U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-341/95012

FACILITY
Fermi 2 Nuclear Plant

License No. NPF-43

LICENSEE
Detroit Edison Company
6400 North Dixie Highway
Newport, MI 48166

DATES
September 22 through November 21, 1995

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AREAS INSPECTED

An integrated inspection effort by resident and region-based inspectors of Fermi's performance in the areas of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was performed for non-routine events and for certain previously identified items.

RESULTS

Assessment of Performance

Within the area of **Operations**, improvements continued with several exceptions. The inspectors identified **five concerns**. Of particular concern was the fact that on **two occasions**, operators failed to recognize and enter technical specification action statements.

- Emergency Diesel Generator (EDG) 11 was rendered briefly inoperable, but operators failed to recognize that it was inoperable and enter applicable technical specification (TS) action statements. (Section 1.2)

- One division of core spray was rendered inoperable during an EDG surveillance, but operators failed to recognized this or enter applicable TS action statements. (Section 1.3)

- Safety battery rack corrosion was identified but not corrected until inspectors identified the large scope of the problem. (Section 1.4.1)

- A number of control rod drive hydraulic control unit accumulators were recharged over a 10 week period with the wrong compressed gas until identified by inspectors. (Section 1.5.1)

- Operators were not questioning some control room indications which appeared to indicate abnormally. (Section 1.5.2)

The inspectors did note that the Operations department coordinated well with engineering during fuel failure investigation and with maintenance during some important maintenance periods.

Within the area of **MAINTENANCE**, continuing weak communications with operations resulted in a significant concern during the conduct of preventive maintenance on a safety related system. The **failure to identify** this **concern** by the **licensee** was considered a significant weakness.

- Unanalyzed load (test resistor) connected to safety related battery during battery charger maintenance rendered the battery unintentionally inoperable. (Section 2.4)

Within the area of **ENGINEERING**, continuing weaknesses existed.

- Calculations for combustion turbine generator 11-1 reliability did not include all applicable data. When identified and recalculated, the turbine did not meet reliability commitments to. (Section 3.3)

Within the area of **PLANT SUPPORT**, performance continued to demonstrate improvements with two exceptions pertaining to station security.

- Inadequate security compensatory measures taken on **two occasions**, identified upon supervisory review. (Section 4.4.1)

- Two document control errors resulted in current revisions not being incorporated. (Section 4.5)

The inspectors' review of selected **SAFETY ASSESSMENT AND QUALITY VERIFICATION** activities were **mixed**. NQA continued to make some good findings, which included:

- Some system engineers operated valves, contrary to policy.

- Following identification by operations that some acceptance criteria for surveillance were improperly identified.

However, the safety assessment function failed to provide backup to operations on a number of occasions during this inspection period. Examples included the improper testing that rendered the battery inoperable (Section 2.4) and the failure to recognize the emergency diesel generator inoperability (Section 1.2).

Summary of Open Items
Violations: Three identified in Sections 1.4.1, 1.5.1, and 2.4
Unresolved Items: Two identified in Sections 1.4.1 and 2.5
Inspector Followup Items: Four identified in Sections 3.1, 3.3, 4.2, and 4.4.1.
Non-cited Violations: Three identified in Sections 1.2, 2.3.1, and 2.3.2

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of ongoing plant operations. The plant operated at or near full power for the entire inspection period. Housekeeping remains good. Recent efforts in painting and lighting in the turbine building were most notable.

1.1 General Service Water System Repairs As previously documented in Inspection Reports 95009 and 95011, numerous problems with the general service water (GSW) system were identified; of particular concern was the identification of cracks and through-wall leaks. During this inspection period the licensee completed ultrasonic and radiographic inspection of select areas of GSW piping. As a result, the licensee identified several areas where the piping had degraded to less than acceptable wall thicknesses. The suspect areas were repaired by weld build up or in one case by installation of a containment box.

In addition, the licensee improved monitoring of the system by increasing the frequency of system walkdowns by operations and maintenance personnel. Though licensee response to indications of degradation of the GSW system integrity was initially slow, the inspections and repairs observed this inspection period were thorough and aggressive and appear to have fully quantified the integrity problems. Inspectors will continue to monitor licensee long term corrective actions to improve GSW system material condition during routine observation of plant activities.

1.2 Operations Failed to Identify Condition That Rendered Emergency Diesel Generator (EDG) 11 Inoperable On September 20, control room operators received the "Div 1 EDG 11 Not Ready for Auto Start" and the "EDG 11 Exciter Trip" annunciators, followed shortly by a call from a maintenance technician reporting that he had inadvertently bumped the EDG 11 exciter bypass switch into the "bypass" position. An operator was promptly dispatched to the EDG switchgear room to reset the alarms.

Control room operators consulted the applicable alarm response procedures and the EDG standard operating procedure, and concluded that the alarm was not a critical EDG trip, and therefore declared that EDG 11 remained operable. This position was discussed with operations management.

The following day, inspectors questioned this operability determination following a control room log review. Inspectors contacted the EDG system engineer, who immediately recognized that a bypassed exciter would prevent closing the EDG output breaker, rendering the EDG inoperable. Upon review, the licensee determined that operator training and procedures failed to identify that the exciter bypass switch in the "bypass" position would prevent the EDG from fulfilling its safety function. Deviation Event Report (DER) 95-0730 was written to document event occurrence and track corrective actions. Technical Specification (TS) actions were not entered, but none were violated during the 15 minutes that EDG 11 was inoperable.

This event occurred, in part, due to inadequate alarm response procedures, and is a violation. Inspectors reviewed licensee corrective actions, and concluded that they appeared adequate to prevent recurrence of this event. Due to the limited duration and minimal safety significance of this event, this violation was minor and will not be cited because the criteria specified in the NRC Enforcement Policy were satisfied.

1.3 Improper Revision of Surveillance Procedure Used, Resulting in Repeat of Failure to Enter Technical Specification Action Statement In DER 95-0644 dated September 1, 1995, the licensee documented that the performance of certain EDG surveillance procedures rendered the associated division of core spray (CS) inoperable during the surveillance. Corrective actions included issuing Temporary Change Notice (TCN) T09103 to the affected surveillance to include an impact statement to clearly identify that CS was rendered inoperable. The TCNs were issued on September 8.

On September 22, one of the affected surveillance (42.302.03 Div. 2 Undervoltage Circuit Functional Check) was performed, but the copy of the issued procedure did not include TCN T09103. A note on the cover sheet attached to the procedure used stated "Performance of this test will cause the associated core spray subsystem to become inoperable for the duration of this test." However, operations was not required to review this portion of the document, but instead relied on the impact statements in the base procedure (which was missing due to the TCN not being included). As a result, operators again failed to enter the applicable TS action statement for an inoperable CS division during the surveillance. Since the duration of CS being inoperable was less than the TS action statement, TS requirements were not violated.

The inspectors concluded that the licensee did a good job identifying the original problem, and in identifying the recurrence. However, administrative control lapses allowed the procedure to be issued without the latest TCN. Additionally, due to inattention to detail, control room operators and maintenance personnel missed an opportunity to prevent recurrence.

1.4 Engineered Safety Feature Systems Material Condition During inspection of engineered safety feature (ESF) system, the accessible portions of the following systems were walked down.

- Emergency Diesel Generator Numbers 11, 12, 13, and 14
- Residual Heat Removal Service Water System, Divisions 1 and 2
- Reactor Core Isolation Cooling System
- Core Spray (CS), Divisions 1 and 2
- 130/260V Battery, Divisions 1 and 2
- 24/48V Battery, Divisions 1 and 2

Condition of the safety systems continued to be good, the exception being the safety related batteries discussed in the following section. However, the inspectors noted the following deficiencies: Spring Hanger (4E21-5300-G06) supporting the CS minimum flow line had a gagging device installed, and a High Pressure Coolant Injection System Test Connection Isolation Valve (E41-F055) with a packing leak that was issuing steam. Neither condition rendered the associated system inoperable, but were conditions which should have been detected during routine system or area walkdowns.

1.4.1 Deterioration of Safety Related Battery Racks On October 3 during inspectors' walkdowns of Divisions 1 and 2 130/260 VDC and 24/48 VDC batteries, the inspectors noted that some of the fasteners on the battery racks were corroded, apparently due to spilled battery acid. A licensee review determined that the fasteners had not corroded sufficiently to affect the seismic qualification of the batteries. The licensee initiated work requests to clean or replace fasteners on the battery racks. Other licensee corrective action included plans to enhanced procedures and training to prevent acid spills during specific gravity tests. These actions are scheduled for the next quarterly maintenance continuing training class.

Additionally, the inspectors questioned the configuration of the polystyrene spacers located between battery cells. The inspectors were concerned that polystyrene spacers were used to separate battery cells and to fill the space on the ends of some racks, but not on all the racks. The racks were classed as seismic category I. The inspectors questioned whether the spacers were in the same configuration as the seismic test configuration and whether the spacers would adequately protect the battery during a seismic event. Pending licensee investigation and resolution of these issues, this is an Unresolved Item (341/95012-01).

During another walkdown of the DC system on November 16, the inspectors observed corrosion on the positive terminal of cell no. 63 of the Division I Class 1E battery. Also, battery racks exhibited corrosion on the support rails on both Division I and II Class 1E battery racks, as well as on the supports beneath the batteries. During the performance of Surveillance Procedure 42.309.03, "Division I, 18-Month 130/260 VDC Battery Check," on May 24, 1994, the licensee identified corrosion at one end of the rack near the terminal box. Work Request (WR) 000Z942204 was initiated to correct the deficiency. Inspector's review of the completed WR identified that the WR did not address removal of corrosion on the rack. On November 15-16, 1995, the inspector observed that corrosion was still evident near the terminal box and that additional deterioration of the racks had occurred since the corrosion was now evident on all Class 1E battery racks. The inspector concluded that the failure to perform adequate corrective action in May 1994 to remove the corrosion from the racks had failed to prevent further deterioration of the racks from corrosion in November 1995 and was a violation of 10 CFR 50, Appendix B, Criterion XVI (50-341/95012-02a).

Following inspector identification of the battery rack corrosion the licensee took immediate action to clean and paint the affected areas of the rack. In addition, several tie rod assemblies were replaced due to severe corrosion. Additionally, cell number 63 terminals were jumpered and cleaned. Inspectors will continue to monitor the material condition of the batteries during routine plant tours.

1.5 Inattention to Details by Operations

1.5.1 **Wrong Compressed Gas Used for Recharging Control Rod Hydraulic Control Unit (HCU) Accumulators** While observing weekly recharging of HCU accumulators on October 19, the inspectors identified that the cart of compressed gas cylinders connected to the HCU recharging rig for the south HCU bank were marked as containing argon, while the rig for the north HCU bank were marked as containing nitrogen. The procedure being used to recharge the HCU accumulators (23.106, Control Rod Drive Hydraulic System) required the use of nitrogen. The operator immediately reported the situation, and appropriate actions were promptly taken. The licensee made an operability determination that the use of argon, or an argon/nitrogen mix, was acceptable for HCU accumulators, and there was no concern for degraded operability.

The licensee's investigation indicated the argon cylinders were brought into the plant on August 7, 1995, and that at least 34 separate HCU recharging evolutions were performed with the argon on at least 9 different HCUs. Additionally, the prior cart of nitrogen was initially replaced with dry air cylinders; the error was noted because different fittings used for air prevented connecting those bottles. Unaware why the wrong fittings existed or even that the bottles contained air, the operator changed the cart for one that could be connected, which happened to contain argon.

The licensee determined that operators did not question or check what gas was received because they did not believe that any other gas was available. Cylinders of nitrogen, argon and dry air are the same color, and oxygen was almost the same, contributed to the failure to identify the wrong gas used. Numerous operators failed to follow the procedure for recharging the south bank of HCUs by injecting argon vice the required nitrogen because they did not check what gas was connected. Licensee corrective actions included investigating how compressed gases are handled, removing all 12-packs that do not contain nitrogen from the protected area, and upgrading markings on gas cylinders to provide easy identification.

Procedure 23.106, "Control Rod Drive Hydraulic System," required that nitrogen of sufficient pressure be used to recharge HCU accumulators. Failure to follow this procedure was a violation of TS 6.8.1.a, which required that procedures be implemented for activities recommended in Regulatory Guide 1.33 (341/95012-03).

1.5.2 Unquestioned Control Room Indications The inspectors questioned operators about why control room indication of reactor water cleanup (RWCU) bottom head drain line flow showed 170 to 200 gpm which was over half of the system total flow. The RWCU system has two 4-inch suctions from the reactor recirculation loops and one 2-1/2 inch bottom head drain line suction. Operators were unable to explain the indications, but stated that indicated flow had been that way for quite awhile. Plant engineering then began to investigate the cause and concluded that there was an indication problem. DER 95-0834 was written. Testing during the last refueling outage (RF04) indicated that bottom head drain line flow was 16 percent of the total RWCU flow (or about 50 gpm). Additionally, the inspectors noted that this indication read 50 gpm after the RWCU system was out of service for a planned system outage. A condition again which was not questioned by operators or engineering.

Similarly, the inspectors noted that main steam line flows indicated in the control room for the A and B main steam lines were about 10 percent higher than for the C and D lines. Operators knew the indication had been that way for at least two cycles, but could not explain why or tell if it was a problem. Maintenance produced a memorandum indicating the different steam line lengths and steam flow connection locations generated this difference in actual steam flows. However, the inspectors identified that the simulator does not model imbalanced steam flows. The licensee was investigating whether RWCU flow indication in the simulator reflected the plant response.

The inspectors were concerned that operators were not questioning control room indications which do not seem right, but were satisfied that they were reading as they usually do. This finding is not consistent with the operator response to the small reactor vessel water level spike discussed in section 1.6, when operators questioned and responded to their indications.

1.6 Unexpected Reactor Water Level Spike Promptly Identified On October 29, operators noticed a small increase in reactor water level on a control room recorder. Operators promptly examined system data to determine the cause. The 2-inch level increase lasted about 15 seconds before the reactor water level control system responded and returned level to normal. The licensee investigated the event and Engineering determined the cause to be the sensor for the steam flow periodically sensing a small localized pressure change which caused a small change in feedwater flow.

Excellent operator attentiveness to changes in indications was evident in the identification of the level spike. In addition, subsequent followup was prompt and coordination with engineering staff was good.

1.7 Follow-up on Non-Routine Events NRC Inspection Procedures 90712 and 92700 were used to perform a review of written reports on non-routine events.

1.7.1 Notice of Enforcement Discretion for Emergency Diesel Generators On September 28 during a review of Instrument and Control (I&C) surveillance coverage, the licensee discovered that the EDG output breaker reclosure circuit and load sequencing of some 480V loads were inadequately tested. The review identified a potential failure which would cause the circuits to be energized immediately upon starting the EDG. For the load sequencer, this failure mode would result in increased initial load on the EDGs. For the reclosure circuit, this failure mode would result in no adverse effects.

The licensee declared all four EDGs inoperable. Due to the scope of work required to verify the operability of the circuits, enforcement discretion for TS required surveillance testing of these specific functions was requested. The licensee believed the worst case condition of all sequenced 480V loads actually being connected to the EDGs at startup was within the capacity of the machine, based on startup testing in which a much larger load had been carried at startup in addition to expected loads.

On September 29, Office of Nuclear Reactor Regulation (NRR) granted enforcement discretion from the required actions of TS 3.8.1.1.d until an emergency technical specification change could be submitted and approved. The licensee committed to perform the necessary testing during the next outage, and submitted an emergency TS change on October 2.

The above surveillance deficiencies were identified while performing review of surveillance overlap problems initiated because of the corrective actions from a previously issued violation (IR 341/94012). Licensee Event Report (LER) 95-007 was submitted to document the issue and corrective actions planned. LER 94-003, which previously documented the surveillance overlap issue, is considered closed. The review and findings were considered a good effort to thoroughly identify and correct the problems in this area.

1.8 Followup on Previously Opened Items A review of previously opened items (violations, unresolved items, and inspection followup items) was performed per NRC Inspection Procedure 92901.

1.8.1 (Closed) Inspection Followup Item 341/93018-03 Operation in single element reactor vessel level control following steam flow perturbations. Concerned that steam flow signal input to 3-element control could lead to a low level scram, single element control was deemed by the licensee to be desirable. The cause of steam flow perturbations was subsequently determined to be radio interference with the steam flow transmitters. Extensive testing was conducted to confirm this cause, and susceptible flow transmitters were replaced during RF04. Additionally, the policy governing radio usage was revised to avoid transmitting near sensitive equipment, and site training was conducted to minimize the possibility of a similar problem in the future. Corrective actions appear adequate and no further concerns were identified. This item is closed.

1.8.2 (Open) Unresolved Item 341/95004-01 Emergency operating procedure (EOP) flowchart steps did not appear to maintain an inerted atmosphere for the torus because drywell (vs. torus) oxygen concentration was used for determining whether air could be used for purging the torus. At the request of the NRC, Detroit Edison reviewed the issue and concluded the "use of the torus concentration may result in a more appropriate purge consideration under some circumstances." By letter dated July 3, 1995, Detroit Edison committed to revise the EOP flowchart for hydrogen and oxygen control to include a consideration of both the torus and drywell atmospheres to determine the most appropriate purge supply for the conditions present. The inspectors concurred with the corrective actions Detroit Edison committed to in response to this item. Detroit Edison planned to complete these corrective actions by January 31, 1996. This item will remain open pending NRC review of the flowchart revision described, and changes to update the Plant Specific Technical Guidelines (PSTGs) and "Differences Document" which reflect the flowchart revision.

1.8.3 (Open) Unresolved Item 341/95004-02 The Fermi PSTG for hydrogen and oxygen control differed from the emergency procedure guidelines (EPGs) in that venting was accomplished by venting the drywell, in addition to the torus, if torus water level was below the bottom of the torus vent. Specifically, PSTG step PC/H-5.1.2 differed from the corresponding revision 4 EPG step, step PC/H-4.2, in this regard. The EPGs directed venting from the torus, if possible, to maximize the effect of torus scrubbing and minimize the amount of radioactivity released. However, by venting the torus and drywell concurrently, torus scrubbing of the release would be precluded and the potential amount of radioactivity released would not be minimized.

Detroit Edison failed to provide adequate justification for the PSTG difference from the EPGs in that their justification was only valid for low pressure conditions. Specifically, the justification for the difference, documented in the "Differences Document" dated February 14, 1995, specified that venting both the torus and drywell was necessary to permit purging the containment with air. While applicable for low pressure conditions, the inspectors identified that the justification was not applicable for higher pressure conditions.

Detroit Edison committed, by letter dated July 3, 1995, to revise their EOPs for hydrogen and oxygen control accordingly. Specifically, Detroit Edison committed to revise the PSTG, the "Differences Document," and the EOP support procedure for containment venting and purge to direct venting through the torus first, then the drywell. In addition, Detroit Edison committed to provide operator training on the revised procedure and strategy. Detroit Edison planned to complete these corrective actions by January 31, 1996. This item will remain open pending NRC review of licensee correction actions.

1.8.4 (Open) Inspection Followup Item 341/95004-04 EOP writer's guides did not ensure that the presentation of information was consistent and benefit to the operators. By letter dated July 3, 1995, Detroit Edison committed to review the comments generated by the NRC and internal audits, and revise the writer's guides and EOP flowcharts based on their review. Detroit Edison also committed to perform an independent review to ensure that the writer's guides and EOP flowcharts agree. Detroit Edison planned to complete these commitments by November 30, 1996. This item will remain open pending NRC review of the revised writer's guides and EOP flowcharts.

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and testing activities. The maintenance activities observed were planned and executed well.

2.1 Observation of Work and Testing The following maintenance and surveillance activities were observed:

- Division 1 and 2 Control Center Heating, Ventilation and Air Conditioning (CCHVAC) Outage Work
- Turbine Lube Oil Repairs

- GSW Weld Buildup Repairs
- Emergency Diesel Generator 12 Operability Surveillance
- Individual Control Rod Scram Time Testing
- Turbine Bypass Valve Operability Surveillance
- Main Steam Isolation Valve (MSIV) Channel Functional Surveillance
- Diesel Fire Pump Operability Surveillance
- Reactor Water Cleanup Outage Work
- Division 1 Standby Gas Treatment (SBGT) Filter Performance Test

For all activities observed, the inspectors noted safe work practices. The activities observed were performed satisfactorily in accordance with procedures. Some problems were identified as discussed below.

2.2 System Outages Well Planned and Executed Safety system outages performed during this inspection period have shown improvement in planning and execution. Planning included all appropriate organizations, which allowed a well-thought out, conservative approach in light of existing equipment problems. Of particular note were the RWCU system outage and the Scram Solenoid Pilot Valve (SSPV) replacement effort.

The RWCU system outage involved extensive valve work and installation of a regenerative heat exchanger bypass line. Dose minimization efforts were thorough and effective, and lessons learned were being discussed even before the work was completed. The work was completed without major difficulties and ahead of schedule, and well below estimated exposure (3.038 person-rem actual, compared to 4.314 person-rem estimated). Coordination appeared to be good, particularly when a pre-fabricated section of the modification piping did not fitup as expected. Dedicated 24-hour outage supervision for maintenance, work control, and radiation protection (RP) contributed to early work completion.

SSPV replacement was performed for 47 HCUs during two power reduction periods during this inspection. SSPV diaphragm hardening was discovered to be an industry issue, and Fermi was replacing them to stay within recommended service life guidelines. Because of the complexity of the core management and TS requirements, planning for these outages was very detailed and well-coordinated.

2.3 Further Instances of Inattention to Detail

2.3.1 **Failure to Follow Procedure Results in Damage to CCHVAC Ground Fault Protection Circuit** On October 23 during preventive maintenance to the Division 2 CCHVAC system, an electrician improperly connected the test leads. The circuit was energized without his partner or a NQA inspector checking the setup, resulting in damage to the circuit. The system was promptly repaired. However, the lack of attention to detail, independent verification, and failure to follow procedure were of concern. This event was documented in DER 95-0823 to initiate and track corrective actions.

Failure to follow procedures is a violation of 10 CFR 50, Appendix B, Criterion V, which requires, in part, that activities affecting quality be accomplished in accordance with documented procedures. However, this violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria in section VII.B(2) of the NRC Enforcement Policy.

2.3.2 **Two Valves Found in the Incorrect Position by Licensee** During corrective maintenance on October 19, Valve P44-F112B (emergency equipment cooling water return from reactor building equipment sump heat exchanger) was found to be seal locked in the fully open position (about 8 turns), vice the seal locked position of 3-1/8 turns open required in the system valve lineup (23.127, Attachment 1B).

During investigation of water leakage into the drain manifold on a Division 2 residual heat removal (RHR) instrument rack on October 29, the low side drain valve for the minimum flow valve switch on the same rack was found mispositioned open. The valve was found to be hard on the backseat. The licensee believed that operators checking the valve falsely determined the valve to be shut due to the force required to unstick the valve, and it had probably been open since it was installed in June 1995.

These events were documented in DERs 95-0818 and 95-0842, respectively, to initiate and track corrective actions.

Failure to follow procedures is a violation of 10 CFR 50, Appendix B, Criterion V, which requires,in part, that activities affecting quality be accomplished in accordance with documented procedures. However, these violations will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria in section VII.B(2) of the NRC Enforcement Policy.

2.4 Inadequate Performance and Control of Division 1 130 Volt Battery Charger 2A-1 Maintenance On October 3, 1995, during performance of maintenance activities on the Division 1 130 Volt Battery Charger 2A-1, the battery charger was restored to service without testing being complete, resulting in a test load being connected in parallel to the battery charger and the Division 1 Battery System for approximately five minutes. Consequently, during this period the Division 1 Battery was inoperable. The maintenance personnel performing the testing and control room operators failed to note the abnormal configuration and, as a result, failed to enter applicable Technical Specification action statements.

The preventive maintenance on the 2A-1 Battery Charger was conducted under Work Request (WR) R032940427 and Maintenance Procedure 35.309.001, Revision 29. In preparation for maintenance procedure step 4.11, Overcurrent Limit, an external resistor bank was connected across the output terminals of the 2A-1 Charger. The spare battery charger was then taken off service and the 2A-1 charger was placed on service. During the performance of the overcurrent test, the test leads to the load resistor bank overheated and began to smoke. The battery charger output breakers were opened and the test was stopped. Inspection of the Battery Charger 2A-1 did not identify any damage to station equipment. The battery charger was placed back on service to verify it was functioning normally. However, the charger was outputting 60 amps, vice the expected output of approximately 100 amps, so the 2A-1 charger was taken off service and the spare charger was placed on service.

Technical Specification (TS) 3.8.2.1, requires, in part, that two operable battery chargers be on service for each divisional battery while the plant is in Operational Modes 1, 2, or 3. For approximately 13 minutes on October 3, 1995, the control room operators failed to recognize that when Charger 2A-1 was placed on service maintenance was not completed and it was not operable. In addition, due to the load resistor bank being connected, the Division 1 Battery was inoperable for approximately 5 minutes. Post event review by licensee engineering determined that following the inadvertent discharge on October 3, the battery would have had sufficient capacity to support calculated plant loads as designed. Due to the short duration of this event, the safety significance was minimal.

Though the four hour and two hour action requirements for TS 3.8.2.1.a and b were not violated, the operators were not aware that they were in the above action statements. The Nuclear Shift Supervisor's log documented that battery charger 2A-1 was not operable and the applicable four hour TS actions for the inoperable charger were in effect. However, the control room operator logs indicated that no TS actions were applicable.

On October 4, 1995, following review of control room logs, inspectors questioned licensee staff on the operability of the battery charger and the Division 1 Battery with the load resistor bank connected. The licensee did not conduct a thorough review of the event until November 2, after additional questioning by the inspectors; the licensee then determined that the Division 1 Battery was inoperable during the event on October 3.

The inspectors reviewed applicable documents and interviewed operations and maintenance personnel. Based on this review the inspectors determined the following:

- Work Request R032940427 and Maintenance Procedure 35.309.001 were inadequate because they failed to prevent the load resistor bank being connected in parallel to the 2A-1 Battery Charger and the Division 1 Battery, rendering the battery inoperable without operations and maintenance personnel realizing it. No guidance was provided to prevent connecting of battery charger to safety related battery during testing.

- The operators, in the control room, were not aware that the load resistor bank was still connected to the battery when they declared the 2A-1 Charger operable.

- Poor communication and inadequate work control between operations and maintenance personnel contributed to the event. The maintenance personnel did not communicate to the control room that a portion of the testing would be done on line, or that work was still in progress on the battery charger when they requested the protection tags to be cleared. Work Control Conduct Procedures require that maintenance personnel ensure that work being performed does not introduce any unauthorized modifications into existing plant systems that will remain in place after return to service. As a result, control room operators assumed that work was complete and that the charger was operable when it was requested to be placed in service.

- Battery Charger 2A-1 testing was still in progress when operations placed the charger on service since they were unaware of the actual configuration. The charger was therefore still inoperable when the LCO was exited. Procedural requirements for returning equipment to service were not followed in that equipment configuration and operability were not checked prior to placing the 2A-1 charger in service.

- The operations staff failed to assess the operability of the DC system or the reportability of the event.

- The following day, the inspectors discussed the event with senior licensee management and expressed concern for operability, but no formal review of the larger issues was undertaken for approximately four weeks. The two DERs that were promptly initiated concerned only the damaged test leads and the charger not being capable of full load current. Battery operability, procedure compliance, and work control were not initially reviewed.

Once the significance of the issue was realized, the licensee conducted a thorough review of the sequence of events. A second independent review utilizing personnel from offsite was planned and was to include the broader issues of communications and work control.

Inadequate corrective action for previous events (February 1995 connecting monitoring equipment to both channels of reactor instrumentation, and September 1994 valve stem ejection event) which occurred in part due to similar root causes (i.e. inadequate work instructions, failure to follow work process procedures, and poor communication) contributed to the occurrence of this event. Based on the occurrence of this event and the licensee's staff failure to promptly recognize the significance of the event, after the NRC inspector questioned the operability of the battery, the inspectors determined that a significant weaknesses existed in the licensee's work control and corrective action processes.

10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," requires that activities affecting quality shall be prescribed by documented instruction, procedures, or drawings, of a type of appropriate to the circumstances and shall be accomplished in accordance with these instruction, procedures, or drawings. Maintenance Procedure 35.309.001, Revision 29, 130/260 Volt Battery Charger Testing, Calibration and General Maintenance, approved April 3, 1995, an activity affecting quality, was not appropriate to the circumstances. Specifically, Step 4.11 was not sufficient to prevent the installation

of a test resistor bank on the Division 1 130/260 Volt Battery, which rendered the battery inoperable without adequate warning. Operations Conduct Manual, MOP05, Control of Equipment, Section 2.3.5, states in part, "Restoring a system and/or component to operable condition shall be accomplished by successful completion of maintenance, operations procedure requirements, and surveillance as required by the NSS/NASS." This is an activity affecting quality. However, the 2A-1 Battery Charger was placed in service while maintenance activities were still in progress. These are considered violations. (341/95012-04)

10 CFR 50, Appendix B, Criteria XVI, "Corrective Actions," requires in part that in the case of significant conditions adverse to quality, measures shall be established to assure that the cause of the condition is determined and corrective action taken to preclude repetition. However, inadequate work control practices, specifically the use of inadequate work procedures and failure to follow work process control procedures, resulted in restoration of Battery Charger 2A-1 with work in progress, rendering the Division 1 130/260 Volt Battery being inoperable, a significant condition adverse to quality. Corrective actions for previous significant events caused by similar inadequate work control practices failed to prevent event occurrence. Events caused in part by poor work control practices include the valve stem ejection event on September 17, 1993, and an unexpected change in reactor vessel level and pressure indication due to inappropriately installed monitoring equipment on February 11, 1995. This is considered a violation. (341/95012-02b)

2.5 Materials Inspector Qualification (38701) The inspectors reviewed the certifications and qualifications for inspectors in the materials inspection area, both at Fermi and the Warren Service Center, Detroit Edison's corporate testing facility. One unresolved item was identified and will be transmitted by a separate letter. The unresolved item concerned the certification of an individual at Fermi in certain areas, and the process by which the individual was certified in those specific areas; no concerns were identified with the Warren Service Center. No safety concerns were identified with respect to material which had been inspected. This is an Unresolved Item (341/95012-05(DRS)) pending further review by the NRC.

2.6 Power Ascension Testing During this inspection period power ascension testing activities were resumed briefly. Pressure regulator testing was performed at 96 percent power, the last testing required at this power. The licensee planned to complete power ascension testing following onsite safety review of data collected at the end of November. The inspectors will continue to monitor power ascension activities.

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of the engineering function.

3.1 Control Rod Drive 30-23 Performance Problems As previously documented in Inspection Reports 95004 and 95009, the licensee experienced control rod drive (CRD) performance problems due to the installation of an improperly sized ball in the CRD mechanism flange check valve. During this inspection period the licensee identified an additional CRD which was exhibiting initial characteristics similar to those seen with CRDs that had confirmed undersized flange check valve balls.

On October 14 during scram time testing, control rod 30-23 was difficult to withdraw following scram time testing, although scram time was normal.

Control Rod 30-23 was rebuilt and installed during the same time period as CRDs 34-31, 26-31, and 10-31. These three control rods had exhibited similar operating characteristics and was removed and disassembled in June 1995. Disassembly revealed that each contained an undersized flange check valve ball, which had wedged in the seat. CRD 30-23 was not inspected in June 1995 because work package documentation indicated that the flange check valve ball was not replaced during the rebuilding process.

Following the CR 30-23 movement problems experienced on October 14, the licensee established a test plan to isolate the problem. The testing failed to identify a specific problem. Control Rod 30-23 scram times fell within the normal scram times of other drives in the core, and the velocity profile of the scrams closely approximated the model of a typical scram. However, the inspectors noted that the results of the testing did not rule out an undersized CRD flange check valve ball as the cause for the CR 30-23 withdraw problems.

On November 2, 1995, the licensee declared CR 30-23 operable based on the normal scram times, velocity profile, and rod movement observed during the testing described above. The licensee's justification for operation did note that the velocity profile and the difficultly in withdrawing CR 30-23 did warrant further investigation and surveillance testing when the control rod was withdrawn. The current licensee plan is to maintain Rod 30-23 fully inserted until mid January 1996, when the rod is to be withdrawn in accordance with the control rod programming plan. Increased monitoring of the rod was planned.

Pending inspector review of further licensee testing of CRD 30-23, this item is an Inspection Followup Item (341/95012-06).

3.2 Conservative, Aggressive Actions Taken to Identify and Suppress Small Fuel Leak On October 9, the off gas radiation monitor indicated a brief increase from its normal reading of 7 mR/hr to 10 mR/hr, and then returned close to normal 20 minutes later. On October 13, during a planned power reduction for scram time testing and turbine valve testing, close monitoring and chemistry samples indicated a possible small fuel leak. The following week, the licensee reduced power to conduct power suppression testing to identify the approximate leak location. Testing confirmed a leak on the core periphery. Three control rods were inserted to suppress power and limit release rate from the leak. Coordination between engineering and operations with regard to this issue was good. The prompt, conservative actions taken to identify and suppress the fuel leak at the earliest indication of a problem was viewed as a strength.

3.3 Improper Combustion Turbine Generator (CTG) 11-1 Reliability Calculations A licensee review of the reliability of CTG 11-1 following a series of trips (as documented on Inspection Report 95011) determined that reliability calculations were improperly performed. CTG 11-1 is designated to provide power during a station blackout. Reliability calculations for this generator did not include all valid starts. The licensee committed to Regulatory Guide 1.155, which endorses NUMARC 87-00 and references NSAC-108. These documents stipulate calculating reliability for the last 20, 50 and 100 starts, using all valid starts from the previous 4 years. The review determined that only TS surveillance data were used, and only a single calculation using 10 years of data was being performed.

CTG 11-1 was used as a peaking unit by Detroit Edison, and therefore had been run to meet system peak load requirements and to perform post-maintenance tests in addition to the TS-required runs; none of these runs had been included in any reliability calculations. The validity of failures during non-TS runs was difficult to determine based on available data because the machine is started and controlled using different circuitry in manual (blackstart) mode and in automatic mode (for peaking load runs).

The inspectors noted that reliability data for runs during 1994 showed no failures, yet DER 94-0245 documented start failures and reliability concerns for CTG 11-1. This disparity was not recognized, and an earlier opportunity to identify the deficient calculations was missed.

Using available data to calculate preliminary reliability, licensee results indicated that CTG 11-1 did not meet committed reliability of 95 percent. The calculation showed a 95 percent reliability for the last 20 starts and 88 percent for the last 50 starts. Previous calculations indicated reliability was 96.2 percent for 133 TS start/runs using data back to 1985. This issue is considered an Inspection Followup Item (341/95012-07) pending review of licensee investigation and corrective actions.

3.4 Turbine Lube Oil Crack Challenged Operators and Engineering On October 4, the licensee discovered the supply line to number 8 turbine bearing developed a crack at a weld for a support lug. The supply lines are inside an outer guard pipe, which are designed to collect oil leakage and return it to the used oil tanks. The inner pipe is supported by sets of lugs welded to the inner pipe, which contact the outer pipe. The outer pipe is supported normally.

The licensee and a contract engineering company analyzed the available data and determined the cause of the crack to be related to turbine vibration. A series of repairs were made to reduce vibration of the pipe, reduce the leak rate, and support the inner pipe. Repairs were expected to reduce or eliminate crack propagation until the next refueling outage.

The licensee also increased monitoring of leakage rate and parameters of the affected bearing, and established a conservative action level for increased leak rate. Additional licensee inspections of the system identified excessive vibration in the supply lines for number 9 bearing, and numbers 4, 5, 8 and 9 jacking oil lines. Repairs to improve their pipe supports were implemented.

The inspectors identified that actions recommended on October 7 to set a maximum leak rate and actions to be taken at that leak rate were not fully implemented by November 1. Procedural changes had been lost before implementation, going unnoticed until brought to the attention of the licensee by the inspectors. Operations then promptly made the procedural changes.

3.5 <u>Commercial Grade Dedication Package Review (38703)</u> Inspectors conducted a limited review of the commercial grade dedication process. Since 1993, only one commercial grade dedication which involved metal testing had been performed. The inspectors considered the dedication to be weak, but acceptable for the intended application. The dedication was for mechanical parts used in a voltage regulator. Technical Service Request 27107 based the dedication upon verification that the material was AISI 4140. However, material verification was limited in that the alloy analyzer used could not verify content for all elements, such as carbon, specified by AISI 4140. The inspectors considered the dedication weak because the limitations of the material verification had not been evaluated by engineering. However, the inspectors considered the limited verification acceptable because the parts were not used in a high stress application.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750 and 83750 were used to perform an inspection of Plant Support Activities. Radiation protection and chemistry continue to be effectively implemented with few exceptions.

4.1 <u>Radiological Controls Continue to be Effectively Implemented</u> The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc., and randomly examined radiation protection instrumentation for use, operability, and calibration.

The site staff continued to be proactive in minimizing dose associated with implementing hydrogen water chemistry (HWC), which was expected to begin during December 1995. During planning for corrective maintenance in high-dose areas, operations, maintenance, and radiation protection routinely discussed how HWC would impact similar future jobs. Remote cameras have been installed to help minimize dose during operator rounds in locations which will increase in dose rate as a result of HWC implementation. Additionally, site-wide training on the impact of HWC implementation was performed to heighten the awareness of the expected new radiological conditions on the site. The inspectors considered the content and presentation of this training to be good.

4.2 <u>Coordination of Alara Consideration for Corrective Maintenance Activities was Inconsistent</u> During the inspection period, a number of steam leaks developed and were promptly identified. Each was reviewed in a coordinated fashion, and a plan developed with proper concern for

ALARA and safety. In most cases, the corrective actions were successful and safely performed. However, in the case of the third MSIV (N11-F609), an unnecessary dose to maintenance personnel was received.

Motor Operated Valve (MOV) N11-F609, developed a significant packing leak inside the turbine building steam tunnel. Following the initial entry for inspection and survey, the decision was made to enter the area (a high radiation area) to attempt to tighten packing and manually backseat the valve, if necessary. The first entry to perform corrective actions ended when the workers discovered that the magnitude and configuration of the leak were such that additional safety measures were required. This entry resulted in unnecessary dose because radiation protection personnel were not properly consulted; the area was initially surveyed just prior to the entry, and conditions of the valve should have been made known to the workers prior to entry. A second entry was also unsuccessful; packing adjustment failed to stop the leak, and manually backseating the valve was unsuccessful. After exiting the area to discuss this problem, control room operators identified that the valve indicated in mid-position. The valve was promptly opened from the control room, resulting in full open indication in 3-5 seconds (full valve stroke was normally about 107 seconds). These actions indicated that the valve has been manually positioned in the wrong direction. However, the maintenance person that operated the valve manually was sure he operated the valve in the correct direction. Additionally, a mechanical maintenance supervisor observing the activity also believed that the valve was correctly operated.

The decision was then made to electrically backseat the valve from the motor control center. Because workers were highly sensitized to the potential for valve damage during the evolution, this was actually performed three times before the valve was fully backseated and the leak stopped. While the plan to minimize the potential for valve damage by manually backseating the valve was a conscious tradeoff for the exposure received (537 mrem), the end result was still electrical backseating of the valve, which required no exposure.

DER 95-0855 was written to investigate this evolution. Station management initially identified that an unnecessary sense of urgency contributed to the event. The possible misoperation of N11-F609 in the manual mode is considered an Inspection Followup Item (341/95012-08), pending licensee investigation of the cause and actual valve characteristics.

4.3 Radioactive Material Located Outside the Radiologically Restricted Area (RRA) During an audit search for inappropriately stored radioactive materials (RAM), radiation protection (RP) personnel located three slightly contaminated items (100 to 250 cpm) outside the RRA, but inside the protected area. Also identified were two tools painted purple (normally only used for contaminated tools) which were not contaminated, but were incorrectly stored. This search was proactive in response to an event at another nuclear power station in which a large number of slightly contaminated items were found outside the radiologically restricted area. DER 95-0811 was written to document the event and identify root cause and corrective actions. At the close of the inspection period, the search for additional improperly controlled RAM continued. The inspectors will monitor the search and corrective actions during future routine inspections.

4.4 Safeguards Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan.

4.4.1 Inadequate Security Compensatory Actions On September 24, 1995, a vital area door failed to alarm when thumblocked open. Compensatory action was taken and a walkdown of the affected area was conducted by security and operations personnel with no anomalies noted. Later the same day the compensatory action was removed and the associated security card reader was disabled. On September 25, upon review by security supervision, it was determined that disabling the card reader was not a proper compensatory measure. Corrective actions were taken including posting a security officer at the door. The NRC was notified of the event in accordance with 10 CFR 73.71. Subsequently, on October 4, 1995, the notification was retracted based on post event investigation results.

Licensee security and maintenance personnel determined that the alarms for the security barrier were functional and had been improperly tested. Based on this, no condition existed that could have allowed unauthorized or undetected access and compensatory measures were not needed.

On September 28, 1995, a security officer again noticed that the electric bolt on the door had not closed to secure the door. The officer was unsuccessful at securing the door, and officers were posted as a compensatory measure for the insecure door. On September 29, the licensee discovered that the officer compensating for the door at that time did not meet requirements committed to in the physical security plan. That officer was replaced with one who met requirements committed to in the physical security plan. Subsequent licensee investigation revealed that other officers performing the same function also did not meet commitment qualifications. The licensee initiated DER 95-750 to document the event and track corrective actions.

The occurrence of the above events was not consistent with the excellent performance previously observed of the licensee's security staff. Licensee security supervision promptly identified the above deficiencies and corrective actions to address the cause for the problems were being developed. Pending inspector review of licensee corrective actions to address the personal performance issues that resulted in the inadequate compensatory measures, this is an Inspection Followup Item (341/95012-09).

4.5 Document Control Errors Identified During this inspection, there were two instances of improper control of procedure revisions. As discussed in Section 3.4, inspectors identified that the TCN to the plant shutdown general operating procedure to incorporate recommended actions to compensate for the lube oil supply line crack was lost prior to entering in the system. As discussed in Section 1.3, the licensee identified that, following a DER identifying that certain EDG surveillance rendered the associated core spray system inoperable, the licensee modified the affected surveillance procedures to incorporate impact statements to preclude recurrence. However, the next time the procedure was performed, the TCN was not included in the copy used. The inspectors will monitor this apparent trend in document control errors during future inspections.

5.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

Inspectors used Inspection Procedure 40500 to evaluate licensee self-assessment activities. Licensee self-assessment activities were mixed. Nuclear Quality Assurance (NQA) invested considerable time in providing coverage during the several power reductions for testing, maintenance, and flux suppression for the fuel leak. NQA continued to make some good findings, which included:

- Some system engineers operated valves, contrary to policy. It was also discovered that operations tolerated this practice by some system engineers.
- Following identification by operations that some acceptance criteria for surveillance were improperly identified and failure to meet them could improperly result in declaring the equipment inoperable when the function actually did not affect equipment operability, NQA recognized the significance and began to drive the issue.

However, the safety assessment function failed to provide backup to operations on a number of occasions during this inspection period, and only after inspectors began inquiries were the following issues investigated:

- Improper testing rendered divisional battery inoperable (Section 2.5)
- EDG 11 inoperability not recognized (Section 1.2)

5.1 <u>Certification of Level III Quality Assurance Inspectors</u> The inspectors reviewed the certifications for Level III quality assurance (QA) inspectors. The licensee certified Level III inspectors in accordance with the requirements of QA Procedure NQP-TQ1-02 "Inspector Certification." Minimum training requirements for the three levels of inspectors were specified in Procedure QP-QA-201 "Selection, Training, and Qualification Program Description." The NRC inspectors reviewed NQP-TQ1-02, Revision 5, and QP-QA-201, Revision 9, and verified that these procedures met the requirements of ANSI N45.2.6-1978, "Qualifications of Inspection, Examination and Testing Personnel for Nuclear Power Plants." The inspectors confirmed that the Level III QA inspectors had the required education, inspection experience, and training required by the procedures before they were certified; however, a concern was identified regarding the technical qualification of a Level III materials inspector, as discussed in section 2.6. The inspectors also confirmed that the licensee had certified Level III inspectors in all areas. Finally, the inspectors confirmed that QA audits of this area were performed and that adequate corrective actions were taken on the findings and observations from these audits. The inspectors noted that in both 1989 and 1991, audit findings were written on the QA inspector certification program. The corrective actions taken were adequate and sufficient to correct the problem and prevent recurrence.

6.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on November 21, 1995, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

* P. Bienick, Supervisor, Plant Engineering
* S. Booker, Assistant Superintendent, Maintenance
* M. Caragher, Supervisor, Plant Engineering
* W. Colonnello, Director, Safety Engineering
* J. Conen, Supervisor, Licensing
* L. Craine, Supervisor, Rad Health
* L. Crissman, GSPRO, Rad Protection
* R. Eberhardt, Director, Nuclear Training
* W. Emerson, Supervisor, I&C
* D. Gipson, Senior Vice President, Generation
* L. Goodman, Director, Nuclear Licensing
* T. Haberland, Superintendent, Planning, Davis-Besse
* A. Hickman, Ombudsman
* K. Howard, Supervisor, Mechanical & Civil Engineering
* R. Johnson, Supervisor, NQA Audits
* P. Kagel, Supervisor, Maintenance
* E. Kokosky, Assistant Radiation Protection Manager
* J. Korte, Director, Nuclear Security
* R. Laubenstein, NSS, Operations
* G. MacHoam, Supervisor, Rad Protection
* J. Malaric, Supervisor Modifications, Technical Engineering
* P. Marquardt, General Attorney
* R. McKeon, Assistant Vice President/Manager, Operations
* W. Miller, Superintendent, Technical Engineering
* R. Newkirk, Supervisor, Licensing
* D. Nordquist, Director, Quality Assurance
* W. O'Connor, Manager Nuclear Assessment
* D. Ockerman, Superintendent of Operations
* M. Offerle, General Supervisor, Radwaste
* S. Peterman, Nuclear Shift Supervisor, Operations
* R. Peters, Supervisor, Electrical
* J. Plona, Manager, Technical Services
* D. Powel, Operations Engineer
K. Precord, Supervisor, Maintenance
* W. Romberg, Assistant Vice President and Manager, Technical
* R. Russell, Supervisor, Training
* G. Scarfo, Supervisor, Design Engineering
* K. Sessions, Supervisor, Work Control

* B. Sheffel, Director, ISI/PEP
* R. Szkotnicki, Superintendent, Outage Management
* J. Thorson, Supervisor, NF and RXE
* K. Togeson, Supervisor, Scheduling
* G. Trahey, Supervisor, ISEG
* W. Tucker, Assistant to Technical Manager
* E. Vinsko, Manager, I&C
* L. Wigley, Project Manager, Turbine
* D. Williams, Supervisor, Rad Protection

Senior Management Meeting

On October 17-18, H. Miller, Regional Administrator, Region III, and B. Holian, Acting Director, Project Directorate III-1, NRR, met with D. Gipson, Senior Vice President, Nuclear Generation, and members of his staff to discuss Fermi 2 material condition and engineering improvement initiatives.

7.0 **VIOLATION FOR WHICH A "NOTICE OF VIOLATION WILL NOT BE ISSUED"**

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of the NRC Enforcement Policy. These tests are: 1) the violation was identified by the licensee; 2) the violation would be categorized as Severity Level IV; 3) within a reasonable time period; and 4) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for previous violation. Violations of regulatory requirements identified during this inspection for which a Notice of Violation will not be issued are discussed in Sections 1.2, 2.3.1, and 2.3.2.

8.0 DEFINITIONS

8.1 Inspection Followup Items Inspection followup items are matters which have been discussed with the licensee, which will be reviewed by the inspector and which involve some action on the part of the NRC or licensee or both. Inspection followup items disclosed during the inspection are discussed in Sections 3.1, 3.3, 4.2, and 4.4.

8.2 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 this inspection are discussed in paragraphs 1.4.1 and 2.5.