U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-369, 50-370
License Nos:	NPF-9, NPF-17
Report No:	50-369/97-09, 50-370/97-09
Licensee:	Duke Power Company
Facility:	McGuire Nuclear Station, Units 1 & 2
Location:	12700 Hagers Ferry Rd. Huntersville, NC 28078
Dates:	May 18 - June 28, 1997
Inspectors:	S. Shaeffer, Senior Resident Inspector M. Sykes, Acting Senior Resident Inspector M. Franovich, Resident Inspector R. Moore, Regional Inspector (Sections E2.2, E2.3) H. Whitener, Regional Inspector (Sections M4.2, M6.8.1, M8.2, E8.1) D. Forbes, Regional Inspector (Section R1)
Approved by:	K. Landis, Acting Chief, Projects Branch 1 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

McGuire Generating Station, Units 1 & 2
NRC Inspection Report 50-369/97-09, 50-370/97-09

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident and Region inspection.

Operations

- Unit 2 control room operator response to the loss of main turbine hydraulic oil system fluid inventory was good, minimizing the potential for a turbine trip and subsequent reactor trip that could have challenged safety systems. (Section O1.2)

- The licensee reported operational events in accordance with the requirements of 10 CFR 50.72. (Section O2.1)

- The overall Unit 2 shutdown for identified steam generator leakage was well controlled. The active monitoring of the identified steam generator leakage and the management decision to shutdown the unit to repair existing leakage was conservative. As a result, no administrative or Technical Specification limits for reactor coolant system leakage were exceeded. (Section O2.2)

- The resolution of the low reactor coolant system loop 'A' temperature indication reading (input to the Unit 2 Operator Aid Computer) was adequately addressed. Alert operator identification of the issue was a good example of maintaining a questioning attitude and attention to detail. (Section O2.3)

- The licensee exhibited superior safety focus in preparing for midloop operations and was proactive in reducing shutdown risk. Enhancements to the procedure for loss of decay heat removal and emergency core cooling system equipment availability were considered good shutdown risk actions with appropriate consideration for Low Temperature Over Pressure (LTOP) restrictions. A pre-job brief was performed with excellent focus on the low thermal margin and examples of operator related industry shutdown events. Reactor coolant system drain down was effectively conducted with good procedural compliance, outstanding communication among reactor operators, and strong oversight. Overall, the licensee's shutdown risk management was a strength. (Section 4.1)

- Control of overtime for plant personnel during this review was adequate. In addition, the licensee's assessments performed on the control of overtime were detailed and provided good oversight. Licensee postings of notices to workers was also adequate. (Sections O6.1 and O6.2)

Maintenance

- In general, the post maintenance test program was satisfactory with good procedures in place to perform retest tasks. (Section M1.2)

- Licensee self assessment and reassessment of retest problem issues resulted in improved performance in this area. (Section M1.2)

- Post maintenance testing program implementation weaknesses were identified related to completeness of the Retest Manual, documentation of the justification for not performing a retest, and retest evaluation with no oversight review. (Section M1.2)

- The licensee had developed, documented and implemented a Planning and Scheduling process which was functioning well. (Section M1.3)

- Monitoring and trending performance data indicated that the Planning and Scheduling process had been effective. (Section M1.3)

- Operators' response to the inadvertent engineered safety feature actuation, which occurred on May 27, 1997, during emergency diesel generator load sequencer testing, was adequate and complied with TS requirements. Operator actions were adequate. A Violation was identified for an inadequate test procedure. (Section M2.1)

- The licensee's final repairs to the Unit 1 high pressure (HP) turbine blade ring locating pins were adequate. However, the repetitive HP turbine steam leaks were identified as an example of incomplete root cause reviews on secondary components. (Section M2.2)

- A weakness was identified concerning the isolation of the instrument air supply to heater drain valves during turbine building cleaning activities due to ineffective vendor oversight. The vendor personnel did not receive sufficient guidance prior to the start of the activity. As a result, the contract workers initiated an operational transient by manipulating Operations controlled equipment. (Section M2.3)

- Unit 1 restart testing following the Steam Generator (SG) Replacement Outage was adequately planned and executed to verify SG design and ensure reliable operation of the Unit 1 control systems. (Section M3.1)

- SG tube inspection and leak repairs were adequately performed. However, the followup to an earlier SG indication in the area of the identified leak led to a missed opportunity to prevent this event. Actions to correct the problem and ensure that other oversights did not occur were good. This problem was identified as an Unresolved Item pending further review of the root cause of the SG inspection process. (Section M4.1)

Engineering

- Once identified, the licensee initiated appropriate actions to address the potential for non-conservative Technical Specification (TS) for inoperable main steam safety valves (MSSV). Although adequate administrative controls were in place and no actual MSSV inoperability occurred, the licensee did not immediately pursue a TS Amendment, which led to delays in final resolution and identification of all pertinent issues. (Section E1.1)

- The addition of a second auxiliary feedwater condensate storage tank (AFWCST) was a timely and positive action to increase auxiliary feedwater supply inventory and improve pump suction reliability. Installation of vortex suppressors was a conservative management decision following detailed engineering analyses. (Section E2.1)

- The modifications completed during the Unit 1 outage demonstrated appropriate control of the design control process at McGuire. Performance was good for modifications, procedures, 50.59 evaluations and screening. (Section E2.2)

- Engineering's upgrade and validation of Design Base Document (DBD) Test Acceptance Criteria (TAC) sheets for Inservice Test (IST) valves was an example of good engineering support to operations. The TACs provided a good design reference for Operations to maintain system operability when safety-related valves were out of service for testing. (Section E2.3)

- Initial Unit 1 fuel assembly K-45 reconstitution work activities were well controlled and good communication and oversight existed between the station and contract employees. Reactor engineering personnel were knowledgeable and the 10 CFR 50.59 evaluation was adequate. Appropriate reactor engineering oversight was present and adequate radiation protection coverage was provided. (Section E3.1)

- The inspectors concluded that the licensee developed adequate procedures and controls for replacement of the battery/charger EVCA. Modification packages for installation of the temporary battery were adequate. Contingencies were established to identify necessary actions in the event of a loss of the temporary battery or the spare charger while replacement was in progress. The licensee delayed return of the battery to service to minimize potential plant impact during Unit 2 draindown and midloop operations. The replacement activities were completed within the authorized TS allowed outage times. (Section E4.1)

Plant Support

- At the time of the inspection, the inspectors determined that the licensee was in the process of developing procedures and work practices to maintain effective contamination controls and to maintain exposures ALARA during work evolutions on two removed SGs. (Section R1)

- Emergency preparedness practice drill scenario was adequate to effectively test the Emergency Response Organization (ERO) participants. The ERO performance was adequate; however, additional management emphasis of ERO expectations was necessary. (Section P1.1)

- Based on the inspectors concerns, the licensee initiated the development of additional testing for the fire suppression system interior loop piping. The inspector concluded that the enhanced testing would provide additional indications of system degradation. The inspectors also concluded that the administrative processes for long-term monitoring of the fire protection system for degradation could be improved. An IFI was identified to evaluate the future enhanced system testing. (Section F3.1)

Report Details

Summary of Plant Status

Unit 1 began the inspection period in MODE 3 (Hot Standby) returning from MODE 5 (Cold Shutdown) following replacement of a failed intermediate range power detector. On May 18, the unit was taken critical. On May 20, with the unit at approximately 6 percent power, an unplanned turbine trip occurred during turbine trip testing. After the apparent cause of the turbine trip was identified, the turbine was again latched and power escalation continued. On May 23, after successful completion of a 10 percent load reduction test from 38 percent power, the unit reduced power to approximately 10 percent to repair a failed seal weld on the high pressure turbine blade ring locating pins. Once repaired, power escalation continued. On May 25, a second 10 percent load reduction test was successfully completed at approximately 78 percent power. Unit power was then increased to approximately 99 percent to allow for performance of secondary heat balances to verify primary and secondary parameters. On May 30, a rapid downpower was performed following identification of a hydraulic fluid leak on the C low pressure turbine intercept valve. At approximately 17 percent power, the operators tripped the main turbine and reactor power was stabilized at approximately 12 percent. On May 31, after leak repairs were completed, power escalation continued. On June 1, a second unanticipated turbine trip occurred during turbine trip testing. The cause of this and the May 20th turbine trips were determined to be equipment malfunctions. Power escalation continued to approximately 100 percent. On June 2, unit power was reduced to approximately 12 percent to repair a repetitive steam leak on the high pressure turbine casing. After repairs were completed, unit power was increased to 100 percent. The unit operated at approximately 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period at approximately 100 percent power. On May 22, a small secondary transient occurred when vendor personnel inadvertently isolated instrument air to moisture separator reheater (MSR) valve controllers. Unit load decreased slightly. On May 27, an inadvertent Engineered Safety Feature (ESF) actuation occurred in Unit 2 during emergency diesel generator (EDG) sequencer testing. On June 2, 1997, both units entered TS 3.0.3 due to an auxiliary building ventilation boundary door being open, which caused both trains of control room ventilation system to be declared inoperable. Subsequent testing determined both trains were operable.

During the inspection period, primary to secondary leakage on the 2A steam generator (SG) increased from approximately 10 gallons per day (GPD) to approximately 65 GPD. On June 13, 1997, plant management decided to shutdown the unit to identify and correct the primary to secondary steam generator leakage. On June 15, the plant entered MODE 5 (Cold Shutdown) to support the steam generator work. Two periods of midloop operation were required to support the leak repair and inspections. The unit was restarted on June 28 from the SG repair outage. At the close of the period, the unit was in MODE 1 (Power Operation), with preparations underway to place the unit on-line.

Review of Updated Final Safety Analysis (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below. Operators' transition to dual unit operations was conducted in a safe manner. Various Unit 1 power changes due to equipment problems were adequately performed. Operator awareness of primary to secondary leakage on the 2A SG was heightened and plant chemistry sampling of the leak was conservative and frequent. The shutdown and restart of Unit 2 to repair the identified the SG tube leakage was conducted in safe manner, which included periods of reduced reactor coolant system (RCS) inventory conditions.

O1.2 Unit 2 Hydraulic Fluid Leak

a. Inspection Scope

The inspectors responded to notification of a hydraulic fluid leak from the Unit 2 Main Turbine Hydraulic Oil (LH) System.

Observations and Findings

On May 30, 1997, the licensee reduced power after identification of a main turbine hydraulic oil system leak. Control room operators began a controlled downpower in accordance with abnormal operating procedure AP/2/A/5500/04, Rapid Downpower. With the unit at approximately 17 percent reactor thermal power, the main turbine throttle valves moved to the closed position after hydraulic fluid inventory was depleted. Operators manually tripped the turbine and generator. The reactor remained at appproximately 17 percent power.

The licensee determined that a hydraulic fluid system fitting failed releasing the hydraulic fluid inventory to the Unit 2 turbine deck and subsequently into the turbine building drains. The drain system was isolated preventing the release of the material to the environment. The licensee conducted immediate repairs of the fitting and completed a thorough cleanup of the turbine building and turbine building sump.

Because the hydraulic fluid was identified as a hazardous chemical, the licensee isolated the turbine building sump discharge until cleanup of the chemical was completed. The unit was subsequently returned to rated power.

c. Conclusions

The inspectors concluded that the Unit 2 control room operator response to the loss of main turbine hydraulic fluid was prudent, minimizing the potential for a turbine trip and subsequent reactor trip that may have challenged safety systems.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 10 CFR 50.72 Notifications

a. Inspection Scope

During the inspection period, the licensee made the following notifications to the NRC as required for information purposes. The inspectors reviewed the events for impact on the operational status of the facility and equipment.

b. Observations and Findings

On May 20, 1997, the licensee made a report in accordance with 10 CFR 50.72 regarding non-conservative Technical Specification (TS) ACTIONs associated with postulated inoperable main steam line safeties. This report was considered a followup to an earlier report on March 20, 1997 describing postulated situations where TS ACTIONS may not require the most limiting power levels for inoperable main steam line safety valve configurations (see Section E1.1 for details). The licensee has submitted a Licensee Event Report (LER) on the issue.

On May 27, 1997, the licensee made a report in accordance with 10 CFR 50.72 due to an ESF actuation which occurred during testing of the Unit 2 EDG sequencer logic (see Section M2.1 for details). The licensee plans to submit an LER on the event.

On June 2, 1997, the licensee made a report in accordance with 10 CFR 50.72 after declaring both trains of auxiliary building and control room ventilation inoperable (TS 3.0.3). Operability of the systems was questioned during ventilation system boundary alterations to support vital battery modifications. However, subsequent testing verified that the systems were operable. The notification was retracted on June 11.

On June 9, 1997, the licensee made revisions to a previous report in accordance with 10 CFR 50.72 due to additional information identified regarding potential operability concerns on the auxiliary feedwater (AFW) suction supply (see Section E2.1 for details).

c. Conclusions

The inspector concluded that the licensee reported the above events in accordance with the requirements of 10 CFR 50.72.

O2.2 Unit 2 Shutdown for Identified Steam Generator Tube Leakage

a. Inspection Scope

The inspectors reviewed the shutdown of Unit 2 for identification and repair of SG tube leakage.

b. Observations and Findings

During the beginning of the inspection period, the licensee had been actively monitoring a primary to secondary leak on the Unit 2 A SG. Monitoring of the leakage was established in February 1997 with an indication of approximately 2 Gallons Per Day (GPD). The TS operational limit for SG primary to secondary leakage is 500 GPD; however, the licensee had established a more conservative administrative limit of 100 GPD for the Unit 2 SGs. Throughout in the inspection period, the identified leakage had increased to approximately 65 GPD. On June 13, the licensee decided to initiate a forced outage to identify and repair the Unit 2 primary to secondary leakage. The Unit 2 SGs were scheduled to be replaced during the next Unit 2 refueling outage scheduled to begin in September 1997. The Unit 1 SGs have already been replaced during the Unit 1 End of Cycle 11 refueling outage.

The inspectors observed portions of the planned unit shutdown and verified SG leakage limits did not increase during the evolution. Operators involved in the shutdown evolutions were attentive and maintained TS parameters within limits. Shift briefing prior to the shutdown highlighted potential problems during the downpower, what contingency measure were required, and stressed monitoring key parameters. The inspectors noted that specific measures were in place to heighten communications between the operating shift and the secondary chemistry staff to monitor the SG leakage for adverse change. On June 15, the unit entered MODE 5 (Cold Shutdown) to establish conditions to support the SG repair work.

c. Conclusions

The inspector concluded that the overall shutdown evolutions were well controlled. The inspector also concluded that the active monitoring of the identified SG leakage and the management decision to shutdown the unit to repair existing leakage was conservative. As a result, no administrative or TS limit for RCS leakage was challenged or exceeded.

O2.3 Unit 2 Low RCS Loop Temperature Reading

a. Inspection Scope

The inspector reviewed the circumstances involving a Unit 2 low RCS loop 'A' temperature reading and the potential impact on calculation of primary thermal power.

b. Observations and Findings

During the inspection period, a Unit 2 operator identified a low RCS temperature indication during a review of inputs into the primary thermal power calculation. At the time, primary thermal power was indicating 103.3 percent and the loop A Tcold was reading 549°F when it should have been reading 558°F.

According to the licensee, above 50 percent power, primary power best estimate calculations are based completely on secondary parameters. Differential temperature inputs for the reactor protection system did not appear to be affected. The licensee's review indicated that this input point to the Unit 2 operator aid computer (OAC) had fluctuating readings between May 21 and May 31. A work order was written; however, no corrective action was required because the indication was found to be correct (i.e., not fluctuating). The licensee plans on monitoring this OAC data point through the system health monitoring program and replace the isolator board (only component that could cause the fluctuations) if any drift is observed. This issue was documented in PIP 2M97-2169.

c. Conclusions

The inspector concluded that the resolution of the low RCS loop 'A' temperature indication reading (input to the Unit 2 OAC) was adequately addressed. Alert operator identification of the issue was a good example of maintaining questioning attitude and attention to detail.

O4 Operator Knowledge and Performance

O4.1 Unit 2 Reduced Inventory Operations

a. Inspection Scope (71707, 40500)

During the inspection period, Unit 2 was shut down in response to identified steam generator (SG) tube leakage. Before the unit entered reduced inventory operations to facilitate SG tube repair, the inspector reviewed the operations and SG inspection schedules to identify any potential periods of increased shutdown risk. The inspector reviewed the forced outage plans to drain down the reactor coolant system (RCS), enter midloop operations, install and remove SG nozzle dams, and re-flood the RCS.

The inspector reviewed station shutdown and abnormal procedures; reviewed pre-job briefing materials; attended a midloop pre-job briefing; witnessed portions of the draindown and midloop operations; confirmed TS compliance; reviewed recommendations from the McGuire Independent Review Team (IRT) assessment of outage risk; and attended the associated PORC meeting on procedure enhancements for coping with a loss of residual heat removal (RHR). The inspector also reviewed Generic Letter No. 88-17, Loss of Decay Heat Removal; the licensee's response to GL 88-17; various plant drawings, control room log books, forced outage schedules, containment integrity controls, and RCS makeup capability.

b. Observations and Findings

Midloop operations were performed on two occasions during the Unit 2 forced outage. Both midloop windows of operation were entered with fuel in the reactor vessel and the vessel head remaining tensioned. The licensee did not off-load the core during the outage.

The first reduced RCS inventory evolution occurred approximately 5 days after reactor shutdown. On June 18, the licensee: (1) drained down the RCS to 28 percent of pressurizer level; (2) calibrated RCS level instrumentation; (3) positioned a video camera for control room monitoring of RCS level on a sight glass; and (4) drained the RCS to approximately 10 inches above the centerline of the RCS hot leg piping. The unit remained in midloop conditions for approximately 20 hours until SG nozzle dams were installed. Upon a postulated loss of Residual Heat Removal (RHR), the margin to core boiling was 10 minutes.

The second RCS reduced inventory evolution occurred approximately 9 days after reactor shutdown. The unit remained in midloop (11 inches above centerline) for approximately 43 hours until completion of remaining SG repair activities, removal of nozzle dams, and installation of SG manways. For this period, upon a potential loss of RHR, the margin to core boiling was 26 minutes during the second midloop.

Before these reduced RCS inventory evolutions, the licensee completed an independent review of proposed shutdown operations. The licensee's Nuclear System Directive 403, Shutdown Risk Management, requires that an independent review team (IRT) assess proposed outage schedules and operations to identify any periods of reduced defense-in-depth for safety functions. The IRT identified reduced defense-in-depth for the RHR function due to the low thermal margin of the first midloop and proposed several contingency actions.

A significant IRT proposal involved enhancement of the loss of RHR abnormal procedure to improve operator response time. To achieve this, operators would immediately initiate RCS feed-and-bleed using a charging pump and safety injection pump. Under a loss of RHR event, this operator action would be taken if a thermal margin of less than 20 minutes existed. To improve response time, the PORC also approved the proposal to have available one charging pump and one safety injection pump in opposite electrical trains with power racked in prior to commencing the initial drain. This system configuration required entry into the Action Statement for Technical Specification 3.4.9.3, Low Temperature Overpressure Protection (LTOP), and was appropriately discussed in the PORC meeting.

Through control room board walkdowns and discussions with the operators, the inspector verified the Emergency Core Cooling System (ECCS) alignment approved by PORC and that controls were in place for RCS venting during reduced inventory conditions. The inspector also verified that the conditions of the LTOP technical specification were satisfied. This included verification of appropriate RCS LTOP vent paths. The inspector also confirmed availability of instrumentation and RCS makeup capability.

Licensee management conducted pre-job briefings before the unit entered reduced inventory to prepare the operating shifts for the infrequently performed evolution. Management expectations and safety concerns were emphasized during the briefing. Plant status was reviewed with particular interest on RCS inventory, decay heat removal capability, containment integrity, and power source and ECCS availability. Excellent attention was given to the fact that the first hot midloop was an infrequent operating condition with low thermal margin. The pre-job briefing material and presentation placed heavy focus on industry shutdown events with emphasis on multiple examples of operator actions that contributed to the events. The inspector also noted a good discussion among the briefing attendees with regard to equipment behavior from past plant experience. This was especially evident during discussion of RCS level instrumentation behavior and which type of instruments provided conservative level indication. The inspector also witnessed a good shift turnover and good communication between outgoing and incoming reactor operators. Operator knowledge and abilities were excellent.

Offsite and emergency power sources were confirmed to be available. Switchyard work and round-cell station battery replacement activities were postponed until after reduced inventory operations. Operators used core exit thermocouples and RHR system inlet temperature to monitor RCS temperature. Operators used RHR heat exchanger outlet temperature for Low Temperature Over Pressure (LTOP) TS restrictions.

The inspector observed the following operations practices to minimize shutdown risk:

- Minimize time in midloop conditions and use of an IRT to assess outage risk

- PORC approved enhancement of AP/2/A/5500/19, Loss of ND (RHR) or ND System Leakage, to allow for earlier operator action to feed-and-bleed the RCS with ECCS equipment

- One charging pump and one safety injection pump in opposite electrical trains available with power racked in, the associated Refueling Water Storage Tank (RWST) flow path available, and adequate RCS venting

- Gravity feed capability from the RWST to RCS (and other makeup sources) remained available

- Thorough Significant Operating Event Report (SOER) 91-01, Pre-job Briefing

- Minimization of control room traffic and other potential operator distractions

- Appointment of an RCS drain down coordinator - Senior Reactor Operator (SRO)

- Excellent SRO/RO discussion of past level instrumentation behavior

- Deferral of all Unit 2 work activities such as periodic tests or maintenance during the drain down

- Deferral of Unit 1 work that could affect Unit 2, such as Performance Tests (PTs) on shared nuclear service water systems

- Full emergency power availability

- Clear management expectations for operators to stop work if abnormal conditions are present

- Clear explanation of roles, responsibilities, and command and control for the drain down

Shutdown risk information was reviewed and discussed routinely during the licensee's plan of the day meetings. The inspector verified the accuracy of the information during daily control room visits.

c. <u>Conclusion</u>

For the reduced inventory evolutions, the inspector determined that there was outstanding communication among reactor operators. A good pre-job brief was performed with excellent focus and examples of operator related industry shutdown events. Pre-job briefing materials were clear and concise. Plant conditions, the low thermal margin, and contingency actions for a loss of RHR were appropriately stressed. There was good participation of operators in pre-job discussions of plant equipment, drain down rates, and reliability of level instrumentation. Operations managers promoted licensed and non-licensed operators to maintain a questioning attitude during the evolutions. Operator heightened awareness and attention to details were evident for reduced inventory and midloop operations.

Overall, the inspector determined that the licensee exhibited superior safety focus in preparing for midloop operations and was proactive in reducing shutdown risk. Enhancements to the procedure for loss of RHR and ECCS equipment availability were considered good shutdown risk actions with appropriate consideration for LTOP restrictions (good balance between shutdown risk and LTOP restrictions). Further, the licensee's actions to drain the RCS were effectively conducted with good procedural compliance and with strong oversight. The inspector concluded that the licensee's shutdown risk management was a strength.

O6 Operations Organization and Administration

O6.1 Overtime Control

a. Inspection Scope (71707)

The inspector performed a review of approved overtime during the most recent months for the plant operations and maintenance groups. The inspector also overviewed licensee records of all personnel overtime exemptions for hours in excess of established limits. Control of overtime for plant personnel is required by Technical Specification 6.2.2.e and NSD 200, Overtime Control. These documents require the licensee to document and properly authorize work hour extensions.

b. Observations and Findings

The inspector reviewed work hour extension documentation for the subject groups and determined that the forms, in general, were properly filled out and reasons for the work hour extensions were appropriate for the circumstances. The inspector verified that the station manager was reviewing a monthly site overtime report to determine that the use of overtime was warranted and not being abused.

The inspector noted that in an overtime control report dated March 21, 1997, the licensee's evaluation of the data identified several discrepancies regarding the timeliness of the required forms. The inspector verified that the appropriate corrective action documents were initiated to address the concerns.

c. Conclusion

The inspector concluded that control of overtime for plant personnel during this review was adequate. In addition, the licensee's assessments performed on the control of overtime were detailed and provided good oversight.

O6.2 Posting of Notices to Workers

During the inspection period, the inspector reviewed the licensee's compliance with the requirements of 10 CFR Part 19.11, Posting of Notices to Workers. The licensee implements these requirements via NSD 205, Posting Requirements. This procedure identifies three locations where required postings are to be maintained. The inspector verified that the licensee conspicuously posted current copies of NRC Form-3 and other required materials such as escalated enforcement and radiological violations in the areas. No problems were observed by the inspectors during this review.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726 and 62707)

a. Inspection Scope

The inspectors observed all or portions of the following work activities:

- PT/1/A/4206/1B Safety Injection Pump 2B Performance Test
- PT/1/A/4200/20A Unit 1 Airlock Operability Test
- PT/2/A/4600/01 RCCA Movement Test
- IP/0/A/3250/12B Train B Diesel Sequencer Timer Calibration
- WO 96089566 Temporary Vital Battery Installation

b. Observations and Findings

The inspectors witnessed selected surveillance tests to verify that approved procedures were available and in use, test equipment in use was calibrated, test prerequisites were met, system restoration was completed, and acceptance criteria were met. In addition, resident inspectors reviewed and/or witnessed routine maintenance activities to verify, where applicable, that approved procedures were available and in use, prerequisites were met, equipment restoration was completed, and maintenance results were adequate.

c. Conclusion

The inspectors concluded that routine maintenance activities were performed satisfactorily.

M1.2 Review of Post Maintenance Testing

a. Scope (62700)

During this inspection period, the inspectors reviewed the work process for controlling post maintenance testing (PMT) and the licensee's corrective actions for failure to perform PMT adequately on a number of occasions in the past 18 months.

b. Observations and Findings

Post maintenance testing was controlled through the Corporate Nuclear System Directive, NSD 408, "Testing," Revision 4; Work Process Manual (WPM) Section 501, "Post Maintenance Testing," Revision 0, "Post Maintenance Testing Guidance Document," Revision 0; and Post Maintenance Test, "Retest List," Revision 0. In general, these documents provided a sound basis for maintenance activities including post maintenance testing. Responsibilities of management, groups, and crafts were described; processes to be followed were specified; and retest requirements were delineated.

In 1996, the licensee identified several cases of missed or near missed retests. Problem investigation Process (PIP) reports were written to determine the causes and to track specified corrective actions for these events. Assessment of the PIPs showed that nearly all retest deficiencies identified in 1996 fell into one of three broad categories as follows:

- Retest Designations: failure of the planner to properly plan a retest into the work plan (human error).
- Retest List Discrepancies: failure of the retest list to encompass all components requiring retest leading to no retest task in the work plan.
- Execution of retest tasks in a timely manner: the work plan was adequate but the retest was not performed in a timely manner. This problem was two fold. First, on occasion tasks were removed from the Technical Specification Action Item List (TSAIL) before retest was performed. TSAIL was an electronic log to identify active maintenance work orders and tasks. Second, a work status communication problem between the craft and operations test group caused unnecessary delays in performing retests.

Actions taken to correct these conditions included the following:

- All work plans received a peer review before issuance.

- Revision of the Retest Manual. Two source documents for required retests were combined into one Retest Manual. This reduced confusion and potential errors in the planning process. Additionally, identified components requiring retest, which were not listed in the Manual, were incorporated into the manual.

- A change was made in the electronic format of TSAIL to prevent entry of tasks. Only work orders could be entered. Therefore, operators were required to review all tasks associated with a work order for completeness prior to removing the work order from the list.

  No corrective action directly addressed the communication problem between the craft and the operations test group.

In May 1997, Work Control Assessment 97-1 was performed to determine if corrective actions taken had been effective. The licensee determined that the corrective actions had not been totally effective as follows:

- Retest Designations: Assigning a peer review of planning work had been effective. No additional cases of failure to include retest tasks in the work plan had been observed.

- Retest List Discrepancies: Revision of the retest list had improved this document. All source information was incorporated into one retest list.

- Execution of retests in a timely manner: A change made to the electronic program allowed only a work order number to be entered into TSAIL. In order to remove completed work from the TSAIL log the operators must verify completion of all task assignments associated with a work order. This resolved the issue of tasks being removed from TSAIL before the work was completed. However, rapid communication of test status between the craft and the operations test group remained a problem.

The inspectors considered that the self assessment and re-assessment of the retest problem issues resulted in improved licensee performance.

During the review the inspectors made several observations regarding program implementation weaknesses, as follows:

- In some instances where the Retest Manual required a retest, planners had issued a task in the work order for the operations test group to evaluate the need for a retest after review of the actual maintenance activities rather than specifying retest required.

- Operations group personnel involved in retest evaluations were highly trained. However, one individual typically reviewed the maintenance activities that had actually been performed and made a determination if retest was required. There was no further oversight of these decisions.

- For some work orders, there appeared to be inadequate documentation in the work management system on why a retest was not required.

- The completeness of the Retest Manual has not been verified by a structured or formal review.

The inspector discussed these items with the licensee. The licensee indicated that a Quality Improvement Team would be initiated to review the retest manual and identified weaknesses.

In addition to review of the above documents, the inspectors reviewed four work packages which contained several work orders and numerous task descriptions as follows:

- Replace Upper Motor Bearing on Residual Heat Removal Pump 1A.

- Repair Safety Injection Valve 1NI-120B Actuator Oil Leak and Seat Leakage.

- PM on freedom of motion of Mechanical Snubbers.

- Repair 1B Main Feedwater Pump Inboard Bearing.

The inspectors determined that the work plans contained adequate instructions for the tasks to be performed; appropriate, approved procedures were identified and used to accomplish these tasks; and procedure references to vendor manual and technical information were included. Retest tasks were performed as required.

c. <u>Conclusions</u>

In general, the post maintenance test program was satisfactory with good procedures in place to perform retest tasks.

Licensee self assessment and reassessment of retest problem issues resulted in improved performance in this area.

Post maintenance testing program implementation weaknesses were identified related to completeness of the Retest Manual, documentation of the justification for not performing a retest, and retest oversight review.

M1.3 Review of Planning and Scheduling

a. Scope (62700)

During this inspection period the inspectors reviewed the licensee's Planning and Scheduling Process.

b. Observations and Findings

The licensee was using a totally electronic work order/task system. The process for planning and scheduling work under the Work Management System (WMS) was described by the Work Process Manual (WPM), Section 500,"Planning," Revision 5. Responsibilities of management, Planners, Schedulers, groups, and crafts were described; processes to be followed were specified; and interface with the electronic system was detailed. Planning was performed by Central Planning (process and WMS expertise) or Field Planning Technicians who are assigned to the execution teams. Central Planning performed the more complex work planning and provided oversight, consistency, and assistance as needed to the Field Planners. Field Planners performed work history reviews and job site walkdowns. They also determined the workforce requirements, need for support functions, and the scope of work to be performed.

McGuire used the concept of system work windows (SSW) to schedule and Execute on-line maintenance. In this process important plant systems were logically grouped and assigned to an execution week within a twelve week rotation. The groupings were designed to:

- eliminate PRA risk due to critical system combinations.
- maximize system/component availability.
- optimize maintenance by consolidating maintenance on components.

Work activities were slotted into the System Work Windows through several paths. Repetitive work such as preventive maintenance (PM) and periodic tests (PT) were controlled through the PM/PT program. These activities were populated directly into the schedule, in a repeating fashion, at prescribed intervals. A minimum of 16 weeks of future System Work Windows were kept populated with PM/PT activities. Corrective maintenance was identified through the work request/work order system. All new work orders were reviewed in the daily Work Order Scoping Meeting for confirmation that the scope was appropriate and for assignment to the appropriate system work window. These meetings were attended by representatives from all departments. When an item reached the seventh week before scheduled execution, it would undergo an intense review process until execution. Emergent corrective work orders which were written to address urgent plant deficiencies, were immediately added to the schedule by the Work Window Manager. These items were reviewed for Risk and sometimes required rescheduling some work activities.

The inspectors also reviewed a number of performance indicators such as the number of planning errors, number of schedule errors, and total reschedules. These indicators showed that the Planning and Scheduling process was working effectively.

Based on review of plant documents and interviews with experienced Planners and Schedulers, the inspectors determined that there were a number of checks and balances in the system to ensure that proper verifications and reviews were performed.

c. Conclusions

The licensee had developed, documented and implemented a Planning and Scheduling process which was functioning reasonably well.

Monitoring and trending performance data indicated that the Planning and Scheduling process had been effective.

M2 Maintenance and Material Condition of Facilities and Equipment (62707)

M2.1 Inadequate Emergency Diesel Generator (EDG) Load Sequencer Testing Resulting in ESF Actuation

a. Inspection Scope

The inspector reviewed an inadvertent ESF actuation which occurred on May 27, 1997, during EDG load sequencer testing.

b. Observations and Findings

Unit 2 was at 100 percent power at the time of the event, with the 2B EDG tagged out of service for performance testing in accordance with IP/0/A/3250/012B, Train B Diesel Sequencer Timer Calibration. Train B ECCSs were also tagged out for testing, but were available. During performance of the EDG sequencer relay testing, a partial Train B sequencer actuation (blackout) occurred which resulted in an autostart of the Turbine Driven (TD) Auxiliary Feedwater (AFW) pump and the standby nuclear service water (NSW) pump, as well as the realignment of various NSW system valves. Operators responded to these indications and instructed the involved test personnel to discontinue the test. While in process of verifying a sliding link position, previously opened by the test procedure, a partial Train B safety injection (SI) actuation occurred. Operators entered appropriate procedures to control the event. The ECCS pumps started and ran in recirculation as designed. No ECCS injection into the RCS occurred as a result of this event. The train A EDG and ECCS systems remained operable throughout the event. The unit remained at approximately 100 percent power.

After the inadvertent SI actuation, the TD AFW pump auto-start signal was still present while engineering personnel reviewed the cause of the event. Operators locally tripped the TD AFW pump following report of a burning smell in the pump area. Tripping the TD AFW pump also limited non-safety AFW supply source usage. The smell was later determined to be from recently installed insulation and not a challenge to the pump. The tripping of the TD AFW pump, coincident with the Train B motor driven AFW pump being technically inoperable, resulted in the unit entering the TS ACTION requirements of 3.7.1.2. Several hours later, it became apparent that the troubleshooting would extend beyond the TS limits for operation; therefore, the operators restarted the TD AFW pump and exited the shutdown Limiting Condition for Operation (LCO). Early on May 28, troubleshooting of the sequencer circuitry was completed and the system was reset. At that time, all ECCS components were returned to standby readiness.

The inspectors reviewed the root cause of the event with the licensee. The train B EDG sequencer timer calibration procedure, IP/0/A/3250/012B, had been revised to incorporate enhanced testing of safety-related logic circuits pursuant to NRC Generic Letter 96-01. Specifically, the existing test incorporated testing of the sequencer test circuitry to ensure that the sequencer would come out of test and begin sequencing if a valid SI or blackout signal occurred. The revised procedure had incorporated the manipulation of a sliding link to maintain a test timer relay de-energized, such that the portion of the circuitry under test would be isolated. However, engineering personnel failed to identify a circuit interaction which bypassed the function of the sliding link. The oversight prevented adequate isolation of the test circuitry and allowed partial sequencer logic to be satisfied when the blackout signal was introduced for the test. Subsequent review also determined that the partial SI occurred when test personnel were attempting to verify the position of the sliding link. The licensee concluded that the nut driver being used to verify the position of the sliding link contacted both sides of the terminal. This caused a momentary SI signal which energized the sequencer loading relays, resulting in the Train B ECCS pump starts.

Initial corrective actions for the event included initial troubleshooting of the cause of the actuations, verification of the expected ECCS and other components to the inadvertent signal, and restoring the equipment to standby status. All equipment responded as expected. The inspectors discussed the test procedure changes and revision processes with engineering personnel and management. Based on the discussions, the inspectors concluded that the reviews for the test procedure (IP/0/A/3250/012B) were inadequate, and resulted in the procedure being inadequate to perform the enhanced test. The inspectors also noted that the independent review also failed to identify the procedure inadequacy.

c. Conclusions

Operator response to the event was adequate and compliance with TS equipment operability was maintained. The inadequate test procedure is a Violation (VIO) of TS 6.8.1 and will be identified as VIO 50-370/97-09-01: Inadequate Test Procedure. During closeout inspection of the LER associated with this event, the inspector will continue to review operator actions associated with securing the TDAFW pump per applicable procedures and appropriate logging of the event.

M2.2 High Pressure (HP) Turbine Blade Ring Locating Pin Weld Defects

a. Inspection Scope

The inspectors reviewed the corrective actions associated with weld problems on the subject components and the extent of condition review.

b. Observations and Findings

On May 23, with Unit 1 at approximately 38 percent power, operators received a computer alarm on the high pressure turbine indicating a high differential extraction zone temperature. A non-licensed operator (NLO) was dispatched and reported that a small steam leak under the high pressure turbine was condensing and running on the local area thermocouple. Engineering management determined that a repair should be completed and after adequate manpower resources were obtained, the unit reduced power to approximately 10 percent. The leak was determined to be on one of eight HP turbine blade ring locating pins, which are installed to hold the stationary HP turbine blades in place. These smooth cylindrical pins are approximately 3.5 inches in diameter and 10 inches long. They are seal welded after installation to form the HP turbine steam boundary and were recently replaced during the Unit 1 End-Of-Cycle (EOC) 11 outage along with the installation of new HP turbine blade rings.

The leaking pin had a one to two inch circumferential weld crack with some evidence of porosity. Examination of the cracked weld and weld historical documentation identified that the eight pin welds had potentially been performed at a low preheat condition (200 vs 350 degrees F). The main steam stop valves were closed for the repair and the HP turbine was under a slight vacuum. The non-code repairs of the failed area were completed at the increased preheat level and involved grinding of the original seal weld and refill. Additional grinding and weld build up were performed on other pins as needed. After visual inspections were performed, the unit increased power.

On June 2, unit power was reduced to approximately 12 percent to repeat the repair of a similar steam leak on the high pressure turbine blade locating ring pins. The second leak was on a different locating pin than the first failure. Subsequent discussion with the pin supplier identified that the pin material was different than what was assumed for the original seal welding. The difference in material specifications resulted in the most ideal weld material not being chosen for the application. An additional contributor to the problem was that a visual inspection was the only NDE performed on the work. Corrective actions for the repetitive problem included:

- Use of more suitable weld roa material (more ductile)
- Review of the weld area to reduce the difficulty in making good quality welds
- Performance of a more thorough non-destructive examination (i.e., magnetic particle testing and dye penetrant testing)
- Review of current non-code repair NDE inspection criteria to determine their adequacy to identify these type of problems

The licensee's corrective actions were documented in Problem Identification Process (PIP) reports 1-M97-2160 and 1-M97-2241. Final repairs for the pin seal were completed and more rigorous NDE evaluations were accomplished. An additional measure to assure proper weld material applications occur on Unit 2 was included in the PIP corrective actions.

c. Conclusions

Based on the above, the inspectors concluded that the licensee's final repairs to the HP turbine blade ring locating pins were adequate. The inspectors also concluded that the repetitive HP turbine steam leaks were an example of incomplete root cause reviews on secondary components.

M2.3 Vendor Control

a. Inspection Scope

The inspectors investigated activities that resulted in the inadvertent isolation of instrument air to the Unit 2 moisture separator reheater drain valve controllers causing an unplanned reactor thermal power increase and a reduction in main feedwater suction supply pressure. The resulting valve realignments also caused a reduction in electrical power output.

b. Observations and Findings

On May 22, the control room operators, responding to various indications and alarms of moisture separator reheater valve movement and decreasing main feedwater suction pressure, started a standby hotwell pump to maintain adequate main feedwater pump suction pressure and dispatched operators to the turbine building to identify the cause. The dispatched operators determined that the moisture separator reheater drain valves had isolated due to a loss of their instrument air supply. The operators re-established instrument air and returned the valves to the normal operating positions. Main feedwater suction pressure, reactor thermal power, and electrical output were returned to normal. Reactor thermal power momentarily increased to approximately 100.7 percent during this transient.

Further investigation identified that vendor personnel had inadvertently isolated instrument air while performing routine turbine building cleaning activities. The vendor had been instructed to use station air instead of instrument air when performing cleaning activities in the turbine building. The inspectors discussed the event with the licensee and reviewed station documentation and determined that the vendor crew had not received adequate instructions to ensure that the work activities were completed without technical errors. Although the use of instrument air was not authorized for the activity, the vendor did not receive sufficient instruction on the potential consequences of repositioning operations controlled equipment. The licensee has established plans to evaluate contract training requirements emphasizing potential operational transients due to manipulating plant equipment.

Conclusions

The inspectors concluded that the isolation of instrument air, which is nonsafety-related at McGuire, was an example of ineffective vendor oversight. The vendor personnel did not receive sufficient guidance prior to the start of the activity. As a result, the contract workers initiated an operational transient by manipulating Operations controlled equipment. This is considered a weakness in the area of vendor control.

M3 Maintenance Procedures and Documentation (62707)

M3.1 Steam Generator Replacement Project (SGRP) Post-Installation Review and Control System Operability Verification

a. Inspection Scope

The inspectors evaluated the results of the licensee's performance testing of the Unit 1 operating characteristics and control system response following replacement of the Unit 1 SGs. The inspectors reviewed selected documentation to verify that post modification activities such as drawing updates, procedure changes, resolution of outstanding issues, and training had been revised to reflect the configuration changes associated with SG replacement.

b. Observations and Findings

Post-Installation Inspections

Inspections of the leak tightness of the system was performed at full temperature and pressure in accordance with NRC approved ASME Code Case N-416-1. SG secondary side hydrostatic testing was performed by the manufacturer. The inspectors and the licensee conducted visual inspections of the reactor coolant system and noted no external leakage.

Steady State and Transient Testing

The licensee performed testing to confirm the SG design and to establish baseline measurements. The testing was conducted during steady state and transient conditions. The performance tests were performed in Mode 1 (POWER OPERATION) with Unit 1 at approximately 38 percent and 78 percent power. Calibration and testing of instrumentation affected by SG replacement was performed prior to testing.

The performance testing was necessary to ensure proper operation of these systems:

- Reactor Rod Control
- Steam Generator Level Control
- Main Feedwater Pump Speed Control
- Pressurizer Level Control
- Pressurizer Pressure Control
- Load Rejection Control (Tavg-Tref mode)

Testing included introduction of false level signals to verify main feedwater control system performance and a 10 percent load reject test was initiated to verify proper control system overall response. A dedicated RO and SRO were assigned to monitor the transient testing. Prior to commencement of the transient testing, the operators were instructed to intervene and abort the testing, if necessary, to preclude a unit trip or equipment damage.

The load drop change rate was set at 2400 MWe/min or 200 percent rated output/min. The total load reduction was 10 percent of rated electric power output. All equipment operated as expected. No manual actions were necessary to stabilize the station during the load rejection testing. Steam Generator levels stabilized at the lower power level. No instability with automatic control systems was experienced nor were there sustained or diverging plant parameters identified. Neither primary or secondary relief or safety valves lifted. No reactor trip, turbine trip or Safety Injection occurred as a result of the load reject.

c. Conclusion

The inspectors concluded that restart testing following the Steam Generator Replacement Outage was adequately planned and executed to verify steam generator design and ensure reliable operation of the Unit 1 control systems.

M4 Maintenance Staff Knowledge and Performance

M4.1 Unit 2 Steam Generator Leakage Inspections and Repair

a. Inspection Scope

The inspectors reviewed the licensee's actions regarding the forced outage inspection of the 2A SG for primary to secondary leakage. Unit 2 was shutdown on June 13, 1997, with an indicated SG leakrate on the 2A SG of approximately 60 to 70 GPD.

b. Observations and Findings

On June 19, with the Unit in MODE 5 (Cold Shutdown), the licensee performed a secondary pressurization test on the 2A SG to approximately 650 psig using a condensate booster pump. The test pressure was held approximately 10 hours. Leakage results identified an approximate 10 drop per minute leak at the 7-60 tube location. No other indications were identified. The licensee reviewed Unit 2 cycle 10 SG inspection data and identified that initial bobbin coil inspections revealed a 2.68 volt non-quantifiable indication. This value did not meet repair criteria; however, the indication received expanded inspection via motorized rotating pancake coil (MRPC). The results were reviewed by SG specialists and no defect was found. However, more in-depth review identified that the anticipated tolerance range of the MPRC measurement was not fully achieved. This problem may have resulted in the no defect decision being based on incomplete data. Current testing confirmed the 100 percent throughwall leak just above the second support plate on the cold leg side. All indications supported the conclusion that the crack was axial. An in-situ pressure test was performed on the 7-60 tube which concluded that the tube met structural acceptance criteria. Specific repairs to the 7-60 tube included plugging and inspection of six adjacent tubes with bobbin coil. No other problems were identified in this area relating to the leaking tube.

On June 20, a conference call was held between NRC and the licensee to discuss the details of the tube degradation and the proposed scope of additional inspections. Based on the indicated root cause of the 7-60 leak, the licensee proposed additional inspections of all positive bobbin indications which were considered to have no defect based on additional MRPC inspections. This initial scope included 377 potential tubes to be re-inspected which were distributed in all four SGs. This total number was reduced to approximately 192 tubes based on review of outage data. All of the subsequent MPRC inspections were performed over the full free span to avoid any potential alignment concerns. These inspections resulted in the additional plugging of 18 SG A tubes, 3 SG B tubes, 3 SG C tubes, and 0 SG D tubes. The additional tube plugging could not be attributed to errors in the previous outage SG inspections due to the additional inservice time on the Unit 2 SGs. Licensee reviews did not identify any tube degradation which exhibited abnormal defect growth characteristics.

c. Conclusions

Based on the licensee's inspection process, scope, and completed repairs, the inspectors concluded that the corrective maintenance was adequately performed. However, the inspectors also concluded that previous followup to a SG indication in the area of the identified leak led to a missed opportunity to identify and prevent this event. At the end of the inspection period, the licensee continued to review the root cause of the SG inspection inconsistencies. Once identified, actions to correct the problem and also ensure that other oversights did not occur were good. This problem will be identified as Unresolved Item (URI) 50-370/97-09-02: Steam Generator Inspection Process, pending further review of the root cause of the SG inspection process.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Violation 50-369, 370/96-06-03: Failure to promptly incorporate vendor recommended torquing guidelines for the Reactor Trip Breaker (RTB) secondary contact assembly block prior to performing maintenance in September 1994. A new Westinghouse Maintenance Program Manual (MPM) for Reactor Trip Circuit Breakers was received in the General Office (GO) by the Operating Experience Assessment (OEA) group on February 14, 1994. OEA issued a General Office (GO) Problem Investigation Process (PIP) report to assign actions for processing the updated manual into the McGuire Document Control System. Due to lack of accountability, assignment of low priority, and inadequate tracking the Manual was not finally processed into the McGuire Document Control Program until January 23, 1995. The new reactor trip breaker (RTB) Manual contained torquing values for the secondary contact block assembly which were not included in the previous manual. In September 1994, a broken secondary contact block assembly was found on 1RTB DS-416 Reactor Trip Breaker during a routine outage PM and was replaced using the then current procedure IP/0/A/2001/006. This procedure was based on the older MPM and did not contain torquing values for the contact block mounting bolts. Subsequently, on July 1, 1996, during an inspection of 1RTB DS-416 Reactor Trip Breaker, the secondary contact block assembly that had been replaced two years earlier was found broken. Overtorquing of the mounting bolts was a probable contributor to the failure.

In response to the violation dated September 20, 1996, the licensee had implemented a new MPM for RTBs into the Document Control System on January 23, 1995. New procedure SI/0/A/2410/001,"Westinghouse DS-416 Air Circuit Breakers Inspection and Maintenance," replaced the old procedure on October 12, 1995. Additionally, training was provided to site engineers and a Champion Tracking Report initiated to aide OEA in tracking site assigned tasks.

The insp tor reviewed the new procedure and verified torque values for mounting the secondary contact block were included. Also, the training lesson for engineering was reviewed and found to be acceptable and the development of the Champion Tracking Report was verified.

M8.2 (Closed) Violation 50-369, 370/96-04-01: Failure to perform performance test PT/2/A/4350/03A, "Electrical Power Source Alignment Verification," prior to entering Mode 6. In the response to the violation dated July 31, 1996, the licensee indicated that other procedures had performed the necessary alignments. The licensee committed to perform a procedure review to determine if procedural changes were necessary. The inspectors reviewed the documentation of these reviews. The licensee determined that no changes to the scheduling process or start up checklists were necessary. However, Operations Management Procedure OMP 5-10, "Routine Task List," was revised to require that any PT item on the list not completed on schedule must be reported to the Operations Support Manager and entered into the Technical Specification Action Item Log for tracking and close out. Licensee actions were considered acceptable.

M8.3 (Closed) Violation 50-369, 370/96-07-01: Failure to demonstrate the operability of the 1A emergency diesel generator (EDG) after EDG 1B was declared inoperable. In response to the violation dated October 24, 1996, the licensee identified the cause as the operator's dependence on memory rather than to adequately research the Technical Specification requirement. Additionally, the procedure PT/1/A/4350/25, "Essential Auxiliary Power System Power Source Verification," did not clearly specify that the redundant train must be run. The inspectors verified that PT/1/A/4350/25, Revision 10, clearly stated that if a EDG is inoperable for reasons other than planned maintenance or testing the other EDG will be run. The inspectors also determined that Management Expectations that the Technical Specification be physically reviewed versus relying on memory was promulgated in a letter to Senior Reactor Operators dated October 21, 1996.

III. Engineering

E1 Conduct of Engineering

E1.1 Non-conservative TS for Inoperable Main Steam Safety Valves (MSSVs)

a. Inspection Scope (37551)

The inspector reviewed the identification process of non-conservative TS ACTION statements associated with the MSSVs.

b. Observations and Findings

On March 20 and May 20, 1997, the licensee identified through 10 CFR 50.72 reports that TS Table 3.7-1, Maximum Allowable Power Range Neutron Flux High Setpoint With Inoperable Steam Line Safety Valves During Four Loop Operation, specified non-conservative values. Specifically, when one or more MSSVs may be inoperable, the TS identified power range neutron flux high setpoints may be non-conservative. The purpose of the setpoints are to assure that secondary system pressure will be limited to within 110 percent of its design pressure during the most severe anticipated system operational transient.

The inspector discussed with the licensee their historical response to the issue. On January 20, 1994, Westinghouse issued a Nuclear Advisory Letter informing utilities that the algorithm used to initially calculate the power range neutron flux high setpoint for the MSSVs was not correct. The basis for the advisory letter conclusions were modeled from uniformly sized MSSVs. McGuire's MSSVs were not uniform, therefore a plant specific study was necessary to determine if McGuire's TS was also non-conservative. In early 1994, the licensee initiated a study and issued a TS interpretation regarding the potential problem, which provided further guidance to operators for operation with one or more inoperable MSSV. In December 1995, the plant specific analysis was completed, and concluded that the TS values for the inoperability of one and two MSSVs allowed for reactor operation at non-conservative power levels. During this time, McGuire has never operated in a condition requiring plant operation to be restricted due to inoperable MSSVs.

The licensee chose to pursue a TS change via their improved TS project plan to reflect the higher reactor power limits; however, during final review for the submittal in early 1997, engineering questioned the bases for the existing power level restrictions. It was subsequently determined that the restrictions for operation with one or more inoperable MSSVs was non-conservative. Once identified, the licensee made the appropriate 10 CFR 50.72 reports, gave additional guidance to operations, and submitted an LER on the subject. In addition, the licensee initiated the TS revision process to revise TS 3.7.1. The licensee stated that the change would be conducted outside of their TS upgrade project.

c. Conclusions

The inspectors concluded that once the entire scope of the problem was identified, the licensee initiated appropriate actions to address the issue. However, the overall resolution of the potential for non-conservative TS ACTION requirements was not completed in a timely manner. Although adequate administrative controls were in place and no actual MSSV inoperability occurred during the issue resolution period, the chosen TS Amendment process led to delays in final resolution and identification of all pertinent issues. The inspectors will review other technical adequacies of the licensee's corrective actions during close-out of associated LER 369/97-04.

E2 Engineering Support of Facilities and Equipment

E2.1 <u>Design Modification of Auxiliary Feedwater (AFW) System Suction Supply</u>

a. <u>Inspection Scope (37551,40500)</u>

The inspector reviewed the implementation of minor modifications to the nonsafety-related suction supply of the AFW system. The inspector reviewed the 10 CFR 50.59 evaluation, related FSAR and Design Bases Document (DBD) sections, and witnessed portions of the field work to modify the system. This is an update of IFI 50-369,370/97-08-04, Potential Airbinding of AFW Pumps.

The AFW air entrainment mechanisms include, but are not limited to, vortexing in the AFW condensate storage tank (AFWCST) and emptying of the upper surge tanks (UST) with the AFW system in a recirculation mode. In 1996, operators identified the AFW pump air binding issues as an operator work around and the licensee initiated engineering analysis to investigate the issue. NRC Inspection Report 97-08 documents the issues, status of the hydraulic studies, and the licensee's compensatory measures.

b. <u>Observations and Findings</u>

During the inspection period, the licensee implemented two design modifications to the AFW suction supply in order to reduce the likelihood of air entrainment into the AFW suction piping. The first modification involved the conversion of an existing filtered water tank (42,500 gallon capacity) into an additional AFWCST. This tank, AFWCST 'B', is located next to the AFWCST 'A' on the service building roof. Combined, the two tanks have a capacity of 85,000 gallons of condensate quality water and doubles the original AFWCST capacity available to either Unit 1 or Unit 2. The second modification involved vortex suppressors that were installed in the suction nozzles of each AFWCST. These modifications were completed on June 12, 1997.

Before completion of the modification, the licensee determined by engineering analysis that a vortex in AFWCST 'A' did not affect past operability of the AFW pumps. The issue involving the air slug from UST interaction with nuclear service water and AFW pump recirculation continued to be indeterminate, pending conclusion of other engineering analysis. Compensatory measures remained in effect until plant procedures affected by the design modifications could be updated and the UST air slug issue dispositioned.

The inspector confirmed through daily control room visits that the compensatory measures remained in-effect before, during, and after the modifications. During implementation of the modifications, Unit 1 AFW pumps were aligned to take suction from the Unit 1 UST. Unit 2 continued to be aligned to the Unit 2 UST.

c. Conclusion

The inspector concluded that the addition of another AFWCST was a timely and positive action to extend AFW inventory and improve pump suction reliability. Installation of vortex suppressors was a conservative management decision, given the licensee's conclusions of their engineering analysis. The associated field work was considered adequate. However, IFI 369,370/97-08-04 remains open pending the licensee's completion of engineering analysis and subsequent NRC review.

E2.2 Outage Modifications (37550)

a. Inspection Scope

The inspector reviewed Nuclear Station Modifications (NSMs) implemented during the current Unit 1 outage. The modification review included verification that design control requirements of Regulatory Guide 1.64 and ANSI N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants, and licensee procedures were implemented. Elements of the design process reviewed included post modification testing, procurement, procedure revision, 50.59 safety evaluation and screening, and field verification of plant hardware changes, as applicable. The following NSMs and minor modifications were reviewed:

- MG 12220/P2 — Reroute Instrumentation and Control (I&C) Tubing for AFW, Main Steam (MS), and MFW Systems
- MG 12419 — Replace Diesel Generator (DG) Train A Cooling (KD) Pumps
- MG 12467/P1 — Replace Bussman FNQ Fuses
- MG 12473 — Relocate DG Lube Oil (LO) Pressure Switches
- MGMM 8289 — Replace Valves 1 NV-457 and 458 with Gate Valves
- MGMM 8676 — Replace Valve 1NC-45
- MGMM 9101 — Qualify Over-thrust of 1NI-147
- MGMM 9114 — DG Engine Drive LO pump Dowel Replacement
- MGMM 9255 — Actuator Replacement on 1ND-19
- MGMM 9269 — Qualify As-left Thrust for 1NM-06

b. Observations and Findings

Post modification testing performed was adequate to verify equipment and system function following the modification. In general, 50.59 safety evaluations were good, in that, responses to screening or evaluation questions were detailed and adequately justified the conclusions. Procurement documentation demonstrated that the appropriate quality level material was used for installed equipment and materials.

c. Conclusion

The modifications completed during the Unit 1 outage demonstrated appropriate control of the design control process at McGuire. Performance was good for modifications, procedures, 50.59 evaluations and screening.

E2.3 Engineering Support to Operations (37550)

a. Inspection Scope

The inspector reviewed the use and validation of Test Acceptance Criteria (TAC) which were developed in conjunction with the design base documents. Applicable regulatory requirements included 10 CFR 50 Appendix B.

b. Observations and Findings

The TAC sheets were developed in conjunction with the Station Design Base Documents and described the design function, operability requirements and verification test criteria for safety-related equipment. The TACs included compensatory actions to maintain system operability if a component was out of service. The station Modification Manual indicated that the TACs were to be used to document test acceptance criteria for station modifications (NSMs) and equipment performance tests. In practice, Operations used the TACs for verifying operability and establishing compensatory measures for systems during on-line GL 89-10 testing of safety-related valves.

In 1996, the Operations and Engineering staffs noted that the TAC compensatory measures had not been validated with 10 CFR 50.59 safety evaluations to assure the alternate system configurations did not introduce an unreviewed safety question. A February 5, 1997, memorandum from the Station Vice President to the Station established parameters for use of the TAC compensatory measures. The licensee recently completed an upgrade of the TACs for Inservice Test Program (IST) valves which standardized the format and validated compensatory measures with 10 CFR 50.59 evaluations. Nuclear Station Directive NSD-203, Operability Policy, was revised on March 26, 1997, to provide guidance on the use of TAC sheets for IST valves.

c. Conclusion

Engineering's upgrade and validation of DBD TAC sheets for IST valves was an example of good engineering support to operations. The TACs provide a good design reference for Operations to maintain system operability when safety-related valves are out of service for testing.

E3 Engineering Procedures and Documentation

E3.1 Unit 1 K-45 Fuel Assembly Reconstitution

a. Inspection Scope (71707)

During the inspection period, reactor engineering personnel performed fuel reconstitution of the K-45 assembly in the Unit 1 spent fuel pool. The inspector performed field observations of the reconstitution and discussed the activities with the cognizant engineer. The inspector also reviewed the 10 CFR 50.59 safety evaluation for use of a crud scrubbing device to remove crud from fuel rods and the use of single rod diameter/oxide measurement equipment. Specifically, the inspector reviewed calculation MCC 1553.26-00-211 which was the safety analysis for mechanical, criticality, shielding, and thermal concerns associated with use of the equipment.

b. Observations

Between June 5 - 9, eight experimental fuel rods were removed from the K-45 lead test assembly for Post Irradiation Examination (PIE). The eight rods are part of an advanced zircaloy cladding program. These rods contained three different types of cladding materials, and the assembly had a high burnup (i.e., over 40 GWd/mtU) with a cooling time of approximately 18 months.

The inspector observed fuel rod removal and reconstitution of the assembly. Stainless steel rods were used as substitutes in the assembly for the removed rods. The fuel rods were loaded into a specially designed basket and will be inserted in the R52 cask canister for shipment. All eight rods will be shipped offsite for hot-cell testing and destructive examination.

The licensee, with support from Framatome, used underwater surveillance cameras to read rod serial numbers and accomplish the reconstitution. Pool water clarity was good and serial numbers were clear and readable on video monitors.

PIE work was also performed in the Unit 1 spent fuel pool to provide baseline data prior to offsite testing. Using a scrubbing device, crud was removed from the cladding of each of the eight rods. This was done to improve eddy current testing to gauge oxidation layer thickness and clad wall thinning. The inspector determined that the licensee's safety analysis for use of the equipment was adequate.

c. Conclusion

The inspector concluded that the K-45 fuel reconstitution work activities were well controlled and that good communication existed among the crew members. Reactor engineering personnel were knowledgeable and the 10 CFR 50.59 evaluation was adequate. Appropriate reactor engineering oversight was present and adequate radiation protection coverage was provided.

E4 Engineering Staff Knowledge and Performance

E4.1 Vital Battery and Charger Replacement Modification

a. Inspection Scope

The inspectors reviewed minor modification packages developed and implemented for the replacement of the Bus A EVCA battery and associated charger. The replacement was necessary to improve reliability of the 125VDC Vital Power System. The currently installed AT&T lineage 2000 series round cell batteries at McGuire have been degrading at a faster rate than was initially anticipated. Due to this unanticipated battery degradation, the licensee established prudent replacement schedules for each of the four batteries and their associated chargers. The round cell batteries from EVCA were replaced with conventional rectangular cell GNB Type NCN stationary batteries. Prior to implementation of the battery replacement modification, an increase in TS allowed battery outage time to 30 days was approved by the NRC.

b. Observations and Findings

The licensee completed replacement of vital battery EVCA and its associated charger during this period. Completion of the remaining three battery/charger replacements was scheduled prior to December 1997. The EVCA battery/charger replacement was conducted under Nuclear Station Modification NSM-52483, Vital Battery EVCA Replacement and NSM-52488, Vital Charger EVCA Replacement. The associated connectors and cabling was replaced under separate modification packages.

Prior to the commencement of the maintenance activities, the inspectors reviewed the modification packages to verify that the licensee's plans were in accordance with TS requirements and the McGuire UFSAR. The inspectors confirmed that a temporary battery was installed under Minor Modification MGMM-8847 and Work Order No. 96089566 on the affected bus during the replacement. The temporary battery bank was composed of low specific gravity AT&T round cells. The affected bus remained energized by spare charger EVCS, backed by the temporary battery. Although the temporary battery was sized to supply the same duty cycle as the normal batteries and configured to the full capacity spare charger, the licensee did not consider the bus fully operable since the temporary battery storage racks were not positioned in a seismically qualified location.

Prior to being connected to the bus, the temporary battery received a full complement of surveillance measurements, including a service test. Temporary ventilation equipment was necessary to prevent unacceptable combustible gas accumulation during temporary battery operation. The replacement EVCA battery was service tested. The factory acceptance test was used to satisfy TS 4.8.2.1.2e rather than performing an onsite performance discharge test. Breaker and fuse upgrades were also conducted to ensure proper breaker coordination.

Contingency plans were also developed and implemented to provide adequate fire, security, and radiological protection during breach of the vital security battery room and RCA. Radiological surveys were performed to ensure that the area could be re-classified as a non-radiologically controlled area. Continuous security coverage was established while vital area doors and fire barriers were disabled to allow equipment removal and replacement.

c. Conclusion

The inspectors concluded that the licensee developed adequate procedures and controls for replacement of the EVCA battery/charger. Modification packages for installation of the temporary battery were adequate. Contingencies were established in the event of a loss of the temporary battery or the spare charger while in the degraded condition. Although the licensee delayed return of the battery to service to minimize potential plant impact during Unit 2 draindown and midloop operations, the replacement activities were completed within the authorized TS allowed outage times.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Tour of Radiological Areas

a. Inspection Scope (83750)

The inspectors discussed with licensee representatives the planning and preparations underway for a site project to remove selected pieces of steam generator tubes and tube sheet components from two removed steam generators (SGs) B and D. This project was contracted through Duke Engineering Services (DES) and Argonne National Laboratory in support of a contract between the Nuclear Regulatory Commission (NRC) and the Department of Energy. Licensee preplanning activities for the evolution was reviewed to determine the adequacy of licensee planning efforts in the area of radiation protection, including: dose estimates, as low as reasonably achievable (ALARA) planning and implementation, and contamination control practices.

b. Observations and Findings

The inspectors discussed specific work preparations to assist qualified radiation protection technicians in planning for survey coverage, radioactive material control and storage, contamination controls, and exposure controls for SG tube and tube sheet removal. The inspectors determined the licensee's plans were to sequence work activities in order to maximize the use of shielding while maintaining exposures ALARA. At the time of the inspection, the inspectors observed preparations being made to construct tent containments with High Efficiency Particulate Air (HEPA) filters around the SGs to be worked. The use of wireless communications, teledosimetry, cameras and other work practices being developed were also discussed as methods the licensee was planning to use to maintain exposures ALARA. Specific work procedures and radiation work permits (RWPs) to support the work evolution had not been finalized at the time of the inspection.

c. Conclusion

At the time of the inspection, the inspectors determined that the licensee was in the process of developing procedures and work practices to maintain effective contamination controls and to maintain exposures ALARA during work evolutions on two removed SGs.

P1 Conduct of EP Activities

P1.1 Emergency Preparedness Drill

a. Inspection Scope

On April 16, the licensee conducted a station emergency preparedness practice exercise. The practice exercise scenario involved a dropped fuel assembly in the spent fuel transfer canal area during refueling followed by a 30 gpm reactor coolant leak from the available train of residual heat removal. The scenario progressed to a General Area Emergency, exercising major components of the McGuire Emergency Plan.

b. Observation and Findings

The inspectors evaluated the practice drill critique. The inspectors noted a number of deficiencies identified concerning Emergency Response Organization (ERO) performance throughout the drill. Concerns were also identified with station security processes and equipment during the Site Assembly portion of the drill. Based on the findings identified in the critique on procedural use and adherence the inspectors determined that additional emphasis on management expectations was necessary to improve ERO performance. The inspectors also noted that increased management involvement in the critique process was necessary to ensure that corrective measures identified during the critique were appropriately evaluated and resolved. The licensee recognized that adjustments were necessary and have formulated working groups to correct the licensee-identified concerns.

Conclusion

The inspectors concluded that the practice drill scenario was adequate to effectively test the Emergency Response Organization (ERO) participants. The ERO performance was adequate; however, additional management emphasis on ERO expectations was necessary.

F3 Fire Protection Procedures and Documentation

F3.1 Adequacy of 3 Year Fire Protection System Flow and Pressure Test (71750)

a. Inspection Scope

The inspector reviewed the licensee's implementation of commitments to perform 3 year fire protection system flow testing.

b. Observations and Findings

The Selected Licensee Commitments (SLC) Manual, Section 16.9, requires that the fire suppression water system be operable at all times. The system is demonstrated to be operable through a series of tests listed in the SLC Manual, Section 16.9-1. The subject test is a system flow test which was last performed in July 1995. The inspectors discussed with licensee fire protection personnel their performance of the 3 year fire protection system flow and pressure test, and whether any performance degradation had occurred from previous tests. No significant degradation was noted; however, trending of the data was minimal. In addition, the acceptance criteria for the test data was not well established. The inspector raised an additional concern regarding the scope of fire protection piping actually tested. Specifically, the McGuire station was not performing this type of testing on the interior loop piping within, for example, the auxiliary building. The licensee was performing this type of testing on overall yard loop piping; however, with this approach, interior loop piping degradation may not be apparent. In 1995, the licensee's Catawba facility identified problems in this area (see PIP 0-C95-1908) via the performance of more specific flow testing; however, the McGuire facility testing had not incorporated similar testing.

Based on the inspectors concerns, the licensee initiated PIP 0-M97-1849 to evaluate what corrective action may be required. By the end of the inspection period, the licensee was preparing a special test which would incorporate additional key sections of the interior loop piping to provide baseline information of system degradation. It should be noted that the McGuire fire protection system, historically, has not exhibited evidence of significant corrosion in the auxiliary or reactor buildings. Based on the reviews, this issue will be identified as an Inspector Followup Item (IFI) 50-369,370/97-09-03: 3-year Fire System Testing, pending completion of the additional testing being developed by the licensee.

c. Conclusions

The inspectors concluded that the development of additional testing for the interior loop piping was prudent and could provide additional indications of system degradation. The inspectors also concluded that the administrative processes for long-term monitoring of the fire protection system for degradation could be improved.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 26, 1997. The licensee acknowledged the findings presented. No proprietary information was identified.

X2 Management/Organizational Changes

On June 18, 1997, the proposed Duke Power and PanEnergy merger became official. Additionally, the following McGuire management changes were announced:

- A. Bhatnagar to become Operations Superintendent at McGuire, effective July 1, 1997
- L. Loucks to assume the position of McGuire Chemistry Manager, effective in November 1997.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Barron, B., Vice President, McGuire Nuclear Station
Boyle, J., Civil/Electrical Systems Engineering
Byrum, W., Manager, Radiation Protection
Cline, T., Senior Technical Specialist, General Office Support
Cross, R., Regulatory Compliance
Davison, Valve Supervisor
Dolan, B., Manager, Safety Assurance
Geddie, E., Manager, McGuire Nuclear Station
Harley, M., Engineering Supervisor
Herran, P., Manager, Engineering
Jones, R., Superintendent, Operations
Michael, R., Chemistry Manager
Jamil, D., Superintendent, Maintenance
Cash, M., Manager, Regulatory Compliance
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical/Nuclear Systems Engineering
Tuckman, M., Senior Vice President, Nuclear Duke Power Company

NRC

S. Shaeffer, Senior Resident Inspector, McGuire
M. Franovich, Resident Inspector, McGuire
M. Sykes, Resident Inspector, McGuire
R. Moore, Regional Inspector
H. Whitener, Regional Inspector
D. Forbes, Regional Inspector

INSPECTION PROCEDURES USED

IP 71707:	Conduct of Operations
IP 71750:	Plant Support
IP 62700:	Maintenance Program Implementation
IP 62707:	Maintenance Observations
IP 61726:	Surveillance Observations
IP 37551:	Onsite Engineering
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 40500:	Self-Assessment
IP 37550:	Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

OPENED

VIO 50-370/97-09-01	Inadequate Test Procedure (Section M2.1)
URI 50-370/97-09-02	SG Inspection Process (Section M4.1)
IFI 50-369,370/97-09-03	3-year Fire System Testing (Section F3.1)

CLOSED

VIO 50-369,370/96-06-03	Failure to Incorporate Vendor RTB Information Into Plant Procedures (Section M8.1)
VIO 50-369,370/96-04-01	Surveillance Not Performed Due to Inadequate Procedure Guidance (Section M8.2)
VIO 50-369,370/96-07-01	Failure to Perform Surveillance on Emergency Diesel Generator (Section M8.3)

DISCUSSED

IFI 50-369,370/97-08-04	Potential Airbinding of AFW Pumps (Section E2.1)

LIST OF ACRONYMS USED

AFW - Auxiliary Feedwater
AFWCST - Auxiliary Feedwater Condensate Storage Tanks
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
GL - Generic Letter
HP - High Pressure
IFI - Inspector Followup Item
IRT - Independent Review Team

LER	-	Licensee Event Report
MOV	-	Motor-Operated Valve
MPM	-	Motor Power Monitor
MRPC	-	Motorized Rotating Pancake Coil
MSR	-	Moisture Separator Reheater
MSSV	-	Main Steam Safety Valve
NCV	-	Non-Cited Violation
NLO	-	Non-Licensed Operator
NRC	-	Nuclear Regulatory Commission
NRR	-	NRC Office of Nuclear Reactor Regulation
PIP	-	Problem Investigation Process
PMT	-	Post Maintenance Test (Retest)
PORV	-	Power Operated Relief Valve
PRA	-	Probabilistic Risk Assessment
PT	-	Performance Test
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RO	-	Reactor Operator
RV	-	Reactor Vessel
RWST	-	Refueling Water Storage Tank
SG	-	Steam Generator
SGRP	-	Steam Generator Replacement Project
SI	-	Safety Injection
SRO	-	Senior Reactor Operator
TI	-	Temporary Instruction
TS	-	Technical Specifications
TSAIL	-	Technical Specification Action Item List
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
UST	-	Upper Surge Tanks
VIO	-	Violation
WO	-	Work Order