. (Open) Violation (341/89030-02(DRP)): Inadequate independent verification. The inspector completed review of the licensee's written response dated February 1, 1990 and initially found the response acceptable. However, upon further review of corrective actions to determine conformance with the written response, the inspector found two areas of concern. Although the licensee committed to reassign responsibility for independent verification of field hardware to operations and maintenance personnel only, no formalized means to ensure this would be properly implemented was initiated. This was communicated to the licensee's supervisor of compliance who indicated actions would be taken to address the matter.

The second area involved the dissemination of the associated critique. The licensee committed to include the critique in the required reading for operations, maintenance and the technical staff. However, on reviewing the required reading forms, a number of personnel had not signed the specified blocks documenting their review of the critique. The inspector questioned the process that ensured these persons eventually read the critique. This item will remain open pending further inspector review.

o. (Open) Open Item (341/89008-11(DRP)): Potential improvements to the turbine to harden against single failure. The licensee evaluated a number of turbine trip initiations under DER 89-0685 and determined that no actions would be cost effective. However, there is one area still under review which deals with the turbine thrust bearing trip (which is presently defeated) and involves utilizing two diverse signals to cause the trip function. That particular aspect is being evaluated under DER 89-1458 and final decision on any actions is not scheduled until August 1, 1990. This matter will remain open until the licensee makes that decision in DER 89-1458.

p. (Closed) Open Item (341/89009-01(DRSS)): Split sample analysis. In a letter, dated March 20, 1990, the NRC provided the licensee with the comparison results of the sampling program. Only a conservative disagreement on Fe-55 was noted. This matter is considered closed.

q. (Closed) Open Item (341/88037-16(DRP)): DER Program. During the inspection period, the licensee integrated the tracking and trending programs for the DER system into one program. There will be approximately a 6 month timeframe for the two systems to be run in parallel to assure that everything is running properly. In addition, the licensee is revising the appropriate administrative procedures to allow the combining of DERs that have a common root cause with appropriate management controls in place.

r. (Open) Unresolved Item (341/88003-02(DRP)): Residual Heat Removal Service Water valves inservice test requirements. The inspector reviewed the licensee's evaluation as to why thermal relief valves, E1156F056A and E1156F056B, should not be in the Inservice Test Program and has no further questions regarding these valves. With regards to discharge valves E1156F068A and E1156F068B, the licensee changed the appropriate surveillance procedures to verify that the valves open and close within expected timeframes and have drafted changes to the Inservice Test Program procedure to include valve opening as an inservice test requirement. The inspector discussed why valve closure was not incorporated into the Inservice Test Program procedure submittal. The licensee indicated that this was an omission and would be corrected prior to issuance of the inservice test program procedure revision scheduled for no later than May 13, 1990. Closure of this item is contingent upon issuance of the Inservice Test Program procedure submittal.

s. (Open) Open Item (341/89201-07(DRP)): Simulator Upgrade. The licensee's present schedule is to complete modeling for the new simulator upgrade by August 17, 1990, merge the new modeling into the simulator by November 1, 1990, and to complete testing of the new upgraded simulator by March 26, 1991.

t. (Open) Open Item (341/89201-08(DRP)): Containment Venting. Final resolution of this matter will be installation of the hardened vent presently scheduled for the third refueling outage.

u. (Open) Open Item (341/89201-01(DRP)): Emergency Operating Procedure Flow Charting. Presently, the licensee is evaluating other plant flow charts to determine optimum format. If the licensee decides to adopt flow charting, the writing and validation of such is scheduled to be completed by August 30, 1990.

v. (Open) Unresolved Item (341/88035-01(DRP)): Deficiencies identified with temporary modifications. This item is further discussed in paragraph 7 of this report.

w. (Closed) Open Item (341/89029-02(DRSS)): Splitting a reactor coolant sample spiked with fluoride, chloride, and sulfide with Brookhaven National Laboratory (BNL). The contract between the NRC and BNL has been terminated and there is no contractor laboratory performing non-radiological chemistry analysis for the NRC. This item is considered closed.

x. (Closed) Open Item (341/89030-07(DRP)): Potential Part 21 Update on Brown Bovari Breakers. The licensee performed an evaluation and determined that the breaker problem was not reportable under 10 CFR Part 21. Information Notice 89-86 updated the industry on this issue. The inspector has no further questions on this matter.

y. (Closed) Violation (341/89011-06(DRP)): Inadequate Fire Watch Qualification Training. The inspector completed a review of the licensee's response to the violation and noted that the fire watch training material was revised to include the plant's applicable Technical Specification requirements. Plant personnel were trained using the new material. The inspector has no further questions in this matter.

z. (Closed) Open Item (341/89011-09(DRP)): Guidelines for Electricians Working on Energized Equipment. These guidelines were a training commitment in LER 87040 which discussed a reactor protection system motor-generator trip caused by electrical testing. The licensee developed course EM-171, "Electrical Safety Awareness," with a final approval date of October 16, 1989. The course was added to the electrical training curriculum on October 17, 1989 and implemented in January 1990 as part of both the initial and continuing training programs. The inspector has no further questions in this matter.

aa. (Open) Open Item (341/89011-07(DRP)): Lubrication Program Review. The inspector reviewed progress on the Plant Manager's Action Plan for improving the lubrication program and noted that of the original 18 items only one was not completed: an evaluation of differences between lubrication frequencies identified in the Preventive Maintenance Program and those in the vendor manuals. A responsible individual has been identified and that effort is in progress for safety-related components. The inspector also reviewed a proposed revision to NPP-35.000.217, "Maintenance Lubrication," and noted that it is more comprehensive than the existing procedure and provides guidelines for relubrication frequency and lubrication of double shielded bearings, addresses mixing of lubricants, and provides improved instructions for lubrication techniques. This procedure is in the final stages of review and approval and is expected to be implemented in the near future. The inspector will continue to monitor this effort through completion of the Plant Manager's Action Plan and its associated Deviation Event Report, 89-0529.

bb. (Closed) Deficiency (89-200-04): Inadequate process for specifying relay coil voltage requirements. This deficiency addressed the failure to specify relay coil voltage ratings based on anticipated maximum and minimum system voltages in the intended application. The licensee performed an evaluation on the voltage boundaries for AC and DC electrical and control components previously designed and procured. This evaluation verified that existing relay installations at Fermi are adequate for the voltage boundary conditions in their respective applications. The licensee had also revised the design verification procedure (FIP-CMI-13) and procurement procedure (MMP-PMI-OI) to ensure that voltage boundaries are explicitly addressed for relays in the design and procurement stages. Based on these actions, this deficiency is considered closed.

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 February 16 to March 30, 1990. 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, residual heat removal complex 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, functioning, and calibrated.

- Standby Liquid Control System
- Core Spray System - Division II
- Noninterruptible Air System - Portion of Division I
- Standby Gas Treatment System - Division II
- Emergency Diesel Generator No. 14
- High Pressure Coolant Injection System

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.

The significant observations and reviews were:

a. The inspector reviewed the non-licensed operator shift schedule and noted that there were periods when operators worked seven successive days without a day off. The inspector questioned whether this shift rotation was in accordance with the Technical Specification requirements and related those concerns to the NRR project manager. Subsequently, NRR verbally informed the inspector that the shift rotation was in accordance with Technical Specifications. All questions on this matter have been answered.

b. During control room walkdowns the inspectors noted discrepancies with the implementation of the control room information system (CRIS). These discrepancies included: 1) Not posting a CRIS dot on improperly functioning damper T41-F173, improperly indicating feedwater check valves, and improperly indicating emergency equipment service water flow; 2) Not clearing CRIS dots on the hydrogen/oxygen monitor and the containment water level recorder once the problem was resolved; and 3) Not properly annotating that the oxygen/oxygen monitor dot was against the monitor in the CRIS log. The root cause of the administrative control errors were twofold:

   . There was a lack of attention to detail by licensed (CRNSO, NASS, NSS) onshift staff in implementing the established program.

   . There was a lack of effective, timely resolution by maintenance and technical support personnel to long standing equipment deficiencies. This has contributed to onshift staff personnel living with deficiencies and considering them the normal condition.

c. Appropriate onshift performance was noted in the handling of Limiting Conditions for Operation (LCO) and in handling the administrative controls of the LCO logbook.

One question did arise following the division I residual heat removal (RHR) maintenance outage in February. The outage required the piping to be drained down rendering both RHR pumps inoperable. The applicable RHR Technical Specification was entered but the less limiting thermal recombiner LCO was not. The inspector inquired of the operating authority as to whether the thermal recombiner LCO had been considered. The operating authority consulted the engineering authority and stated that the thermal recombiner LCO was not applicable. The inspector was pursuing the engineering authority's rationale at the conclusion of the inspection period and the results of this additional followup will be documented in the next routine inspection report, (341/90007(DRP)).

d. Licensed operators appropriately handled off-normal events.

One example was the March 7, 1990 power increase to 102.5 percent for approximately 100 seconds. The cause of the power increase was an inadvertent pushing of the master recirculation flow control pushbutton by an operator while performing routine recorder checks. Power was immediately reduced upon recognition of the problem and there was no indication of any fuel failure as a result of the power transient. DER 90-184 was written to document this particular action and determine appropriate corrective action to this problem.

Another example was the March 22, 1990 emergency diesel generator No. 14 fire more fully discussed in paragraph 6.

e. On March 2, the inspector noted that Technical Specification Amendment 51 had been incorporated into the control room books the previous day. Further review of the amendment determined that a change in the Ultimate Heat Sink surveillance requirements was included and the inspector then asked the operating shift which procedure(s) implemented the new requirement. The licensee subsequently determined that no procedure changes had been made to implement the change. Later that day, the inadequacy was corrected. This item will be further reviewed as part of the Technical Specification Improvement Program evaluation.

f. On March 13, 1990, the licensee informed the resident inspector that two snubbers were found inoperable when performing the required visual snubber inspection during refueling outage (RF) 01. The two snubbers appeared to have been slightly corroded due to water leakage. To prevent further damage, watertight boots were installed on the snubbers. However, Technical Specification surveillance requirement 4.7.5(c) discusses the need to find the cause of the visual inspection rejection, remedy the problem and functionally test the affected snubber in the as-found condition. When all of these conditions were met, then the snubber could be considered operable. In lieu of meeting these conditions, a snubber would have to be considered inoperable and an increased inspection period enacted for that snubber. For two inoperable snubbers Technical Specification requires a subsequent visual inspection within 4 1/2 to 7 1/2 months. The inspector indicated to the licensee, that in lieu of a change to the Technical Specifications, that the inspection would be required. The licensee indicated that a Technical Specifications change request would be submitted to change wording to eliminate the subsequent as-found test if the cause of the visual inspection failure was remedied.

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 is assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were observed:

- PM D928891127 General Maintenance Inspection of SBFW valve N21-F002
- WR 007C890914 Install Level Gauges on SGTS Division II Cardox Tank
- WR 001D900118 Balance of SGTS Division II Exhaust Blower
- PM Y581890922 Perform Testing on Control and Power Circuits for SGTS Heaters
- WR 003C890612 Overhaul Actuator X4103F134
- WR 004C891201 EDG 12 Switchgear Room Exhaust Damper Actuator

Following completion of maintenance on the SBFW valve and the SGTS exhaust blower, the inspectors verified that the associated systems were returned to service properly.

Significant observations were:

a. Regarding WR 007C890914, upon completion of work on the cardox tank, Deficiency Notice Tag (DNT) 011B060888 dated June 8, 1988 remained on tank isolation valve T46-F020B indicating a packing leak existed. This led the inspector to question the licensee as to why the valve had not been repaired while the tank was drained for installation of a new level gauge . Review by the licensee determined that the packing leak had been repaired on September 1, 1988. The licensee indicated that the tag would be removed.

b. During the standby gas treatment system outage, on March 13, 1990, a number of scheduling deficiencies and poor work practices were noted. The licensee initiated a critique on poor system outage performance. A number of the corrective actions appear appropriate to deal with the specific problems, and some broader corrective actions were recommended to address the planning and scheduling interface problems. The inspector will continue to review outage performance for continued improvements and determine whether any improvements are achieved in this area. Some of the problems were:

   1. The initial attempt to balance the SGTS exhaust blower resulted in a substantial increase in vibration during the interim test run on the fan. Subsequent balance attempts were better and fan vibration was reduced. However, the need to weld the balance weights directly on the fan blading was not foreseen prior to start of the work. The potential damage to the blading, that could occur with in situ welding, resulted in a decision to remove the weights just placed and to reschedule the welding to the next system outage when the fan could be removed from its housing.

      During the subsequent surveillance run on the system, the setscrews holding the fan shaft in place backed out sufficiently to allow the fan to shift and come in contact with the housing. The operators immediately shut down the system and an inspection of the fan was performed. No significant damage was found, the shaft was realigned, the setscrews were "staked," and the surveillance run restarted. No further problems were noted and the system was declared operable.

   2. Regarding PM Y581890922, the inspector noted that although the work package necessitated opening SGTS charcoal adsorber access hatches, no verification was required to ensure the hatches were properly closed and latched at the completion of the maintenance activity (as is required during other manipulations of the hatches). This concern was communicated to the Nuclear Shift Supervisor who indicated he would perform a review of the return-to-service requirements for that maintenance item. Subsequently, the work package was modified to include a verification that the hatches were properly closed and latched.

c. Previously, on January 4, 1990, the Standby Gas Treatment System (SGTS) exhaust fan on division I failed in a surveillance test. The failure was attributed to the set screw on the bearing cap backing out and allowing the shaft to move causing damage to the bearing and the shaft. When this matter was discussed with the resident staff, maintenance supervision stated that the other set screws on the companion division would be checked and assured tight.

   Subsequently, the division II SGTS fan failed as discussed in 4.b.1. above. Subsequent determination by the licensee was that the set screws on the companion fan had not been checked for tightness and that a communication failure between the general supervisor of mechanical maintenance and a foreman in mechanical maintenance had taken place. The general supervisor was under the mistaken impression that this check of the division 2 SGTS fan had taken place. The individuals involved were counseled as to their responsibilities in assuring that appropriate corrective actions are taken.

d. Regarding W.R. D928891127, the inspector observed that the tagout for the standby feedwater system was poor in that the pump motor was designated for tag out last after all the valves were tagged including closure of the discharge and suction valves.

e. During an EDG outage at the end of the inspection period two packages were cancelled due to a failure to stage the appropriate tools. Due to the length of time the diesel had been taken out of service, the Technical Specification required diesel generators testing had to be initiated.

f. The resident staff witnessed the 50 percent downpower performed over the weekend of March 30, 1990 and noted that appropriate planning, scheduling and work sequencing occurred during the downpower.

g. While reviewing the licensee's four week maintenance schedule, the inspector noted that annual preventative maintenance had been scheduled on the diesel fire pump for March 22, 1990. A review of the preventative maintenance task versus the Technical Specification 18 month preventative maintenance activities, revealed minimal differences in the two activities. The inspector brought to the licensee's attention surveillance requirement 4.7.7.1.2.c., which requires that the diesel fire pump be subjected to an inspection, in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service of the diesel fire pump, at least once per 18 months during shutdown. The inspector noted that performance of preventative maintenance, while the unit was in operation, was in conflict with this Technical Specification surveillance requirement. This matter had been previously reviewed by fire protection inspectors in the summer of 1989 at which time the licensee keyed the 18 month surveillance in the surveillance tracking program to cold shutdown. However, the preventative maintenance program, which is separate from the surveillance tracking program, had this other similar inspection that was not keyed to cold shutdown. Subsequently, the licensee deferred preventative maintenance activities on the diesel fire pump. However, it was apparent that there was corrective maintenance necessary to be performed on the diesel fire pump at which time the licensee discussed whether this could be done at power. The inspector stated that the requirement for maintenance in cold shutdown was exclusive to preventative maintenance activities, and pointed out that the loss of the diesel fire pump eliminated black start capability for the fire suppression system. The operating authority acknowledged this condition and stated that prudence dictated black start capability through diesel power to a general service water pump or a pumper unit. The inspector noted these prudent actions under consideration by the licensee. Furthermore, the inspector noted that the 18 month surveillance on the diesel fire pump would come due in the September/October 1990 timeframe. In lieu of any changes to the requirements, the licensee will be forced to declare the diesel fire pump inoperable. Also, the inspector noted that the preventative maintenance specified by the manufacturer was contingent upon the diesel continuously in service in lieu of standby a significant period of time. These preventative maintenance manufacturer's recommendations do not appear to be consistent with actual uses of the equipment. This matter was not identified during the general physics review of preventative maintenance duties, but was identified by the Detroit Edison preventative maintenance staff. Presently, the licensee is in dialog with Cummings Diesel Company to establish an appropriate preventative maintenance program for the length of service of the diesel fire pumps. Delineation of the appropriate preventative maintenance program of the diesel fire pump is considered an open item (341/89005-01(DRP)).

h. During review of the LCO logbook and abnormal lineup sheets the inspector determined that approximately 20 work requests were outstanding on RHR complex dampers. Operability of Residual Heat Removal (RHR) Complex ventilation damper actuators has been a persistent problem for which previous licensee corrective actions have not been effective. These dampers are fitted with ITT Hydramotor actuators and repeated failures have been evidenced by actuator shaft binding, leakage at the seals, and shaft and bushing scoring. The licensee's most recent program to resolve this problem consists of two parts: an overhaul of all damper actuators under the guidance of a vendor representative and an evaluation of installation and setup procedures for these actuators. The evaluation of the installation and setup procedures has revealed that in some cases linkages were being installed backwards due to misunderstanding of the configuration on the part of the mechanics. The evaluation also revealed that the actuator setup for closing the dampers was closing the damper too tightly, causing excessive blade to blade pressure, and putting a sideways moment on the actuator shafts. This moment was felt to be a contributor to the damage noted above. During this inspection period the licensee staff was reinstalling actuators and returning the dampers to operable status. At the close of the inspection four dampers were awaiting reinstallation pending schedule restraints. The continued operability of these dampers will be monitored by the inspectors to assess the effectiveness of this corrective action program.

No violations or deviations were identified in this area.

5. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications during the inspection period 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.

a. The inspectors witnessed the following test activities:

- 24.208.003 Division II EESW Pump and Valve Operability Test
- 24.307.014 EDG No. 11 - Start and Load Test
- 24.307.016 EDG No. 13 - Start and Load Test
- 24.404.004 Division II SGTS Filter and Secondary Containment Isolation Damper Operability Test
- 27.112.003 Turbine Generator Mechanical Overspeed on Load Test
- 54.000.003 Control Rod Scram Insert Time Test
- 24.307.017 Emergency Diesel Generator No. 14 - Start and Load Test

Significant observations were:

1) During performance of 24.307.014 the inspector noted the following:

a) The operator failed to perform the verification at the end of step 5.2.40 (that the Emergency Diesel Generator [EDG] was isolated from the autostart logic and from the air start supply) prior to manually barring the engine over as required by the procedure.

b) Procedure steps 5.2.40.1 through 5.2.40.9 were not performed in sequential order. When the operator performing the surveillance was questioned as to the reason, he indicated that the subject steps were only checkoff items and could be done in any common sense order. Since he was to initial on the line only following completion of all nine steps, he stated administratively, there was no requirement for completing the steps in order. However, a review of the subject steps revealed that certain steps had to be performed in order, i.e., the air receiver outlet valves isolated before opening the cylinder bleed valves.

Since many procedures include this type of checkoff step, a sample of licensed operators (both RO and SRO) were questioned as to the requirements of performing checkoff steps sequentially. Some operators indicated that all steps in a surveillance were to be done in sequence with no exceptions. Other operators felt that multiple checkoff steps could be performed either concurrently or out of order.

With operators inconsistently interpreting what was allowed, the inspector approached operations department management on this matter. Management indicated that they expected procedure checkoffs, such as this to be followed as written with the Nuclear Shift Supervisor authorizing any deviation.

The inspector was not able to determine a root cause for this inconsistency in operating philosophy. It was unclear if this was a training inadequacy, a miscommunication of management expectations to the shift crews, or a problem with the subject procedures.

A Deviation Event Report (No. 90-0174) was initiated as a result of performing the checkoff steps out of sequence.

c) The operator did not initially verify two control room annunciators as required by step 5.2.40.2. When subsequently questioned by the inspector, the operator admitted not doing the verification although the step had been checked as complete. He indicated that the skipped step had been an oversight on his part and that he would check the sequence recorder at test completion to verify the appropriate annunciators had come in as required.

Licensee followup actions included: counselling the operator on management expectations on procedure adherence; issuing a memorandum in the night orders to all shift crews describing the event and again reiterating the requirement to adhere to procedures; and developing more intensive administrative controls training by the operating authority/training organization. The pilot initiative will be with LCO and abnormal lineups. Feedback as to the effectiveness of the sessions will include QA observations of administrative controls implementation. Completion of the effectiveness review will be accomplished in approximately 90 days and if successful, procedure compliance will be an area included in the training.

The above observations are considered a violation of administrative procedure NPP-PR1-01, "Nuclear Production Technical Procedures," (341/90005-02(DRP)). However, inspector review has determined that a notice of violation is not warranted because this meets the criteria of 10 CFR 2, Appendix C, Part V.A.

2) On March 1, 1990, while performing turbine generator mechanical overspeed onload test 27.112.03, the control room operator selected the wrong pushbutton during the performance of the test. The test was suspended at that point and operations supervisory personnel directed appropriate reviews to determine the corrective action necessary to prevent the turbine from tripping. A recovery plan was initiated, developed, and implemented to appropriately reset the test logic. These actions were successful and properly controlled.

b. The inspectors performed a record 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:

- 24.138.006 Jet Pump Operability Test
- 24.404.003 Standby Gas Treatment System Valve Operability Test
- 24.413.001 Division I and II Control Center Chilled Water Pump and Valve Operability Test
- 27.000.002 Attachments 1 & 2, Shiftly, Daily, Weekly, and Situation Required Performance Evaluations
- 42.302.001 Functional Test of 4160 Volt Emergency Bus Division I Undervoltage Circuits
- 44.010.025 RPS and NSSSS - Main Steam Line Radiation, Division I, Channel A1/A, Functional Test
- 44.010.027 RPS and NSSSS - Main Steam Line Radiation, Division I, Channel A2/C, Functional Test
- 44.030.263 ECCS-Reactor Vessel Water Level (ADS Level 3 and Feedwater/Main Turbine Level 8), Division I, Channel A Functional Test
- 54.000.007 Core Performance Parameter Check
- 64.713.019 Radiological Effluents Routine Surveillances

Regarding 24.138.06, the licensed operator performing the surveillance mistakenly converted the jet pump differential pressures to decimal equivalent (i.e., divided each by 100). This resulted in the graph, used to verify the allowable values, being plotted incorrectly. Subsequently, two Shift Technical Advisors (STAs), and a Nuclear Assistant Shift Supervisor (NASS) reviewed the completed surveillance but failed to identify the error. The Nuclear Shift Supervisor (NSS) did not review the completed surveillance; however, the surveillance was signed off as satisfactory. No other reviews were scheduled from this point nor required by the licensee's administrative program. The inspector, during the next shift, reviewed the completed procedure and questioned why jet pump differential pressures were all nearly identical. At this point, the NSS that currently was onshift also reviewed it and agreed that the graph had been plotted incorrectly.

Licensee followup actions included counselling of the involved individuals, preparation of a formal critique (90-006), inclusion of the critique into operator required reading, issuance of a memorandum by the lead reactor engineer to all STAs addressing the need for an increase in attention to detail in this area, and the initiation of actions to develop a training program concerning consistency in using and applying administrative controls and procedures.

This matter is considered a violation of the requirements of administrative procedure NPP-CT1-01, "Surveillance/Performance Package Control," (341/90005-03(DRP)). However, inspector review has determined that a notice of violation is not warranted because this meets the criteria of 10 CFR 2, Appendix C, Part V.A.

No other violations or deviations were identified in this area.

6. <u>Followup of Events</u> (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 are as follows:

a. Secondary Containment/SGTS Damper Failures F010 & F407: In previous inspection periods, the inspector questioned the operating staff as to why damper T41F010 exhibited unusual stroking characteristics in the open direction. The operating staff stated that it did stroke erratically open, but closed within the required Technical Specification timeframe since the safety-related function is only in the closed direction. The damper was placed on accelerated stroke time testing and failed the close stroke time criteria during this inspection period. Based upon this failure, the inspector inquired as to whether any dampers exhibited this same erratic stroke time and, if so, what actions the licensee was taking to assure that they were repaired prior to their failure. Subsequently, the licensee reviewed stroke time damper data and determined that damper T46F407 also exhibited erratic stroke times. The inspector reviewed the stroke time data for this particular damper and noted increased stroke times since December 1989. The licensee indicated that this valve would be repaired during the standby gas treatment outage of March 13, 1990. However, a work request was not written on T46F407 until the inspector inquired of damper problems after the T41F010 failure and, due to work package preparation constraints, this damper was not incorporated into the standby gas treatment outage. The week afterwards the damper was troubleshot and the actuator shaft deburred improving stroke time performance.

The failure analysis of the original damper, T41F010, preliminarily indicated a material failure of the actuator spring. However, the final root cause of the failure had yet to be ascertained and would be completed by April 6, 1990. The failure mechanism for these damper actuators and the corrective action taken is considered an open item (341/89005-04(DRP)).

b. HPCI Test Valve Failure: On February 17, 1990, the HPCI test line isolation valve to the Condensate Storage Tank (CST) E4150F008 failed during HPCI testing. DER 90-0140 was initiated by the licensee on this valve failure. Subsequent review by the licensee determined that the closed torque switch setting was inappropriate and allowed the motor to operate at stalled conditions. In the last motor operated valve diagnostic testing (MOVATS), in the spring of 1988, this high amperage condition was observed and documented. Subsequently, the torque switch setting was lowered to 2.5 versus the vendor recommendation of 2.75. After setting to 2.5, the engineer who reviewed the MOVATS status, dispositioned the lower torque switch setting by referencing the vendor recommended setting of 2.75 and directed that the torque switch setting be returned to 2.75 when possible. Field data was not appropriately utilized in this torque MOVATS disposition. In November of 1989, a letter from the engineering organization was issued to the maintenance organization stating that when the torque switch setting was changed to 2.75 no MOVATS testing would be necessary. This was based on the original MOVATS testing in 1988. The rational, utilized in the letter, was inadequate in that the engineer did not adequately review the MOVATS data to assure that it was appropriate to have a setting of 2.75. On February 14, 1990, the torque switch was changed to 2.75 and subsequently, during HPCI testing, the valve motor burned up due to operation in the stalled condition. A number of areas of weakness were identified as a result of the valve failure. There were:

- Two instances of inadequate engineering directions to the maintenance organization to reset the torque switch to 2.75. First, the original disposition, in 1988, of the MOVATS data and, secondly, the information utilized to generate the letter in November of 1989.

- There were no operating restrictions on this valve. This is the direct current valve and repeated operation of the valve causes overheating. Since the valve is used as a throttle to establish the appropriate flow for HPCI surveillance testing there is only a short number of duty cycles, operation for five minutes within a one hour period, that can be placed on the valve. This limitation was never procedurally incorporated.

Corrective actions to this situation, include: reviewing the other DC valve in the companion RCIC system to assure that the torque switch setting is correct; implementing a revision to the surveillance procedures associated with RCIC and HPCI to establish a duty cycle limitation; implementing a revision to Procedure 47.306.01, "Signature Analysis for Motor Operated Valves," to be included in the technical check sheet verification that setting current is satisfactory within 90 days; and reviewing all MOVATS test results to assure the same inadequate technical disposition of MOVATS test results had not occurred within 60 days. Given the corrective action established by the licensee in this area, the inspector considers the corrective action adequate to deal with the problem.

This event clearly reflected the necessity to use field data to establish torque switch settings in lieu of vendor recommended calculational torque switch settings.

c. RHR Suction Line Failure Analysis: During startup activities from the first refueling outage, the licensee ran the HPCI system and the associated RHR divisions for HPCI testing. After extended HPCI testing and running of the RHR system in the torus cooling mode, there was a failure of an instrument tap on the suction of the C RHR pump. The inspector inquired as to whether the analysis performed on RHR vibration had identified this as a high vibration point in the analysis. The licensee informed the inspector that the analysis had not been completed on the RHR system. All the data necessary had been provided to the appropriate engineering organization for review, but the analysis would not be completed until April 1990. The inspector questioned whether the vibration analysis data would encompass simultaneous operation of one RHR pump in each RHR division in the torus cooling mode. The licensee responded "No" and, subsequently, provided an analysis of that condition to the inspector on January 22, 1990. The analysis supported that there should be no unknown vibration associated with the dual pump operation in this particular configuration. The inspector will follow up with the licensee once the analysis is completed, to determine whether this instrument tap was considered a point of high vibration and whether any corrective actions are warranted. This matter is considered an open item (341/9005-05(DRP)).

d. Painting Sprinkler Heads in Diesel Fire Pump Room: During the inspection period, the inspector reviewed DER 90-0168 which reported that two of the five fuseable links within the diesel fire pump room had been painted over potentially rendering the room inoperable. The inspector reviewed the licensee's evaluation for operability of equipment within the room and determined that the equipment has remained operable.

e. Potential Inoperability of the Mainsteam Isolation Valve Leakage Control System on March 2, 1990: The licensee retracted the associated 50.72 notification on March ., 1990. Further evaluation by the licensee of this event determined that the surveillance testing methodology, at full power with 1000 psig in the main steam lines, caused air to adversely affect the instrument responses that were in question. The instruments involved were the containment pressure to steamline pressure differential pressure indication and resulted in the instrument not responding as desired. Originally the licensee considered that snubbers in the line between the pressure source and the pressure transmitter were plugged. Further evaluation determined that the problem was contingent on plant conditions and on which test was being run. It should be noted that during the original troubleshooting efforts, performed by the licensee under work request 016D900301, to replace the snubber associated with differential pressure transmitter B21-N487, that a main steam line low flow gross failure trip occurred on two of the steam line flow transmitters for steam lines C and D. This occurred during draining activities when an excess flow check valve closed due to excessive flow. The licensee took the appropriate LCO action statements associated with the two failed steam line flow transmitters. Corrective actions were appropriate.

f. Drain Valve Found Closed Potentially Rendering NIAS Division I Inoperable on March 21, 1990: (Further discussed in paragraph 7.d of this report).

g. Small Lagging Fire on Emergency Diesel Generator No. 14 on March 22, 1990: During performance of Surveillance 24.307.017, "Emergency Diesel Generator No. 14 - Start and Load Test," a small flash fire occurred near the exhaust/turbocharger connection. The fire was short-lived and self-extinguished in less than two minutes.

The engine was immediately shut down and plant personnel at the diesel used a carbon-dioxide fire extinguisher to ensure that the fire remained out. This is the second fire of this nature, the first occurring approximately one year ago.

Discussions with the licensee staff revealed that these fires are a known industry problem with Fairbanks-Morse 38TD8-1/8 diesels. The cause is a pooling of lubricating oil on a small shelf which is part of the engine block under the turbocharger inlet. The major contributor to this pool of oil is a deficiency in the crush rings which seal the exhaust pipes to the turbocharger inlet. When the diesel is started a small quantity of lubricating oil from the cylinders is blown through the exhaust pipe and leaks out from the crush rings onto that small shelf. A much smaller contribution is made from small leaks at the end of the engine which also collects on the shelf. As the engine warms up during a start, the oil vaporizes. On a fast start and load there is a significant temperature differential between the exhaust pipe and the block and as the vaporized oil rises past the exhaust pipe, it flashes. On a slow start the temperature differential is not as great (the exhaust pipe does not heat up as quickly) and the oil completely vaporizes before the exhaust pipe reaches the oil's flash point. The vendor, Colt Industries, is presently testing a new design crush ring and six month test results appear favorable. If the testing is completed satisfactorily, a Service Information Letter will be issued and Colt will make the new crush rings available to engine owners.

The licensee has been controlling the situation by wiping down the diesels prior to performing the surveillance start and on a semi-annual basis, removing insulation and completely cleaning the control end of the engine. The routine wipe down was not performed prior to this particular engine start because the system engineer was in a morning planning meeting. Following a thorough cleaning and replacement of a lagging pad, which was scorched by the fire, the engine was restarted and the surveillance satisfactorily completed. The licensee review of the event has concluded that since the fire was self-extinguished, the diesel remained operable and could have continued to run had it been required. Deviation Event Report (DER) 90-0226 was written to document the event and identify root cause and corrective actions. Root cause has been determined and is discussed above. The inspector discussed corrective action with the licensee staff. For the short term, the frequency of the cleaning of the control end of the engine will be increased. In the long term, the new crush rings will be procured when Colt makes them available and will be installed in the next refueling outage during performance of the 18 month Technical Specification Surveillance 34.307.001, "Emergency Diesel Generator - Inspection."

No violations or deviations were identified in this area.

7. Review of Temporary Modifications

During the inspection period, the inspector conducted a review of the Temporary Modification program as well as the implementation of selected temporary modifications under the program. Administrative procedure FIP-OP1-02, Temporary Modifications (revision 2) was the control mechanism evaluated. The inspector had no concerns with the procedure as written. The following temporary modifications were reviewed to verify proper implementation under FIP-OP1-02.

T.M. 86-135	Alignment of Annunciator 6D18 Into Two Groups.
T.M. 88-093	Block Open Pressure Control Valve to MSR.
T.M. 88-055	Disconnect Sample Line at N71-F802 and Route New Line to TB Basement.
T.M. 88-105	Main Turbine Hi/Hi-Hi Vibration Setpoint Change.
T.M. 89-019	Installation of Pipe Cap on NIAS Aftercooler Drain.
T.M. 89-024	Removal of P50 Check Valve Internals.
T.M. 90-001	Tack Weld LP Stop Valve Limit Switch Mechanism Boss to Shaft.
T.M. 90-004	Installation of Temporary Thermocouple on RWCU Pump B Seal Plate.

The following observations were made:

a. Regarding T.M. 86-0135, although the temporary modification split the original offgas level annunciator into seven annunciators (using six spare windows), no Alarm Response Procedures (ARPs) were referenced as critical documents affected by the TM. This, despite the re-review, was done in 1989 for all outstanding TMs to upgrade them to the requirements of the current program.

b. Regarding T.M. 88-055, the inspector noted two control room drawings in the full size binders with the same drawing number (6M721-2400-3) and the same revision (J). Information on the drawings was different. One drawing was crossed out in red with a note to use the other drawing on the facing page. The crossed out drawing was "controlled" while the other one did not have a "controlled" stamp on it and all of the revision approval blocks blacked out. In addition, the TM redlined on the crossed out drawing did not show on the other. When this was brought to the attention of the operating shift, they indicated they were not aware of the replacement drawing status nor what was required for its use.

The shift contacted the acting supervisor, Engineering Design who indicated the new drawing was, in fact, not a "controlled" drawing but was an interim drawing that reflected the as-built condition of the EDPs posted against the original. That was why the drawing was not stamped and the revision approval blocks were blacked out. The reason the interim drawing was added to the binder was to eliminate the need to redline the original drawing to include all the posted EDPs. It was believed that the large amount of redlining which would have been involved would have been difficult for the operators to understand.

Review concluded that this action was allowed under the current administrative controls but that communications to the operating shifts as to the intent and application of the interim drawing was weak. This resulted in the TM redlining not being transferred as required on this drawing.

Further review by the inspector revealed that another drawing associated with T.M. 88-055 (6M721-5724-2 rev F) also was posted with an interim drawing. In this case, the TM was found to be redlined on the interim drawing. However, the inspector determined that the interim drawing was placed in the binder and the original drawing crossed-out on December 8, 1989 but the TM redlining was not transferred to the interim drawing until January 21, 1990.

c. Regarding T.M. 89-019, the work request (WR 006C890629) referenced on the installation record as the control mechanism to install the TM was incorrect.

d. On March 20, 1990, during a field walkdown of the TM 89-019, the inspector noted that the NIAS aftercooler drain valve, P50-F206A was closed. This appeared to be contrary to system operating procedure (SOP) 23.129, "Station and Control Air System," in which the valve lineup sheet indicated the valve was to be open. The operating shift was contacted and an operator dispatched who verified the valve was mispositioned. A review was then initiated to attempt to determine the cause for it being closed. Results of the review were inconclusive. No reason for the mispositioning could be determined. The valve was last known to be properly positioned on February 28, 1990. This is considered a violation (341/90005-06(DRP)) of 10 CFR 50, Appendix B Criterion V, "Instructions, Procedures, and Drawings," in that the abnormal position was not recorded on an abnormal lineup sheet in accordance with DECo procedure NPP-OP1-08 section 5.1. There was potential safety significance associated with this valve out of position in that it could have rendered one division of noninterruptible air inoperable.

The inspector followup into this situation revealed two other licensee deficiencies not directly related to the valve mispositioning. The first dealt with nonlicensed operator (NPPO) rounds. Shiftly, rounds sheets directed NPPOs to verify that the aftercooler drain line was not plugged. This was being accomplished by NPPOs feeling for air exhausting out the open drain line and then checking "satisfactory" on the rounds sheet. However, even if the line was not plugged no air could exhaust unless the NIAS compressor, normally a standby unit, was on. NPPOs stated that supervisors had been told of this deficient tour sheet item and nothing was done. The inspector reviewed all rounds tour comment sheets and noted that no one ever submitted a comment sheet for this situation. Apparently, this matter was never submitted for revision. The licensee was initiating actions to determine if other tour sheet items were discrepant.

The other problem dealt with procedure 27.129.03, "NIAS Valve Lineup Verification." This procedure was written and issued after TM 89-019 was implemented. Therefore, the valve lineup did not reflect the valve position changes and valve omissions associated with the TM. The procedure was checked by the procedure preparer as not needing validation. Subsequently, when the procedure was performed in November 1989 there were discrepancies that should have required a temporary change notice (TCN) to the procedure. None was initiated. When the procedure was performed in December 1989 a TCN was initiated but it did not encompass one of the valves affected by the TM. In the third performance of the procedure in January 1990 a second TCN was initiated that rectified all the valve position problems. It took operators numerous attempts to recognize and properly implement the TCN process for this procedure. Use of the TCN process is another candidate for inclusion in the licensee's intensified administrative controls training initiative.

Most of the TM deficiencies were reflective of previous problems with the implementation of the temporary modification program as documented in inspection reports 88035, 89034 and 90002. There are three reasons for the TM implementation errors:

- Temporary modifications have not been incorporated as permanent design changes in a timely manner. There are still active TMs from 1985 and every year since. This excessively strains the administrative controls to keep all other interfacing programs (procedures, alarm responses, operator aid, etc.) current.

- Inattention to detail by personnel implementing the TM program.

- Lack of training of operating shift members on "draft" drawings incorporated into control room drawings.

No other violations or deviations were identified in this area.

8. Licensee Event Reports 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 86011 Rev. 1, MSIV Exceed Leakage Requirement.

b. (Closed) LER 87025 Rev. 1, RPV Level Scram.

c. (Closed) LER 88026 Rev. 1, Unidentified Leakage.

d. (Closed) LER 87041, Standby Gas Treatment System AMX Parameter Deletion.

e. (Closed) LER 89034 Rev. 1, Fire Watches Not Performed in Compliance with Technical Specifications.

f. (Closed) LER 89039, Inadvertent ESF Actuation During Surveillance Activities Causing Partial Load Shedding of Bus 72E Activating Emergency Equipment Cooling Water and Emergency Equipment Service Water Due to Personnel Error.

g. (Closed) LER 89036, Reactor Scram Due to an Inadvertent Manually Initiated Mainsteam Isolation Valve Closure.

h. (Closed) LER 89027, Engineered Safety Feature Actuations Occurring During Meggering of Reactor Protection Circuits. Corrective actions were three-fold. The first was to initiate stricter control of relay room keys. The second was to sensitize the operations, I&C, maintenance, and electrical departments to this particular event. The third was to assure that wiring diagrams in addition to schematic diagrams are utilized when performing maintenance in relay room cabinets. The inspector verified that the appropriate training programs had been modified to include this event in the continuing training. Maintenance and operations initial training program have included this event in their required reading program. In the additional training programs, the necessity to include wiring diagrams was a portion of the training and now has been initiated through the training program as a standard practice to be followed by all maintenance personnel. The inspectors interviewed a number of operators to ascertain whether they were fully aware of the new stricter key control program. Based upon those interviews, the inspector determined that notification of the NSS was not always being accomplished under the new control program. This matter was brought to the attention of operations management, which updated the night orders, to assure that all licensed operators were fully cognizant of the need to notify the NSS. A sign was affixed to the key cabinet instructing operators to notify the NSS whenever a key is released to the relay room.

No violations or deviations were identified in this area.

9. Information Notice Followup

Each of the following I.E. Information Notices (IEN) was reviewed by the resident inspectors to verify that: 1) the information notice was received by licensee management, 2) a review for applicability was performed, and 3) if the information notice was applicable to the facility, applicable actions were taken or were scheduled to be taken.

a. (Closed) Information Notice 87-59: Potential RHR Pump Loss.

b. (Closed) Information Notice 88-01: Safety Injection Pipe Failure.

c. (Open) Information Notice 87-23, Loss of Decay Heat Removal During Low Reactor Coolant Level Operations. This Information Notice was originally transmitted to certain departments of the licensee's organization for information only in 1987. In a subsequent re-review of operating event reports, that is ongoing by the licensee, DER 90-194 has been written to re-review this information notice to determine any appropriate corrective actions by the licensee. This information notice followup will remain open contingent upon completion of the licensee's evaluation of DER 90-194.

No violations or deviations were identified in this area.

10. Other Inspection Activities

During the inspection period the resident staff reviewed certain other specific areas of licensee's activities.

a. The inspector to assessed the adequacy of the licensee's root cause analysis and corrective actions regarding the potential use for the significantly out-of-specification, non-safety related fasteners.

The only fastener batches effected was NENB-9 which was an SAEJ429 Grade 2 bolt. In its original response to this bulletin, dated January 14, 1988, the licensee stated that the impact of the discrepancy associated with the NENB-9 bolt was under evaluation by Detroit Edison's Engineering Department. In a subsequent response, dated August 18, 1988, the licensee documented that two more samples from the same bin were tested by the Engineering Research Department (ERD) and these samples demonstrated the same physical and chemical properties as the sample NENB-9. Further investigation by the licensee identified that the supposed grade 2 bolts were in reality grade 8 bolts. This grade 8 bolt is susceptible to a failure by stress. However, given that the grade 8 bolts were being used in a grade 2 application, the licensee determined, through calculation, that cracking was not to be expected. The licensee indicated that only six of the 100 bolts associated with this batch were installed in the facility. Three bolts were destroyed during testing and 91 were to be scrapped. The inspector requested and received documentation that the 91 bolts were scrapped. Based upon ERD's evaluation of the grade 2 applications to the grade 8 bolts, the inspector did not see a need for removal of the six installed bolts. The inspector considered the licensee's actions adequate.

(Closed) TI 2500/27: Inspection requirements for NRC Bulletin 87-02, "Fastener Testing to Determine Conformance With Applicable Material Specifications."

b. (Closed) TI 2515/103: This TI is only applicable to pressurized water reactors and not boiling water reactors.

No violations or deviations were identified in this area.

11. Generic Letter Followup

(Closed) GL 84-23: Reactor Vessel Water Level Instrumentation in BWRs. This matter was adequately reviewed in inspection report 88030 paragraph 15.b.

No violations or deviations were identified in this area.

12. Followup of TMI Action Items (NUREG-0737)

During the inspection period, the following TMI Action Items were reviewed:

a. (Open) I.G.1.3: Special Low Power Test Program for BWRs. NUREG-0660 and NUREG-0694 initially provided the objectives which were to be met under this item. Those were to conduct a special test program during low power operation to provide technical information on plant response beyond that provided by the normal startup test program. Each operating crew was either to directly conduct these additional tests or were to observe test performance.

One of the subject tests originally specified was a simulated station blackout event. Subsequent licensee review determined that performance of this test could have caused equipment damage in the drywell, and in a letter to the NRC dated February 14, 1983, declined to do the particular test but rather to perform a set of alternative tests. This was consistent to the BWR Owners Group submittal to the NRC dated February 4, 1981. On June 29, 1983, the NRC issued Generic Letter 83-24 which also addressed this issue and endorsed the deletion of the station blackout test. The generic issue of station blackout is still outstanding at this time and is currently being tracked under Unresolved Safety Issue A-44.

The special tests that the licensee committed to conduct and provide augmented operator training on under Task item I.G.1 included:

a. At least one reactor scram transient.
b. At least one pressure regulator transient.
c. At least one turbine trip transient.
d. Operation of the HPCI and RCIC systems.
e. At least one water level setpoint transient.

From discussion with licensee personnel, these tests were conducted during the startup test phase and operator training was completed by direct observation of the tests. To document this, a master list of the subject tests cross referenced to the ones operators observed was prepared at the time. The list was maintained by the Startup Engineer-Test Phase with a copy provided to the Operations Engineer. However, when the inspector requested a copy of the master list, it could not be found.

The licensee indicated that although the original could not be located, each startup test package included the operator training sheets and the list could be reconstructed. This task item will therefore remain open until the master list is reconstructed and the inspector completes review of the list.

b. (Closed) TMI II.E.4.2: Containment Isolation Dependability. The area left to be resolved with this TMI dealt with Clarification Item No. 7 of NUREG 737, "Clarification of TMI Action Plan Requirement." In Clarification Statement No. 7, it states, "Seal Closed Purged Isolation Valve shall be under administrative control to assure that they cannot be inadvertently opened." The licensee's original position was different, as discussed in Inspection Report 88030, Paragraph 15d, on this matter. Following this inspection, in 1988, the licensee reviewed its position and submitted a letter to NRR, dated September 14, 1989, documenting the present method used to assure that these purge valves stayed closed. In a letter dated March 28, 1990, the NRC responded that the licensee's present method was satisfactory. As such, this TMI Item is considered closed.

No violations or deviations were identified in this area.

13. Followup on Violations Related to Providing Innaccurate Information to the NRC

On February 12, 1990, the Deputy Executive Director of Nuclear Materials Safety, Safeguards, and Operations Support issued a letter to the licensee in which the license was modified and three notices of violations were issued (341/90005-07(DRP)), (341/90005-08(DRP))and (341/90005-09(DRP)). Corrective actions to these violations included establishment of a candor committee to improve communications with the NRC and providing training to Fermi management personnel on the NRC. A creed was established in the forward of the Business Plan to clearly state that communications with the NRC were to be accurate and complete. The internal procedure governing communications with the NRC was revised to assure accurate information was presented to the NRC. Weekly meetings have been initiated with the Resident Staff and periodic meetings are held with Regional and Headquarters Management staff to discuss issues of concern. Additionally, training has been initiated in the form of technical staff and managers training, steps to effective plant supervision; root cause analysis; and human performance evaluation system training to help in determining problems and communicating appropriate resolutions to the NRC. The corrective action system was changed to lower the threshold for identification of problems and the corrective action reports (DERs) were provided to the Resident Staff. In 1988 an accountability program was initiated by the licensee. There have been a number of improvement programs initiated in terms of the Technical Specification Improvement Programs, Security Improvement Program, Self SALP Program, and Performance Based Quality Assurance Audits. All of these corrective actions have helped to sensitize licensee personnel to the necessity of accurate and complete information to the NRC. The inspector has been cognizant of these improvements initiated by the licensee from 1986 through the present time. In addition, the inspector reviewed FMD-RA1, "Interfacing with Regulatory Agencies and Industry Organizations," and found that it established adequate direction to plant staff on dealing with the NRC. These violations are considered closed.

14. Management Meetings

a. On February 17, 1990, in Region III, a management meeting was conducted between NRC Region III Management and the Licensee's Management to discuss corrective actions to recent plant maintenance problems.

b. On March 16, 1990 a periodic management meeting was conducted between NRC Region III management and DECo management to discuss:

- Plant Performance
- Status of Human Factor Deficiencies
- Refueling Outage Critique Results
- A 1988 Safety Evaluation on a RHR Minimum Flow Valve
- Overall Safety Evaluation Upgrades
- Maintenance Team Inspection Response
- Lubrication Action Plan Status
- Past & Planned Plant Communication System Improvements
- Accountability Action Plan Status

c. On March 27, 1990, the Systematic Assessment of Licensee Performance (SALP) Meeting was held at the Fermi site in the Nuclear Operation Center.

15. Organizational Changes

During the inspection period a new Technical Engineering Superintendent was appointed. The inspector reviewed the new individual's qualifications against ANSI 18.1 (1971) and determined that the standard was fulfilled.

16. 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. Three open items disclosed during the inspection are discussed in Paragraphs 4.g, 6.a and 6.c.

17. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in paragraph 1) on April 4, 1990, 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.