UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos. 50-369/88-20 and 50-370/88-20

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Facility Name: McGuire Nuclear Station 1 and 2

Docket Nos.: 50-369 and 50-370

License Nos.: NPF-9 and NPF-17

Inspection Conducted: June 25, 1988 - July 22, 1988

Inspectors: _____ 8/19/88
W. Orders, Senior Resident Inspector — Date Signed

_____ 8/19/88
D. Nelson, Resident Inspector — Date Signed

_____ 8/19/88
R. Croteau, Resident Inspector — Date Signed

Approved by: _____ 8/19/88
T. A. Peebles, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine unannounced inspection involved the areas of operations safety verification, surveillance testing, maintenance activities, and follow-up on previous inspection findings.

Results: In the areas inspected, two violations were identified. Activities observed indicate a weakness in determining system status during outages (see paragraph 8). A strength was noted in licensee response to inspector concerns generated from events occurring at other facilities (see paragraph 10).

Within the areas inspected, the following violations were identified:

Inadequate procedure/failure to follow procedure with respect to draining of steam generators without blocking the automatic start of an auxiliary feed pump, and to removing the 2B off site busline from service without an adequate procedure and without properly aligning switch gear assemblies.

Failure to meet the intent of Technical Specifications with respect to the McGuire Safety Review Group surveillance of plant activities.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*N. Atherton, Compliance
D. Baxter, Operations
L. Bost, Design Engineer
J. Boyle, Superintendent of Integrated Scheduling
S. Copp, Planning Engineer
*J. Day, Compliance
*J. Foster, Health Physicist
*B. Hamilton, Superintendent of Technical Services
*S. LeRoy, Licensing, General Office
T. McConnell, Plant Manager
W. Reeside, Operations Engineer
*M. Sample, Superintendent of Maintenance
R. Sharp, Compliance Engineer
*A. Sipe, Safety Review Group Chairman
*J. Snyder, Performance Engineer
*B. Travis, Superintendent of Operations
R. White, IAE Engineer

Other licensee employees contacted included construction craftsmen, technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview

2. Unresolved Items

An unresolved item (UNR) is a matter about which more information is required to determine whether it is acceptable or may involve a violation or deviation. There were no unresolved items identified in this report.

3. Plant Operations (71707, 71710)

The inspection staff reviewed plant operations during the report period to verify conformance with applicable regulatory requirements. Control room logs, shift supervisors' logs, shift turnover records, and equipment removal and restoration records were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel.

Activities within the control room were monitored during shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in applicable station administrative directives. The complement of licensed personnel on each shift met or exceeded the minimum required by Technical Specifications.

Plant tours taken during the reporting period included, but were not limited to, the turbine buildings, the auxiliary building, Units 1 and 2 electrical equipment rooms, Units 1 and 2 cable spreading rooms, Unit 2 reactor building, and the station yard zone inside the protected area. The Unit 2 reactor building was walked down prior to entry into mode 4 following the refueling outage. Several minor deficiencies were noted which the licensee took action to correct. Overall cleanliness was adequate.

During the plant tours, ongoing activities, housekeeping, security, equipment status and radiation control practices were observed.

a. Unit 1 Operations

Unit 1 began the period at full power. On June 26 at 12:05 p.m., the unit sustained a 50% load rejection due to the loss of one main feed pump. A non-safety load center, SMXL, de-energized due to several electrical grounds. This load center powers the main feed flow elements which control the feed pumps' recirculation valves. The de-energized flow elements indicated zero flow causing the recirc valves to fully open. This created an actual high flow condition causing feed pump suction pressure to decrease. One feed pump tripped on low suction pressure. Sufficient suction pressure remained to supply the remaining feed pump. Operators manually started both motor driven auxiliary feed pumps to assist in maintaining steam generator levels during the transient. The unit returned to full power early the next day. Except for several brief periods of load following, the unit remained at full power for the remainder of the period.

b. Unit 2 Operations

Unit 2 began the period in the end-of-cycle 4 refueling outage which commenced on May 27. The outage is on schedule with a planned return to service on July 27.

On June 24, with the unit defueled, a loss of off site power occurred. In preparation for maintenance on the B off site power switch gear, plans were made to realign incoming power such that the A busline would be supplying all loads. Normally, each busline supplies two 6.9 KV buses, but alternate alignments can be made to allow a single busline to supply all four 6.9 KV buses. To prepare for the maintenance, the two 6.9 KV buses normally supplied by the B busline were to be aligned to their alternate source, the A busline. With this intent, the control room operator mistakenly aligned the two 6.9 KV buses normally supplied by the A busline to their alternate source, the B busline. Therefore, the B busline, not A, was supplying all electrical power. The B busline Primary Circuit Breakers (PCB) were then opened from the switchyard causing all off

site power to be lost to Unit 2. Both emergency diesel generators (DG) automatically started to supply power to the emergency buses, however, the A DG tripped on an indicated overspeed condition. (The licensee determined later that an actual overspeed did not occur, but was simulated by blockage in a pressure instrument sensing line. This problem was corrected during on-going outage maintenance.) No other abnormalities occurred during the event.

The licensee considers the cause of the loss of off site power to be attributed to the operator's error. The operator was performing a section of operating procedure OP/2/A/6350/05, AC Electrical Operation Other Than Normal Lineup, when initially aligning the 6.9 KV buses. This procedure provides generic instructions for switching any of the four 6.9 KV buses to their alternate power supply. It refers to the 6.9 KV buses as the "applicable" or "respective" buses and to the buslines as the "normal" or "standby" power supplies so that this single procedure can provide instructions for any of the numerous lineups possible. In order to successfully use this procedure, the operator must have additional instructions, either written or verbal, to provide the desired final lineup. In this case the desired lineup was provided by the operator's supervision. The licensee considers that the instructions to the operator were accurate. The operator understood the intended alignment, but performed the opposite action than he had intended to perform. The control board mimic bus for this system is accurate, removing any cause for confusion as to which breakers should have been operated to make the desired lineup. A second operator made a similar error in that an entry into the reactor operators' log was made stating that the lineup was about to be performed. The lineup described was the same incorrect lineup that the first operator was making.

The general operating procedure used by the operator does not provide instructions for operating the PCBs to de-energize the busline once the initial lineup is complete. Investigation by the inspector revealed that a second document, Removal and Restoration (R&R) tagout 28-616, was specifically prepared for this maintenance. This document provided specific sequence and components for tagging in order to ensure that the B busline remained de-energized during the maintenance. R&R's are considered by the licensee to be procedures and are to be followed as such. As stated in Operations Management Procedure 2-17, Tagout/Removal and Restoration (R&R) Procedure, one of the purposes of R&Rs is "to allow the removal and restoration of equipment to be accomplished in a specific manner by directing the sequence of the steps involved in repositioning the equipment and indicating the desired removal and return position." In this case, the R&R did not direct the sequence of steps involved to achieve the desired alignment but only provided specific instructions for tagging once the busline was de-energized. It referred to the generic instructions contained in the operating procedure (presumably to align the 6.9 KV buses) but did not provide the desired alignment of the buses nor did it provide for opening the PCBs.

The NRC considers that the operator did not follow the operating procedure in that the incorrect 6.9 KV buses were aligned to their alternate power supplies. Also both the operating procedure and the R&R procedure were inadequate in that neither specified the desired alignment of the 6.9 KV buses nor provided for opening the PCBs. A more specific procedure would have aided the operator in the repositioning of equipment. This constitutes two examples of a violation of TS 6.8.1 for failure to follow procedures and for an inadequate procedure. (Violation 370/88-20-01)

While draining the Unit 2 steam generators on July 18 to establish proper chemistry for heatup, the auto start signal to the turbine driven auxiliary feedwater (TDCA) pump was received opening the steam admission valves SA-48 and SA-49 and isolating blowdown. The Unit was in mode 5 at the time with no steam pressure so the TDCA pump did not inject water into the steam generators.

The steam generators were being drained in accordance with OP/2/A/6250/03A, Steam Generator Cold Wet Layup Recirculation. Step 2.10 of the procedure directed IAE to defeat the feedwater isolation signals but no step was included to defeat the TDCA auto start signal on low-low steam generator level. The procedure was subsequently changed to block the auto start signal and the systems were returned to normal.

This event demonstrates that OP/2/A/6250/03A was inadequate in that performance of the OP resulted in an unplanned ESF actuation. This constitutes a third example of a violation of TS 6.8.1 for an inadequate procedure (Violation 370/88-20-01).

4. Surveillance Testing (61726)

Selected surveillance tests were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy and conformance with applicable Technical Specifications.

Selected tests were witnessed to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, that system restoration was completed and test results were adequate.

Detailed below are selected tests which were either reviewed or witnessed:

MP/0/A/7150/7	On Line Ice Basket Weight Determination Process
PT/0/A/4200/18	Ice Bed Analysis
TT/2/A/9100/269	DG Starting Air/Instrument Air Blackout Header Test

No violations or deviations were identified.

5. Maintenance Observations (62703)

Routine maintenance activities were reviewed and/or witnessed by the resident inspection staff to ascertain procedural and performance adequacy and conformance with applicable Technical Specifications.

The selected activities witnessed were examined to ascertain that, where applicable, current written approved procedures were available and in use, that prerequisites were met, that equipment restoration was completed and maintenance results were adequate.

No violations or deviations were identified.

6. Licensee Event Report (LER) Followup (90712, 92700)

The following LERs were reviewed to determine whether reporting requirements have been met, the cause appears accurate, the corrective actions appear appropriate, generic applicability has been considered, and whether the event is related to previous events. Selected LERs were chosen for more detailed followup in verifying the nature, impact, and cause of the event as well as corrective actions taken.

(CLOSED) LER 370/86-02: Reactor Trip on Intermediate Range High Flux Signal During Unit Shutdown. This item is associated with Unresolved Item 370/85-46-01 discussed in paragraph 7 of this report. This item is closed.

(CLOSED) LER 369/86-14: Train B Safety Injection In Mode 5. This event involved an inadvertent safety injection while testing reactor trip breakers. The licensee has made appropriate procedure changes to prevent recurrence. This item is closed.

7. Follow-up on Previous Inspection Findings (92702)

The following previously identified items were reviewed to ascertain that the licensee's responses, where applicable, and licensee actions were in compliance with regulatory requirements and corrective actions have been completed. Selective verification included record review, observations, and discussions with licensee personnel.

(CLOSED) Unresolved Item 370/85-46-01: Intermediate Range Detector Not Calibrated Following Replacement. This item involved a reactor trip caused by an intermediate range detector during a plant shutdown. The detector at fault had been recently replaced and subsequent calibration was deemed unnecessary by the licensee due to the increased sensitivity of the new detector. As a result, the intermediate low power reactor trip set points were not verified. The safety significance of this event was small in that more conservative set points resulted. The licensee has changed the procedure for detector replacement to require setpoint calibration in all cases. This item is closed.

8. Maintenance of System Status During Outages

During this reporting period two problems developed in which inadequate maintenance of system status contributed to the cause:

The first example involved an inadequate containment integrity verification. Prior to commencing Unit 2 fuel load (entering Mode 6) a containment integrity verification was performed. During this process valve NV-245, charging line containment isolation valve, was determined to be shut by the operator's observation that the Operator Aid Computer (OAC) indicated that it was shut. Neither the red or green control board indicators were illuminated which prompted the operator to consult the OAC. The licensee considers this to be an acceptable practice in normal situations. The valve, however, was undergoing maintenance, was disassembled and was unable to provide containment integrity. The OAC indicated the valve to be shut because the valve actuator remained in the shut position following disassembly. Fortunately, a check valve in the same line provided a second containment integrity barrier. Upon discovery of the problem, Operations took action to revise the containment integrity procedure to require additional verification if the OAC is the only means available for determining valve position. This corrective action is appropriate for this specific occurrence, but does not address the underlying problem of entering an operational mode without meeting all the mode change requirements. In this case, Operations did not have means for determining that all maintenance required to be complete was actually completed.

The second example involved a test of the Unit 2 diesel generator starting air system. During the Unit 2 outage, a test (TT/2/A/9100/269) was performed to assess the diesel starting air (VG) system's ability to supply the blackout header of the instrument air (VI) system. The first phase of this test consisted of lining up VG to the VI blackout header in a static mode and monitoring VG and VI pressure to determine the VI demand on VG. The test was deemed successful when very little VI demand i.e. leakage occurred. The licensee had expected more significant leakage and was surprised at the results. The VI blackout header supplies pressurized air to numerous air operated valves whose actuators are known to have air leaks. Regardless of the unexpected results, plans were undertaken to assess system performance in a dynamic state. The inspector conducted a walkdown of the portions of the systems involved with the test and discovered that most of the VI blackout header was isolated for outage maintenance. Since most of the valve actuators supplied by the blackout header were isolated, the test did little more than demonstrate that the VI piping did not leak. The licensee was unaware of the system status prior to the test. When it was reperformed later in the outage, significantly different results were obtained.

In these two examples it is obvious that actual system status was not known. The NRC considers the licensee's inability to accurately track maintenance during an outage to be a weakness. The licensee has recognized this weakness and stated that steps are being taken to improve.

According to the licensee the "Projects 2" computer program, when fully implemented, will provide a means by which outage maintenance items can be tracked to assess the status of the maintenance at any time. The NRC will continue to monitor the licensee's performance in this area.

9. NAMCO Limit Switch Environmental Qualification Concerns

A concern arose at the Catawba Nuclear Station regarding the environmental qualification (EQ) of NAMCO limit switches. Identical limit switches are installed on numerous safety and non-safety related valves at McGuire. The concern was that incorrectly installed gaskets on the switch covers would permit moisture to enter the switch internals thereby possibly shorting electrical contacts. A consequence could be that safety related valves that shut on an Engineered Safety Features (ESF) actuation would reopen when the safety signal is reset instead of remaining in the safety position.

The licensee conducted an inspection of all installed NAMCO limit switches on Unit 2. Four were found with incorrectly installed gaskets and repaired. Design Engineering analyzed that these four would have had no adverse impact during an ESF actuation.

Due to Unit 1 being in operation, not all switches were accessible for inspection. Therefore, the licensee conducted a consequence analysis for all Unit 1 inaccessible limit switches. In one case compensatory measures were taken: Valve 1RV76A is one of several valves that provide Phase B inside containment isolation for the containment ventilation headers. The seismically designed boundary for this system is limited to the piping between these valves and the outside containment isolation valves. Assuming a seismic event and a single active failure of the outside containment isolation valve(s), the potential exists for radioactive release if these valves failed to remain shut upon resetting the Phase B containment isolation signal. The licensee made compensatory Emergency Procedure changes to verify that 1RV76A remains shut after Phase B reset. Additionally, the corresponding outside containment isolation valve will be assured shut prior to the phase B signal being reset. The licensee stated that 1RV76A will be inspected and/or repaired at the next Unit 1 trip or during the next outage. All remaining inaccessible limit switches were deemed to be of no risk to safety by the licensee's consequence analysis. All inaccessible switches will be inspected either at the next unit trip or during the next unit outage. Several accessible Unit 1 limit switches were found with incorrectly installed gaskets and were repaired but in each case the licensee determined through consequence analysis that there were no past safety concerns. The licensee documented all conclusions in a Justification for Continued Operation (JCO).

10. Emergency Core Cooling System (ECCS) Sump Line Verification

During the inspection period, the Resident Inspection Staff informed the McGuire plant manager of an incident at another facility involving debris in a containment sump line which caused a loss of pump suction during a test. McGuire unit two was in the final stages of a refueling outage, which is the only time an inspection of similar lines could be performed.

During a resultant review of the documentation associated with the maintenance history of the lines, the licensee noted that maintenance on a valve on one of these lines had resulted in the detection of a piece of debris in the valve seat.

The licensee performed an inspection of the applicable piping. No debris was found. A similar inspection is to be performed on Unit 1 during the upcoming 1988 refueling outage.

The effort expended to resolve the status of the McGuire sump suction lines is indicative of a positive attitude toward safety and is considered a strength.

11. McGuire Safety Review Group Operation

Background

In report 50-369,370/88-14 it was reported that on November 30, 1987, a Diagnostic Evaluation Team (DET) began an initial two-week evaluation at the station and corporate offices.

The DET report was transmitted to the licensee on April 8, 1988. One of the findings documented in that report concerned the McGuire Safety Review Group (MSRG). Specifically, it was determined that (1) the MSRG had not been performing all functions identified as part of the McGuire licensing basis and resultantly did not appear to have been meeting the intent of McGuire TS 6.2.3.3 and 6.2.3.4, and (2) the scope and focus of current MSRG activities had evolved to the point that the majority of the group's time was spent on investigation of plant events, with little or no time spent on surveillance of plant operations and maintenance activities.

Resident Inspector Staff Review

The resident inspection staff review of the MSRG and requirements pertaining thereto included a review of:

a. Station Directive 3.1.32

b. Supplement 4 to the McGuire Safety Evaluation Report (SER)

c. Charter of the Station Safety Review Group (SSRG)

d. Section 6.2.3 of the McGuire Station Technical Specifications

e. The DET Team Report

f. The results of an Office of Nuclear Reactor Regulation (ONRR) review of commitments relative to the MSRG

Based on a review of the references listed above and discussions with ONRR and NRC Region II staff, the resident staff review was refined to deal exclusively with MSRG compliance with applicable Technical Specifications.

Discussions with the MSRG chairman, review of the SRG Work Assignment Log covering the period of 1986 through the present, and review of the Inplant Reviews conducted by the MSRG during that time, led to the following conclusions:

a. The majority of the MSRG's time is spent generating incident investigation reports (IIR's). The Work Assignment Log revealed that during the period 1986 - June 1988, 203 IIR's were generated but only 15 Inplant Reviews were performed. (Inplant Reviews are independent reviews of station activities, and are not necessarily coupled with IIR's; these come closer to meeting what was intended by Three Mile Island (TMI) action item I.B.1.2). This reveals that 93% of the MSRG's efforts were devoted to the generation of IIR's.

b. Other than those reviewed in the course of performing an incident investigation, procedures are not reviewed programmatically to determine adequacy.

c. Other than those reviewed in the course of performing an incident investigation, design changes are not programmatically reviewed to insure all safety concerns are properly addressed.

Ultimately, Technical Specification 6.2.3 Station Safety Review Group, is the culmination of the negotiations of commitments relative to TMI Action Item I.B.1.2. To reiterate, the intent of an ISEG (MSRG) is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, Licensee Event Reports, and other appropriate sources which may indicate areas for improving plant safety. It is expected that this group develop detailed recommendations for revised procedures, equipment modifications, or other means of achieving the goal of improved plant safety. A principal function of the independent safety engineering group is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practical. These findings were discussed with the Nuclear Safety Review Board (NSRB) and MSRG Chairmen on June 13, 1988. The NSRB Chairman indicated that the current operation of the SRG's at the Duke facilities was patterned after the description of an ISEG in NUREG 0800, Standard Review Plan, (SRP) Section 13-4., and that the resident's findings were a redefinition of the requirements.

A subsequent re-review of that section of the SRP confirmed the following:

a. The ISEG is to perform independent reviews of plant operations in accordance with the guidelines of item I.B.1.2 of NUREG-0660 and NUREG-0737.

b. The groups function is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information for areas for improving plant safety; and to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable.

c. The group is to perform independent reviews and audits of plant activities including maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities.

Based on the resident inspection staff review, it was concluded that the intent of technical specifications 6.2.3.3 and 6.2.3.4 were not being met by the current operation of the MSRG.

This was identified as an unresolved item (50-369,370/88-14-03) pending results of a meeting which was held on July 18, 1988. The meeting which involved participants from ONRR, NRC Region II, and the licensee was held in order to conclusively identify the intent of T.S. 6.2.3.3 and 6.2.3.4 and to determine if the current operation of the MSRG meets those requirements.

Conclusions

Based on the results of the July 18, 1988, meeting, and the input from an ONRR staff representative present at the meeting and involved in the generation of the requirements, the following conclusions were reached:

a. The current operation of the MSRG does not meet the intent of T.S. 6.2.3.3 which requires that the MSRG maintain surveillance of plant activities to provide independent verification that these activities are performed correctly. This finding is predicated on the review of the MSRG Work Assignment Log and discussions with the MSRG chairman and NSRB Director. During the period spanning 1986 until June of 1988, the MSRG did not perform routine independent surveillance of plant operations and maintenance activities to provide independent verification that these activities were performed correctly. The NRC does not consider the performance of Incident Investigations to adequately satisfy this requirement.

   This is a Violation of T.S. 6.2.3.3 (50-369, 370/88-20-02)

The current operation of the MSRG does not appear to meet the intent of T.S. 6.2.3.4 which requires that the MSRG make detailed recommendations for revised procedures and equipment modifications to the Director of the Nuclear Safety Review Board. The licensee indicated that since T.S. 6.2.3.4 is titled "Authority" they are authorized to perform the actions of T.S. 6.2.3.4 but not required to perform them.

This area will remain Unresolved pending the resolution of the licensee's position relative to their interpretation of the requirement and discussion with ONRR staff. (50-369/88-14-03)

12. Information Meetings with Local Officials (94600)

On July 19, 1988 a seminar was held with local public officials. The meeting was held with the cooperation of the licensee in the McGuire Nuclear Station Energy Explorium auditorium and was comprised of two sessions.

The first session was a private meeting between NRC representatives and the local officials. The objectives of the session were:

To familiarize public officials with the mission of the NRC.
To introduce key NRC personnel associated with the McGuire facility.
To discuss lines of communication between the public officials and the NRC.
To discuss the status of the facility and related community concerns with public officials.

Representatives from four surrounding counties were in attendance as well as the NRC Section Chief responsible for McGuire, the NRC Region II Director of State and Government Affairs, the Resident Inspector from the Catawba facility and the McGuire Resident Inspectors.

The second session was comprised of a private meeting/plant tour with the McGuire Plant Manager.

Following the tour, Duke sponsored a working dinner which was attended by local officials, Duke and NRC personnel.

The meeting, which was the first of this format in Region II was successful in conveying the necessary information and improving public relations.

13. Containment Spray Heat Exchanger 2B

On July 15 a heat balance test was run on containment spray (NS) heat exchanger 2B in accordance with PT/2/A/4208/04B, Train 2B Containment Spray Heat Exchanger Performance Test. Test results indicated that heat transfer capability had decreased to approximately one million BTU/hr-F (approximately 35 percent of design but 75 percent of what is actually

necessary according to the FSAR). FSAR section 6.2.1.1.3.1 specifies an NS heat exchanger capacity of 1.47 million BTU/hr-F. Test results from May 25, 1988, indicated heat transfer capability at approximately 45 percent of design. The licensee has written an operability determination stating that the heat exchanger is considered operable based on the ice inventory of the ice condenser and the current heat transfer capability of the NS heat exchangers. The licensee stated that calculations show peak containment pressure is predicted to remain below 15 psig.

Following the July 15 heat balance test, the service water side of the heat exchanger was cleaned but only minor amounts of material was found. The heat balance was again run on July 19 and the results were very similar to the July 15 test.

The licensee intends to inspect the primary side divider plate gasket to determine if bypass flow is hindering performance and a new gasket design is being evaluated. Several long term actions are also being evaluated. The inspectors will continue to monitor the licensee's actions in this area.

14. Exit Interview (30703)

The inspection findings identified below were summarized on July 22, 1988, with those persons indicated in paragraph 1 above. The following items were discussed in detail:

(OPEN) Violation 370/88-20-01, Inadequate Procedure/Failure To Follow Procedure with respect to Draining of Steam Generators without blocking input to ESF actuation and with respect to Removing an Off Site Busline From Service without an adequate procedure or without properly aligning switch gear assemblies (see paragraph 3).

(OPEN) Violation 369, 370/88-20-02, McGuire Safety Review Group Failing To Meet Intent Of Technical Specification Requirements (see paragraph 11).

(OPEN) Unresolved Item 369, 370/88-14-03, McGuire Safety Review Group Failing To Meet Intent Of Technical Specification Requirements (see paragraph 11).

Weakness with respect to determining the status of plant systems during outages (see paragraph 8).

Strength with respect to responding to inspector concerns arising from events occurring at other facilities (see paragraph 10).

The licensee representatives present offered no dissenting comments, nor did they identify as proprietary any of the information reviewed by the inspectors during the course of their inspection.