UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos. 50-369/93-32 and 50-370/93-32

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242-1007

Facility Name: McGuire Nuclear Station 1 and 2

Docket Nos. 50-369 and 50-370   License Nos. NPF-9 and NPF-17

Inspection Conducted: December 19, 1993 - February 5, 1994

Inspector: W. H. Miller Jr. 3/2/94
for G. Maxwell, Senior Resident Inspector   Date Signed
Senior Resident Inspector

G. Harris, Resident Inspector
P. Hopkins, Resident Inspector, Catawba

Approved by: M. Lesser 3/3/94
M. Lesser, Section Chief   Date Signed
Division of Reactor Projects

Accompanying Personnel:

W. Miller, Project Engineer, Region II
R. Watkins, Project Engineer, Region II

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance observations, and emergency preparedness. Backshift inspections were performed on December 22, 27, 28, 29, 30, 31, 1993 and January 1, 2, and 23, 1994.

Results: In the area of operations, the inspectors discovered that valves were modified during the last Unit 2 refueling outage from fail

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open to fail closed valves. This change had not been redmarked on the control room drawings (paragraph 2.d.1.).

In the area of operations, the inspectors determined that the failure of MSIV 2SM5 to fully close on demand and the failure of MSIV 2SM7 to close when tested at normal operating temperature have been attributed to inadequate clearance between the yoke rods and the yoke rod guides (paragraph 2.d.3.). Even though the licensee has taken immediate action to correct this deficiency, this item is considered an example of poor engineering maintenance support and management oversight and is considered to be the major cause of maintenance testing not being properly conducted on Unit 2 MSIVs (paragraph 2.d.4).

In the area of operations, the inspectors determined that the training program was weak in providing the operators with sufficient information about the modification of four steamline drain valves (paragraph 2.d.6.).

In the area of plant operations, an issue was identified involving the licensee's failure to correctly report an event to the NRC in a timely manner. This condition was evaluated by other RII NRC personnel during the week of January 10, and the results of this evaluation will be documented in Inspection Report 50-369,370/94-04 (paragraph 2.d.7.).

In the area of maintenance, one potential violation was identified because of the licensee's failure to maintain an adequate volume of fuel oil in accordance with technical specifications for the 1B emergency diesel generator fuel oil storage tank (paragraph 4.a.).

In the area of maintenance, one non-cited violation was identified during a routine review of maintenance training records. The plant staff determined that two mechanical maintenance supervisors and one IAE supervisor did not meet the educational requirements established by ANSI Standard N18.1-1971 and Technical Specification 6.3.1. (paragraph 4.c.).

In the area of maintenance, the inspectors identified a weakness involving technical personnel's failure to notify the control room operators of the start of a performance test (paragraph 4.d.).

In the area of maintenance, the inspectors identified that diesel generator reliability was above station goals and performed as expected when required during recent events at McGuire (paragraph 4.e.).

In the area of maintenance, the inspectors identified that weak planning and scheduling of work activities has contributed to safety system unavailability (paragraph 4.e.).

In the area of plant support, the inspectors concluded that the licensee's housekeeping is acceptable. The station recently has begun to trend housekeeping discrepancies as part of its problem investigation report system. Continued management attention is needed in this area (paragraph 4.f.).

In the area of maintenance, the inspectors concluded that the licensee's cold weather preparation was adequate during the recent freezing conditions. During the month of January record low temperatures were experienced by the facility (paragraph 4.f.).

In the area of maintenance, the inspectors concluded that a number of transients and reactor trips were experienced by the plant due to equipment problems. For example, at least 12 trips over the past several years can be attributed to problems with the main feedwater system (paragraph 4.j.).

In the area of maintenance, the inspectors concluded that the licensee's current backlog of work is above goals (paragraph 4.g.). The inspectors also concluded that the licensee's current work control system has significant deficiencies that are being corrected by the new work control process. (paragraph 4. h.).

In the area of maintenance, the inspectors concluded that the majority of the maintenance performance problems were caused by lack of procedure adherence, lack of self checking and inadequate written instructions. In addition, human performance errors account for a significant number of maintenance problems. A review of trends for inadequate maintenance work practices by the inspectors revealed no detectable improvement (paragraph 4.i.).

In the area of maintenance, the inspectors identified that the licensee's foreign material exclusion policy needs increased attention and is considered a weakness. (paragraph 4.i.).

In the area of maintenance, the inspectors concluded that the licensee's preventive maintenance program is satisfactory; however, does not appear to sufficiently address component aging problems.

In the area of maintenance, the inspectors determined that the licensee has an effective predictive maintenance program. The program has been effective in detecting and assisting in the troubleshooting and diagnosis of equipment problems (paragraph 4.k.).

In the area of maintenance, one violation was identified involving two examples of a failure to implement the required compensatory surveillances for an inoperable diesel generator (paragraph 4.b.).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Baxter, Support Operations Manager
*A. Beaver, Operations Manager
*J. Boyle, Work Control Superintendent
D. Bumgardner, Unit 1 Operations Manager
B. Caldwell, Training Manager
M. Cash, Engineering Supervisor
*R. Cross, Compliance Specialist
T. Curtis, System Engineering Manager
*C. Cuthbertson, System Engineer
*R. Deese, Safety Review Group
J. Foster, Station Health Physicist
F. Fowler, Human Resources Manager
*G. Gilbert, Safety Assurance Manager
P. Guill, Compliance Engineer
B. Hamilton, Superintendent of Operations
B. Harkey, Mechanical Maintenance
B. Hasty, Emergency Planner
*F. Hayes, Human Resources
P. Herran, Engineering Manager
*B. Johansen, Operations
L. Kunka, Compliance Engineer
E. Geddie, Station Manager
*T. McMeekin, Site Vice President
*W. Matthews, Engineering and Electrical
R. Michael, Station Chemist
*M. Nazar, Instrument & Electrical Maintenance Superintendent
T. Pederson, Safety Review Supervisor
N. Pope, Instrument & Electrical Superintendent
*R. Roberts, System Engineer
R. Sharpe, Regulatory Compliance Manager
D. Tapp, Mechanical Maintenance General Superintendent
*K. Thomas, Engineering
B. Travis, Component Engineering Manager
R. White, Mechanical Maintenance Superintendent

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

NRC Resident Inspectors
*G. Maxwell, SRI
P. Hopkins, RI
*G. Harris, RI

*Attended exit interview

2. Plant Operations (71707, 92700 and 93702)

a. Observations

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 reviewed. 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 number of licensed personnel on each shift met or surpassed the minimum required by Technical Specifications (TS).

Plant tours taken during the reporting period included, but were not limited to, the turbine buildings, the auxiliary building, electrical equipment rooms, cable spreading rooms, and the station yard zone inside the protected area.

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

b. Unit 1 Operations

Unit 1 operated at 100% power until January 23 at 2:00 a.m. when the unit was conducting a planned shutdown to test its main steam isolation valves. A steam generator tube leak was detected when the unit reached 25 percent power. The initial indications came from condenser air ejector radiation monitor alarms. Chemistry samples confirmed that steam generator D was leaking at a rate of approximately 100 gallons per day. There had been no recent identified leakage from this steam generator. The licensee continued to shutdown the unit as required by its administrative limit of 50 gpd leakage through any one steam generator. The licensee placed the unit in cold shutdown and pressure-tested all steam generators for leakage.

The unit has been shutdown twice before during the past six months due to steam generator tube leaks. One leak occurred when a crack developed in a sleeved tube. The second leak occurred during the subsequent startup because a pulled tube plug had not been adequately welded in place.

The repairs to the steam generator were still in progress at the time of the report.

c. Unit 2 Operations

The unit operated at 100% power until December 27, 1993, when a Loss of Offsite Power Event occurred on Unit 2. This was caused by the failure of an insulator in the switchyard. This was followed by a failure of the Unit 2 Turbine Generator to runback. Bus Line 2A subsequently tripped on overcurrent. A reactor trip occurred at 10:07 p.m. because of a power range high flux rate signal, followed by a turbine generator trip and the opening of the 2A generator breaker. This resulted in the loss of Unit 2 offsite power. The subsequent cooldown resulted in a safety injection and a main steam line isolation. The B 2SM-5 main steam isolation valve failed to close fully, resulting in the 2B steam generator blowing down to a near dry condition. The licensee declared an Unusual Event. As a conservative measure the licensee activated the Technical Support Center, Operations Support Center, and staffed the Emergency Operations Center. Offsite power was restored to Unit 2 at 11:43 p.m. The licensee repaired the failed main steam isolation valve and replaced the failed bus line insulator. Unit 2 returned to Mode (startup) operation on January 6, 1994. The unit has operated at or near 100% power since this event occurred.

d. Follow-Up on Short Term Required Corrective Actions Prior to Restart

On December 28, an Augmented Inspection Team (AIT) was chartered. The team was on site from December 29, 1993, to January 1, 1994, to review the loss of offsite power event. A confirmatory action letter was issued to obtain Region II concurrence prior to restart. An exit meeting was held with the licensee on January 5, 1994. The AIT findings were documented in RII Report 50-369,370/93-33. Between January 4 and 6, prior to Unit 2 restart, the resident inspectors conducted followup inspections of the short term corrective action items. The results of the followup inspections are documented below.

Loss of Off-Site Power

1. Control Room Drawing Redmarking

During the Unit 2 Loss of Offsite Power incident some steam line drain valve positions were in question. IAE personnel were asked to verify that these valves were closed. They had some trouble determining the valve position. After the event a PIP (2-M93-1338) was written to determine why there was confusion over determining the valve position. During investigation of this PIP it was discovered that the valves were modified during the last Unit 2 refueling outage from fail open to fail closed valves on August 31, 1993. This change had not been redmarked on the control room drawings. The drawings were only stamped to signify that a modification was completed. The control room drawings were not used during the actual event and the lack of redmarking was not a factor during the event; however, an inquiry was made about the procedures for redmarking control room drawings after plant modifications.

Redmarking of control room drawings (flow diagrams and electrical one-lines) is supposed to be done after a modification is completed. This shows the operator what has been changed, since the new revised drawing may not be issued for several months. The licensee discovered that Operations was redmarking a selected number of changes following modification work and not all the changes. The criterion was that if the modification was important to normal plant operation, it would be redmarked; if not, then redmarking would not be done. The drawings were stamped, indicating the modification, and made available to the operators (filed in the document room in the back of the control room). Judgement was being used by the operations staff to determine what should or should not be redmarked.

Following the LOOP, the licensee decided to redmark the complete modification information on the control room drawings in accordance with the procedure. This decision was made for several reasons. Redmarking all modification information on the drawings would eliminate any confusion the operators might have about whether a particular modification was indicated on the drawing or not. Redmarking all changes would also eliminate subjective judgement on the part of the operations staff.

On January 4, the inspectors observed the work of approximately 20 engineering personnel who were assigned to audit and update all flow diagrams and electrical one-line drawings used in the control room and operations shift office. During that time about 150 drawings in the control room and the same 150 in the shift office were updated with complete modification information. The types of information added to the drawings were 1) instruments (not vital to operation) moved or changed, 2) piping classification that had changed, and 3) cable numbers or breaker ID numbers that had changed. None of this information was determined to be detrimental to operation because it was missing; however, the drawings were incomplete. Currently all control room and operations shift office flow diagrams and electrical one-line drawings are completely up-to-date. The plant staff indicated that, in the future, they will redmark complete modification information on the control room and shift office flow diagrams and electrical one-line drawings when each modification is completed. The licensee has changed the procedures and Station Directives to eliminate judgmental factors from redlining drawings. The inspectors believe the changes will contribute to an improvement in maintaining the control room drawings.

The inspectors will continue to evaluate drawing control in the control room and work areas. This is an Unresolved Item 50-369,370/93-32-03: Redline control room drawings.

2. Rupture of Reactor Coolant Pressurizer Relief Tank Rupture Discs

On December 27, coincident with an offsite power loss, reactor trip, turbine trip and safety injection, and unusual event, the reactor coolant pressurizer relief tank (PRT) rupture disc failed due to the cycling of NC PORVs. The inspectors reviewed the work requests that directed the work to replace and repair the discs.

The inspectors determined that the PRT and its associated rupture discs functioned as designed during the Loss of Off-Site Power/Reactor Trip/Safety Injection event on 12/27/93. The PRT is protected against a pressurizer discharge exceeding the tank's design value by these two rupture discs, which discharge into containment. The pressurizer power operated relief valves (PORVs) were cycled by the operators at the controls during the event in response to increasing pressurizer level and pressure from safety injection. Additionally, manual control of PORVs was utilized to lower NC pressure to within dry S/G DP limits. The operation of these valves also prevented the undesirable opening of the spring loaded pressurizer safety valves. The pressurizer safeties did not lift during this event.

The inspectors reviewed plant drawings and noted that the PRT and the two rupture discs are detailed on plant drawing MCM-1201.04-101. Drawing MC-2690-271 shows details of the steam deflector arrangement for the PRT; the drawing details 1) elbows that direct/deflect discharge towards the primary shield wall, and 2) supports on these deflecting elbows.

The inspectors reviewed the completed work packages for the repairs and evaluation of the PRT system prior to plant restart and observed that the licensee completed the following corrective actions prior to restart:

- replaced both rupture discs on the PRT;
- evaluated PRT pressure data collected during the event; and
- inspected and evaluated PRT and associated piping, inspected 4 normally closed diaphragm valves, (found no signs of overpressurization or leakage from the PRT nozzle welds at the rupture discs); inspected the PRT steam deflector supports, the snubbers in the immediate area of

water spray were inspected and tested with no problems identified.

The inspectors' evaluation was completed through interviews, observations of PRT pressure data, and review of work requests, repressurization of the systems and testing data. The inspectors agreed that the PRT was operable prior to restart.

3. Failure Of MSIV To Close During LOOP

a. Main Steam Isolation Valves

During the LOOP event, main steam isolation valve 2SM5 failed to fully close on demand from a main steam isolation signal.

The inspectors were in the control room or in the TSC during the event and were present during the MSIV 2SM5 problem investigation, maintenance repair, and testing. Following the event, the licensee began an immediate investigation and corrective actions. Component engineering performed a preliminary cause evaluation and determined that the lower spring plate was mechanically bound to the valve yoke rods. The probable cause was inadequate clearance between the yoke rod guides and the yoke rods. 2SM5 was visually inspected on December 28th and was found to be mechanically bound approximately 1-3/4 inches off of the seat. The binding was due to inadequate clearance between the yoke rods and the yoke rod guides. This was verified when the yoke rod guides were loosened, which allowed the valve to fully close. This valve was then stroked several times and exhibited no signs of binding. Subsequent valve stroke testing revealed no binding or other indications of valve damage.

Investigation of the maintenance procedure revealed an inadequacy; the exact setup dimensions for the yoke rod guides were not provided in the maintenance procedure, or was the vendor supplied maintenance manual incorporated. Based on data obtained from the Unit 2 troubleshooting and conversations with the equipment manufacturer, the maintenance procedure was revised. The revised procedure also will be used for adjustment of the yoke rod guides on Unit 1.

Vendor supplied information included required clearance of .015 to .030 inches between the yoke rods and the yoke rod guides at any point along the bottom spring plate travel with the valve at full operating temperature. This information was not in the procedure. The licensee requested clearance specifications for ambient conditions (valve open or closed) and for valves at normal operating temperature in the full open position. These clearances would account for thermal expansion of the valve body and would establish the inspection criteria for the Unit 1 valves. The specified clearance was .060 to .070 inches. All MSIVs were reset to these dimensions.

While inspecting the MSIVs, the licensee found that on 2SM3, the horizontal yoke rod guides were located on bottom yoke rods. On the remaining valves, these guides were located on the top yoke rods. The manufacturer was contacted to discuss the design requirements for yoke rod guide location. The manufacturer indicated that guide location is of no consequence with McGuire's valve orientation (operator installed in a vertical plane).

On January 6, Unit 2 MSIVs were tested to the revised test requirements (valve at full operating temperature) prior to restart.

The inspectors observed these tests, which required the plant to be in Mode 3, 557°F and 2235 psig. The tests included:

1) opening the valves,
2) closing the valves,
3) adjusting the valve horizontal and bottom yoke rod guides to .030 inches, and
4) closing the valves to assure performance

All but the "A" SG MSIV (2SM7) were successfully opened, closed, adjusted and then cycled closed. Valve 2SM7 encountered binding slightly off the closed seat when the performance closure test was being attempted. The valve's pilot valve was about 1 inch off its seat, which would not ensure that 2SM7 was fully closed. The test was stopped and the valve vertical yoke guide rod pins were loosened. The pilot valve then closed to within 1/4" off the closed seat, this indicated that the valve had bound up. The valve top vertical yoke rod guides were removed. The yoke rod guide pin contact surfaces to the yoke were inspected and their ends were machined square with their threads. The yoke rod guides were reinstalled, clearances were adjusted, and the valve was successfully tested. The binding of 2SM7 appears to have resulted from the uneven surface condition of the rod guide pins. The inspectors observed that the valves were tested in accordance with the details outlined on Work Order WC93093214.

Following the successful completion of the tests on each of the Unit 2 MSIVs, the inspectors agreed that the valves functioned to close satisfactorily and that the failure mechanism for these valves had been identified and corrected.

Failure of 2SM5 to fully close and the failure of 2SM7 when tested at normal operating temperature has been attributed to inadequate clearance between the yoke rods and the yoke rod guides.

The inspectors will continue the evaluation concerning the failure of 2SM5 failure to close, this condition will be identified as an Unresolved Item 50-369,370/93-32-04: Failure of MSIV 2SM5 to close.

b. Licensee Control of Vendor Information

During the post reactor trip review, an evaluation was made of the failure of 2SM5, Unit 2 "B" SG main steam isolation valve, to fully close on main steam isolation signal. As a result, the licensee identified a maintenance problem associated with vendor manuals not being incorporated into the maintenance procedures. Subsequently, an evaluation was done to determine any short term procedure changes associated with safety related equipment based on pending technical bulletins and vendor manuals.

An assessment of the current state of updates to safety related documents and procedures due to vendor changes was made by the licensee. During this review, several items were identified as not being tracked under the current programs such as PIP, OEP, MM, SPR. Several items would need long term corrective actions. But, no item was identified that would prevent Unit 2 startup.

The following items are changes that were initiated prior to the PIP program, and reflect changes which have not been tracked for completion, and have not been completed.

- Review of new RN Pump Manuals

- Set up procedures based on the Grinnell diaphragms life extension data determined by Design Study MGDS-0076

- Review issuance of documents affected by outstanding Load Capacity Data sheets

The current process requires a PIP, and consequently a MM to issue a document and current changes due to vendor information is handled by the PIP, OEP, MM programs.

Several vendor letters were found to be issued, that had not been turned into the OEP Group to be reviewed for applicability as OEP items.

The licensee completed an operability evaluation and found both units post and presently operable. The licensee scheduled to complete the following actions to upgrade site vendor manuals:

- Initiate PIP for review and issue of new RN pump manuals and update procedures to reflect charges if necessary.

- Initiate PIP to set-up procedures based on Grinnell diaphragm life extension data which was determined by Design Study MGDS-0076.

- Initiate PIP to review and issue documents affected by outstanding Load Capacity Data sheets.

- Initiate four (4) PIPs, each to address each vendor letter which needs to be processed to the OEP group for review and possible inclusion in the OEP program.

- Provide training to all Engineering personnel on the handling of vendor letters and changes as they relate to initiating OEP items.

- Determine 'f a periodic review of safety related vendors manuals is necessary to insure agreement with current procedures.

- Review McGuire Site Directive 751, "Document Management Control of Documents", for possible revision for control of vendor communications.

The inspectors reviewed vendor manuals, maintenance procedures, and interviewed personnel associated with the review and evaluation of vendor manual processing.

Even though the licensee has taken immediate action to correct this deficiency, this item is considered an example of poor engineering maintenance support and management oversight and is considered to be the major cause of maintenance testing not being properly conducted on Unit 2 MSIVs.

The poor control of vendor information will continue to be evaluated by the inspectors. This condition will be identified as an Unresolved Item 50-369,370/93-32-05: Vendor information for safety related equipment.

4. Evaluation of 2SM5 For Potential Valve Seat Damage

Since 2SM5 was subjected to steam flow while partially open, the possibility for seat damage was evaluated by System Engineering. The calculation was performed to determine the approximate velocity across the valve seat. Calculated velocities were compared to steam flow velocities encountered by the valve during full power operation and to industry standards.

The inspectors observed that engineering assumed for full power operation, a valve throat port diameter, to provide a port cross-section of approximately 5.4 square feet. Records showed operating parameters for full power operation to be 4,000,000 Lbm./Hr. and a steam pressure of approximately 1000 psig. The steam tables for specific volumes under these conditions is .46 Cu. Ft./Lbm. This converts from Lbm./Hr. to Cu. Ft./Sec., and using the port cross-section of 5.4 Sq. Ft., steam velocity past the seat is approximately 96 Ft./Sec.

With the valve in the partially open position and operating parameters of: saturated steam conditions at 400 PSI, a mass flow rate of 500,000 LBS/HR., the volume is 1.16 Cu. Ft./Lbm. The valve port cross-section was estimated by distance the valve was open when inspected on December 28th. The bottom spring seat was approximately 1-3/4 inches from the lowermost position as evidenced by the scrub marks on the yoke guides. With a pilot valve travel of 1 inch, this placed the main valve disk approximately 3/4 inches off the valve seat. The valve port cross section was calculated to be .52 Sq. Ft. Under these conditions, the steam velocity across the seat was approximately 310 Ft./Sec. The valve was operated under this condition for less than 1 hour. Since the steam flow velocity remains within recommended values for piping design, there was no reason to assume seat damage.

5. Operator Training On Unit 2 Modifications Of Main Steam Line Drain Valves

- Concerning the LOOP which occurred on December 27, the resident inspectors evaluated the licensee's training program. The inspectors focused on four miscellaneous main steam line drain valves which were modified during the most recent Unit 2 refueling outage (June-August, 1993). The inspectors verified that the training staff required that each of the Unit 2 SROs, ROs, and non-licensed operators who were on shift during the LOOP to read the modification summary for each outage modification that affected a Unit 2 piece of equipment, system or valve as it related to operations. One of the modifications, NSM-22401, required changing the failed state of four miscellaneous main steam line drain valves. These valves; 2SM-83, 2SM-89, 2SM-95, and 2SM-101, were changed from FAILING OPEN to FAILING CLOSED upon loss of power. The inspectors verified that these operators were also briefed by live lecture about the changes which were made to the four valves.

- Each steam generator has a two inch drain line located upstream of the MSIVs. The four valves, one each per steam generator, are installed in these drain lines. Following the LOOP operations personnel were apparently confused by information being provided to the control room as it related to the failed condition of these valves. As a result, they directed the maintenance staff to "properly" position these valves. In haste, neither operations or maintenance referred to the correct drawings to affirm the properly failed position of the valves. Subsequently, maintenance unknowingly opened the four drain line valves instead of assuring that the valves were closed. This incorrect action under different circumstances, could have contributed to the rapid cooldown of the plant and expedited the voiding of "B" SG, which had an MSIV (2SM5) stuck partially open.

- The inspectors determined that the training program was weak in providing the operators with sufficient information about the modification of these four drain valves.

The inspectors will continue to evaluate the circumstances and conditions that involved the work controls associated with mis-positioning the Unit 2 main steam line drain valves. This condition will be identified as an Unresolved Item 50-369,370/93-32-06: System configuration control.

6. Reportability Per 10CFR50.72 Not Properly Completed

The inspectors interviewed licensee personnel, listened to NRC taped telephone conversation messages, interacted with members of the AIT Team and reviewed the various logs associated with the LOOP event. As a result, the inspectors determined that the confusion concerning the information that was reported to the NRC Duty Officer immediately following the loss of off-site power was as follows:

- On December 27, at 10:07 p.m., Unit 1 and 2 at 100% power, Unit 2 experienced a reactor trip, followed by a turbine trip, then an engineered safety feature (ESF) actuation.

- Just prior to the reactor trip, the offsite power supply to Unit 2 failed. The initiator of the event was the failure of off-site power and was the result of the failure of an insulator located in the switchyard. When the unit experienced the loss of offsite power, then reactor trip and turbine trip, the lights went off on the Unit 2 side of the control room, including the power for the control room FAX machine.

- The control room SRO made initial notification to state and counties: "NOUE due to loss of all offsite power". This notification was verbal and within the 15 minute requirement. Upon completion of faxing to state and counties, the control room shift support technician mistakingly faxed the State/County Notification form to the NRC. Per RP/0/A/5700/10, Immediate Notification Requirements, it is appropriate to fax the NRC form RP-10 to NRC prior to call for ease in communication. Faxing cannot take the place of verbal notification.

- The NRC Duty Officer called the control room as a result of the FAX. A communicator had been called in to the control room but was not given a complete turnover. The shift support technician informed the communicator of the FAX to NRC. The communicator began talking from the State/County Notification form. The communicator was also under the mistaken impression that the NRC had already been notified. As a result, he failed to report the problem with the MSIV and incorrectly responded to some questions.

As an interim precaution, the licensee procedure OMP 2-2, Shift Turnover has been temporarily revised to require a designated SRO be responsible for emergency NRC notifications.

This condition was evaluated by other RII NRC personnel during the week of January 10, and the results of this evaluation will be documented in RII Report 50-369,370/94-04.

7. Post Reactor Trip Ice Condenser Inspection

After the Unit 2 Reactor Trip on December 27, a post trip inspection was made of the ice condenser to assess its status. A first entry into containment showed that ice bed melting with several lower inlet doors open. Later on December 28, the ice was removed from these doors and they were returned to normal service condition.

An operability evaluation of the ice condenser was completed and indicated the system to be operable following the PRT rupture disk event. Operability was assured by completing all applicable Technical Specification inspections, evaluations and surveillance requirements. The licensee's evaluation was summarized in design calculation (MCC-1201.17-00-0012). However, the basis for determining operability was based on completion of the surveillance requirements. The design calculations were not necessary for assuring operability.

The inspectors verified by interviews, record review and observation, that the following Technical Specifications verifications were performed:

- TS 4.6.5.1.a — Verify ice bed <27F.
- TS 4.6.5.1.b.1 — Chemical analysis of boron concentration and pH.
- TS 4.6.5.1.b.2 — Verify adequate ice mass.
- TS 4.6.5.1.b.3 — Verify adequate flow passage area.
- TS 4.6.5.1.c — Verify structural integrity of basket.
- TS 4.6.5.2 — Verify ice bed temperature monitoring system operable.
- TS 4.6.5.3.1 — Verify operability of lower inlet doors.

·	TS 4.6.5.3.2.a(b)	Verify operability of intermediate doors.
·	TS 4.6.5.3.3	Verify operability of top deck blanket.
·	TS 4.6.5.4.a	Verify operability of lower inlet door position monitoring system.
·	TS 4.6.5.4.b & c	Verify operability of lower inlet door position monitoring system.
·	TS 4.6.5.5.1 and 2	Personnel door integrity.
·	TS 4.6.5.7	Floor drain operability.

The inspectors agreed that the evaluation by the licensee to determine operability of the ice condenser was acceptable, prior to restart.

8. Unit 2 Mode Change

Prior to the plant heatup to Mode 4, the inspectors observed operations personnel while they were completing the following mode change manipulations:

- OP/2/A/6100/01, Controlling Procedure for Unit 2 Startup to Mode 4

  The inspectors followed and observed the implementation of the above procedure. This procedure controls the sequence of activities that must occur prior to entering mode 4 and before reactor startup.

  Electrical buses and inverters were energized with the tie breakers open between redundant buses within the unit and between Unit 1 and Unit 2 including DC channels must be operable.

  Procedures for separate systems were completed and documented on the mode 4 checklist. Systems such as nuclear service water (RN) system component cooling water (KC) systems were verified as operable.

  The inspectors observed IAE and maintenance personnel implement different positions of the procedure when required. Coordination was very good and demonstrated the cooperation of the different departments when needed to accomplish a common goal.

- PT/2/A/4255/03A&B, SM Train "A" and "B" Valve Stroke Timing Shutdown

- PT/2/A/4200/28A, Train Slave Relay Test for SSPS (T-A)

No violations were identified.

3. Surveillance Testing (61726)

a. Observed Surveillance Tests

Selected surveillance tests were reviewed and/or witnessed by the resident inspectors to assess the adequacy of procedures and performance as well as conformance with the applicable TS.

Selected tests were witnessed to verify that (1) approved procedures were available and in use, (2) test equipment in use was calibrated, (3) test prerequisites were met, (4) system restoration was completed, and (5) acceptance criteria were met.

The selected test(s) listed below were reviewed or witnessed in detail:

- The inspectors met with the technicians who were to perform IP/0/A/3207/03D, NIS Power Range Uncompensated Ion Chamber Testing. Primarily, this procedure provides a safe and effective method to verify and test the NIS power (PR) uncompensated ionization chambers (UIC) open receiving assembly. The inspectors reviewed the procedure and observed the implementation of the procedure, to include interface with operations, the control room SRO and the IAE supervisor responsible for the conduct of the procedure.

  The conduct of this procedure also would identify, if present, water and/or moisture in the system and if there was a ground fault that could give erroneous readings or the intrusion of noise in the system. Since Unit 2 had experienced an unplanned shutdown from a trip, apparently caused from a loss of offsite power, there was the possibility of moisture in the system.

  The inspectors observed the equipment checks, such as the analyzer, probes and wiring and the review of the procedure by the two technicians. Conversations with the technicians gave high confidence that planning had taken place and that supervision was apparent. The technicians were experienced and aware of the rules of performance to include verification of the process of procedural adherence. Technical Specifications were complied with and the procedure was clearly documented and verified and approved. The inspectors observed the process and concluded that the procedure was properly implemented, verified, documented and the work was properly supervised.

- The inspectors observed the implementation and completion of the functional testing of the 7300 Reactor Protection System. Procedure PT/1/A/4601/04, Protection System IV Functional Test was used. Through the use of the procedure the licensee complies with Technical Specification by performing periodic functional tests on Channel IV of the 7300 Reactor Protection System. The process results and the ability to insure and verify that parameters such as bistable and computer setpoints, recorders, protection system indicators, annunciator alarms and status lights were verified to be functional and operable.

  The inspectors verified that the proper test equipment was utilized and had been properly inspected and calibrated. The inspectors observed and verified the procedure review by the technicians and their functional check of the test equipment. During steps of the procedure where double verification of a step(s) requiring visual and physical verification, the technicians verified the steps properly and promptly documented their actions.

  The inspectors observed that the test group interfaced with the control room SRO and the RO who was aware of the test maintenance taking place, and of the functional testing taking place and possible consequences of a potential error that could take place during the performance of functional testing of the 7300 Reactor Protection System.

  The inspectors observed and verified the performance of the functional test and concluded that the functional test was adequately performed by competent experienced personnel who were adequately supervised and that the control room personnel were cognizant of the tests and the procedure was properly documented and approved by appropriate personnel.

- PT/1/A/4205/02A, NF Train A Valve Stroke Timing - Quarterly Test. The purpose of this test is to measure the stroke time of the containment isolation valves for the Ice Condenser Glycol system to verify that these valves will close within the time specified by the McGuire Pump and Valve Inservice Testing Program. The inspectors observed operations performance of this test from the auxiliary building and noted that the operators were using the correct procedure, were adhering to good work practices, and identified no discrepancies. The stroke timing was being recorded by other test personnel within the control room.

The stroke time for all of the valve tested by the procedure were within the time specified.

4. Maintenance Observations (62703 and 62700)

The inspectors reviewed the plant current maintenance program in the areas of material condition, work control, maintenance, evaluation of training, maintenance work practices, maintenance backlog and equipment reliability. The inspectors conclude that the Mcguire station maintenance program was satisfactory, but improvement is needed in a number of areas to ensure safe plant operations and equipment reliability.

a. Diesel Generator 1B Fuel Oil Storage Tank Level Inaccuracy

During routine preventive maintenance it was discovered that the fuel oil level for the 1B diesel generator was below the minimum technical specification requirements. Technical specification 9.4.6.3 requires that the fuel oil tanks contain a minimum of 39,500 gallons. This discrepancy was discovered On November 15, 1993, while IAE technicians were performing a required calibration check of the 1B DG fuel oil tank level gauge. The fuel oil level was found to be 4500 gallons below the technical specification requirement. At this level, the diesel generator would not have been able to maintain full load for five days as required.

Preventive maintenance was performed on the gauge under work order 93044452 and was required to be performed every two years. The IAE crew discovered that the gauge read 43,000 gals, while the actual level was 35,000. The IAE crew informed operations who declared the 1B diesel inoperable on November 15, 1993.

The plant staff immediately ordered 7,000 gallons of diesel fuel oil and restored the tank to technical specification values on November 16, 1993. Calibration checks were conducted on all of the other fuel oil gauges; 1A, 2A, and 2B. The 1A fuel oil gauge was found to be out of tolerance but the tank volume was above the required minimum. The Unit 2 level gauges were found to be within tolerance.

The licensee tracked fuel oil consumption on a Monthly Fuel Oil Report, PT/0/B/4700/65. A review of that report by the licensee and resident inspectors revealed that the 1B diesel generator, due to inadequate fuel oil tank levels had been inoperable for over five months. Additionally, the inspectors and licensee discovered that there were two periods of time the redundant diesel generator was simultaneously inoperable due to scheduled work.

The gauge in question was a Barton 288A pressure type. The gauge consists of an indicator and switch that are calibrated separately. The indicator and switch are actuated by different linkages. The switch is setup to send signals to an annunciator alarm at the DG Control Panel when the setpoint 40,866 +/- 750 gallons is reached which in turn sends an alarm to the Control Room. This alarm was never actuated possibly due to a stuck switch. The switch did actuate after having been exercised during the troubleshooting activities.

The inspectors identified that on several prior occasions the gauge had been found to be out of tolerance. A modification to install a more reliable and accurate gauge had been planned, but was later postponed by the licensee. Although the licensee had postponed the installation of the new gauges, the calibration frequency of the gauges was not increased to assure that the gauge accurately reflected tank level. Since this event, the licensee has increased the PM frequency from 2 years to three months.

The inspectors observed the calibration of 1B fuel oil gauge. They observed the technicians disassemble the gauge and apply a silicon based lubricating substance to the roller and cam assembly. The inspectors questioned the technicians on this practice. The inspectors reviewed the procedure and the appropriate vendor manual and could not find an instruction that permitted the use of this substance. At the request of the inspector the licensee made inquires to the vendor on the use of the lubricant. The vendor stated that the parts should be cleaned with demineralized water and a cotton swab and not the lubricant in question. The licensee stated that they plan to change their procedure to reflect the use of demineralized water to clean the component. The inspectors reviewed past work packages but could not find any documented records that showed the use of lubricant. The inspectors informed the IAE staff about the possible use of unapproved lubricants on the gauges. The licensee staff initiated an evaluation to determine the effects of the use of this lubricant. The licensee determined with the assistance of the vendor that the lubricating substance would evaporate and not harm the components.

Corrective action has been planned that includes: 1) the implementation of the modification to replace the gauges and 2) evaluations to determine if there is a need to enhance the monthly fuel oil report procedure.

The plant staff has had prior opportunity to correct the deficiency with the gauges by increasing PM frequency. In addition, the event caused one diesel to be unknowingly inoperable for an extended period of time and on at least two occasions both diesels were inoperable. The failure to maintain an adequate volume of fuel in the fuel oil storage tank in accordance with technical specifications is a Violation, 50-369/93-32-01, Fuel oil volume below Technical Specifications.

b. Missed Specification Surveillance on 2A Emergency Diesel Generator

On January 24, 1994 the 2A diesel was removed from service to perform routine maintenance. Operators are required to verify the operability of the off-site power sources in accordance with technical specification 3.8.1.1d. The 2A diesel was declared inoperable on January 24, 1994, at 0500 for scheduled maintenance. The technical specification states that offsite power sources should be verified operable within one hour and once every 8 hours by performing surveillance 4.8.1.1.1a. On shift operating crew did not recognize that this surveillance had not been performed until over 10 hours later, missing two required surveillances. This is a frequently performed surveillance and the licensee uses a clock and a performance test as a reminder. The offsite power sources and the unit's remaining diesel generator were operable during this period. The inspectors also determined that when the 1B diesel was declared inoperable on November 15, the licensee failed to test the redundant diesel as required by Technical Specifications. The failure to perform a surveillance within its required interval is a Technical Specification Violation. This is Violation 50-369,370/93-32-07: Failure to perform a Technical Specification verifications as required following diesel generator inoperability.

c. Maintenance Qualification and Training

During a routine review of training records, the licensee plant staff determined that two mechanical maintenance supervisors and one IAE supervisor did not meet the educational requirements (i.e., lack of a high school diploma or equivalent) established by ANSI Standard N18.1-1971. Technical specifications 6.3.1 states that personnel shall meet or exceed the minimum qualification of ANSI N18.1.-1971 for comparable positions and the supplemental requirements in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licenses. Both of the licensee employees had extensive experience at the facility since construction and initial plant startup. The supervisors had transferred from the construction group and had worked their way to the supervisory position. However, the licensee failed to review their background against established requirements prior to them obtaining the position. The supervisors had held these positions for 3 to 4 years. The licensee conducted an extensive evaluation of the individuals work history and performance. Even though the mechanical maintenance supervisors were felt not to be a threat to plant safety, as a result of the licensee reorganization of the maintenance department, they were reassigned to other positions. The licensee has evaluated the previous performance and work history of the IAE supervisor and decided that he would remain in position as a supervisor. The licensee determined that his lack of a high school diploma poses no immediate threat to his ability to continue to perform his job function in a safe manner. The inspectors determined this corrective action to be acceptable; the IAE supervisor is currently enrolled in training that will allow him to complete his educational training requirements within the next 12 months.

Inspectors informed the licensee that, because the criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied, this item would be identified as Non-Cited Violation 50-369,370/93-32-02: Maintenance personnel not meeting minimum qualification requirements of ANSI N 18.1.

d. Emergency Core Cooling System Venting Periodic Test

A pressure transient occurred on the residual heat removal (ND) system during the performance of PT/0/A/4200/19 Emergency Core Cooling System Venting. This air venting is performed on a 31 day periodic basis to ensure that the ND system piping is filled with water. During the venting of valve ND-80, high point vent, the ND system pressure dropped from 100 lbs. to 40 lbs. The ND system pressure is normally 40 lbs., however the pressure was elevated due to in-leakage. The sudden drop in ND pressure caused concern among the shift operators and operations staff. The venting operation is performed in accordance with operations' Special Order 93-22. The order instructs operations personnel to maintain discharge pressure less than 350 psig and to depressurize if it exceeds this value. Numerous leaks had been repaired on the ND system during the last refueling outage and the system had been considered tight. Despite the in-leakage, the ND system is capable of being maintained at pressure.

The operations staff technician did not inform the shift operators of his intent to perform the PT. The shift operators concluded that the sudden drop was due to the venting of valve ND-80. Although, this task had been performed several times in the past the operator stated that he had opened the valve faster and further. The NRC inspectors questioned why the operating crew was not aware of the performance of the venting operation. The inspectors reviewed the performance test log book for both Unit 1 and Unit 2. The inspectors concluded that it was a common practice not to inform operations prior to starting this performance test.

The failure of technical personnel to notify the control room operators of this performance test is a concern from both a personnel and plant safety perspective and is considered a weakness. The licensee counseled the technicians on the need to inform the control room prior to starting this test.

e. Safety System Unavailability Data For The Past 12 Months

Safety system unavailability performance indicator program monitors the readiness of important safety systems to respond to off-normal events or accidents. Monitoring safety system unavailability data allows an assessment of operations and maintenance practices.

The inspectors evaluated the data and noted that diesel generator unavailability was good for the last 12 months. Generally, the diesel generator reliability was above station goals and the diesels performed as expected when required during recent events at McGuire. This improvement can be attributed to the use of dedicated maintenance crews, predictive maintenance and optimization of preventive maintenance. Additionally, dedicated maintenance crews, modifications such as new governor controls, speed switches, day tank level instrumentation, and significant improvements in the planning and control of DG down day work activities, and increased on-line work have increased diesel availability.

The data showed that unavailability of the auxiliary feedwater system and high pressure injection system was higher than the station goals for the period. The major contributors to this increase was attributed to problems experienced with service water system maintenance and the planning, scheduling and coordination of work activities. In one example, auxiliary feedwater, service water, and high pressure injection pumps were taken out of service to obtain an oil samples; however the tasks were delayed extensively because of lack of coordination of NLOs. In another example, the 2A service water pump reassembly was delayed because a new spare rotating element retrieved from the warehouse could not be installed causing a 80 hour delay in returning the pump to service.

The inspectors examined additional data and found an improving performance trend in the auxiliary feedwater and high pressure injection systems. The inspectors will continue to monitor these indicators for adverse trends.

f. Plant Material Condition

The inspectors conducted material condition inspections of the auxiliary and turbine building areas. The inspections took place over several days. The inspectors focused on material condition deficiencies that were not identified or included in the work control system. The inspectors observed that equipment was properly serviced (i.e., lubrication, drive belts, filters), fluid system integrity is maintained, instruments and gauges were operational, protective cabinet doors and electrical enclosure covers are installed, equipment and system are properly insulated, industrial safety and radiological hazards are minimized. The inspectors also observed equipment cleanliness, temporary modifications, temporary environmental protection and unauthorized modifications.

A low number of deficiencies were observed that had not been previously identified indicating that the licensee is alert to deficiencies.

The inspectors toured the turbine building and found evidence of a number of oil and water leaks; however most were identified and captured.

The licensee recently published radiological surveys that showed a decreasing trend in the number of catch basins and contaminated floor space. These parameters are indicative of the licensee's efforts to minimize radioactive fluid system leaks and housekeeping and cleanliness practices.

Equipment in general appeared to be in good working order showing minimal degradation from lack of lubrication or preservation.

Temporary modifications had been properly logged and were awaiting permanent repair. No unauthorized modifications were found during the area walk downs.

Storage areas including the turbine building lube oil storage areas were clean and orderly.

Housekeeping was generally satisfactory. The inspectors observed the turbine building and auxiliary building to be generally free of dust, dirt and trash. The station recently has begun to trend housekeeping discrepancies as part of its problem investigation report system. PIP 0-M93-0451 identified that current practices involving maintenance of personnel and material logs were ineffective in accurately controlling entry of personnel and materials into and exit from permanent level 3 housekeeping areas such as the fuel pool area. The inspectors concluded that increased attention is needed in this area.

The number of control room instruments out of service has shown a downward trend. The existing number of instruments out of service was approximately 45. The station has an existing goal of less than thirty instruments out of service.

Operators are currently having to work around several pieces of equipment that have not been functioning properly for an extended period of time. This equipment includes the boric acid flow controller for the reactor makeup system. The system has not functioned as designed for several years. Blended flow concentrations are typically 100-300 ppm less than nominal. The plant has had a history of accumulator check valve leakage. The shift crews have to fill accumulators 3-4 times daily on both units. Inleakage into the residual heat removal system has been a long term problem. The station has not been able to resolve these equipment problems and they remain as operational concerns for the plant.

Cold weather preparation proved to be adequate during the recent freezing conditions. During the month of January record low temperatures were experienced by the facility. Despite several days of below freezing temperatures only a few plant components were affected.

g. Maintenance Work Backlog

The inspectors reviewed and evaluated the station's existing maintenance backlog and noted there were a significant number of non-outage maintenance work requests including corrective maintenance. Corrective maintenance is the repair and restoration of equipment or components that have failed or not performing their intended function. Corrective maintenance does not include modification work, technical specification surveillances, or preventive maintenance actions. The corrective maintenance backlog consists of all open power plant corrective maintenance work orders, including those awaiting parts, engineering evaluations or plant conditions. (e.g., awaiting for a specific train to be taken out of service) not requiring a unit outage.

The inspectors reviewed the existing corrective maintenance backlog of work orders and found over 174 work orders to be greater than twelve months old. Nineteen work orders were on hold due to engineering review. The current plant performance indicator non-outage maintenance backlog was nearly fifteen hundred backlog items. The total non-outage maintenance backlog is nearly twenty-five hundred items. A review of the maintenance backlog trend showed a decreasing trend in the early part of 1993, but the trend leveled out as a result of continuing outages. A backlog quality improvement team was assembled by the licensee, but the effort has not been continuous.

The inspectors reviewed the current backlog of preventive maintenance items and noted over 74 items in the backlog that were over twelve months old. A number of the items were on hold due to engineering review.

The inspector concluded that the backlog is above station goals. The licensee is implementing new work control system with the objective of minimizing the backlog of work.

h. Work Control System

The licensee work control process contains deficiencies in the planning, scheduling, work package preparation, and the coordination of work that prevents the process from being fully effective in implementing maintenance at the station. Some of the deficiencies in scheduling include lack of integrated scheduling, lack of scheduling support organizations, and lack of resource loading. These deficiencies have resulted in coordination problems. In the planning of work there are several deficiencies which include inconsistencies in conducting pre-job scoping of work activities; and there is little or no preliminary troubleshooting. In addition, the database for equipment failure is incomplete which results in a poorly planned work package.

Moreover materials and spare parts are sometimes not allocated or available.

The inspectors observed several maintenance work activities. Several of the work activities were delayed due to inefficiencies in the work control system. For example, the inspector observed that one job that involved adjusting packing on a non-safety related component took nearly three hours to start due to lack of work package documentation. Other jobs noted by the inspector had similar delays in starting. A review of work control statistics showed that only 50% of planned jobs started on time. These deficiencies have been recognized by the licensee who has developed extensive plans to implement a new work control process. The new process is planned to be implemented over the next year and a half. Key changes in the work control process include improved origination of work such as through the use of electronic operators rounds sheets. In addition, some minor repairs are planned to be made without the use of work orders. Another key change is the Single Point of Contact (SPOC) team. The team will act as a clearinghouse for emergency work. The SPOC will be responsible for the coordination of troubleshooting teams, the planning and execution of emergent and normal work requests, and the scheduling of work in an execution window.

Other planned improvements include schedule resource loading, focused planning, scheduling of support functions, revised work performance indicators, and the use of new work control support technology.

The inspectors noted that the new work control system would create a work control center; this plan would shift the administrative burden from the control room SRO to an SRO located in the work control center outside of the control room.

The inspectors concluded that the new work control process should provide corrective actions for identified deficiencies in the stations current work control. The inspectors will continue to follow the implementation of this process.

i. Maintenance Work Practices

The inspectors directly observed in field maintenance activities. The inspectors observed each work activity with emphasis on adherence to procedure and/or work package instructions, correct tool use, use of measuring and test equipment, knowledge of work activity, work coordination etc. These activities included the following:

Work Order 91127357, Functionally verify instrumentation for Diesel Generator 1A connected to Mega Data Gathering Panel for Diesel Generator 1A. Diesel Generator 1A is provided with instrumentation for diesel fuel oil volume, diesel water cooling temperature, lube oil pressure, starting air pressure and diesel engine crankcase vacuum which are transmitted to the data gathering panel. The main control unit for this data gathering panel had been out of service for several months due to a defect. This work request verified system operability after repairs had been completed on the main console and the system had been returned to service. The inspectors witnessed IAE technicians activities in the verification of the operability of the system. These technicians appeared well knowledgeable of the system operation and of the test requirements. No discrepancies were noted.

Work Order 93068629, PM/PT on 1EMF36 High High Vent Radiation Monitor for Unit 1. The inspectors witnessed IAE personnel in the calibration of the High High Radiation Monitor for Unit 1. Procedure IP/0/A/3005/10, Radiation Monitoring System High Range Area Channel Calibration, was used for these work activities. IAE personnel used the correct procedure, tools, and calibration instruments and followed the procedure requirements in completing the work activities. The monitor was calibrated and the system was returned to service; however, during the calibration, the data logger for the monitor was found to be out of tolerance. This did not affect the operability of the monitor. A work order was generated to repair the data logger. No other discrepancies were noted.

Work Order 93070980, Repair Bearing in Pump 1MWPU0060 (Ventilation Condensate Drain Tank Pump 1A). This work was performed by IAE personnel and required the motor to be disconnected, bearing removed and replace, and reconnect the motor to the pump. The inspectors found the IAE personnel working on this job without the work request at the work location. The work request was in the IAE Shop. Also, there was no procedure available which covered the work activities. The licensee's position is that the work activities were within the skill of the craft personnel. The inspectors observed the work activities and noted that the employees appeared to be knowledgeable of the work activities and were using the appropriate tool for the required work.
PM WO# 94000080 01 Inspect Main Feedwater Valve Positioners.

The following additional activities were reviewed:

CM WO# 93070980 01 1B VUCDT Pump Oil Leak

CM WO# 940000556 01 Leak on Isolation Valve Root Valve

PM WO# 93092434 01 D/G Air Compressor Preventive Maintenance

CM WO# 94003129 01 Repair NCP2D Control Leak Flow Low Instrument

No other discrepancies or violations were observed during the conduct of these observations. The work was conducted in accordance with established procedures.

The inspectors reviewed the problem investigation reports whose cause could be attributed to inadequate maintenance. The inspectors concluded that the majority of the maintenance performance problems were caused by lack of procedure adherence, lack of self checking and inadequate written instructions. For example, PIP 1-M93-0590 identified that inadequately written instructions caused workers not to weld a valve stem to a plug for valve 1HW-81. The Unit 1 was forced to reduce from 100% to 20% power and the repair took over two hours. An example of lack of procedural adherence is PIP-1-M93-0377 which reports that a welder removed bonnets of residual heat removal valves 1ND12 and 1ND13 without referencing a procedure. He removed the bonnets using a pipe wrench and extender which put an excessive tensional force on the associated piping. An example of the lack of self checking is PIP-1-M93-0878, which identified that a non-ASME code bonnet was installed on a Duke Class C diaphragm valve. The maintenance crews failed to notice that the valve tag on the bonnet specified that the bonnet assembly was to be a different type than the one listed in the work package. In addition, no suitability evaluation was performed as required. Other examples of human performance errors that have caused maintenance problems include the following. PIP 2-M92-0036, reported that IAE personnel were performing maintenance on D/G sequencer 2A Timers when an inadvertent safety injection occurred causing the D/G breaker to open. In another example, PIP 1-M93-0873 identified that the plant was shut down when a leaking SG tube caused primary to secondary leakage to exceeded administrative limits. The leaking tube had not been identified during a previous analysis. PIP 2-M93-0017, identified that during repair of the Unit 2 standby make-up pump and discharge damper housing threads were galled to the tee threads. This prevented the damper from being further dissembled or repaired. The extended repair caused the 7 day limit to be exceeded as specified in SLC 16.9-7 which requires that a special report be sent to the Commission.

The inspectors review of PIPs and special reports also revealed that foreign material exclusion work practices were inadequate. The failure to properly reinforce necessary foreign material exclusion practices has caused some equipment to plant operation and safety to be degraded. For example, PIP 1-M93-0575 identified that during 100% power operation the 1B feedwater flow regulating valve was placed in manual control for reactor protection system testing. This caused a feed pump transient which caused level in the A S/G to increase. The operator tried to close the main feed regulating valve but could not. The cause of the failure was determine to be debris in the valve cage which was replaced during scheduled outage maintenance of this valve. PIP 0-M93-1182 reported that while performing pressure test of low pressure side of Unit 1 and 2 feedwater transmitters the associated vent lines were found blocked with debris. PIP 1-M93-0487 reports that IAE personnel found Unit 1 service water valve RN277 would not cycle due to the presence of a small plastic object blocking a solenoid air port. PIP 1-M93-0244 identified metal shaving and chips inside the bell housing of the 1B containment spray heat exchanger. PIP 2-M93-0735 identified three foreign objects on the S/G D secondary side tube sheet. The objects were found stuck in the hard sludge pile between the tubes and were unretrievable. PIP 1-M93-1377 reports that debris from a reroofing operation inadvertently entered the Spent Fuel Building from an existing opening in the roof. Work progressed for nearly a week before the problem was discovered. The inspector reviewed Inplant Review report 93-043, and found six occurrences of inadequate foreign material exclusion work practices during 2 EOC-8 refueling outage. The licensee is aware of the foreign material exclusion problem and is revising its current procedure and counseling its workers on the need for adequate measures to implement foreign material exclusion practices. This area needs increased management attention and is considered a weakness.

A review of problem investigation reports for the past year revealed corrective maintenance in some cases did not fix the problems. Improper assembly of component and inadequate post maintenance/modification were also significant contributors to the performance of inadequate maintenance. For example, the 1B fuel oil bypass pump was repaired three times due to misassembly of the mechanical seal on the shaft. In another example, during a licensee inspection, the wrong type of breaker had been installed in a safety related motor control center.

The inspectors review of existing trends showed that inadequate maintenance work practices were a continuing problem for the station.

j. Main Feed Regulating Valve Performance and Reliability

The inspectors reviewed the station's power history for the past year. The station's availability and capacity factors were below industry median. The review showed that main feed regulating valves along with steam generator tube degradation continue to be the primary contributors. A review of station operating history revealed that twelve reactor trips can be attributed to problems with the mainfeed regulating valves over a ten year period.

The inspectors discovered that some of the problems associated with the valves were due to changes in the delta-p across the control valves. The original design delta-p was 50 psid. The current value for delta-p is 127 psid. The resulting delta-p requires the regulating valves to be throttled in less than optimum conditions. In addition, the station currently operates with the bypass valves full open which results in some bypass valve piping erosion. Operating with the valve in the full open condition permits additional operator response time (approx. 30 seconds) in the event of valve failure.

The licensee has determined that the existing valve design is inadequate. The double ported design of the valves are prone to vertical instability due to dynamic forces at a high delta-p. In addition this valve trim is over sized for existing system conditions resulting in flow induced vibration. The licensee plans to modify the valve trim with a single ported design. The single ported design balances static forces and minimizes dynamic forces thus eliminating vertical instability concerns. Other problems with the valves include mechanical fuse failures, recurring body to bonnet leaks, and the inability to perform routine preventive maintenance tasks in a safe manner.

The licensee proposes to change out main and bypass valves control circuit fuses with a better design, and install an improved body to bonnet gasket design, and has installed a permanent access platform at the regulating valves.

The licensee also has found that the main feed regulating valves were susceptible to single point control circuitry failures. In response the licensee plans to install redundant control circuitry.

The inspectors reviewed the problem investigation reports for maintenance problems and found that the threshold for reporting was reasonably low. The inspectors reviewed the timeliness of reporting and found that maintenance personnel were not meeting station goals for reporting discrepancies within one day of discovery; typically it took nearly three days to report the discrepancy. The inspectors found that the cause, proposed resolution and corrective action verifications occurred within the scheduled time period. Most maintenance related MSEs were closed within the station goal time frame.

The station has developed a priority list of equipment and work arounds and has formulated a quality improvement team to develop an effective strategy to combat some of its long standing equipment problems. The identified components include main feed regulating valves, steam generators, cold leg accumulators, radiation monitoring equipment, residual heat removal, system inleakage, battery capacity, ECCS check valves, boric acid flow controller, D/G fuel oil tank instrumentation, and pressurizer heater problems,

The inspectors conducted an extensive review of the stations equipment failure reports for the previous 18 month period. The inspector noted that components such as diesel start air compressors and dryers, ice condensers air handling units, power operated relief valves, and dc power system battery chargers had significant failure rates. Some of the components had repeat failures during the period. For example, Unit 2 diesel air start dryers had failed eight times during this period. The licensee conducts a continuous review and evaluation of these components to determine failure causes and develop solutions.

The inspectors concluded that the station has been weak in resolving long standing equipment and repeat failure equipment problems.

k. Preventive Maintenance

The McGuire Predictive Maintenance/Monitoring Program is designed to determine machine condition and predict machine problems before they occur. This program provides early predictions of machine degradation and provides sufficient time to schedule required repairs in conjunction with the plants operating schedule and refueling outages. A Preventive Maintenance Program is also provided to reduce machine wear and fatigue. The following Predictive Maintenance technologies are used to monitor machine condition at McGuire:

- Routine vibration trending and analysis
- Continuous vibration monitoring
- Oil condition trending and analysis
- Infrared thermography
- Motor current trending and analysis
- Various motor winding testing
- Erosion/Corrosion testing

The Preventive Maintenance program uses the following technologies:

- Lubrication of grease lubricated bearings
- Shaft balancing in rotating equipment
- Coupling alignment

The Predictive/Preventive Maintenance (P/PM) Program is accomplished by a staff consisting of three engineers and a supervisor with assistance by technicians from the maintenance organization. The 1993 report on the program accomplishments has not been completed; however, during 1992, the program identified and resolved 15 vibration related problems and several thermography related and oil trending and condition related problems.

The inspectors reviewed the P/PM program's 1992 Cost Saving Analysis Reports, the CSI 1992 audit report, interviewed the licensee's predictive maintenance program staff personnel and observed several predictive maintenance activities.

The inspectors conducted a review of problem investigation reports and component failure rate data. Some components were degraded due to lack of preventive maintenance that resulted in wear and aging. For example, a lake level instrument was not included in the preventive maintenance program resulting in an inaccurate lake level indication. In another numerous areas on the exterior of the steel containment vessel where observed to be corroded due to lack of preventive maintenance to ensure coatings are applied. The fuel transfer system emergency pull out cable shear pin failed allowing the cable to become entangled in the fuel transfer system support wheels. The control room air handling units was found to be degraded with worn gaskets, missing bolts and other corroded components due to lack of preventive maintenance. The licensee implemented corrective action to correct the identified weaknesses.

A review by the inspectors of maintenance/testing events causes reveals that inadequate preventive maintenance accounted for a number of the events logged in this category. Also, the problem investigation reports have shown an increasing failure trend due to component aging and degradation.

The inspectors have made the licensee aware of the fact that preventive maintenance content and frequency must be adjusted when as found conditions and increasing failure rates suggest that such action is warranted as discussed in the diesel fuel oil gauge inaccuracy section of this report (para.4.a)

The current program contains over 11,000 preventive maintenance tasks. The station plans to implement a preventive maintenance task optimization program. The program will review maintenance history and causes and develop, modify and delete tasks where necessary.

It has been recognized that the station has an aggressive predictive maintenance program. The program has been effective in detecting and assisting in the troubleshooting and diagnosis of equipment problems.

The inspectors concluded that the station's program was satisfactory but increased management attention is needed to prevent equipment reliability problems.

5. Emergency Preparedness (71707 and 93702)

On October 20, 1993, McGuire Nuclear Station performed the Annual NRC graded exercise. This exercise involved state and county participation and began before normal working hours. There was a failure to meet the 30 minute accountability for Site Assembly. In 37 minutes all groups had been accounted for however, there still was an influx of emergency responders coming through the PAP. Approximately 193 responders were processed during the Site Assembly. Not all emergency responders were able to notify Security that they had made it to the Emergency Facility at the time Site Assembly was called off.

As a result, the licensee made the decision to perform three "unannounced" site assemblies in conjunction with TSC/OSC activations. A short summary of these activities are as follows:

12/7/93
- Activated BS/OSC at 13:45.
- Initiated Site Assembly 13:50.

- Secured from Site Assembly at 14:15 with all personnel accounted for.

12/8/93
- Activated BS/OSC 8:00 p.m.
- Initiated Site Assembly 8:11 p.m.
- Secured from Site Assembly at 8:38 p.m. with all personnel accounted for.

On December 17, 1993, the McGuire Nuclear Station initiated an Emergency Drill Alert.

The resident inspectors observed and verified that emergency assignments had been made for the licensee Emergency Response Team. Adequate staff was available to respond in a timely manner to the simulated emergency.

The inspectors observed that the TSC was quickly organized by designated personnel. In general, personnel demonstrated a good working knowledge of the responsibilities required during an emergency.

The inspectors verified that Security had accounted for all personnel within the required time restraints. The inspectors observed and verified that normal responses to plant needs were timely and responsible.

These site assembly activations were successful in that the 30 minute time requirements were satisfied. The licensee has six upcoming TSC/OSC/EOF practice drills scheduled for 1994. Their upcoming drills should provide further opportunity for the licensee to adequately demonstrate successfully accountabilities and management cohesiveness.

6. Exit Interview (30703)

The inspection scope and findings identified below were summarized on February 7, 1994, with the Station Manager and members of his staff. The following items were discussed in detail:

Violation, 50-369/93-32-01, Fuel oil volume below Technical Specification requirements (para. 4.a.)

Non-Cited Violation 50-369,370/93-32-02: Maintenance personnel not meeting minimum qualification requirements of ANSI N 18.1. (para. 4.c.)

Unresolved Item 50-369,370/93-32-03: Redline control room drawings (para. 2.d.i.)

Unresolved Item 50-369,370/93-32-04: Failure of MSIV 2SM5 to close (para. 2.d.3.a.)

Unresolved Item 50-369,370/93-32-05: Vendor information for safety related equipment (para. 2.d.3.b.)

Unresolved Item 50-369,370/93-32-06: System configuration control (para. 2.d.5)

Violation 50-369,370/93-32-07: Failure to perform Technical Specification verification following diesel generator inoperability (para. 4.b.)

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.

7. Acronyms and Abbreviations

AIT	-	Augmented Inspection Team
BS	-	Back Shift
ECCS	-	Emergency Core Cooling System
gpd	-	gallons per day
IAE	-	Instrumentation and Electrical
LBM/HR	-	Pounds Per Hour
LER	-	Licensee Event Report
LOOP	-	Loss of Offsite Power
MM	-	Minor Modification
MSE	-	More Significant Event
MSIV	-	Main Steam Isolation Valve
NC	-	Reactor Coolant System
NOVE	-	Notice of Unusual Event
NRC	-	Nuclear Regulatory Commission
NRR	-	Office Of Nuclear Reactor Regulation
OEP	-	Operating Experience Program
OMP	-	Operations Management Procedure
OSC	-	Operations Support Center
PIP	-	Problem Investigation Process
PORV	-	Power-Operated Relief Valve
PR	-	Power Range
PRT	-	Pressurizer Relief Tank
psig	-	Pounds Per Square Inch Gauge
RCS	-	Reactor Coolant System
RI	-	Resident Inspector
RN	-	Nuclear Service Water
RO	-	Reactor Operator
SI	-	Safety Injection
SPR	-	Station Problem Report
SRI	-	Senior Resident Inspector
SRO	-	Senior Reactor Operator
SSPS	-	Solid State Protection System
TS	-	Technical Specification
TSC	-	Technical Support Center
UIC	-	Uncompensated Ionization Chamber
URI	-	Unresolved Item
VIO	-	Violation
WO	-	Work Order