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

Report Nos. 50-369/94-06 and 50-370/94-06

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

Facility Name: McGuire Nuclear Station 1 and 2

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

Inspection Conducted: February 6, 1994 - March 12, 1994

Inspector: W. H. Miller Jr. for G. Maxwell, Senior Resident Inspector — 3/29/94 Date Signed

G. Harris
Resident Inspector

Accompanying Inspectors: K. Kavanagh, Reactor Engineer Intern, McGuire
W. Miller, Project Engineer, RII
R. Watkins, Project Engineer, RII

Approved by: M. Lesser, Section Chief, Division of Reactor Projects — 3/30/94 Date Signed

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance observations, Temporary Instruction 2515/115 - Concerning Plant Records for Non-licensed Operators and followup on previous inspection findings and licensee event reports. Backshift inspections were performed on February 7, 12, 14, 18, 19, 20, 21, 26, 27 and March 4 and 6, 1994.

Results: In the area of operations, the inspectors determined that operator response to plant challenges was good (paragraphs 2.d,e,f,g).

In the area of maintenance, corrective actions for previously identified inadequate control of vendor work activities have not been effective. Failure to control vendor maintenance on the auxiliary building's roof resulted in the removal of material from a radiologically controlled area (RCA) without a radiological survey as required by the Radiation Work Request. This issue is characterized as a Violation 94-06-01 (paragraph 4.f.) and indicates that problems continue in the area of vendor control.

In the area of maintenance, maintenance on the 1NI-94 check valve resulted in check valve leakage in excess of TS limits during heatup after steam generator plugging had been completed. The unit was forced to shut down and drain down to midloop for the check valve to be reseated. This issue is characterized as an unresolved item (paragraph 4.e.) for further review of procedural adequacy.

In the area of maintenance, the licensee identified that they were not performing a required technical specification surveillance for the high neutron flux (low setpoint) reactor trip and the permissive 10 setpoint. The inspectors concluded the licensee's immediate and planned corrective actions were adequate. This issue is characterized as an non-cited violation (paragraph 3.b.).

In the area of maintenance, the inspectors concluded that the decision to plug and remove from service all sleeved tubes decreases challenges to plant safety systems due to steam generator tube leaks (paragraph 4.b.).

In the area of maintenance, the inspectors concluded that modifications made to diesel generators timing relay for the low lube oil pressure trip increases starting reliability and reduces the number of unnecessary trips without causing diesel degradation (paragraph 3.a.).

In the area of maintenance, the inspectors concluded that the maintenance and testing of Unit 1 mainsteam isolation valves was adequate to ensure that they function as designed when required (paragraph 4.c.).

In the area of maintenance, the inspectors concluded the management of work activities for safety-related systems resulted in the unnecessary delay in returning a piece of safety related equipment to operable status (paragraph 4.g.).

In the area of maintenance, the inspectors concluded that the licensee has been proactive in its use of motor current analysis in combination with vibration analysis to detect and diagnose problems with some of its equipment (paragraph 4.h.).

Organizational Changes:

During this reporting period, several site organizational changes were initiated by the licensee. Most of the changes affected the maintenance and engineering groups. However, the Superintendent of Operations, Bruce Hamilton, was transferred to a position in the Duke Corporate Office in Charlotte, North Carolina. He was replaced by Ron Jones, who was previously the Superintendent of IAE at the Catawba site.

The changes in maintenance and engineering have been partially completed and will continue over the next few months. These changes are being made to improve communications within various site organizations, to maximize the use of personnel and are necessary to implement the proposed changes to the site work control process. In addition to the reorganization changes, some new positions have been created to further ensure the success of the work control process.

REPORT DETAILS

1. <u>Persons Contacted</u>

<u>Licensee Employees</u>

D. Baxter, Support Operations Manager
A. Beaver, Operations Manager
*J. Boyle, Work Control Manager
D. Bumgardner, Unit 1 Operations Manager
*B. Caldwell, Training Manager
*M. Cash, Engineering Supervisor
R. Cross, Compliance Specialist
*T. Curtis, System Engineering Manager
*R. Deese, Safety Review Group
*E. Geddie, Station Manager
*G. Gilbert, Safety Assurance Manager
B. Hasty, Emergency Planner
*F. Hayes, Human Resources
*P. Herran, Engineering Manager
*R. Jones, Superintendent of Operations
*E. Geddie, Station Manager
*T. McMeekin, Site Vice President
W. Matthews, Engineering and Electrical
*M. Nazar, Instrument & Electrical Maintenance Superintendent
*R. Sharpe, Regulatory Compliance Manager
*K. Thomas, Engineering
*B. Travis, Component Engineering Manager
R. White, Mechanical Maintenance Superintendent

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

NRC Resident Inspectors
*G. Maxwell, SRI
*G. Harris, RI
*K. Kavanagh, Intern
*R. Watkins, RII

*Attended exit interview

2. Plant Operations (71707)

a. Observations

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

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

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

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

b. Unit 1 Operations

Unit 1 was in a forced outage during the first portion of this reporting period to allow repair of leaking steam generator tubes. The unit was returned to 100% power on February 25 and remained at 100% until March 4, when power was reduced to about 32%. The power reduction was conducted by the operators when they noticed the "A" steam generator main feedwater containment isolation valve, 1-CF-35, drifting closed. The valve was repaired with a temporary modification and the plant was returned to full power on March 7 and operated there through the remainder of the reporting period.

c. Unit 2 Operations

Unit 2 operated at 100% power throughout the reporting period.

d. Operator Response to Plant Challenges

Feedwater Isolation Valve Failure 1CF-35

The inspectors determined from control room records that on March 4, the operators noted that the main feedwater containment isolation valve, 1CF-35, for the "A" steam generator was drifting closed. The control room operators received a computer alarm, D0737, S/G A CF Hydro Filter D/P Lo, and noticed the valve was going closed. The operators placed the controller in manual but could not open the valve. The operators dispatched an NLO to the valve who verified that the valve was going closed. The NLO established communications with the control room and the CR SRO predicted when the valve would go full closed. The operators entered procedure OP/1/A/6100/03 and reduced power rapidly to stabilized the unit at 32% power, at which time the valve went closed. The actions of the operators prevented an unnecessary trip and a challenge to the plant's reactor protection safety system. The repair and maintenance of the valve is described in section 4.d.

e. Power Range Nuclear Instrumentation Channel Failure N-41

The inspectors evaluated the control room logs and observed that on March 4, the operators noticed a steadily increasing power mismatch on their control room display which was indicative of a power range nuclear instrumentation failure. Although no annunciator was actuated, the operators continuously monitored the failing instrument and subsequently declared it out of service and thus prevented any undesirable transients on the plant. The instrument was taken out of service in accordance with established abnormal procedures. IAE personnel tested the instrument but found nothing wrong with it. The instrument was declared operable and returned to service.

f. Unit 1 Start Up and Mid-loop Operations

The inspectors witnessed the start-up of Unit 1 after the forced outage. The inspectors observed that the operators were attentive to their indications and controls during the start-up. The start-up was slow and controlled and proceeded without incident. Criticality was reached within established parameters. When questioned by the inspectors the operators were mindful of procedural precautions and limitations. Good communications were established between reactor engineering, inverse multiplication plotters and the control board operators.

g. 7300 Process Card Failure Causing S/G 2A Water Level Transient

A review of work orders and control room records, and interviews with operators revealed that a process control card for the Unit 2 steam generator water level failed causing water level to increase in steam generator 2A. The nuclear control operator quickly diagnosed the problem and took manual control of the water level controller and returned water level to its programmed value; the operator then deselected the channel and eventually placed the system back in automatic in accordance with established procedures. The action of the operator prevented an unnecessary plant transient and challenge to safety systems. The process card was repaired and returned to service.

The inspectors concluded that operator response to these plant challenges was good.

h. Other operational challenges that were evaluated by the inspectors included the following:

1) Train B of ND for Unit 2 was declared inoperable when the licensee discovered that the pressure switch in the recirculation line was not environmentally qualified. The system was unavailable for an extended period of time due to lack of replacement parts. A spare switch was eventually

found and calibrated. The ND system was returned to service within the time limit required by TS.

2) Unit 1 unidentified leakage showed a steady increase after startup and peaked at 0.8 gpm. Most of the leakage could be attributed to leakage by the seat of valve NV-137, VCT to Recycle Hold-Up Divert valve. The unidentified leakage, near the end of the reporting period, showed a declining trend. The licensee has scheduled repairs on the valve during the next refueling outage.

3) Inleakage into the 1B cold leg accumulator had caused pressurization of the accumulator above allowed values. A Special Order, 93-07, instructs operators to reduce level and take samples to ensure that accumulator boron concentration is within TS limits. The licensee was continuing to evaluate this problem.

4) Pressurizer Pressure Alert annunciator frequently inadvertently actuated for unknown reasons. The problem with the annunciator has existed for at least four months. The annunciator warned operators that the reactor coolant system pressure was low. The licensee has attached a recorder to the alarm pressure circuitry to analyze the problem, but has yet to determine the cause of the annunciator actuation. The inspectors have noted a decrease in the frequency that the annunciator inadvertently actuates. The plant staff stated that they will continue to evaluate the problem.

No violations or deviations were identified.

3. Surveillance Testing (61726)

Observed Surveillance Tests

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

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

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

a. 2A Diesel Start Failure

The 2A diesel failed to start as required during monthly surveillance test PT/2/A/4350/02A due to low lube oil pressure trip. The apparent cause of the trip was slow pressure buildup in the lube oil pressure sensing lines. The low lube oil pressure circuitry provided a 15-second time delay, which allowed pressure to increase to 28 psig before actuating a trip circuit. The engine lube oil pressure must be at this value to actuate pressure switches PS1 and PS2 after 95% speed is achieved to prevent a trip.

The licensee declared the diesel inoperable and performed off-site power verifications and ran the other diesel as required by technical specifications.

Work Request 94006930 was initiated to remove any carbon particulate that may have been blocking the sensor lines. This was usually done as a scheduled annual preventive maintenance task as a result of a earlier failures. Carbon deposits have been entering the fuel oil from the exhaust because of vacuum (negative pressure).

This was the only valid start failure in the last 20 failures on this diesel and was the third in the last 100 starts.

The licensee initiated MM-5429/30 to change the timing delay relay from 15 seconds to 30 seconds to allow the diesel engine lube oil to reach the desired pressure. After the adjustment was made, the 2A diesel was ran three times. The inspectors observed these diesel runs and noted that during the first two, the diesel low pressure alarm actuated; however, no trips occurred and no discrepancies in the diesel's performance were observed.

The licensee recognized that the adjustment of the pressure switch does not eliminate the cause of the slow pressure buildup. But the timer adjustment did help to eliminate unnecessary trips. Running the diesel for the additional 15 seconds would cause the shaft to turn an additional 130 rotations when there was an actual loss of oil. However, the bearings are trimetal and will protect the crankshaft from serious damage until the shaft stops.

The inspectors concluded that the diesel generator starting reliability maybe enhanced as a result of the modification.

b. Missed Technical Specification Surveillance for High Neutron Flux Low Setpoint Reactor Trip & P-10

The licensee discovered through conversations with the engineering staff at Catawba that a Technical Specification surveillance requirement, 4.3.1.1, had been missed on several occasions because of an inadequate procedure.

Technical Specification 3.3.1 required that the reactor trip system instruments have a minimum of three operable power range nuclear instrumentation and that the high flux (low setpoint) trip must be operable in Mode 2 (startup) and Mode 1 with the reactor power less than P-10. The power range high flux low setpoint trip was provided to protect the core from the effects of a startup accident while at low power conditions. The at power permissive P-10 blocked source voltage and provided an input to the "At Power" permissive, P-7.

Periodic test procedure, PT/0/A/4600/14D(E,F,G), NIS Power N-41(N-42,N-43,N-44) Range Analog Channel Operational Test, did not test the high flux (low setpoint) bistable. Presently, test procedures are performed with the detector signal cable connected, which does not allow the setpoints to be verified. Therefore, setpoints cannot be verified below the present power level. For example, at 100% power the detector signals could be imposed with an additional 8% test signal to verify reactor trip at 108% power but could not be decreased to verify the 25% or 10% setpoints. The verification of setpoints was not current beyond 30 days, following a refueling startup.

Further investigation revealed that, at various times in the past, both Unit 1 and Unit 2 were operated when this bistable was not adequately tested.

Subsequent investigation revealed that the event was cause by personnel failing to recognize that under a normal conditions the high flux (low setpoint) bistable was not being tested. An investigation revealed that the procedure in use for this testing had not been written in a manner that would test these bistables when reactor power was above their setpoint. The test procedures allowed the use of a built-in test feature of the power range channel, and was written in accordance with the guidelines established by the vendor. Although the procedure was written based on documents received from the vendor, the personnel who wrote and reviewed the test procedure did not give the procedure a sufficiently indepth review. This allowed a procedure to be used that was technically inaccurate.

Upon discovery of the problem, the IAE personnel initiated appropriate procedure changes to disconnect the detector input cable from the power range circuitry while testing the low setpoint bistable. IAE technicians successfully tested the high flux (low setpoint) bistables on all four channels. Tests of the bistables did not indicate a degraded condition. In addition, the high setpoint was operable.

The licensee has decided to request a technical specification amendment to serve as long-term corrective action for the problem.

Inspectors informed the licensee that, because the criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied, this item would be identified as Non-Cited Violation 50-369,370/94-06-03, Failure to implement an adequate procedure to test a safety feature.

c. Diesel Generator 1A Operability Test, PT/1/A/4350/02A

On March 3, 1994, the inspectors observed PT/1/A/4350/02A, Diesel Generator 1A Operability Test, and performed a walkdown of the 1A diesel generator and its associated components. The test was conducted in accordance with the procedure and verified that the diesel generator 1A was operable. The inspectors also walked down the 1A diesel generator and its components. The inspectors found the material condition of the 1A diesel generator and its auxiliaries to be acceptable.

4. Maintenance Observations (62703)

Resident inspectors reviewed and/or witnessed routine maintenance activities to assess procedural and performance adequacy and conformance with the applicable TS.

The activities witnessed were examined to verify that, where acceptable, approved procedures were available and in use, prerequisites were met, equipment restoration was completed, and maintenance results were adequate.

The following maintenance activities were reviewed or witnessed in detail:

a. WO 94007920-1, Bi-Weekly Preventive Maintenance on Unit 1 Rotating Equipment

On February 10, the inspectors witnessed the preventive maintenance inspection and measurement of vibration on service water pump 1B component cooling water pumps 1B1 and 1B2 and reactor building ventilation system (VL) fan 1A. The inspections and measurements were performed using procedure numbers MP/0/A/7300/01, Rotating Equipment-Preventive Maintenance, and MP/0/B/7450/20, VL Fan Vibration Alarm Response, Remote Monitoring and Preventive Maintenance. These inspections are performed bi-weekly on all of the principle operating rotating equipment, i.e., turbine, main feedwater pumps, service water pumps, charging pumps, etc. The Unit 1 equipment was inspected one week, and the following week the Unit 2 equipment was inspected. These inspections and tests are performed by mechanical maintenance. On the date of this observation, the inspectors noted that the mechanical maintenance technician was well versed in the required inspection and test requirements, the technician's actions were appropriate, the test equipment used was appropriate and properly calibrated, and the procedures were current. The number of components inspected and tested on this date was lower than normal since Unit 1 was off-line for a steam generator maintenance outage.

b. 1D Steam Generator Repair Activities

Unit 1 was shutting down to Mode 2 for hot testing of the main steam isolation valves on January 22, when a S/G tube leak was detected. The operators received a trip II alarm on EMF-33 steam jet air ejector monitor; in addition N-16 steamline monitors indicated a small tube leak in S/G 1D. EMF-34 steam jet air ejector monitor reading was received and increased to a trip II condition shortly thereafter. The operators entered an AP-10, NC System Leak within Capability of Both Charging Pumps, and proceeded to shutdown the unit. Radiation protection and chemistry manual calculations were conducted and indicated that secondary leakage was in the 106-165 gpd range. The unit was shut down and cooled down in accordance with established procedures to permit repair operations.

Repair crews subsequently found that the leak in the 1D S/G was a result of a circumferential crack at the upper kinetic weld of a tubesheet sleeve in tube 11-75. The tube was later removed for further analysis. The crack was identical to the one found in the 1A S/G tube 39-72, which resulted in a forced outage in August 1993.

As a result of the crack in the tube 39-72, a susceptibility to stress corrosion cracking ranking of all 720 sleeved tubes was performed, which estimated a projected tube life as a function of parent tube material properties. The ranking of tube 11-75 showed that this tube should have been able to remain in service well past the proposed S/G replacement date. As a result of the crack in 11-75, the licensee decided to remove all sleeved tubes in Unit 1 from service until the true root cause of the sleeved tube cracks could be determined. As a result of the recent plugging operations, 13.6% of all tubes are currently plugged in the Unit 1 steam generators.

Prior to implementing repair operations, a plug verification inspection was performed to ensure that all installed plugs were in place. The plug verification was performed as a result of the tube plug failures caused by inadequate torquing at Oconee. The licensee concluded that twenty-one tubes, which had been plugged, needed to be replugged because torque out values could not be verified.

Preinspection pressure testing revealed some weeping sleeves in all steam generators except for the 1C steam generator. The tubes were identified and repaired.

Tube 9-80 was to be removed for further analysis but could not due to a buildup of metal chips during tube removal cutting operations. The presence of the chips caused the cutting device to jam which resulted in several days delay in removing the tube.

Because of the extensive delay, the licensee decided not to remove the tube for analysis.

As a result of the steam generator repairs the heat transfer surface area has decreased requiring the #4 main turbine generator governor valve to be operated in a slightly more open position.

The inspectors concluded that the licensee's decision to plug all sleeved tubes in Unit 1 should reduce the number of challenges to plant safety systems which have resulted from steam generator tube leaks.

c. Unit 1 Main Steam Isolation Valve Maintenance & Testing

On February 24, 1994, the inspectors observed corrective maintenance and testing on Unit 1 main steam isolation valves (MSIV). The maintenance and testing of the valves was initiated as a result of the failure of 2SM5 to fully close during the LOOP event in December, 1993. Failure of 2SM5 to fully close and the failure of 2SM7 had been attributed to inadequate clearance between the yoke rods and the yoke guide rods. The Unit 1 valves were tested to the revised test requirements (valve at full operating temperature) prior to restart. The valves had been previously scheduled to be tested on January 24, 1994 but were postponed due to a steam generator tube leak, which resulted in a forced outage.

The inspectors observed the pre-job briefing of the crews. Critical steps were reviewed with the crew members as well as lessons learned. The inspectors observed these tests, which required the plant to be in Mode 3, 557 °F, and 2235 psig. The inspectors observed the valve testing and verified that the valves did close fully by performing independent measurements. The valve measurements showed that all valves were fully closed. The inspectors also reviewed the closure times for the valves. All times were within the acceptance criteria.

The inspectors observed the maintenance and testing which included: 1) opening the valves, 2) closing the valves, 3) reopening the valves, 4) cleaning yoke rods and general inspection, 5) closing the valves, 6) replacing the bottom yoke guide rods and setting clearances, and 7) closing the valves to assure performance.

Following the successful completion of the tests on each Unit 1 MSIVs, the inspectors agreed that the valves closed satisfactorily and that the failure mechanism for these valves had been identified and corrected.

d. Main Feedwater Containment Isolation Valve 1CF-35 Failure

The inspectors evaluated the circumstances and conditions which resulted in valve 1CF-35 drifting closed. The inspectors noted that on March 4, 1994, the Unit 1 control room received computer alarm D0737, S/G A CF Hydro Filter D/P Lo, and control board indication that 1CF35, main feedwater containment isolation valve, was in an intermediate position. An NLO was dispatched to investigate the problem and reported that 1CF35 was drifting closed. The SRO calculated the time to full closure of 1CF35 and directed the load reduction at a maximum rate of 150 MW/min. OP/1/A/6100/03 Enclosure 4.2, Controlling Procedure for Unit Operation Power Reduction, was utilized to reduce power and to transfer main feedwater flow to the steam generator upper nozzles prior to the full closure of 1CF35. During the load reduction, the reactor operator discovered that the steam generator B, C and D main feedwater containment isolation valves, 1CF30, 1CF28 and 1CF26 respectively, would not close from the main control board as required in Step 3.12.2 of the aforementioned operating procedure. 1CF26, 1CF28 and 1CF30 were left open and the reactor operators continued to execute the procedure. The load reduction was discontinued at approximately 320 MW_e (32% full power) just prior to the full closure of 1CF35. Work Order number 94018951 was generated to investigate and repair 1CF35.

During the investigation, the maintenance crew discovered that pressure switches PS2 and PS4 were out of tolerance. PS2 was one of the three pressure switches which controlled the actuation and deactuation of the pump that charged the nitrogen N_2 accumulator of the valve. The inspector determined that the safety function of the valves would not have been inhibited. Upon a feedwater isolation signal, the N_2 accumulator would thrust 1CF35 into the fail closed position. PS4 was used for control room indication of low N_2 pressure. IAE recalibrated PS4 but was unable to properly calibrate PS2. Furthermore, the maintenance crew discovered that the solenoid valve, SV2, was leaking slightly. This allowed hydraulic fluid to leak to the top of the cylinder and close 1CF35 while attempting to recharge the accumulator.

The maintenance crew installed three different SV2 valves from the warehouse; all SV2 valves were degraded and allowed hydraulic fluid to leak to the top of the cylinder. The original SV2 valve was reinstalled since it appeared to leak the least amount of hydraulic fluid. PS2 replacements were not in stock, therefore, a temporary modification was initiated. The temporary modification removed PS2 from the actuator's circuitry and installed a toggle switch in order to perform the actuator accumulator recharge by manual operator action. Maintenance alerted operations that the leakage through SV2 would cause the open side pressure to decrease and slowly close 1CF35 during manual recharge. Operations would utilize OP/1/A/6100/10F, 1CF35 S/G A Lo N_2 Pressure, which required manual recharge of the accumulator as an immediate operator action if a main feedwater isolation had not occurred. OP/1/A/6100/10F provided operator guidance for indication of 1CF35 intermediate position.

The root cause failure analysis of PS2, SV2 and control board operation of 1CF26, 1CF28 and 1CF30 was not completed. The licensee stated that they would not know the root cause until the valve was disassembled during the next refueling outage. This will be identified as Inspector Follow-up Item 94-06-04, Main feedwater containment isolation valve 1CF-35 failure.

e. Check Valve 1NI-94 Maintenance and Subsequent Leak

During the outage following the Unit 1 steam generator tube leak, maintenance work was performed on two check valves associated with the cold leg accumulators. The check valves, 1NI-82 and 1NI-94, had been leaking roughly 0.7 and 0.8 gpm, respectively. These check valves are classified by TS 3.4.6.2 as RCS pressure isolation valves. The basis for TS LCOs are to prevent gross valve failure and subsequent intersystem LOCA.

On February 10, 1994, with the RCS drained down to centerline, the check valves were isolated. Maintenance technicians opened check valve NI-94 and removed the valve bonnet and disc assembly. The disc assembly was wrapped in lead and transported to the hot shop for inspection; the valve bonnet was reinstalled. Nozzle dams were installed in the steam generator hot legs and operators began to refill to 20% pressurizer level for steam generator tube plugging. However, the RCS was drained again when leakage from the valve bonnet was detected. The maintenance technicians had not properly torqued the bonnet nuts after the disc assembly had been removed. The bonnet was reinstalled, and refill of the NC system was resumed.

On February 17, 1994, when the RCS was drained to centerline for switching the steam generator vent path, maintenance technicians went back into both check valves to make repairs. The valve internals were removed and inspected.

The inspectors were informed that the component engineer identified damage to the disc and valve body seats. The cause of the leakage was identified as coining or wear on the seating surfaces of the valve and the body seat. The licensee attributed the damage to the configuration of the check valves, downstream of the ND connection to the cold leg accumulator injection line. For each accumulator, two check valves are positioned downstream of the accumulator isolation valve: one upstream of the ND connection and one downstream. Only the second of the two check valves exhibited damage. The ND piping upstream of the connection to the injection line for the B Train accumulators (Loops 3 and 4) was configured such that a series of elbows induced flow turbulence. This turbulence was compounded at the connection to the accumulator in a T-configuration. The licensee hypothesized that a vortex of the ND system was generated from this piping configuration and caused the valve to chatter, which resulted in wear to the valve seating surfaces.

The valve had been designed such that disc travel (in a swinging orientation) in the open position was limited by a backstop. The backstop was designed to limit the travel distance to a position from which the disc could readily swing closed at the appropriate reduced (or reversed) flow velocity. To prevent damage to the new internals the licensee redesigned the disc backstop. The area of contact with the back of the disc was modified and enlarged so that, during full flow, the back of the valve would rest completely against the projection in the valve body, covering the entire surface area of the back of the valve and, thereby, eliminating any opposing, closing forces on the valve.

On February 16 the maintenance technicians installed the modified internals in 1NI-82 and 1NI-94, obtained adequate contact between the disc and valve seats, and doweled the disk bracket onto the valve body ledge. A test bladder had been installed prior to valve reassembly so that an air test for seat contact verification could be conducted. Both valves passed the air test. The disc brackets were removed to provide sufficient clearance for test bladder removal. On February 17 the disc bracket was reinstalled on the valve body ledge via the alignment of the dowels with the dowel holes that had been bored during the initial installation.

On February 19 system pressure and temperature were increased. During check valve testing an operator identified check valve leakage in excess of the TS limit. The unit was shut down, the RCS was drained again, and maintenance technicians conducted air tests on 1NI-82 and 1NI-94. The air test revealed leakage within TS limits on 1NI-82; however, 1NI-94 leakage exceeded the TS limit.

On February 19 the RCS was again drained to centerline, and maintenance technicians removed the valve bonnet to inspect the valve disc. According to the component engineer, the disk bracket for 1NI-94 was noticeably cocked (approximately 1/16 of an inch) at an angle, indicating that it was not flush against the valve body ledge that it rested upon. Maintenance technicians inspected the disc to ensure that there was no damage. They then attempted to torque the disc bracket hold-down bolts, but they were sufficiently tight at 110 ft-lbs. Technicians then tapped the disc bracket down and were then able to torque the hold-down bolts. This process of tapping down the disc bracket and torquing the hold-down bolts was iterated two or three times until the disk bracket was flush against the valve body ledge. The technicians used feeler gauges to ensure proper disk bracket placement and, therefore, disc and body seat contact. On February 20 the valve bonnet was reinstalled and the unit proceeded to start-up. The unit reached Mode 4 on February 23.

The inspectors discussed the event with the component engineer, who revealed that the maintenance technicians installed the new valve internals, conducted the air pressure leak test, removed the disc assembly to retrieve the test bladder, and reinstalled the disc assembly. The technicians had noticed a gap between the disc and body seats in the location readily visible from the valve lid opening (at the top of the disc). A technician tapped the disc closed with his finger and assumed that the valve would seat under normal system pressure. The inspectors were informed by the plant staff that to the component engineer's knowledge, a supervisor was not present during the post-air-test work, no discrepancy was noted in the procedure, and no attempt was made to notify the supervisor for guidance. The technicians proceeded to reengage and torque the valve lid nuts, and refilling of the NC system was resumed. This inadequate seating had resulted in the valve leakage in excess of TS limits.

The inspectors reviewed the work package for the 1NI-94 check valve and determined that the procedure did not provide any method of removing the test bladder after successful completion of the air test. The procedure also did not provide guidance for reestablishing valve integrity by verifying flush alignment of the disc bracket to the valve body ledge (using feeler gauges, depth micrometers or calipers). Furthermore, the procedure contained two critical hold points in the initial valve installation steps for which there was no signature block on the corresponding sign-off sheet. The additional time in mid-loop operations and personnel exposure incurred by the maintenance required to reseat the valve introduced added risk and personnel exposure that would have been avoided if procedures had been adequate.

The inspectors reviewed the corrective actions proposed by the licensee to modify the procedure and provide sufficient guidance for maintaining valve integrity after it has been established and verified by an air test. However, the licensee is still in the process of evaluating the procedure changes and will not finalize these changes until they have completed their review. The inspectors will complete their evaluation of the procedures when the changes have been finalized and the procedures have been released and incorporated into the maintenance work program. Therefore, this is identified as Unresolved Item, 50-369/94-06-02, Inadequate Maintenance Caused by Inadequate Procedures.

f. Control of Vendor Work Activities During Auxiliary Building Roof Repairs

On March 3 and 4, 1994, a vendor was removing materials from the roof of the reactor auxiliary building. Roofing repairs had been made and the vendor was asked to remove the materials from the roof by the job sponsor. An RP manager who happened to see the vendor collect their materials through a window sent a contractor to the roof of the auxiliary building to notify the vendor that a radiological survey of the materials was required before the materials could leave the site. According to the RP contractor, the vendor wrote down the name and telephone number of the RP manager he needed to contact to request a survey once all of the materials had been collected at one location, the skid located beside the auxiliary building. The vendor agreed to call the RP manager and stated that the materials would be left there over night and would not be removed until the following day. RP did not receive a telephone call from the vendor the following day, Friday, March 4. On Monday, March 7, the RP manager checked to see if the material had been removed. He determined through discussions with the Facilities and Commodities group that it had been removed the previous Friday. However, when he followed up on the results of the radiological survey, he discovered that a survey had not been conducted on the material. The licensee's Radiation Protection Manual, Section 1.4.1 requires work to be performed under an approved radiation work permit. SRWP 2, used for this job, specifically required materials removed from the area be surveyed.

The inspectors interviewed the job sponsor responsible for the vendor. According to the job sponsor, unused materials had, in the past, been removed from the roofs of various buildings that were considered radiologically controlled areas (including the auxiliary building and spent fuel pool building) without being surveyed for radiological contamination. A precedent had apparently been established whereby certain materials were routinely removed from the roofs of these buildings and circulated within and outside the plant, presumably clean areas, without a survey. The job sponsor realized that old roofing material that had been removed from the roof for repairs required a survey; however, he was not aware of the RP requirement of a radiological survey of new, unused materials, tools and equipment, although they were in the RCA.

The inspectors reviewed Management Directive 105, Control of Non-Assigned Individuals and Organizations Performing Work or Directing Activities in the Station, dated February 24, 1994 (effective date). This directive was written in response to the fire event on the roof of the fuel handling building on August 12, 1993, to correct weaknesses in the control of vendor activities. The vendor involved in the fire was the same vendor involved in the failure to conduct a radiological survey incident. This directive was written to serve as an information package for site personnel while sponsoring non-assigned individuals and organizations. Job sponsors are encouraged to read the directive before they initiate the process to bring a non-assigned individual on site.

The responsibilities of the sponsor are provided in Appendix A of the directive, Sponsor's Checklist for Non-Assigned Individuals and Organizations. This appendix listed the steps necessary for a non-assigned party (vendor) to gain entry into the site (e.g., access requirements, qualifications and technical training, radiation protection requirements, work control scheduling, and maintenance planning). The checklist stipulated that successful completion of Level II GE training was required. The inspectors asked the job sponsor if any formal training or even an informal orientation was required to qualify as a job sponsor. The sponsor stated that no preparation or training was provided. However, the job sponsor was responsible for considering all work activities that could have an adverse impact on the site (i.e. trenching, roofing, breaching of security barriers, switchyard work, etc.) and communicating specific expectations to be met by vendors. The assigned sponsor was also responsible for interfacing with other groups, including Security, Radiation Protection, Work Control, etc. to facilitate station entry and proper work execution by vendors.

Contrary to the responsibilities delineated in Management Directive 105, the job sponsor failed to be aware of and intimately familiar with RP requirements and failed to interface with RP to ensure that requirements were met prior to the removal of materials from the RCA. Apparently, the job sponsor did not contact RP when the vendor's work was completed and they were preparing to leave the site with their materials.

The inspectors also interviewed the vendor, specifically the crew supervisor. When asked if the work on the auxiliary building roof was conducted in an RCA, the crew supervisor answered yes. The crew supervisor stated that they were working under an RWP and had been wearing dosimetry. When asked if he was familiar with the RWP, the crew supervisor said he was "somewhat" familiar with it. He also indicated that they had been working on the roofs of various buildings for close to a year and had received their GET training before they began working and that, considering the time that had elapsed since then, all of the material covered may not have been retained a year later. The crew supervisor stated that an RP representative had told him that a survey of the materials being removed from the roof was required before they could be taken off site, but did not recall taking the name and phone number of a contact person to call once all materials had been collected in the skid beside the auxiliary building so that a survey could be conducted. The crew supervisor also indicated that he did not return the following day, Friday, March 4, to pick up the materials; another vendor employee was sent to retrieve the materials. The crew supervisor failed to mention to that person the required radiological survey. As a result, no phone call was made to RP or the job sponsor to verify that the survey had been conducted before the materials were taken off site.

When the RP manager realized on the following Monday, March 7, that the materials had been removed before they were surveyed, he immediately called the vendor to inquire about the location of the materials. An RP technician was sent to the vendor's establishment to conduct the survey. All equipment and material from McGuire roof work surveyed emitted less than 0.05 mr/hr, which was the licensee's administrative limit.

Because there was no exposure to the public, this incident was of minimal safety significance. However, because control and oversight of vendor work activities has been the subject of previous concerns and corrective actions should have prevented this event, this is identified as Violation 50-369,370/94-06-01, Failure to Survey Materials Leaving RCA.

g. Safety System Unavailability

While investigating causes for the unavailability of plant safety systems the inspectors noted that during the Train B diesel down day on February 28, the 1B service water pump had been removed from service to perform a routine oil change using WO 94006364. With the pump removed from service the crew performed the maintenance and noted a discrepancy in the procedure. The delay in processing the procedure change resulted in an 8.3 hour delay.

The inspectors concluded that the planning for the job should have been better and identified the procedure problem. This delay could have been avoided and resulted in an unnecessary delay in returning the equipment to operable status.

h. Motor Current Signature Analysis

The inspectors evaluated the licensee's implementation of a new method of combining motor current signature analysis and vibration analysis to detect electrical and mechanical failures in electric motors. At the time, motor current signature analysis could only be utilized to predict broken rotor bars within motors. Motor current trending and analysis was performed on Unit 1 and Unit 2 hotwell pumps, condensate booster pumps, C heater drain tank pumps and most of the 4160 volt and 6900 volt motors. The data was acquired on a quarterly basis using a machinery analyzer with current probe, CSI-2110.

The predictive maintenance team which contained five maintenance and one electrical personnel would analyze the data as it was collected, verifying the data was within the specified ranges. The data was then downloaded to a computer and if there was a significant problem detected, the data would be analyzed by the vibration analyst.

The combination of motor current signature and vibration analysis predicted a cracked rotor bar in the 1A condensate booster pump

(CBP). Upon further investigation, the licensee found a cracked rotor base with 41 of 53 rotor bars broken prior to a probable failure of the CBP.

The inspectors noted that the licensee was proactive by incorporating the motor current signature analysis into their predictive maintenance program.

5. Temporary Instruction 2515/115 - Verification of Plant Records

a. NRC Information Notice 92-30 titled Falsification of Plant Records, was issued on April 23, 1992. NRC Temporary Instruction 2515/115 was issued on May 29, 1992 to provide guidance for evaluating licensee's ability to obtain accurate and complete log readings from licensed and non-licensed operators, as it relates to Information Notice 92-30. The inspectors observed that other Region II personnel have previously evaluated the McGuire site's methods of assuring that licensed and non-licensed operators were conducting and appropriately documenting routine surveillances (rounds). The results of that evaluation was documented in Region II monthly Resident Inspection Report 50-369,370/92-23, paragraph 7.0.

The inspectors evaluated the McGuire Safety Review Group Inplant Review Report Number 92-16. The report documented the results of Safety Review Group for verification of plant records and logs. Those records and logs that were evaluated covered the time period between March 1, 1992 and September 18, 1992. Each of the shift operating crews (A through E) were evaluated, both day shifts (7:30 a.m. - 7:30 p.m.) and night shifts (7:30 p.m. - 7:30 a.m.) were included. Safety Review Group identified four visual inspection entries into Unit 1 and Unit 2 motor generator set rooms and entries into both of the interior doghouses, main steam valve rooms, that could not be confirmed by comparisons with the NLO printouts. All of these entries occurred during the service building outside round on the night shift (7:30 p.m. - 7:30 a.m.) of July 16-17, 1992, by the same individual.

The individual was interviewed by the Safety Review Group and no explanation nor recall of any abnormal circumstances on the night in question was provided. The group then increased the survey sample for operations. The survey included all recorded rounds completed by the individual during the sample period (March 1, 1992 - September 18, 1992). As a result, the group did not identify any other discrepancies. The group documented that the discrepancies "were the result of a simple omission, with no malice or intent to deceive."

The inspectors interviewed the Safety Review Group evaluators and determined that the four entries which were apparently missed did not actually result in the watch standby documenting false readings or parameters. Rather, the specific round that was not made served as a "general observation" in those 4 rooms mentioned above. However, corrective actions have been made by the licensee to reduce the likelihood of recurrence. For example, Attachment 2 to the NLO Surveillance Checklist, Round Standard, were revised to identify specific expectations of NLOs during "general observation" rounds. Also, the NLO round sheets were revised for all plant areas to identify each area to be examined during rounds.

b. The inspectors reviewed the Shift Assignment Sheets for each of the five shifts (A through E) from November 29, 1993 through March 1, 1994. The inspectors selected four day shift and four night shift assignments for each of the five shift crews of NLOs on Unit 2. Those selected were assigned their operator duties in the auxiliary and the turbine buildings. The inspectors compared the NLO round sheets, for items to be checked, with the security CAD printouts. In every instance the logs and the security printouts indicated consistency. That is, the printouts showed that the NLOs were in the specified controlled areas, as required by procedure, to allot them access to the equipment specified on their round sheets for observation.

c. NLO Rounds

The inspectors accompanied the Unit 1 NLO on his general inspection sensory tour of the turbine and service building on March 1, 1994. The Operations Management Procedure 2-8, NLO Surveillance, required NLOs to perform the second round in the latter half of the shift at approximately 3 p.m. for day shift and 3 a.m. for night shift. The complete turbine and service building surveillance checklist was required to be preformed during the sensory round, although no parameters or checks were marked on the rounds sheet. The inspectors noted that the NLO replaced oil-soaked wipes around equipment, replaced burnt-out light bulbs, and appeared to be aware of general plant cleanliness.

The inspectors accompanied the Unit 1 NLO on his first round of the auxiliary building on March 2, 1994. OMP 2-8 required the NLO to verify the specified plant parameters were in the correct range and to document and notify the unit supervisor of any out of normal conditions. The inspectors noted that the NLO entered rooms that were posted "Notify HP prior to entry." At the time, rooms with this posting were Unit 1 containment spray pump B room, Unit 2 containment spray pump A room, and Unit 2 residual heat removal pump A and pump B rooms. Upon further questioning of the shift health physics (HP) staff, the inspectors learned that radiation work permit (RWP) 2 allowed operators on routine surveillance not to contact HP upon entering the aforementioned rooms.

On March 2, 1994, the inspectors accompanied an NLO during his rounds of the Unit 2 Auxiliary Building. The inspectors were furnished with a copy of the NLO's rounds sheets and verified that he observed each item listed on the rounds sheets and confirmed that parameters were within their specified ranges. The NLO also noted the condition of equipment and indications that were not included on his list as a proactive practice. The rounds sheets were not structured to list items in an order that corresponds with the NLO's inspection path.

6. Followup on Previous Inspection Findings and Licensee Event Report (90712, 92702 and 92701)

The following previously identified items and Licensee Event Reports were reviewed to verify that the licensee's responses, where applicable, and actions were in compliance with regulatory requirements and corrective actions have been implemented. This verification included record review, observations, and discussions with licensee personnel.

a. (Closed) Violation 369, 370/92-08-03, Failure to Follow Procedures Resulting in Configuration Control Events.

The licensee responded to this violation by letter dated May 13, 1992. The violation involved five examples of configuration control problems. The following corrective actions were taken by the licensee to prevent recurrence:

- Changes to operator's round sheets and the reason for the changes are now communicated to the non-licensed operators.

- This configuration control event was discussed with all maintenance technicians and the importance of notifying operations Control Room personnel if a plant device is found mispositioned or misaligned was stressed.

- Operations and Chemistry personnel evaluated the interface process for plant equipment that is under control of both Operations and Chemistry; Chemistry management covered this event with their staff; Chemistry personnel have reviewed all procedures under their control to assure that configuration control is adequately addressed; Chemistry procedures associated with tank recirculation activities have been revised and enhanced; procedures for taking samples from Fuel Oil Storage Tanks have been revised such that Train A tanks will be sampled on a different day than Train B tanks; and Procedure CP/1 (2)/A/8600/41 has been revised to require notification of the Control Room SRO prior to fuel oil tank recirculation and sampling activities.

- Procedure HP/0/B/1003/39 has been revised such that the procedure steps that require independent verification are clearly identified. When other radiation procedures are due for review and revision, the independent verification steps will also be clearly identified.

- A Component Mispositioning Working Group (CMWG) has been formed to use Human Performance Enhancement System methodologies to identify probable causes of component mispositioning events and to recommend effective means to prevent recurrence. This program continues in progress.

The inspectors reviewed PIP Nos. 1-M91-0178, 1M92-0056, 2-M92-0033 and 2-M92-0073 and supporting back-up data which documented that the inspectors determined that the corrective action for this item had been completed.

b. (Closed) Violation 369/92-13-01, Failure to Follow Procedure Resulting in an Engineering Safety Features (ESF) Actuation.

The licensee responded to this violation by letter dated June 26, 1992. This violation involved an inadvertent ESF actuation which was caused by a technical error in an operational procedure and by personnel error due to inadequate procedure guidance. The procedure error consisted of a steam generator level setpoint in the procedure based on the unit operating at full power in lieu of being based on shutdown conditions which was the condition of the plant at the time of this event. The personnel error involved the Reactor Operator at the Controls misinterpreting the applicable procedure which resulted in the operator leaving a Main Condensate Booster Pump running in lieu of stopping the pump as required.

The inspectors verified that the licensee has taken the following corrective actions to prevent recurrence:

- Procedures OP/1 (2)/A/6250/03A have been revised to state that when steam generator level stops increasing in fill rate, continue filling for 20 minutes then secure feeding by closing valves. These procedures have also been enhanced by adding a step which states that while establishing wet lay up conditions in a steam generator, all condensate boosters pumps shall be off.

- The intent and purpose of the initial conditions in procedures was reemphasized to the operators during the requalification training classes held October 12 to December 18, 1992.

- A Procedural Compliance Group was formed by the licensee to address situations in which procedures are not properly used. This group developed a number of initiatives which included the development of a procedure adherence training tape which was incorporated in the site training program for all site employees. Nuclear System Directive 704, Technical

Procedure Use and Adherence, which provides management expectations for technical procedure and adherence for the staff at Duke Nuclear Stations has also been issued.

The inspectors reviewed PIP Nos. 1-M91-0177 and 1-M92-0087, Procedures OP/1 (2)/A6250/03A, and Nuclear Policy Manual Section 704, and verified that the above corrective actions had been completed.

c. (Closed) Violation 369, 370/92-13-02, Failure to Meet TS for Auxiliary Feedwater Pumps.

The licensee responded to this violation by letter dated July 10, 1992. This violation was also discussed in an Enforcement Conference which was held in the Region II Office on June 8, 1992. The violation involved excessive air in the Nuclear Service Water System (RN) to the Auxiliary Feedwater (CA) System. The RN system is the assured makeup flow to the CA system. To prevent recurrence, the inspectors verified that the licensee has taken the following corrective actions:

- McGuire Engineering personnel coordinated the installation of additional vents to the RN system to improved flexibility in the venting of the system to establish water solid condition in the system.

- The previous temporary venting system installed at 1RN-835 and 2RN-815 to assure operability of the CA system were upgraded to a permanent venting system.

- McGuire Engineering developed a lesson learned package, RN/CA Air Entrainment Affecting CA Pump Operability, on this event which was communicated with appropriate personnel.

- A synopsis of the lessons learned package was incorporated into the design input/criteria guidance of McGuire's Modification Manual.

The inspectors reviewed PIPs 0-M93-0115 and 0-M93-0183, Training Package - RN/CA Air Entrainment Affecting CA Pump Operability (including training attendance lists), and Modification Manual Section 6.5.3, Design Input/Criteria, Check List Item 32 and verified that the corrective actions had been completed.

d. (Closed) Inspector Follow-up Item 369, 370/92-24-03, Follow-up of Valve Interaction Evaluation.

This item was opened to follow-up on the licensee's corrective action for LER 369/90-22, Both Trains of the Residual Heat Removal System Were Inoperable During Quarterly Valve Stroke Time Testing Because of Improper Scheduling. The LER was issued when the licensee discovered that cycling Valve 2NI136B could degrade the Residual Heat Removal System in the event of a large break LOCA.

The System Engineering group performed Design Study MGDS-0188 on the stroke time testing for the safety related valves at McGuire and judged that the quarterly valve stroke time testing on these valves presented no operability concerns. The only corrective action required from this study was to revise procedure OP/0/A/6450/11 to show that Valve 1YC-37 is normally closed.

The inspectors reviewed PIP 0-M90-0180 which documented the completion of the licensee's corrective action on this item and verified that the corrective actions on this item had been completed.

e. (Closed) Inspector Follow-up Item 369, 370/92-24-04, Review of Licensee's Investigation for Sealing Throttled Valves.

The inspectors previously identified approximately 50 valves in the Control Room Ventilation (VC) System and Chilled Water (YC) System, which were partially opened and throttled to obtain the required flow in the system. Quick verification that these valves are in the correct position was not possible without fully opening and reopening these valves. Therefore, to address the inspectors' concern, the licensee performed an investigation to determine if these throttled valves should be provided with tamperproof seals.

A Study was conducted by the licensee's System Engineering group of all safety related systems which employee throttle valves and dampers to ensure that adequate controls existed for maintaining these throttled valves and dampers in their preset position. The study found that as a whole, adequate controls existed on maintaining the throttled valves and dampers in their pre-set position. For example, a number of components were throttled during flow balance surveillance activities and the positions are documented in the Control Room Data Book and by other procedures. Tags are provided on these valves to provide notification that the valves are not to be manipulated without first contacting the Performance Duty Engineer or the Shift Manager. Other throttled valves are maintained in position by stem locknuts which requires a special wrench to loosen/tighten. A notification tag is also provided for these valves. The licensee's evaluation found that there was no history of these valves being mispositioned such that the operation of the system was affected.

The licensee's evaluation determined that no additional means to control throttle valve position were justified and, therefore, were not required. This resolves the inspector's concerns.

f. (Closed) Violation 369, 370/92-28-02, Failure to Follow Procedures for the Problem Investigation Process (PIP).

The licensee responded to this violation by letters dated February 11, 1993, and March 25, 1993. The violation involved completing the review of PIP report without identifying a root cause or actions necessary to prevent recurrence.

The following corrective actions have been implemented by the licensee to prevent recurrence:

- "Root Cause" training is now required for all personnel generating a cause analysis for a PIP and for all personnel who approve the identified Root Causes.

- For significant events, PIP Section III, Problem Evaluation, must be approved by a Section Manager, Superintendent or higher level manager. Section III of the PIP includes the root cause determination and proposed resolutions. The corrective actions are developed from the proposed resolutions. Less significant events can be approved by any Division Manager or designee.

- Outstanding items processed through the old problem investigation review process will be reviewed and signed by the Safety Review Group to ensure proper root causes have been identified.

- Less significant events are to be routed to the Safety Review Group and this group will periodically audit a sample of these events to ensure that proper root causes are being assigned.

The inspectors reviewed PIP 0-M93-0044 which documented the corrective action for this item and verified that the corrective actions had been completed.

g. (Closed) Unresolved Item 369, 370/93-18-07, Operation of unit 2 systems and equipment - unplanned mode change.

This unresolved item was identified as Violation I. A. in an enforcement letter to the licensee dated January 13, 1994. The licensee responded in a letter, dated February 10, 1994.

The following corrective actions have been implemented by the licensee:

1. Operations personnel developed a reading package describing the event. Communication breakdowns that led to the event were addressed in the reading package, which was reviewed by all licensed operators and staff personnel before October 1, 1993.

2. A case study training lesson was developed and presented in licensed operator requalification. The entire event was

examined with emphasis on communications and teamwork. This also included simulator training on cooldown and depressurization with excess letdown in service. Case study training was completed on December 16, 1993.

3. Operations Management personnel modified the format of the Operations Shift Briefings to shorten them, reduce the number of persons involved and set expectations for participation. If any of the key members (SS, C/R SRO, Unit SRO, ROATC, or BOP) is diverted from the briefing, it is suspended until that person returns.

4. The individual RO was taken off of shift for a four-week period and assigned to a training instructor for mentoring on proper communication. Various tasks were assigned to the individual to enhance his understanding of proper communications. He was returned to service on November 13, 1993.

5. Bold lines have been placed on the procedural Heat-up and Cool-down Curves at the mode change temperatures as further reminders to the operators in the control room.

6. The licensee determined that alarms from the Operator Aided Computer (OAC) to warn of impending mode changes associated with primary system temperature are needed. The OACs from both units will be replaced during scheduled refueling outages in 1995 and 1996. Enhancements made during these replacements will resolve this problem.

The inspectors reviewed these corrective actions and verified that the corrective actions were adequate and appropriate.

h. (Closed) Unresolved Item 369, 370/93-18-08, Operation of unit 2 systems and equipment - TS surveillance requirements on the ice condenser inlet door position monitoring system.

This unresolved item was identified as Violation II. in an enforcement letter to the licensee dated January 13, 1994. The licensee responded in a letter, dated February 10, 1994.

The following corrective actions have been implemented by the licensee:

The annunciator response procedure for "Ice Condenser Lower Inlet Doors Open" has been changed to give the operators guidance under the following conditions:

EITHER perform a qualitative assessment of the Inlet Door Position Monitoring System and log that assessment, or log the Inlet Door Position Monitoring System inoperable and apply the action statement.

No additional corrective are planned.

i. (Closed) LER 369/92-08, Unit 1 Experienced a Reactor Trip/Turbine Trip as a Result of a Defective Procedure.

On July 26, 1992, while operating at 99.5 percent power, Unit 1 experienced a Reactor/Turbine trip on over temperature delta temperature (OTDT). The trip was caused by the loss of Main Feedwater Pump Turbine 1B condenser vacuum which resulted in a load rejection or Turbine runback. However, due to an electrical problem with an amplifier card, which processes reactor coolant average temperature (T-ave) signal to the condenser steam dump valves, the T-ave exceeded the OTDT setpoint in two of the four channels. This caused the reactor to trip. The licensee's investigation revealed that the condenser steam dump valves did not operate at the correct time due to improper calibration of the mixing amplifier card. The licensee implemented the following corrective actions to prevent recurrence:

- Component Engineering personnel evaluated the procedures used to test and calibrate the Steam Dump Control System and found that the calibration procedure did not specify the type of portable power supply test equipment to be used. Further evaluation and tests found that some types of portable test equipment produced an input test voltage signal higher than would normally be transmitted by the Steam Dump Control System. The inconsistent voltages produced during the testing activities caused the system to be improperly calibrated. To correct the problem, Procedure IP/0/B/3001/03, Steam Dump Control Calibration, has been revised to specify the type of portable test equipment to be used and to provide dynamic acceptance criteria.

- Component Engineering personnel inspected Main Feedwater Heat Exchanger Isolation Valves 1RC41, 1RC43, 2RC41 and 2RC43 for proper stem and gear alignment to ensure full open position. This work was accomplished by work request Nos. 9205226, 9205227, 9205229 and 9250230.

- System Engineering personnel conducted a review of similar valves on Units 1 and 2 for comparable arrangement and condition. No similar valves were identified which if mispositioned could cause a unit trip.

- System Engineering's investigation as to why Valve 1RC43 was not in the full open position did not identify any procedural deficiencies or any other possible causes.

The inspectors reviewed PIP 1-M92-0123 and back-up data including the System Engineering valve evaluation report (1-M92-0123C) and verified that the corrective actions for this LER had been completed.

j. (Closed) LER 369/92-10, Unit 1 Containment Integrity was Violated Because of a Design Deficiency, Equipment Failure, and an Unknown.

On September 16, 1992, McGuire Safety Review Group personnel were conducting an investigation for the resolution of a potential problem identified with Unit 1 mechanical penetration M-309. This penetration contains the piping from the Nuclear Sampling (NM) System. The piping system through the penetration consists of a single pipe supplied from two sampling loops, Loop 1 and Loop 4. Each of the two sampling loops lines is provided with a containment isolation valve which is located within the Containment Building. The outside containment isolation valve for the single pipe line is located in the Auxiliary Building. A flow element, NMFE5260, is installed between these isolation valves. The piping between these isolation valves is considered part of the containment isolation boundary. The flow element was connected to the piping by means of flange connections which required a gasket to seal the flange faces. The Safety Group's investigation found that on July 20, 1984, penetration M-309 developed a steam leak at the flange connection. This leak was small. Repairs on this leak were not completed until December 6, 1984, and the repairs were not accepted by operations personnel until December 13, 1984. This penetration was not logged as inoperable during this time as it should have been. TS Section 3.6.1.1 requires containment integrity during Modes 1, 2, 3, and 4. Without containment integrity, integrity must be restored within 1 hour or the unit must be in at least Mode 3 (Hot Standby) within 6 hours and in Mode 5 (Cold Shutdown) within the following 30 hours. This LER documented that Unit 1 was in violation of the TS during the time that the penetration was inoperable, i.e. flange gasket seal was leaking.

To prevent recurrence, the flange connections for flow element NMFE5260 have been replaced by welded pipe connections. The inspectors reviewed PIP 0-M92-0118 and verified that this work had been completed. The licensee's investigation also identified several additional containment penetrations that contained flange connections. The investigation verified that appropriate administrative procedures were in place which identified that these flange connections were part of the containment penetrations and that these penetrations were required to be retested following any maintenance activity.

k. (Closed) LER 369/92-11, A TS Violation Occurred Due to Inoperable Engineered Safety Features Actuation System Instrumentation.

During the performance of routine maintenance on the Auxiliary Feedwater (CA) pressure switches on December 10, 1992, two pressure switches were found to be outside of their specified setpoint limits. The purpose of these pressure switches is to detect the loss of normal pump suction sources and to change the suction to the assured RN supply. This ensures that a long term supply of water is available to mitigate the consequence of a design basis event. The pressure switches outside of their setpoint limits rendered the Unit 1B Motor Driven CA pump and Unit 2 Turbine Driven CA pump inoperable. These pressure switches had previously been recalibrated on October 29-30, 1992.

TS 3.3.2 Action Item (a), which requires an inoperable CA pump to be restored to operable service within 72 hours or place the unit in at least Mode 3 within the next 6 hours and in Mode 4 (Hot Shutdown) within the following 6 hours, was not satisfied during this period. Therefore, this event was reported to the NRC and corrective action to prevent recurrence was initiated. The corrective action included replacement of the original pressure switches with switches from another manufacturer, Static O-Ring, Inc. These two pressure switches were installed and monitored for two months. The new switches were found to be superior to the original switches. Therefore, all of the CA pressure switches were replaced with the Static O-Ring switches. The licensee is reviewing this item for generic applicability at Catawba and Oconee.

The inspectors reviewed PIP 2-M92-0515 along with the supporting documentation and verified that this modification had been completed.

l. (Closed) LER 370/92-10, Unit 2 Experienced A Reactor Trip/Turbine Trip As A Result of An Equipment Failure.

On August 24, 1992, while operating at 100 percent power, Unit 2 experienced a Reactor Trip/Turbine Trip. The trip was caused during the replacement of a failed indicator lamp on the Unit 2 Main Control Board in the circuit for the Generator Field Breaker. The contacts on the indicating lamp base shorted electrically when the operator replaced the failed lamp. This caused the Field Breaker to open which caused the anticipatory protection circuit to pick up, Generator Power Circuit Breaker to open, initiating a full load rejection; however, the turbine runback from the load rejection was not successful. The indicating lamp is in series with the trip coil and a short across the lamp base will cause the trip coil to energize. Plant systems responded properly to the trip transient.

The inspectors verified that the licensee had taken the following corrective action to prevent recurrence:

- Following Component Engineering and Operations personnel evaluation of this event, a different type tool was provided for the removal and replacement of failed indicator lamps. Operations personnel were trained during the January 5 - February 2, 1993, in the proper use of the new lamp removal/installation tool and have been directed to use this new tool in the removal and installation of lamps from the Main Control Boards.

- Component Engineering personnel have conducted an evaluation of the Main Control Board indicator lamps and identified a different type of indicator lamp to replace the existing lamps. The proposed lamps are of a higher quality than those presently being used. The proposed lamps are currently being evaluated by the Electrical Engineering and Operations groups. If found to be acceptable, the new lamps will be installed under work request No. 93090243-1 and Temporary Modification No. 6395, with installation to be completed by early 1995.

7. Exit Interview (30703)

The inspection scope and findings identified below were summarized on March 17, 1994, with the Station Manager and member of his staff. The following items were discussed in detail:

Violation, 50-369,370/94-06-01, Failure to Survey Material Leaving RCA. (paragraph 4.f)

Non-Cited Violation, 50-369,370/94-06-02, Inadequate maintenance procedures causing missed technical specification surveillance. (paragraph 3.b)

Unresolved Item, 50-369/ 94-06-03, Maintenance work procedure for repair of 1NI-94 check valve.(paragraph 4.e)

Follow-up Item 50-369/ 94-06-04, Repair of main feedwater isolation valve, 1CF-35 (paragraph 4.d)

The licensee representatives present offered no dissenting comments, nor did they identify as proprietary any of the information reviewed by the inspectors during the course of their inspection. The licensee was informed by the inspectors that the items discussed in paragraph 6 were closed.

8. Acronyms and Abbreviations

BS	-	Backshift
CA	-	Auxiliary Feedwater System
CAD	-	Control Access Door
CMWG	-	Component Mispositioning Working Group
GET	-	General Employee Training

gpd	-	gallons per day
gpm	-	gallons per minute
HP	-	Health Physics
IAE	-	Instrumentation and Electrical
ESF	-	Engineering Safety Features
LCO	-	Limiting Conditions for Operations
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
MSIV	-	Main Steam Isolation Valves
MW/min.	-	Megawatts per minute
NC	-	Reactor Coolant System
ND	-	Residual Heat Removal System
NIS	-	Nuclear Instrumentation System
NLO	-	Non-licensed Operator
NRC	-	Nuclear Regulatory Commission
OAC	-	Operator Aided Computer
OMP	-	Operations Management Procedure
OTDT	-	Over Temperature Delta Temperature
PIP	-	Problem Investigation Process
psig	-	pounds per square inch gauge
RCA	-	Radiological Control Area
RCS	-	Condenser Circulating Water System
RI	-	Resident Inspector
RN	-	Nuclear Service Water System
RO	-	Reactor Operator
ROATC	-	Reactor Operator At The Controls
RP	-	Radiation Protection
RWP	-	Radiation Work Permit
S/G	-	Steam Generator
SRI	-	Senior Resident Inspector
SRO	-	Senior Reactor Operator
TS	-	Technical Specification
VC	-	Control Room Ventilation System
VCT	-	Volume Control Tank
VL	-	Reactor Building Ventilation System
WO	-	Work Order
YC	-	Chilled Water System