U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Power Company
Facility:	McGuire Generating Station, Units 1 & 2
Location:	12700 Hagers Ferry Rd. Huntersville, NC 28078
Dates:	April 6 - May 17, 1997
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Enclosure 2

EXECUTIVE SUMMARY

McGuire Generating Station, Units 1 & 2
NRC Inspection Report 50-369/97-08, 50-370/97-08

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

- The refueling and restart of Unit 1 from the refueling/Steam Generator Replacement Project (SGRP) outage was conducted in a good manner. Operations control of the restart activities was good; however, increased operator attention to detail could have prevented a reactor trip which occurred during startup testing activities (Section O1.1).

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

- Operators responded appropriately to inadvertent main feedwater pump trips and resulting Auxiliary Feedwater (CA) Engineered Safety Features (ESF) actuation. An Unresolved Item was identified to evaluate the licensee's root cause investigation process concerning the valve vault level switches (Section O2.2).

- Startup evolutions, including Unit 1 preparation for criticality and zero power physics testing, were well controlled. Significant improvements in the reactivity management program have occurred in the last few years as a result of a 1995 reactivity excursion during startup at the Catawba plant. Briefing packages for the evolutions were detailed and highlighted specific items to help focus operators on conducting safe plant manipulations. Operations and Engineering management oversight of the evolutions was evident (Section O4.1).

- Plant Operations Review Committee (PORC) presentation/evaluation of component mispositioning data was beneficial. Licensee management was committed to make additional changes to necessary processes to further improve performance in this area of configuration control (Section O7.1).

- The inspector concluded that the presentation of the Unit 1 Cycle 12 core reload change summary to the PORC was well prepared and allowed the PORC members to assess changes incorporated in the new reactor core parameters. The proposed reactor physics training for PORC members should further improve their knowledge in assessing this area (Section O7.2).

Maintenance

- Review of the performance of a variety of Emergency Core Cooling System pump performance testing completed during the Unit 1 SGRP/refueling outage indicated that the identified pump performance was within limits. System flow balancing was accomplished in accordance with the established procedures (Section M1.1).

- Maintenance technicians demonstrated a good questioning attitude in identifying a residual heat removal pump motor bearing problem. The station response to the potentially degraded residual heat removal pump upper motor bearing was conservative and provided for improved equipment reliability (Section M2.1).

- Licensee actions in correcting and restoring a failed condensate booster pump motor was good. The inspectors also noted this motor failure as another example of the overall motor reliability concern that was previously identified and recognized by the licensee (Section M2.2).

- Licensee preparation, planning, and execution of the Unit 1 ESF testing equipment was exceptional. Equipment operated as designed with minimal necessary repairs. Good equipment performance during the test was determined to be indicative of good outage maintenance and testing (Section M2.3).

- The inspector concluded that the decision to repair a leaking conoseal connection was conservative and the repair activities were accomplished in a safe manner. However, during disassembly of the degraded component, root cause determination techniques could have been better incorporated (Section M2.4).

- A Violation was identified regarding inadequate analog channel operational test procedures for testing power range channels N-41 and N-42. The licensee's evaluation of the resulting reactor trip and subsequent restart assessments were adequately performed (Section M3.1).

- Unit 1 reactor building had been adequately returned to operational condition prior to power operation. Significant improvements in reactor building material condition and housekeeping were achieved (Section M4.1).

- The outage management group was effective in planning, scheduling, and managing refueling outage activities. Established station and SGRP outage exposure goals were aggressive. Good ALARA (As Low As Reasonably Achievable) exposure planning was evident (Section M4.2).

- The licensee has developed a good process for evaluating and planning maintenance evolutions according to their associated risk. Maintenance management has been effectively implementing the process and increasing the site overall awareness of risk associated maintenance evolutions. This area was identified as a strength (Section M7.1).

- The licensee placed appropriate emphasis on foreign material exclusion within the main generator housing (Section M7.2).

- Two Non-Cited Violations were identified concerning: the failure to maintain complete and accurate information; and the failure to follow procedure. Once identified, the licensee was proactive in assuring that required quality assurance documents were complete and accurate in all material aspects. All other issues were corrected in a timely manner (Section M8.1).

Engineering

- An Inspector Followup Item was identified concerning several potential challenges to the CA suction supplies which were identified by the licensee. Compensatory measures to prevent potential CA condensate storage tank vortexing were prompt and effectively implemented. The aggressive schedule to incorporate design modifications to eliminate the vortexing concerns were also positive actions to maintain CA system reliability (Section E1.1).

- The licensee's identification and corrective actions taken for the missing swivel bracket bolts in a Unit 1 ice condenser basket were adequate (Section E2.1).

- Corrective actions for previous FNQ type fuse failures were adequate. Licensee personnel were cognizant of the issue scope and implementation of the associated modification was well performed (Section E2.2).

- Licensee followup inspection for Oconee related pipe failures was adequate. Repairs to moisture separator reheater drain branch connections were sufficient to meet the applicable code requirements (Section E4.1).

Plant Support

- The licensee provided adequate monitoring of a small Unit 2 steam generator "A" tube leak and had previously established conservative administrative primary to secondary leakage limits as compared to TS allowable limits. The leak appeared to exhibit some steady growth characteristics (approximately nine gallons per day at the end of the inspection period (Section R4).

- The licensee's sponsoring of the routine Emergency Planning (EP) Task Force Meeting was indicative of good management support of the EP area. The meeting facilitated open discussions to improve existing EP processes and the licensee's interaction with the local officials during events (Section P2.1).

- The licensee's fire prevention efforts regarding a previous turbine oil spill event were effective in preventing a potential fire threat to the turbine building. Contingency measures were well established (Section F1.1).

Report Details

Summary of Plant Status

At the beginning of the inspection period, Unit 1 was defueled, in day 52 of the planned 86-day End of Cycle (EOC) 11 steam generator replacement/refueling outage. Throughout the period, Steam Generator Replacement Project (SGRP) activities were conducted in a safe manner. Specific SGRP reviews were documented in inspection reports 369/97-03, 97-05, and 97-07. During the period, SGRP activities were completed, the unit was refueled, and Engineered Safety Features (ESF) system testing completed. On May 14, during MODE 3 (Hot Standby) preparations for restart, a reactor trip occurred due to procedural inadequacies associated with bypassing power range trip channels and permissives. After conducting a post trip review, startup evolutions resumed and the unit was started on May 15. Later the same day, the licensee identified that an intermediate range power detector had failed and needed to be replaced. The unit was shutdown to MODE 5 (Cold Shutdown) for the replacement of the detector. At the end of the inspection period, the unit was in MODE 3 preparing for MODE 2 (Startup) operations.

Unit 2 began the period operating at approximately 100 percent power. On April 18, Unit 2 power was reduced to approximately 28 percent to allow for additional modifications to the Main Feedwater (CF) isolation valve solenoids to prevent overtemperature conditions. In addition, condenser tube leakage troubleshooting was conducted. After appropriate testing, the unit returned to 100 percent power on April 21. The unit then operated at approximately 100 percent power for the remainder of the inspection period.

Review of Updated Final Safety Analysis Report (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. The refueling and restart of Unit 1 from the refueling/steam generator replacement outage was conducted in a good manner. Operations control of the restart activities was good; however, increased operator attention to detail could have prevented a reactor trip which occurred during startup testing activities (see paragraph M3.1). In addition to the issues discussed in this report, other final steam generator replacement outage inspections were detailed in NRC Inspection Reports 369/97-03, 97-05 and 97-07.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 50.72 Notifications

a. Inspection Scope

During the inspection period, the licensee made the NRC event notifications listed below. The inspectors reviewed the events for impact on the operational status of the facility and equipment.

b. Observations and Findings

- On April 8, 1997, the licensee made a report in accordance with 10 CFR 50.72 regarding a Notification of Unusual Event (NOUE) condition. Specifically, the event involved two vendor employees who had discontinued employment, and entered the protected area prior to security being notified to delete their security badges. The NOUE was conservatively declared due to the subject "intrusion". Upon discovery, the individuals were located and escorted off-site within nine minutes of the entry. The individuals did not enter a vital area. On April 9, the NOUE was retracted after investigation revealed there was no malicious intent on the part of the individuals to harm plant employees or equipment. The individuals had re-entered the protected area for the purpose of retrieving personal items.

- On May 12, 1997, the licensee made a report in accordance with 10 CFR 50.72 due to an ESF actuation involving starting of the Unit 1 Auxiliary Feedwater (CA) pumps on a loss of main feedwater. The loss of main feedwater was determined to be inadvertently caused by actuation of exterior main steam valve vault (MSVV) Hi Hi level switches. This event is further discussed in Section O2.2. The licensee plans on submitting a Licensee Event Report (LER) on the subject event.

- On May 12, 1997, the licensee made a report in accordance with 10 CFR 50.72 due to a potential degraded condition regarding air entrainment of the CA system through vortexing of the CA Condensate Storage Tank (CST). This and other associated problems are further discussed in Section E1.1.

- On May 14, 1997, the licensee made a report in accordance with 10 CFR 50.72 due to a reactor trip on Unit 1 during MODE 3. An ESF actuation of feedwater isolation also occurred as a result of the conditions as expected. This event is further discussed in Section M3.1. The licensee plans on submitting an LER on the subject event.

- On May 14, 1997, the licensee made a report in accordance with 10 CFR 50.72 due to briefly entering Technical Specification (TS) 3.0.3 for having both trains of source range power instrumentation inoperable. The condition was associated with the above report concerning the Unit 1 reactor trip. The licensee plans on submitting an LER on the subject event.

c. Conclusion

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

O2.2 Unit 1 ESF Actuation due to tripping of Main Feedwater pumps

a. Inspection Scope

On May 12, 1997, an ESF actuation occurred involving the automatic start of the Unit 1 CA pumps on a loss of main feedwater. The unit was in MODE 3 at the time of the event. The inspector reviewed the ESF actuation to assure safety equipment reacted as expected.

b. Observations and Findings

It was determined that the main feedwater pumps received a trip signal due to inadvertent actuation of the Unit 1 exterior Main Steam Valve Vault (MSVV) Hi Hi level switches. This circuitry has safety-related, 2 out of 3 logic and provides flood protection for equipment Environmental Qualification (EQ) within the valve vaults by initiating a feedwater trip signal on Hi Hi valve vault level. The loss of feedwater caused the automatic start of both trains of CA pumps, resulted in isolation of Steam Generator (SG) blowdown, and started available nuclear service water pumps. The inspector verified that the equipment actuated as required and operators appropriately responded to the conditions. No control room alarms were received prior to the event.

At the end of the inspection period, the licensee had initiated a failure investigation process and were focusing on potential manufacturing deficiencies associate with the level switches. All of the Unit 1 switches had recently been replaced during the SGRP/refueling outage. The inspectors also raised questions concerning the testing adequacy of the switches after installation. This item will be identified as Unresolved Item (URI) 369/97-08-01, Root Cause of MSVV Level Actuation, pending completion of the licensee's root cause investigation.

c. Conclusions

The inspectors concluded that the operators responded appropriately to the inadvertent main feedwater pump trips and the resulting ESF actuation. Other plant equipment responded as required. An Unresolved Item was identified to evaluate the conclusions of the licensee's root cause investigation.

04 Operator Knowledge and Performance (71707)

04.1 Overview of Unit 1 Criticality/Startup Activities

a. Inspection Scope

During the inspection period, the inspector witnessed preparations for a criticality and zero power physics testing for Unit 1 restart.

b. Observations and Findings

One of the evolutions witnessed included the preparations for criticality and Zero Power Physics Testing (ZPPT) of Unit 1. The inspector focused on overall control of the preparations, operator awareness of plant parameters, interactions between operators involved in the restart and reactor engineering personnel monitoring reactor status. The inspector noted good communications between operators and reactor engineering personnel discussing preparations for criticality. During the inspector's observation, operators appeared to be well informed of anticipated changes in plant parameters for an approach to criticality.

The inspector also reviewed the pre-job briefing package for the approach to criticality and ZPPT evolutions and attended one of the briefing sessions. Nuclear Site Directive (NSD) 304, Reactivity Management, requires that reactor startups be treated as an infrequently performed evolution. The purpose of the briefing was to discuss with operators and other involved personnel how the approach to criticality and withdrawal of the control rods was going to be controlled and performed. Emphasis was placed on plant parameters the operator at the controls should monitor; limits on reactivity additions; and the frequency for monitoring. Communication lines between reactor engineering personnel and operators were clearly delineated. Command and control functions were well established.

In addition, the briefing included discussions on low power events at other stations and the UFSAR design basis event of an uncontrolled rod withdrawal to heighten operator awareness to these potential problems. During the exit meeting, the inspector commented that the role and responsibilities of Instrumentation and Electrical (IAE) technicians in the command and communication lines could be included in future briefing packages as a potential enhancement. It did not appear that any communication problems among the operators, reactor engineers, and IAE technicians significantly contributed to a reactor trip during the power range instrument calibration (see Section M3.1). In addition to the above, plant personnel used conservative practices such as setting power range reactor trip setpoints to no higher than 5% full power (Technical Specifications require below 25% full power) and the nuclear engineering manager requiring that the qualified reactor engineer and the dedicated Senior Reactor Operator (SRO) independently calculate the estimated critical rod position.

c. Conclusions

The inspector concluded that the startup evolutions, including Unit 1 preparation for criticality and ZPPT, were well controlled and accomplished in a professional manner. The inspector acknowledges the significant improvements in the reactivity management program that have occurred in the last few years as a result of a 1995 reactivity excursion during startup at the Catawba plant. Briefing packages for the evolutions were detailed and highlighted specific items to help focus operators on conducting safe plant manipulations. Operations and Engineering management oversight of the evolutions was evident; specifically, Operations Shift Manager (OSM) involvement with the operator at the controls.

O7 Quality Assurance in Operations (40500)

O7.1 Review of Misposition Component Trend Data

a. Inspection Scope

Assessment of the licensee's focus on component mispositioning events.

b. Observations and Findings

On April 29, the inspectors attended a presentation to McGuire management regarding recent evaluations of plant mispositioned component trends. The purpose of the meeting was to evaluate available information to determine what additional measures may be necessary to address the current levels of mispositioned components. The review was presented by the mispositioned component coordinator and included the most recent 1996 summary report of misposition problems. Historical data of previous years data and efforts taken to address previous trends were discussed in detail. The team concluded that although the significance of the events had substantially declined, the number of mispositionings being identified were not ideal. It was recognized that the threshold for reporting problems in this area had been lowered; therefore, more less significant issues were expected.

Operations, Maintenance, and plant Chemistry management also provided insight to actions taken to date and proposed additional steps being implemented to address specific areas identified for improvement. These included increased personal awareness for configuration control, focus on the use of self-checking training aides, verifying procedural adequacy and implementing preoperational valve lineups. Other areas for improvement were also discussed which included improving component labeling and various group assessments to further identify areas for improvement. The inspector discussed several areas outside of the licensee's mispositioned component program scope area which may have applicability. The licensee agreed to research those areas for potential incorporation.

c. Conclusion

The inspector concluded that the evaluation of component mispositioning data was beneficial. Licensee management was committed to make additional chrnges to necessary areas to further improve performance in this area of configuration control.

O7.2 Plant Operations Review Committee (PORC) Review of Unit 1 Core Reload Parameters

a. Inspection Scope

Assessment of PORC's review of the Unit 1 core reload change summary.

b. Observations and Findings

On April 29, the PORC was presented with a summary of the McGuire Unit 1 Cycle 12 core reload change summary. The Reactor Engineering supervisor presented the information to allow the PORC to review changes incorporated in the reinstalled core parameters. The inspectors considered that the information was presented in a logical manner which allowed the PORC to assess changes from the previous to the current core design. Differences in the parameters were discussed and determined to remain within TS allowable limits. The presentation also discussed the status of generic issues associated with fuel and rod cluster assemblies. The PORC concluded that the changes associated with the Unit 1 reload were appropriate. The engineering supervisor also informed the PORC that a training lesson was being developed for the PORC members and other management to further heighten their awareness of core operating parameters and design variations. This would increase the PORC members' knowledge of these activities to provide better oversight of this area.

c. Conclusion

The inspector concluded that the presentation of the Unit 1 Cycle 12 core reload change summary to the PORC was well prepared and allowed the PORC members to assess changes incorporated in the new core parameters. The proposed reactor physics training for PORC members should further improve their knowledge in assessing this area.

O8 **Miscellaneous Operations Issues** (92700)

O8.1 (CLOSED) LER 50-370/96-03: Unit 2 Reactor Trip Occurred Due To Reactor Coolant Pump Motor 2B Failure.

The inspectors conducted followup inspection of the licensee's actions to resolve concerns associated with the failure of the Unit 2B Reactor Coolant Pump (RCP) motor on May 22, 1996. The motor failure was the result of a stator fault. Protective relaying circuits functioned as designed to protect the motor and the resulting single loop loss of flow caused a reactor trip. The windings were determined to be insufficiently secured to prevent operational vibration from degrading the stator winding insulation.

The inspectors noted during previous reviews that each of the Unit 1 and Unit 2 RCP motor stators had been refurbished or replaced following the stator fault event with the exception of the 1A RCP motor. The currently installed RCP motor stators had at least 90 percent of the stator end turns secured to the surge ring to provide sufficient rigidity to prevent vibration induced degradation of the winding insulating material. During the recently completed Unit 1 EOC11 outage, the licensee completed replacement of the Unit 1 A RCP motor stator. The 1A stator replacement was the final corrective action identified in LER 50-370/96-03 to be completed.

Based on the licensee's response in correcting the potential trip hazards associated with stator degradation and completion of the corrective actions, the inspectors considered LER 50-370/96-03 to be closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726, 62707)

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.

a. Inspection Scope and Observations

The inspectors reviewed portions of the following work activities:

- PT/1/A/4204/04C - Residual Heat Removal (ND) Pump 1A and 1B Head Curve Testing
- PT/1/A/4209/12A - Charging (NV) Pump 1A and Valve Testing
- PT/1/A/4209/12B - NV Pump 1B and Valve Testing
- PT/1/A/4206/15A - Safety Injection (NI) Pump 1A and Valve Testing
- PT/1/A/4206/15B - NI Pump 1B and Valve Testing
- PT/1/A/4204/04C - ND Pump 1A and 1B Head Curve Retest

b. Conclusions

Review of the performance of a variety of Emergency Core Cooling System (ECCS) pump performance testing completed during the Unit 1 SGRP/refueling outage indicated that the identified pump performance was within limits. System flow balancing was accomplished in accordance with the established procedures. No problems were identified by the inspectors.

M2 Maintenance and Material Condition of Facilities and Equipment (61726, 62707)

M2.1 Unit 1 Residual Heat Removal Pump Upper Motor Bearing Failure

a. Inspection Scope

The inspectors reviewed the licensee's actions following indication of motor bearing failure during surveillance testing of the Unit 1 B Residual Heat Removal (ND) pump.

b. Observations and Findings

On April 22, 1997, with Unit 1 defueled, maintenance technicians detected an unexpected noise at the 1B ND pump motor. The technicians notified their supervisor of the unexpected noise. As a result, diagnostic testing was performed. Vibration data acquired during fuel unloading when the pump was in service was compared to the current levels. Indication of a flaw on the inner race of the thrust side bearing was identified. Although the vibration levels met ASME acceptance criteria, the licensee decided to replace the bearing set since the failure rate was dependent upon operating conditions. The bearing replacement was conducted prior to fuel reload to minimize any potential loss of shutdown cooling risks. No past operability concerns existed since the equipment operated satisfactorily during fuel unload and was repaired prior to core alterations.

The degraded upper motor bearing was sent to the licensee's metallurgy laboratory for analysis to aid in the root cause evaluation. The laboratory identified a spall on the inner race of one bearing which appeared to be due to contact fatigue. The licensee also stated that outside contractor support may be obtained to determine the actual thrust bearing loads at various flows. The information would assist in validating the adequacy of the bearing and lubricant for the application and ensure that current predictive maintenance practices are appropriate.

c. Conclusions

The inspectors concluded that maintenance technicians demonstrated a good questioning attitude. The station response to the potentially degraded bearing was conservative and provided for improved equipment reliability.

M2.2 Unit 2 Condensate Booster Pump Motor Failure

a. Inspection Scope

The inspectors evaluated the unexpected Unit 2 A condensate booster pump motor trip.

b. Observations and Findings

The condensate and feedwater system consists of three 50% capacity condensate booster pumps and hotwell pumps. Two of three condensate booster and hotwell pumps are normally in operation. The third condensate and hotwell pump remain in standby. The standby pumps receive an autostart signal on low main feedwater pump suction.

Early in the inspection period, the 2A condensate pump tripped with the unit at 100 percent power. The standby hotwell and condensate pump auto started and main feedwater pump suction pressure returned to normal. The licensee investigated and determined the 2A condensate pump trip was attributed to motor stator insulating material breakdown. The damaged motor was immediately removed and shipped to a certified repair shop. Although Unit 1 was in Mode 6 (refueling) of a scheduled shutdown for steam generator replacement, the licensee decided against replacing the damaged motor with a motor from Unit 1. Loss of the standby condensate booster pump increases the unit potential for a reactor trip due to failure of a second booster pump.

The licensee received a refurbished motor from a certified repair shop. The motor was installed and tested in accordance with station procedures. The licensee discovered during the testing that the indicated motor bearing temperatures exceeded expected values. The repair facility was contacted for technical support. Facility representative arrived on site, reviewed motor performance data and initially determined the cause to be a faulty rotor. However, further investigations revealed that the higher than expected motor bearing temperatures were caused by incorrect gauge wire used in the measuring thermocouple. The wiring was replaced, the pump was operated, and motor bearing temperature indication returned to acceptable values.

c. Conclusions

The inspectors concluded that the licensee's diligence in correcting and restoring the failed motor was good. The inspectors also noted this motor failure as another example of the overall motor reliability concerns that have been previously identified and recognized by the licensee.

M2.3 Unit 1 Engineered Safeguard Features (ESF) Testing

a. Inspection Scope

The inspectors witnessed portions of the Unit 1 Train A ESF testing conducted May 1-2, 1997, following steam generator replacement activities and prior to Unit 1 restart from the control room.

b. Observations and Findings

The inspectors witnessed the Train A test to confirm that the licensee appropriately tested attributes of station equipment that may have been affected by outage maintenance activities. The test was performed to: (1) demonstrate the ability of the Emergency Diesel Generator (EDG) to start and load in response to a manually initiated Safety Injection, Phase A Isolation, Phase B Isolation and Blackout; (2) demonstrate that when the EDG is paralleled with offsite power, an SI returns the EDG to standby status and the emergency loads are sequenced onto the offsite power supply; (3) demonstrate EDG starting, load shedding, and emergency load sequencing in response to a Blackout; and (4) ensure that the correct movement of valves in response to an SI, Phase A Isolation, Phase B Isolation, and Blackout occur. The inspectors confirmed that the A train test was performed with the equipment in its normal lineup. Control room instrumentation response to changes in equipment status was adequate. The inspectors also noted that few corrective work requests were generated following the test.

The inspectors reviewed the test procedure and noted that the procedure had sufficient detail to provide adequate guidance to personnel performing the test. Coordination between Operations, Maintenance and Engineering was good. The inspectors observed a good pre-job briefing, as well as routine briefs throughout the performance of the test. Unit 2 operations staff prepared for the Unit 1 ESF testing by reviewing appropriate abnormal and emergency procedures as a conservative measure to ensure that the test realignment of shared equipment would not adversely affect Unit 2 operations. Additional licensed operator support was available to minimize the impact on the normal operating crews during testing. Routine maintenance and testing activities were minimized on Unit 2 during Unit 1 ESF testing.

c. Conclusions

The inspectors concluded that licensee preparation, planning, and execution of the Unit 1 ESF testing was exceptional. Equipment operated as designed with minimal necessary repairs. Good equipment performance during the test was determined to be indicative of good outage maintenance.

M2.4 Repair of Leaking Unit 1 Conoseal Port

a. Inspection Scope

After reassembly of the reactor in MODE 5, the licensee identified that conoseal port #2 was leaking. The inspector reviewed the licensee's activities associated with the rework repair.

b. Observations and Findings

The leak was identified on one of the five core exit thermocouple columns which exit the reactor head assembly sealed by conoseal assemblies. Work order 96064661-05 was being performed to inspect for leakage at low Reactor Coolant System (RCS) pressure (300 psig). Upon identification, initial corrective actions attempted to retorque the suspect area; however, minor leakage still existed. Operations, maintenance, and engineering personnel determined that a repair was necessary and would involve an additional RCS drain down to approximately 120 inches above the reactor flange. The RCS drain down was safely performed. Inspection of the disassembled conoseal revealed that the upper gasket appeared to be deformed. The licensee postulated that the gasket may have been installed inverted; however, personnel performing the repair did not note the orientation of the gasket prior to removal. The subject conoseal was reassembled, all five assembly housings retorqued, and no leakage was identified at the 300 psig RCS inspection window. Based on the work performed, engineering determined that no additional conoseal work was required.

c. Conclusion

The inspector concluded that the decision to cooldown and repair the leaking conoseal connection was conservative, and the repair activities were accomplished in a safe manner. However, during disassembly of the degraded component, root cause determination techniques could have been better incorporated.

M3 Maintenance Procedures and Documentation

M3.1 Unit 1 Reactor Trip During MODE 3 Power Range Instrumentation Calibration

a. Inspection Scope (61726)

The inspector reviewed the unit's response to the reactor trip and evaluated the licensee's post trip review process to ensure all potential problems were properly evaluated prior to restart.

b. Observations and Findings

On May 14, a Unit 1 reactor trip and feedwater isolation occurred. The reactor trip occurred on 2 out of 4 logic for turbine trip/reactor trip during power range instrumentation calibration. Prior to the event, the reactor was in Mode 3 with shutdown banks A and B withdrawn, RCS boron diluted, and a stable reactor temperature of approximately 557°F. Station personnel were preparing for an approach to criticality and subsequent Zero Power Physics Testing (ZPPT). As part of the preparations, the licensee entered TS 3/4.10.3 "Special Test Exception" which requires, in part, that each power range channel shall be subject to an Analog Channel Operational Test (ACOT) within 12 hours prior to initiating startup and physics tests.

In preparation for an approach to criticality, the reactor engineering group requested an ACOT on power range channel N-42 be performed since 12 hours had elapsed since the last ACOT on N-42. Power range channel N-41 was connected to the reactivity computer for ZPPT. In this configuration, N-41 was inoperable and must be placed in the tripped condition. In order to save time, the licensee decided to bypass power range channel N-41 in lieu of disconnecting the computer and restoring N-41 to operable status. Bypassing a power range channel is permitted by Technical Specifications and is how calibration of a single power range channel is normally performed with the reactor at power; however, use of channel bypassing with multiple channels affected was a new evolution.

The licensee used procedure PT/1/A/4600/014D, NIS Power Range Channel N-41 Analog Channel Operational Test, to bypass the reactor protection system functions for N-41. However, Permissive P-8 (high reactor power-low reactor coolant flow) is not tested by this procedure and as such the permissive remained unblocked. The technicians and operators did not recognize that P-8 remained unblocked and there was no guidance in the ACOT procedure to check the status of P-8. Using a simulated 120 percent power signal, technicians conducted the ACOT of N-42. With P-8 unblocked and the turbine tripped, 2 out of 4 reactor trip logic was satisfied when simulated reactor power exceeded 48 percent of full power (P-8). A feedwater isolation also occurred due to low reactor coolant system temperature (lo Tavg) bistables still active since they were not clear until the reactor was at higher temperatures with the unit online. P10 permissives, which automatically turns source range high voltage off above 10 percent power, were also overlooked during the evolution. This resulted in both source range instrumentation trains being briefly (less that one second) inoperable prior to the reactor trip. The licensee plans to address all the associated impacts to the plant in an LER.

Following the event, the licensee discovered that procedure IP/0/A/3207/09A, Bypassing Power Range Channels In Tripped Condition, should have been used to properly bypass N-41. This procedure provides steps necessary for bypassing an inoperable power range channel and associated bistable outputs. The technicians were not cognizant that this procedure should have been used to bypass N-41. The technicians used the bypass steps provided in the governing ACOT procedure PT/1/A/4600/014D. The inspector interviewed plant personnel on the status of the root cause investigation. Plant personnel indicated that corrective actions for a 1994 PIP (0-M94-0331) led to the development of IP/0/A/3207/09A. At the end of the inspection period, the licensee was examining if an undue number of separate supporting procedures were being used for ACOTs on power range channels whereby the likelihood of errors may increase.

The inspector reviewed the governing ACOT procedures for testing power range channels N-41 and N-42. The ACOT procedure PT/1/A/4600/014D used to bypass N-41 was determined to be inadequate since it failed to reference and transition to the supporting procedure, even though the ACOT governing procedure was written for use with the reactor in any Mode. The ACOT procedure Section 2.2 "References That May Be Needed to

Perform Procedure" failed to reference IP/0/A/3207/09A, steps in the body of the ACOT procedure did not transition to this supporting procedure, and the ACOT procedure itself contained insufficient guidance to properly bypass an inoperable power range channel to allow testing of another channel, as evidenced by the event. The licensee's work control planning may have also contributed to the event with respect to not identifying the supporting procedure in the job scope for plant preparations for criticality and ZPPT. This issue will be identified as a Violation 369/97-08-02, Inadequate Procedure for performing ACOT Testing.

c. Conclusions

The inspector concluded that overall, the licensee's evaluation of the reactor trip and restart assessments were adequately performed; however, a Violation was identified regarding inadequate ACOT procedures bypassing the reactor protection function of power range channel N-41 to permit testing of channel N-42.

M4 Maintenance staff Knowledge and Performance (62707)

Maintenance Staff Knowledge and Performance (62707)

M4.1 Unit 1 Material Condition/Housekeeping Inspections

a. Inspection Scope

The inspectors conducted walkdown inspections of the Unit 1 reactor building. The inspectors placed particular emphasis on identification of fibrous material that may cause complications during the recirculation phase of ECCS operation.

b. Observations and Findings

During MODE 5 restart preparations, the licensee performed numerous walkdowns to prepare the unit for containment closeout and began restricted reactor building access. Individuals and materials entering containment for final restart preparations were logged in and out of the building by the Shift Work Manager. The inspectors conducted detailed walkdowns of portions of the lower reactor building and pipe chase areas to asses the licensee's restart readiness. The inspectors performed reviews on various system piping, focusing on system integrity, potential systems adversely impacted by the outage, and support systems to major components. No adverse conditions which could affect the safety function of safety-related equipment were identified.

Maintenance equipment used during the SGRP had been safely removed. Protective covers used to minimize foreign material intrusion into the containment sump during maintenance activities had been removed and the sump was devoid of debris. No visible indications of system leakage were identified. Temporary shielding and scaffolding used during the outage had been removed from the building. Subsequent followup inspections by the licensee using sensitive thermography equipment identified a small crossover leg loop drain valve leak on the 'B' steam generator. The licensee tightened the valve to reduce the suspected leakage.

The inspectors evaluated the newly installed blanket insulation used on the replacement generators. The original mirror insulation was replaced with fiberglass mass within a fiberglass cloth blanket insulation. The fiberglass blanket was covered by a stainless steel jacket to minimize damage to the cloth. The blanket insulation was supported by rings mounted around the circumference of the steam generator shell. The original insulation could not be reused due to the dimensional differences between the old and new SGs. The licensee also stated that the new blanket insulation should provide for improved thermal performance. The inspectors evaluated insulation installation from the main steam nozzle to primary system nozzles. The insulation was adequately installed and no concerns were identified.

c. Conclusions

The inspectors concluded that the Unit 1 reactor building had been adequately returned to operational condition prior to power operation. The inspectors noted significant improvements in reactor building material condition and housekeeping that were implemented during the outage.

M4.2 Outage Planning and Scheduling

a. Inspection Scope

The inspectors evaluated outage results to determine the effectiveness of the licensee's outage planning and scheduling efforts.

b. Observations and Findings

The inspectors reviewed the scope of outage activities identified for 1EOC11. The planned outage duration was 100 days. The inspectors recognized that several significant maintenance activities had been planned for the outage. The licensee performed steam generator replacement, operator aid computer replacement, emergency diesel generator overhauls, high pressure turbine and main generator refurbishment. Refueling activities, in general were well performed with minimal interruptions from equipment problems. The inspectors noted that the job scope for the significant activities did not change appreciably, indicating good pre-outage work planning. These activities, in conjunction with routine outage activities, were conducted such that an optimum amount of work was accomplished with appropriate emphasis on nuclear safety, personnel safety, quality maintenance, and ALARA (As Low As Reasonably Achievable) exposure considerations. The licensee was also effective in incorporating emergent corrective maintenance activities into the schedule.

c. Conclusions

The inspectors concluded that the outage management group was effective in planning, scheduling, and managing refueling outage activities. The outage was completed in 95 days. Established station and SGRP outageexposure goals were aggressive. The inspectors noted that ALARA initiatives were evident.

M7 Quality Assurance in Maintenance Activities (62707)

M7.1 Review of Critical On-line Maintenance Control

a. Inspection Scope

The inspectors reviewed the licensee's process control of critical on-line maintenance.

b. Observations and Findings

The licensee's process is defined in Work Process Manual (WPM) 601 and Maintenance Directive 2.3.1. The licensee had developed the current process through benchmarking other utilities' maintenance programs. Within the licensee's process, work activities are categorized into four classifications of maintenance--normal, complex, critical, and emergent critical. Each category is defined by significance, TS Limiting Condition for Operation (LCO) outage duration, impact on the unit operation (potential or actual), etc. All of the categories were integrated into the licensee's established system work window rotation process which provides for additional structure for implementing the process. Some of the attributes of the critical on-line maintenance plans include: specific owners for every task; compensatory and contingency measures pre-established; decision points clearly defined; detailed schedule; pre-job briefing which included Generic Letter (GL) 91-01 guidance; and management presentations on the activities. Checklists incorporate these and other attributes to assure orderly completion for critical maintenance evolutions. To date, the license has qualified 14 individuals to be critical maintenance managers.

The category of complex maintenance was recently added to provide additional oversight of activities which did not meet the criteria for critical; however, it did warrant additional planning, coordination, and preparation to ensure error-free execution. Work activities considered for complex maintenance include significant system shutdown (for example EDG down days), multiple TS equipment impacts for maintenance, rescheduled work due to ineffective initial plans, and complex work activities which require continuous coverage. Complex maintenance activities are assigned a work sponsor who is responsible for designated activities throughout the completion of the work.

c. Conclusions

Based on the review of maintenance directives and observations of maintenance planning implementation, the inspector concluded that the licensee has developed a good process for evaluating and planning maintenance evolutions according to their associated risk. Maintenance management has been effectively implementing the process and increasing the site overall awareness of risk associated maintenance evolutions. This area was identified as a strength.

M7.2 Maintenance Response To Foreign Material Exclusion (FME) in Turbine Generator

a. Inspection Scope and Observations

During Unit 1 main generator outage refurbishment, a large ratchet came apart which allowed numerous metallic pieces to fall into the main generator windings. Maintenance personnel initiated a Problem Investigation Problem (PIP) report and raised a concern for identification of all the missing pieces prior to placing the generator in service. The licensee recognized the need to remove all of the foreign material and took apart a similar rachet to identify each item. Extensive searches were performed for several days, which included the use of vacuum devices and mirror inspection. Partial disassembly of the generator was required. All of the known pieces were eventually recovered from the generator.

b. Conclusions

The inspector concluded that the licensee placed appropriate emphasis on FME within the main generator housing.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (CLOSED) URI 50-369/96-01-04: Apparent Failure to Follow Procedure (Disassembly, repair and re-assembly on Kerotest 'Y' type check valve 1NV233)

During the McGuire Unit 1 refueling outage (1EOC10) in January 1996, maintenance was being performed on valve 1NV233, a 2" diameter KEROTEST type check valve in the mini-flow path for the 1B charging pump. The seal weld on the valve was leaking and the maintenance work order was to replace the existing valve with a new one.

On January 3, 1996, an Electrical Systems Support valve technician initialed Step 11.4.5 of Procedure MP/0/A/7600/04, Kerotest "Y" Type Check Valve Corrective Maintenance, which states: "Install NEW body to cover gasket in body."

On the evening of January 3, 1996, the night shift noted that the valve was assembled but not torqued. Although documentation was incomplete, it indicated that final checks on the valve were satisfactory and the valve appeared ready to torque. Due to incomplete documentation, the night shift was concerned and confused. The supervisor directed the technicians to disassemble the valve and begin the work task again. When the valve was disassembled, the technicians identified that the gasket was not new, as it had been previously torqued. The licensee advised the NRC of a potential falsification of a Quality Assurance Document.

The NRC Office of Investigations initiated an investigation to determine if a Quality Assurance Document had been intentionally falsified. The investigation concluded that the technician had purposely decided to use the old gasket and intentionally signed the procedure step claiming that the gasket had been replaced. A copy of the synopsis of the investigation report is attached.

10 CFR 50.9(a) states, in part, that information required by the Commission's Regulations to be maintained by the licensee shall be complete and accurate in all material aspects. The failure to maintain complete and accurate information required by the Commission's Regulations is a violation. This licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-369/97-08-03, Failure to Maintain Complete and Accurate Records).

Technical Specification 6.8.1.c requires that written procedures be established, implemented and maintained covering the activities recommended in Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33 states in part that maintenance which can affect performance of safety-related equipment should be performed in accordance with written procedures. Step 11.4.5 of Procedure MP/O/A/7600/04 states "Install <u>NEW</u> body to cover gasket body". The failure to install a new gasket in accordance with the licensee's procedure is a violation. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-369/97-08-05, Failure to Follow Procedure).

<u>Conclusions</u>

Two Non-Cited Violations were identified concerning: the failure to maintain complete and accurate information; and the failure to follow procedure. Once identified, the licensee was proactive in assuring that required quality assurance documents were complete and accurate in all material aspects. All other issues were corrected in a timely manner.

<u>III. Engineering</u>

E1 Conduct of Engineering (37551)

E1.1 <u>Potential Air Binding of Auxiliary Feedwater (CA) Pumps</u>

a. <u>Inspection Scope</u>

During the inspection period, the licensee addressed potential mechanisms for air entrainment into the CA system and subsequent air binding of the CA pumps. The first issue involved CA pump vulnerability from air entrainment due to a vortex that could develop in the auxiliary feedwater condensate storage tank (CACST) under certain design basis events (DBEs). Also under certain DBEs, a second issue was identified involving air entrapment from other mechanisms (e.g., tank depletion, pipe break, etc..) from interactions of the nonsafety-related CA water sources and the safety-related CA water source.

The inspector reviewed the compensatory measures, attended PORC meetings, reviewed the 10 CFR 50.59 evaluation, consulted the UFSAR and facilities individual plant examination for Probabilistic Risk Assessment (PRA) insights, and verified that corrective actions were implemented to minimize the potential for air binding CA pumps. The inspector also performed an examination of the CA system nonsafety-related suction sources, plant abnormal and emergency procedures, previously identified issues related to CA air entrainment from tank depletion, compliance with the licensing basis, and applicability of regulatory requirements.

b. Observations and Findings

Background information on the CA water sources and subsystems, as well as the inspector's observations and findings on the air entrapment issues, are discussed in the following sections.

Auxiliary Feedwater System Water Sources Description

Each unit's CA system may use several nonsafety-related water sources which are, in order of preference, the CACST, the unit's upper surge tanks (USTs), and the unit's condenser hotwell. These sources are the normal supplies for the unit's CA system. The assured, safety-related water source for the CA system is the nuclear service water system (NSWS). Auxiliary feedwater pump suction will automatically swapover to NSWS when low CA pump suction pressure conditions (below approximately 3 psig) are present.

The CACST has a maximum capacity of 42,500 gallons of high quality water and is the primary water source for the auxiliary feedwater system. Normally, both units (total of six CA pumps) take suction from this common, atmospheric tank. Each unit also has two USTs that together have a maximum capacity of 85,000 gallons and are normally used as water sources for the CA systems upon depletion of the CACST. The USTs normally operates under a vacuum. Each unit's CA system may also use its respective condenser hotwell water (170,000 gallon maximum capacity) if available during a design basis event.

Each unit has a motor operated valve (1/2CA-6) to isolate the CACST. Isolation of the CACST requires a manual operator action that may be performed locally or from the control room if normal power is available. The USTs may be isolated locally only with 1CA-4 or 1CS-18 and 2CA-4 or 2CS-18 for each unit, respectively. The above valves are nonsafety-related and do not receive emergency power in the event of a Loss-of-Offsite Power (LOOP) and loss of normal station auxiliary power. Also, CACST level indication in the control room would be lost during a LOOP event. The CA system design assumes that once transferred to the assured source, the nonsafety-related sources would not affect the safety-related portion of the system. However, it should be noted that no automatic isolations occur to prevent interactions. The issues concerning vortexing and other air entrapment mechanisms identified are discussed below.

CA Pump Air Binding from CACST Vortex

Under certain DBEs, the licensee identified that a vortex could develop in the CACST, draw air into the CA suction piping, and damage or airbind the pumps. The vortex would form prior to CA suction swapover to NSWS. This potential condition was reported under 10 CFR 50.72 on May 12, 1997. The licensee identified the potential for CACST vortexing while analyzing CA nonsafety-related suction source reliability (see sub-section below). The most limiting case was a main steam line break coincident with a dual unit LOOP where both units were drawing off the CACST and the CA motor and turbine driven pumps were discharging at a high flow rate due to loss of instrument air (nonsafety-related). This scenario could result in a vortex within approximately 15 minutes of the event initiation.

To provide immediate protection against this postulated event, plant engineers proposed compensatory measures to minimize the risk of air binding the CA pumps from vortexing until plant design modifications could be implemented. This issue and compensatory measures were reviewed and approved by PORC prior to restart of Unit 1 which was shutdown for refueling and replacement of steam generators. An NRC/Licensee conference call was held on May 9 to discuss these issues. The inspector verified the implementation of the following compensatory measures:

- Valve 2CA-6 (Unit 2 CA suction from CACST) was closed and power was removed to reduce the rate of inventory draindown (reduce likelihood of vortex formation in the CACST).

- Unit 2 primary water source for CA was aligned to the USTs. This action made Unit 2 more susceptible to a NSWS CA supply swapover. Unit 2 was intentionally selected to protect the newly installed Unit 1 SGs from raw water (NSWS).

- The licensee developed special procedures to isolate the USTs (Units 1 & 2) with level below 5.5 ft and isolate the CACST from Unit 1 CA with 35% level indication. The step to isolate the USTs on low level was incorporated to eliminate the concern for air entrapment from USTs operation (see sub-section below).

- Use of two dedicated non-licensed operators (one for each unit), with procedure in hand at all times, to implement each unit's special procedure upon certain plant conditions (e.g., LOOP, reactor trip, Safety Injection, etc.).

- The procedures were time validated and the affected valves accessibility was evaluated.

- Maximum levels in the CACST and USTs were maintained.

- Maximum pressure in the instrument air system (IAS) was maintained.

- The dedicated Non-Licensed Operators (NLOs) frequently monitored the USTs and CACST levels and IAS pressures.

The compensatory measures augment steps in the Abnormal Procedures (AP)/Emergency Procedures (EP) that already instructed operators to isolate the CACST and on low levels to prevent air entrainment (see sub-section below) since these tanks are not automatically isolated on low tank levels. The licensee has proposed plant design modifications to address vortexing concerns. The licensee will convert an existing filtered water tank (approximately 42,500 gallons) into an additional CACST and install anti-vortexing devices in the suction inlet in both the existing CACST and the new tank.

The licensee is also evaluating past operability of the condition.

<u>CA Pump Air Binding From Other Air Entrapment Mechanisms</u>

Currently, the licensee has identified an additional potential concern regarding CA operation using suction from the USTs after the tanks have been drained into the CA suction piping and CA pump recirculation has been initiated. This problem may potentially occur before or after a service water to CA suction swapover. Auxiliary feedwater pump recirculation flow will continue to go to the USTs after the tanks empty. The possibility exists that CA pump air binding could occur in this configuration if air is trapped in the suction piping and pushed to the CA pumps. Based on interviews with plant engineers, the inspector was informed that an air slug greater than several cubic feet could damage the pumps according to the pump vendor. Validity of air entrapment through USTs/CA operation is pending additional hydraulic studies. However, the licensee has factored this concern into the compensatory measures noted in the previous sub-section.

In 1996, the licensee embarked on an extensive CA suction source reliability study for issues related to CA air entrapment. This effort was taken because many PIPs have been written since 1992 on these issues. Under various DBE scenarios, these mechanisms involve interactions among the CACST, USTs, and condenser hotwell and between these systems and the NSWS. The licensee has contracted Framatome Technologies to perform analyses of pipe breaks in the nonsafety-related CA piping, interactions between the CACST and USTs upon tank depletion, use of the condenser hotwell, CA pump flow demand, and interaction with the NSWS water supply.

The inspector reviewed several of the previous PIPs, corrective actions, and other related station documents and discovered conflicting characterizations of the safety importance of manual isolation actions. The McGuire Operations Training manual and PIPs indicate that operator action to isolate empty USTs are critical to prevent air entrapment in the CA suction piping. The inspector's preliminary review of the McGuire PRA did not reveal extensive modeling of the CA system that captures air entrainment failure modes and critical operator actions to prevent CA pump air binding.

Between 1992 and 1994, some corrective actions were taken to address the concerns, most notably steps in the AP/EPs were added to isolate the CACST and USTs upon tank depletion to prevent air entrainment. However, the inspector interviewed station engineers who stated that engineering judgement was used at that time to determine that there was a low probability of air entrapment in the CA suction piping, even though there are several piping loop seals in the CA suction piping. Some estimates in 1994 indicated up to 20 linear feet of voided pipe could exist. The licensee did not consider single failure criterion applicable to CACST isolation valves or tank level instrumentation since the system was classified as nonsafety-related.

Pending conclusion of the licensee's hydraulic studies, sufficient information was not available to the inspector to ascertain applicability of regulatory requirements to these important to safety CA sources or the exact vulnerabilities that may exist. Pending further review, this issue will be identified as Inspector Followup Item (IFI) 369,370/97-08-04, Potential Air Binding of CA Pumps.

c. Conclusions

The inspector concluded that compensatory measures were prompt and effective to deal with the CACST vortexing issue. The aggressive schedule to implement design modifications to eliminate the vortexing concerns are also positive actions to maintain CA system reliability. Compensatory measures adequately capture steps necessary to minimize air entrapment from USTs interaction with CA recirculation operation.

However, the inspector considered UFSAR documentation on CA operation to be non-detailed. Specifically, the UFSAR does not reflect that the automatic swapover to NSWS also involves manual operator action to isolate the nonsafety-related water source to prevent air entrainment. Auxiliary feedwater air entrainment (other than vortexing) was identified as early as 1992 and multiple PIPs have been written since then related to the potential CA pump air binding. Potential significant weakness in the PRA exist if these critical operator actions to prevent a common mode failure of CA are not properly reflected. The air entrainment from emptying of the CACST or USTs, or use of the condenser hotwell is still indeterminant until completion of hydraulic studies. The inspector considers the licensee's engineering analyses as a partial design basis reconstitution effort for the CA system.

E2 ENGINEERING SUPPORT OF FACILITIES AND EQUIPMENT (37551)

E2.1 Missing Swivel Bracket Bolts in Ice Condenser Basket

a. Inspection Scope

The inspectors reviewed the licensee's followup to a degraded condition identified on the Unit 1 ice condenser.

b. Observations and Findings

The licensee's routine inspection of ice condenser baskets during the Unit 1 EOC11 refueling outage, disclosed that an ice basket (5-6-9) was missing both swivel bracket bolts. This basket had been vibrated empty during this outage as part of the maintenance program, while executing ice condenser maintenance procedure SM/0/A/8510/007, under WO 96064989.

By review of the associated Problem Investigation Process (PIP) Report 1-M97-0907 and through discussions with the cognizant engineer, the inspectors ascertained the following:

- Swivel brackets were designed for attaching the ice basket to the lower support steel, so that they would not eject from the ice condenser during a Design Bases Loss of Coolant Accident (DBLOCA).

- Each swivel bracket has two (2) stainless steel bolts which hold the two symmetric halves of the swivel bracket to the bottom of the basket and the swivel base.

- The swivel base is pinned to a clevis on the lower support structure.

- The swivel bracket's bolted joint was designed to facilitate weighing the baskets and vibrating the ice out for replenishment purposes.

By review of completed work orders, the inspectors ascertained that the licensee's immediate corrective action was to assure that the bolts were torqued to the requirements specified by procedure. In addition, the licensee checked the torque on a sample of baskets whose ice had never been replaced or vibrated out since the installation of swivel brackets and found them acceptable.

A followup investigation determined that the root cause of loose or missing bolts was associated with vibrating the ice out of the baskets for replenishment during maintenance. This determination was made as part of an evaluation performed on the Unit 2 ice condenser, when a similar condition was identified by maintenance during the 2EOC10 refueling outage. That problem, which was documented in PIP 2-M96-1025, involved two swivel brackets; one had one of the two bolts missing and the other had both bolts disengaged/backed out. Following an extensive inspection of Unit 2 ice condenser baskets, an operability calculation MCC-1201.17-00-0011 and an operability assessment by Westinghouse determined that a swivel bracket with one missing bolt was capable of performing its design function.

In reference to the basket with two missing bolts, the Westinghouse evaluation analyzed the potential for and consequences of a small number of ejected baskets. Their determination was that with a 1% swivel bracket failure rate, approximately 0.26% of all baskets in the ice condenser could conceivably pass through the intermediate deck. The Westinghouse analysis also determined that the ejected baskets would travel approximately 15 feet until striking the top deck structure and grating, which would prevent their exit from the ice condenser. Westinghouse concluded that this limited number of ejectable basket movement, even when combined with some non-ejectable basket movement, would not effect the performance of the ice condenser system.

c. Conclusions

The inspectors concluded that the licensee's identification and corrective actions taken for the missing swivel bracket bolts in a Unit 1 ice condenser basket were adequate.

E2.2 Review of FNQ Fuse Replacement Project

a. Inspection Scope (62707)

The inspector reviewed activities associated with the replacement of FNQ type fuses during the Unit 1 EOC10 outage.

b. Observations and Findings

Bussman type FNA fuses equipped with spring loaded indicating pins were used in the original design for both Class 1E and non-1E applications at McGuire. Over the years McGuire has experienced failures of these types fuses where the fuses opened with no electrical problem in the circuit. The FNA fuses were replaced with FNQ type fuses in all 1E applications and replaced on an "as-fail" basis for the non-1E applications.

Subsequent to this replacement, McGuire experienced mechanical failure of FNQ type fuses similar to the FNA type failures. FNQ type fuses smaller than 3.2 amperes have an internal spring to assist fuse opening at low currents. After 10 confirmed mechanical failures resulting in two reactor trips over a three year period, a decision was made to replace the FNQ type fuses.

NSM MG-12467/P1, Replacement of Bussman FNQ Fuses with Non-detectable Failure Modes, was accomplished in the outage 1EOC11. This modification replaced FNQ type fuses that were identified as susceptible to the established failure mode, with Little Fuse FLQ type fuses of the same ampere rating. Fuses identified for replacement were critical valve circuits. Critical valve circuits were identified as circuits whose failure of the fuse could trip the unit and challenge safety systems.

The inspector reviewed the modification package and the fuses identified for replacement. The inspector concluded that a rigorous review to determine fuse replacement needs had been performed, resulting in an adequate listing of fuses for inclusion in the modification.

Additionally, the scope of the modification included replacement of fuses in 1E applications whose failure would be non-detectable. For example, these included fuses such as control board indicator lights whose failure would not cause loss of the indicator light, or control board receiver gauges whose fuse failure would not result in the gauge indicating offscale. Also, fuses whose failure could result in a significant transient were also incorporated into this modification.

The inspector discussed the scope of the modification with the appropriate personnel. Electrical implementation procedures used for the fuse replacement were also discussed and reviewed. The inspector found the responsible personnel knowledgeable of the procedures and the work in progress.

c. Conclusions

The inspector determined that the scope of the corrective actions for FNQ type fuse failures were adequate. Licensee personnel were cognizant of the scope and implementation of the associated modification.

E4 Engineering Staff Knowledge and Performance (37551)

E4.1 MNS Response to the Oconee Heater Drain Pipe Rupture Event

a. Inspection Scope

During the present SGRP outage, the licensee performed an inspection of heater drain piping in Unit 1 to look for branch connections that lacked adequate weld reinforcement.

b. Observations and Findings

The inspectors reviewed the licensee's findings as a result of the inspections. The results indicated that weld reinforcement was lacking in two drip legs in heater drain line 'A' (HA), and two in heater drain line 'B' (HB). Based on ANSI B31.1 Code requirements and design pressures, the licensee determined that the two 18" x 4" drip legs in HA were under-reinforced by 73% and the two 20" x 4", by 24%. To document this problem, the licensee issued Problem Investigation Report No. 1-M97-0879 and Minor Modifications 9149 and 9150 to perform the weld reinforcement repairs. Through discussions, a field inspection and document review, the inspectors determined the following:

- MNS has six separate drain lines that expand across control valves and proceed downhill to the heaters.

- Walkdowns showed the second stage MSR drain line, had no low points where a water slug could accumulate.

- Engineering's review of stress analysis calculations determined that all tees in the Moisture Separator Reheater Drain (HS) system were manufactured fittings. Other systems had fabricated tees and laterals, but most of these were manufactured by Grinnell pipe fabricators. Historically, branch connections made by Grinnell were found to meet ANSI B31.1 Code requirements.

- During construction, balance of plant piping and associated branch connections were designed to ANSI B31.1 Code requirements, but there were no requirements to retain these calculations or to forward them to the site.

c. <u>Conclusions</u>

The inspectors inspected the repaired branch connections and determined that the additional weld buildup to the existing reinforcement was sufficient to meet the applicable code requirement.

E8 Miscellaneous Engineering Isues (92903)

E8.1 <u>(CLOSED) URI 369,370/96-10-04</u>: Evaluation for Spent Fuel Pool (SFP) Area Painting Project

This URI was identified to evaluate several projects performed under the work order process and to determine if adequate screenings for potential 50.59 issues were performed. The inspector determined through interviews and review of available documentation, that reviews were performed for this maintenance evolution which adequately evaluated the subject work for 50.59 impact criteria. Numerous discussions were conducted with engineering personnel and station management regarding the threshold for completing 50.59 screening reviews for complex maintenance activities. The licensee agreed that improvements could be made in this area as indicated by this and other examples identified by the inspector. One recent example involved the blocking of a temporary trailer over a safety-related pipe trench. While the piping could not have been adversely impacted, more thorough review and documentation could have been performed. As a result of the inspectors observations, the licensee developed new guidance that was recently incorporated in the 10 CFR 50.59 screening and evaluation process dated February 5, 1997. The guidance presented Duke wide clarification of expectations for performing and documenting adverse impact screenings for important equipment and the importance of utilizing the appropriate administrative process for evaluating maintenance and modification evolutions. Recent inspections in the area of outage modifications reiterated that the licensee's efforts in this area have been improving. This item is closed.

IV. Plant Support

R4 Staff Knowledge and Performance in Radiological Protection and Chemistry

R4.1 Steam Generator 2A Primary to Secondary Leakage (71750)

a. Observations and Findings

During the inspection period, the licensee monitored a small primary to secondary Steam Generator (SG) tube leak which was identified on the 2A SG. At the end of the inspection period, the leakage was estimated by plant chemistry to be approximately nine Gallons Per Day (GPD) and exhibiting slow growth characteristics. The licensee was actively monitoring the identified leakage to identify any step changes and keeping operations and management informed of the leak progression. The licensee is maintaining an administrative allowable leakage limit of 100 GPD for continued operation. The current TS limit for this type of leakage is 500 GPD for Unit 2 operation. The Unit 2 SGs are scheduled to be replaced during the upcoming Unit 2 cycle 11 refueling outage scheduled to begin in September 1997.

b. Conclusions

The inspectors concluded that the licensee was providing adequate primary to secondary leakage monitoring of the degraded SG 2A condition and had previously established conservative administrative leakage limits as compared to TS allowable limits.

P2 Status of EP Facilities, Equipment, and Resources (71750)

P2.1 Emergency Planning Task Force Meeting

a. Inspection Scope and Observations

On May 13, the inspector attended portions of a routine Emergency Planning (EP) Task Force Meeting at the McGuire site. Such meetings are conducted on a frequent basis to facilitate good communications between the licensee, State, and local government personnel concerning a variety of Emergency Preparedness topics.

b. Conclusions

The inspectors concluded that the licensee's sponsoring of the routine EP Task Force Meeting was indicative of good management support of the EP area. The meeting facilitated open discussions to improve existing EP processes and the licensee's interaction with the local officials during events.

P8 Miscellaneous EP Issues (92904)

P8.1 (CLOSED) IFI 50-369,370/96-04-05: Verification of SSS Activation Time During Emergency Plan Drill (capability to perform time critical tasks during SSS activation in conjunction with EP evolutions has not been verified)

This item identified a concern with the licensee's capability to assure the time critical tasks of the Standby Shutdown System (SSS) activation were accomplished during the altered operations command structure which was implemented when the Technical Support Center (TSC) was activated during the Emergency Plan (EP) condition. During an EP drill on May 29, 1996, the time critical SSS tasks were not met due to communications problems inherent in the TSC command structure. The licensee subsequently evaluated the SSS activation tasks and the TSC command structure communications and implemented changes to the communications process during an EP activation. Emergency Plan Drill 97-01 conducted on February 18, 1997, adequately demonstrated the performance of time critical tasks for SSS activation during EP conditions. This item is closed.

F1 Control of Fire Protection Activities (71750)

F1.1 Fire Prevention Activities Associated with Previous Turbine Oil Spill

a. Inspection Scope

The inspectors reviewed fire prevention activities in response to a turbine oil spill which occurred during the Unit 1 refueling outage.

b. Observations and Findings

The subject turbine oil spill was previously discussed in Inspection Report 369,370/97-04. During this inspection period, the inspector reviewed the condition of the Unit 1 turbine building piping and equipment affected by the oil. The inspector was specifically concerned that residual oil may pose a fire threat to the affected area. The specific oil has an auto-ignition between 750 and 850 degrees F; however, oil soaked insulation sources have been reported to have much lower ignition points. This potential mechanism was determined to be an oxygen exothermic reaction within the insulation. The licensee received this information through researching their industry experience databases.

Licensee's corrective actions for the spill included replacement of a large amount of potentially oil soaked piping insulation. Prior to restart of the unit, the inspectors performed walkdowns of the areas affected by the spill to evaluated the licensee's response. In general, the corrective actions for the spill were thorough. The as-left areas were oil free and in good condition. Normally inaccessible areas were opened and cleaned to remove any residue. During initial heatup of the system piping, the licensee posted fire watches around the affected areas. Special fire fighting equipment was stationed in the area which would be most effective on an oil fire and the watches were focused on the areas most vulnerable (i.e., areas of hottest temperatures). Part of the monitoring included the use of laser temperature probes which allowed the fire watch to search for changing piping hotspots during the secondary side heatup. Prior to heatup, the inspector did identify some evidence of oil soaked insulation outside of the established boundary, which was promptly addressed by the licensee. The inspector noted that despite the licensee's best efforts in removing all the oil, residual oil continued to seep from inaccessible areas onto piping and other components. The inspectors monitored the area during restart of the unit and determined that the licensee's efforts were effective during this period.

c. Conclusions

The inspectors concluded that the licensee's fire prevention efforts regarding a previous turbine oil spill event were effective in preventing a potential fire threat to the turbine building. Contingency measures were well established.

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 May 23, 1997. The licensee acknowledged the findings presented. No proprietary information was identified.

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
Dolan, B., Manager, Safety Assurance
Geddie, E., Manager, McGuire Nuclear Station
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
N. Economos, Regional Inspector
S. Rudisail, Regional Inspector
R. Moore, Regional Inspector

INSPECTION PROCEDURES USED

IP 71707: Conduct of Operations
IP 71750: Plant Support
IP 62707: Maintenance Observations
IP 61726: Surveillance Observations
IP 40500: Self-Assessment
IP 37551: Onsite Engineering
IP 92700: Onsite LER Followup
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

OPENED

369/97-08-01	URI	Root Cause of MSVV Level Actuation (Section O2.2)
369/97-08-02	VIO	Inadequate Procedure for performing ACOT Testing (Section M3.1)
369/97-08-03	NCV	Failure to Maintain Complete and Accurate Records (Section M8.1)
369,370/97-08-04	IFI	Potential Air Binding of CA Pumps (Section E1.1)
369/97-08-05	NCV	Failure to Follow Procedure (Section M8.1)

CLOSED

50-370/96-03	LER	Unit 2 Reactor Trip Occurred Due To Reactor Coolant Pump Motor 2B Failure (Section O8.1)
50-369/96-01-04	URI	Apparent Failure to Follow Procedure (Disassembly, repair and re-assembly on Kerotest 'Y' type check valve 1NV233) (Section M8.1)
369,370/96-10-04	URI	Evaluation for SFP Area Painting Project (Section E8.1)

50-369,370/96-04-05	IFI	Verification of SSS Activation 23 Time During Emergency Plan Drill (capability to perform time critical tasks during SSS activation in conjunction with EP evolutions has not been verified) (Section P8.1)

LIST OF ACRONYMS USED

ACOT - Analog Channel Operational Test
ALARA - As Low As Reasonably Achievable
ASME - American Society of Mechanical Engineers
CA - Auxiliary Feedwater System
CACST - Auxiliary Feedwater Condensate Storage Tank
CF - Main Feedwater System
CFR - Code of Federal Regulations
DBE - Design Basis Event
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EP - Emergency Plan
ESF - Engineered Safety Feature
FME - Foreign Material Exclusion
FSAR - Final Safety Analysis Report
FWST - Refueling Water Storage Tank
GPD - Gallons Per Day
HS - Moisture Separator Reheating Drain
IAE - Instrument and Electrical
IAS - Instrument Air System
IFI - Inspector Followup Item
LER - Licensee Event Report
LCO - Limiting Condition for Operation
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
MS - Main Steam
MSSV - Main Steam Line Safety Valve
MSVV - Main Steam Valve Vault
NCV - Non-Cited Violation
NOV - Notice of Violation
NOUE - Notice of Unusual Event
NRC - Nuclear Regulatory Commission
NRR - NRC Office of Nuclear Reactor Regulation
NSD - Nuclear Site Directive
OSM - Operations Shift Manager
PIP - Problem Investigation Process
PORC - Plant Operations Review Committee
PRA - Probablistic Risk Assessment
QA - Quality Assurance
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
RO - Reactor Operator
SFP - Spent Fuel Pool
SGRP - Steam Generator Replacement Project

SI - Safety Injection
SRO - Senior Reactor Operator
TS - Technical Specifications
UFSAR - Updated Final Safety Analysis Report
URI - Unresolved Item
USTs - Upper Surge Tanks
VIO - Violation
WO - Work Order
WPM - Work Process Manual
ZPPT - Zero Power Physics Testing

SYNOPSIS

This investigation was initiated by the U.S. Nuclear Regulatory Commission, Office of Investigations, Region II, on March 22, 1996, to determine if an individual at the Duke Power Company, McGuire Nuclear Station, intentionally signed and falsified step 11.4.5 of a procedure (quality assurance document) claiming that he replaced a valve gasket when he did not.

The evidence developed during this investigation substantiated that this individual purposely decided to reuse the old gasket and intentionally signed the procedure step claiming that he had replaced the valve gasket.