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

Report Nos. 50-369/95-29 and 50-370/95-29

Licensee: Duke Power Company
422 South Church Street

Docket Nos.: 50-369 and 50-370

License Nos.: NPF-9 and NPF-17

Facility Name: McGuire Nuclear Station 1 and 2

Inspection Conducted: December 17, 1995 - January 27, 1996

Inspectors: S. B. Rudisail 2/15/96
for G. Maxwell, Sr. Resident Inspector Date Signed
per telcon
G. Harris, Resident Inspector
M. Sykes, Resident Inspector
S. Rudisail, Project Engineer
N. Economos, Reactor Inspector (paragraphs 3.1, 3.2, 3.3, 3.4, 3.5, 3.6, and 3.8)
F. Wright, Reactor Inspector (paragraph 5.2.1, 5.2.2, 5.2.3, 5.2.4, and 5.2.5)
L. Stratton, Safeguards Inspector (paragraph 5.1)
J. Kreh, Emergency Preparedness Inspector (paragraph 5.3.1)

Approved by: Richard J. Freudenberger 2/22/96
for R. V. Crlenjak, Chief, Branch 1 Date Signed
Division of Reactor Projects

SUMMARY

Scope:

Inspections were conducted by the resident and/or regional inspectors in the areas of plant operations, maintenance, engineering and plant support. Some of the inspections were conducted during backshift hours. Backshift inspections were conducted on December 17, 23, 24, 26, 27 and 28, 1995 and January 11, 15, 18, 22, 23 and 25, 1996.

Enclosure

Results:

Plant Operations Licensee control of plant conditions during Unit 1 mid-loop reduced inventory operations was comprehensive with adequate awareness of shutdown risk (paragraph 2.2). Licensee communication, coordination, procedural adherence, equipment performance, and safety focus was good during fuel offload and reload (paragraph 2.3). The licensee has completed cold weather preparations in anticipation of severe weather (paragraph 2.4). The licensee has proposed several improvements to the current Nuclear Safety Review Board's methods of operation (paragraph 2.6). The licensee has implemented several initiatives that should improve the root cause analysis process (paragraph 2.7) Operators manually actuated auxiliary feedwater after steam was lost to the Unit 2 main feedwater pump turbine. The loss of steam was due to an inadequate procedure. A Non-Cited Violation was identified (paragraph 2.8.1).

Maintenance Maintenance on an airline check valve was observed. Procedures were adequate and personnel were well trained and knowledgeable to perform their assigned tasks (paragraph 3.1). Surveillances observed were performed in accordance with well written procedures. Diesel generator 1B and safety injection pump 2B appeared to be adequately maintained as they both performed well within acceptance criteria (paragraphs 3.3 and 3.4). The main steam safety valves responded well to setpoint pressure testing requirements, however IFI 369,370/95-29-03: MSSV testing while the plant is in Mode 1 was documented to review the licensee's decision to change the time of testing from outage to power operation (paragraph 3.2). The safety injection pump 1B rotating element was replaced to address concerns identified in a recent 10 CFR Part 21 Notification (paragraph 3.5). Eddy Current examination of S/G tubes resulted in fewer than expected number of tubes requiring repair. No new failure mechanisms were identified. A total of 307 tubes were plugged. Following this fuel cycle, these steam generators will be replaced. A review of ISI records of safety related welds showed that the records were complete and accurate, examinations were consistent with applicable code requirements and certifications of equipment and personnel were in order (paragraph 3.6.3). Several unexpected power disruptions to selected motor control centers and

lighting panels occurred during 1EOC10 (paragraph 3.7).

Engineering

The licensee has begun removal of Thermo-Lag fire barrier material from the station. The complete removal of the material is currently scheduled to be completed during the upcoming Unit 2 End-of-Cycle 10 (2EOC10) outage (paragraph 4.1). The 1A and 1B reactor coolant pump seal housings were modified to improve performance (paragraph 4.2). The licensee has completed a design basis document program that should significantly improve the licensee ability to ensure that the design basis of specific plant components and systems is maintained (paragraph 4.3).

Plant Support

Escorts and visitors were knowledgeable of their responsibilities and the licensee was in compliance with their procedures and Section 6.2.2 of the approved Physical Security Plan (paragraph 5.1). The licensee's RP program was adequately managed and effectively implemented with all individual personnel exposures within 10 CFR Part 20 limits (paragraph 5.2). Outage planning, effective ALARA program activities and reduced outage lengths continued to reduce collective outage doses during refueling outages. Less than 128 man-REMs were recorded during the 1EOC10 outage (paragraphs 5.2.1, 5.2.2, 5.2.4, and 5.2.5). A Non-Cited Violation (NCV) concerning inadequate postings of radiation areas was identified (paragraph 5.2.3). A special inspection was conducted to review the licensee's implementation of changes to the program for respirator qualification of emergency response personnel as provided in Revision 95-2 of the Emergency Plan. The licensee had not actually implemented changes that appeared to decrease the effectiveness of the Plan as written (paragraph 5.3.1).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 8.

1.0 Persons Contacted

Licensee Employees

+Allgood, J., Safety Review Group
#Barbour, J., Manager Quality Assurance Technical Services
*Baxter, D., Operations Group
+Boyle, J., Work Control Superintendent
#*Cross, R., Technical Support Specialist
*Curtis, T., Engineering Group
@#*Dolan, B., Safety Assurance Manager
+#Geddie, E., Station Manager
@*Hasty, R., Emergency Planning Manager
+#*Herran, P., Engineering Manager
+Jones, R., Operations Superintendent
*Lindsay, A., Operations Training Manager
@#*McMeekin, T., Vice President, McGuire Station
+Nazar, M., Maintenance Superintendent
+Sherrill, B., Radiation Protection Supervisor
#Silvers, D., Maintenance Group
#Shupping, J., Manager, McGuire Steam Generator Maintenance
@+#Snyder, J., Manager, Regulatory Compliance
#Underwood, G., Quality Assurance Technical Support
*White, R., Training Manager

Other licensee employees contacted included operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC Resident Inspectors

@+#*Maxwell, G., Senior Resident Inspector
@+#*Harris, G., Resident Inspector
@+#*Sykes, M., Resident Inspector

+Attended Exit Interview on January 12, 1996
#Attended Exit Interview on January 18, 1996
@Attended Exit Interview on January 25, 1996
*Attended Exit Interview on January 26, 1996

2.0 OPERATIONS (NRC Inspection Procedure 71707, 40500, 71714, and 60710)

Throughout the inspection period, inspectors conducted facility tours to observe operations and maintenance activities in progress. The tours included entries into the protected area and radiologically controlled areas of the plant. During these inspections, discussions were held with operators, radiation protection technicians, instrument and electrical technicians, mechanics, security personnel, engineers,

supervisors, and plant management. Some operations and maintenance activity observations were conducted during backshift inspections. The inspectors attended licensee meetings to observe planning and management activities. The inspections confirmed Duke Power Company's compliance with 10 CFR, Technical Specifications (TS), License Conditions, and Administrative Procedures. No cited violations were identified.

2.1 PLANT STATUS

Unit 1 entered the reporting period while in End-of-Cycle 10 (1EOC10) refueling outage. The duration of the outage was 42 days. The unit was returned to power operations on January 25, 1996. Major activities that were completed during the outage included: main condenser expansion joint replacement, inspection of the B and C low pressure turbines, steam generator maintenance, fuel assembly inspections and extensive primary and secondary valve repair and replacement. Major plant changes completed during 1EOC10 included: limits on Boron concentrations were increased, reactor vessel head vent valves were replaced, a new loose parts monitor was installed, the containment ventilation system was modified, and the need for the use of thermo-lag insulation was eliminated.

Unit 2 entered the reporting period in Mode 5 following a forced outage to replace leaking reactor vessel head vent valves 2NC272, 2NC273, 2NC274, and 2NC275. Following the replacement and testing of the valves, the unit was returned to power operation on December 23 and operated essentially at 100 percent power for the remainder of the reporting period.

2.2 Unit 1 Reduced Inventory/Midloop Operations

Unit 1 entered reduced reactor coolant system inventory conditions in order to install steam generator loop nozzle dams and to remove access manway covers. Prior to these operations and during reduced inventory conditions, the inspectors reviewed the schedule for entering reduced inventory conditions. The inspectors reassessed the planned work scheduled for the period of reduced/midloop conditions to identify any activity that might cause reactor coolant system level disturbances. The inspectors discussed the established controls and procedures used during these conditions with Work Managers, Operations Shift Supervisors, and Reactor Operators.

Briefings were conducted by licensee management prior to entering reduced inventory to prepare the shift for the infrequently performed evolution. Procedural changes, management expectations, and safety concerns were communicated during the briefings and were reemphasized to the operating shifts during shift turnover briefings. "Defense in Depth" sheets, which assess plant status based on reactivity, decay heat removal capability, containment integrity, reactor coolant system inventory, power availability, and spent fuel pool cooling were reviewed

and updated, if necessary, during each shift by the Shift Work Manager. This information was reviewed and discussed during the daily outage team and station management meetings. The inspectors routinely verified the accuracy of the information during daily control room visits.

During the reduced inventory/midloop operations, two main power sources were available through the auxiliary transformers and two emergency diesel generators were available. The reactor coolant system temperature was monitored by using core exit thermocouples and residual heat removal system inlet temperature. Two independent indications of reactor coolant system level were in place.

Independent reactor coolant system makeup methods were available which included both trains of the residual heat removal system, one train of safety injection, one train of charging and a gravity drain feed path from the refueling water storage tank. The inspectors verified that controls were in place for an adequate reactor coolant system vent during reduced inventory/midloop conditions. These controls were provided in procedure OP/1/A/6100/02, Controlling Procedure for Unit Shutdown. A containment closure coordinator was assigned to Unit 1 to monitor the status of all closure exceptions and ensure that they could be promptly closed, if required.

In summary, the inspectors reviewed the licensee's administrative controls for entering reduced inventory/midloop condition as well as the preparations for and draining of the reactor coolant system. As a result of the reviews, the inspectors considered licensee controls of plant conditions to be comprehensive and appropriately implemented. The inspectors verified that the licensee demonstrated adequate shutdown risk awareness and sensitivity.

2.3 Core Unload/Reload - Unit 1

The inspectors witnessed core unloading activities in the control room, reactor building, and fuel handling building and reviewed procedures governing these activities. The inspectors determined that operations and engineering personnel adequately coordinated activities in the fuel handling building and reactor building. During core unloading and reloading, good repeat back communication was observed between the control room, spent fuel building, and reactor building crews. Core unloading and reloading operations were conducted in accordance with procedures PT/0/A/4150/37, Total Core Unload, and PT/0/A/4150/33, Total Core Reload. The inspectors noted that several improvements had been made to these procedures. However, some problems were experienced with the spent fuel and reactor building cranes. The licensee has formed a special task force to evaluate ways to improve the equipment reliability.

Interviews were conducted with members of the spent fuel and reactor building crews. These individuals were aware of the safety significance

of their duties as well as other plant activities that could have an adverse impact on the core unloading and loading process. Significant event briefings were held by the licensee prior to conducting refueling operations.

During visual inspections of the lower core support plate following core offload, the licensee discovered several small pieces of copper wire. Copper wires were also removed from this area during two previous Unit 1 outages. The copper wires were identified as residual material from the kinetic welding process formerly used for steam generator tube plugging. The material was removed prior to core reload.

As a result of the procedure reviews, observations, and discussions, the inspectors concluded that licensee communication, coordination, procedural adherence, conservative decision making, determination of roles and responsibilities, and safety focus was good during core offload and reload activities.

2.4 Cold Weather Preparation

The inspectors evaluated station cold weather preparations. The inspectors verified that procedures were adequate to ensure that exposed instrumentation and piping was protected during cold weather months. The licensee used several methods of freeze protection that included electrical heat tracing and insulation. The inspectors determined that the heat tracing and insulation should provide adequate cold weather protection. However, because there were no local indicators, the inspectors could not readily determine equipment operability. The inspectors discussed this observation with Operations management and were informed that operators were equipped with portable test equipment to determine adequacy of freeze protection equipment, while performing rounds. The inspectors also reviewed licensee guidance that was provided to operators responding to freeze protection annunciators. The inspectors determined adequate actions were included to prevent freezing in the absence of a freeze protection system. Based on the inspectors observations and review of station cold weather protection procedures, the inspectors concluded that systems, in general, were adequately protected; however, the program did not include details of responsibilities for implementation.

2.5 Failure of Component Cooling Water Isolation Valve 1KC1A

On January 19 during system flow balancing, control room operators could not fully open component cooling water auxiliary building non-essential header return isolation valve, 1KC1A. A review of motor power monitoring data showed the valve to have a high running load. The licensee determined that this could be the result of a degraded shaft hub seal. Based on Generic Letter 89-10 calculations, there was more than adequate torque available to close the valve. However, further degradation of the hub seal had apparently increased valve binding and

rendered the actuator incapable of closing the valve. The valve replacement could not be completed because a spare valve was not available. Because of the inoperability of 1KC1A, scheduled preventive maintenance and surveillance cannot be completed on the B train of component cooling water system until the valve is repaired and/or replaced. The valve is currently in its safe position (closed) with power removed to prevent inadvertent operation.

A Plant Operations Review Committee meeting was held to review the immediate and long term corrective actions. The inspectors noted that the licensee has evaluated constraints associated with long term operation of the B train of component cooling water. Further, an alternate alignment to allow A train cooling of the auxiliary building non-essential header was developed and supported by a 10 CFR 50.59 evaluation. The operating, abnormal, and emergency procedures were modified to reflect the operational limits associated with 1KC1A being closed as well as the alternate alignment for auxiliary building-essential header cooling. The licensee also identified a need to review testing procedures associated with the component cooling water system to identify any potential concerns. The inspectors concluded that the licensee was apparently taking appropriate actions to compensate for the degraded component until the valve can be replaced or repaired.

2.6 Nuclear Safety Review Board

The licensee has proposed several improvements to the current Nuclear Safety Review Board (NSRB). The improvements are the result of a licensee self-assessment that showed the current NSRB practices were not consistent with the industry in certain areas. The areas identified as needing improvement included meeting frequency, board composition, and Board oversight through internal audits and assessments. The licensee has implemented changes to the current NSRB to address the above issues that includes consolidation of the three nuclear site boards, addition of Site Vice President and Station Managers to the NSRB, quarterly board meetings, schedule enhancements, and focus team reviews of selected materials. The inspectors concluded that the changes should further improve the NSRB function and effectiveness.

2.7 Initiatives for Improving the Root Cause Program

The licensee contracted a vendor to perform an evaluation of the root cause analysis process. As a result of this effort the licensee has implemented several initiatives to improve the root cause analysis process. These initiatives included the following:

- New categories for human error, inappropriate action, organization, and programmatic failure modes

- Additional training for root cause evaluators

- New methodologies such as Stream Analysis and Organization and Programmatic Interface

- Numerical goals for number of root cause analysis

- Evaluation of root cause for each significant event

Other initiatives included improvements in common cause and apparent cause evaluations and cause code trending. The inspectors determined that these initiatives should improve the licensees root cause analysis process.

2.8 Close Out Issues

2.8.1 (Closed) LER 50-370/95-04: Manually initiated actuation of both unit 2 motor driven auxiliary feedwater pumps due to loss of auxiliary steam supply to the main feedwater pump turbine

On December 16, operators manually actuated both motor driven auxiliary feedwater pumps to maintain steam generator levels after auxiliary steam to the main feedwater pump turbine was isolated. At the time of the event, Unit 2 was in Mode 3 and the reactor operators were cooling to Mode 5 to allow repairs on the reactor vessel head vent valves. Unit 1 was in Mode 5 for scheduled refueling outage 1EOC10 and was being controlled by procedure OP/1/A/6100/02, Controlling Procedure for Shutdown.

Since both units were shutdown and incapable of supplying adequate steam to the necessary loads, one of the plant auxiliary electric boilers was being used to provide steam to both the Unit 1 and Unit 2 components. The Unit 1 reactor operators were performing various steps in procedure OP/1/A/6100/02. This procedure directed the Unit 1 operators to close the Unit 1 and Unit 2 auxiliary steam header isolation valve, 1AS74. Since both units steam loads were being supplied from the same auxiliary boiler, the steam supply to the Unit 2 main feedwater pump turbine was isolated. Unit 2 operators responded by manually actuating both motor driven auxiliary feedwater pumps to maintain steam generator levels. The error in closing valve 1AS74 was subsequently discovered and the valve was reopened to restore normal feedwater flow to the Unit 2 steam generators.

The licensee identified the event as a manual Engineered Safeguard Features actuation and made a four hour notification to the NRC in accordance with licensee procedure RP/0/A/5700/10, NRC Immediate Notification Requirements, and 10 CFR 50.72. The inspectors reviewed the circumstances surrounding this event and determined that controlling procedure OP/1/A/6100/02 did not originally recognize the interaction of systems and components for this particular plant configuration. Subsequent reviews and revisions of the procedure also failed to recognize the procedural deficiency.

The inspectors concluded that the failure to perform adequate verification and validation of procedure OP/1/A/6100/02, Controlling Procedure for Unit Shutdown, was a violation of McGuire Technical Specification 6.8.1. However, because of the low safety significance of this event and the prompt corrective actions taken by the licensee to develop a more thorough process to aid in the prevention of similar events. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. For tracking purposes the item will be identified as a Non-Cited Violation, NCV 50-369,370/95-29-02: Loss of steam due to an inadequate procedure. The condition was also documented by the licensee LER 50-370/95-04. Based on the inspectors review and evaluation, the LER is also closed.

2.8.2 (Closed) IFI 50-369,370/94-30-01: Refueling Issues

The inspectors previously noted several discrepancies with the licensees conduct of refueling operations. These discrepancies included the monitoring of source range instrumentation, sampling of spent fuel pool boron concentration, refueling equipment reliability, key control, procedure adequacy, refueling equipment modifications, communications refueling personnel roles and responsibilities, and monitoring of spent fuel pool level and temperature. Based on a review and implementation of licensee corrective actions and direct observations of refueling operations during the 1EOC10 outage, the inspectors considered this item closed.

3.0 MAINTENANCE (NRC Inspection Procedures 62703, 61726, 73052, 73755 and 92702)

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.

The selected tests and maintenance activities included:

Procedure/Work Order	Equipment/Test
PT/2/A/4600/01	Rod Control Cluster Assembly Movement Test
PT/0/A/4600/77	Full Length Rod Control Cluster Assembly Drop Timing

PT/1/A/4206/10	Residual Heat Removal Injection Test (Acoustic Magnetic Check Valve Test)
PT/0/A/4600/016A	Fire Detection System Operational Tests
PT/1/A/4206/15A	1A Safety Injection Pump Head Curve Performance Test
TT/0/B/9100/484	Rod Control Timing Verification Test
PT/1/A/4200/22	ND Suction and Automatic Swapover Timing Test and Functional Verification
PT/2/A/4200/28B	Train B Slave Relay Test
PT/1/A/4206/15B	1B Safety Injection Pump Head Curve Performance Test and Acceptance Testing of Various NI Check Valves
PT/0/A/4150/28	Criticality Following a Change in Core Nuclear Characteristics
PT/0/A/4150/10	Boron Endpoint Measurement
PT/0/A/4150/11A	Control Rod Worth Measurement: Rod Swap

The inspectors concluded that the above tests were conducted in accordance with the procedures. No cited violations or deviations were identified.

3.1 On-line Repairs to Check Valve 2VG116

Prior to this inspection the licensee had replaced the air dryers and associated check valves 2VG115 and 116 to 2A diesel starting air system. Following this replacement, the licensee noticed that the compressor feeding one of the two lines began to come on line more often than expected (i.e., approximately twice per shift). While monitoring this problem, the second compressor began to cycle in the same manner. The licensees investigation revealed that the replacement valves were failing to seat properly causing a loss of air pressure in the line. This caused the compressor to start and reestablish line pressure.

The inspector observed the disassembly and inspection of valve 2VG116 and associated disk. The maintenance work on the subject valve was performed under work order #95096495. The licensee checked dimensions to verify tolerances and inspected the seat for imperfections. Following discussions with the vendor, Anchor Darling Valve Company, the licensee machined off a small amount of material from the disk stem which allowed the valve to seat properly, which fixed the problem. A post maintenance test disclosed that the valve was functioning properly as there was no evidence of further leakage.

3.2 Performance Test PT/0/A/4250/01: Main Steam Line Safety Valve Setpoint Test, Unit 1

The purpose of this surveillance test was to verify that the main steam code safety valves relieved at the proper set point pressure. Controlling documents as indicated in the subject procedure included Technical Specifications (TS) 3/4.7.1 and Table 3.7-3 and, ASME Section XI IWV-3500. By review of these documents, the inspector noted that reference to IWV-3500 was inappropriate in that the code of record, Section XI 1989 Edition, references ASME/ANSI, OM (Part 10) as applicable for testing of safety-related valves. This was verified by review of the licensee's valve Inservice Testing Program in effect since March 1, 1994, which referenced ASME/ANSI, OM (Part 10). Through discussions with cognizant licensee personnel, the inspector ascertained that the subject procedure would be revised to reference the proper code.

As delineated in TS 3/4.7.1 Table 3.7-3, Loop "D" safety valves SV2 through SV6 were scheduled for testing during this outage. On December 12, 1995, with the unit operating at approximately 91 percent power, in Mode 1, the inspector observed the testing of valves SV2, SV3, and SV4. Through discussions with supervisory personnel, the inspector ascertained that valve SV5 had failed the test which resulted in testing four additional valves from Loop "B"; valves SV14 - SV17. The inspector observed testing of all the valves in this sample. By work observation and through document review, the inspector ascertained the following:

Five of the nine valves tested required more than the code minimum two consecutive openings at set point pressure and within code tolerance to qualify the tests as satisfactory. Valve SV2 was opened six times; one of the openings was aborted because of a partial lift. Valve SV5, which failed code acceptance criteria after three openings, required a field adjustment before it met acceptance criteria, for a total of five openings. Valves SV14, SV15, and SV17 were opened four times before meeting acceptance criteria.

The inspector expressed concern over the number of times that these valves were opened while the plant was operating in Mode 1. The inspector also expressed a concern that the repeated openings of these valves for test purposes increases the probability of a valve getting

stuck in the open position. A stuck open valve could challenge plant systems, put the plant into an emergency action condition, and could establish a potential for nuclear safety questions. By review of the licensee's 50.59 evaluation, the inspector ascertained that this test was previously performed in Mode 3 during unit startup, following a refueling outage and it took approximately six hours to complete. However, in order to reduce outage time and remove the test from a critical path window, the licensee decided to perform the test with the unit on-line. Prior to implementing this change, the licensee consulted with industry experts and other utilities who endorsed this approach. Site Engineering, Operations and other technical personnel reviewed the proposal and generated a 50.59 evaluation for Unit 2, dated November 21, 1994. Basically, the 50.59 evaluation states that this procedure change:

1. Does not involve an unreviewed safety question.

2. It is bounded by FSAR Chapter 15.1.4, Inadvertent Opening of A Steam Generator Relief or Safety Valve.

3. Does not adversely impact systems, structures or components important to safety.

Also, the inspector noted that the 50.59 evaluation places considerable emphasis on the short test time duration of the valve lift as being less than five seconds, that this test will not increase the probability of these valves to stick open, and that emergency procedures were in place to deal with a stuck open valve situation.

In conclusion, the inspector met with the licensee's representative and stated that the 50.59 evaluation did not appear to address this mode change (i.e., 3 vs. 1), from an impact to nuclear safety aspect. This position is derived from the fact that each time a main steam line safety valve is lifted, the potential exists for it to stick open as evidenced by the FSAR analysis, T.S.3.7.1.1 and the emergency operating procedures in place for such an event. Consequently, it would appear that the higher the number of lifts per valve, the higher the probability of it sticking open and therefore challenging plant systems.

In response to these concerns, the licensee issued two Problem Investigation Process (PIP) reports, O-M95-2201 and O-M95-2202. These PIPs request Engineering to review the benefit of changing this test from an outage to an on-line (innage) activity, and to have PORC evaluate the mode change from a nuclear safety aspect. More importantly it requests PORC to refine the review process such that it reviews activities being moved from outage to innage when they have a potential for impacting nuclear safety.

Following the close of this inspection, the inspector informed the licensee that this item would be identified as an inspector follow up

item (IFI) to allow for further review of responses to the above mentioned PIPs. IFI 50-369,370/95-29-03, MSSV testing while the plant is in Mode 1.

Except for the Mode change and the expressed concerns discussed above, the actual tests were performed in accordance with procedures and were consistent with code requirements. Personnel were adequately trained and knowledgeable of their assigned tasks. The activity was well planned and adequately supervised by cognizant personnel.

3.3 Performance Test PT/1/A/4350/36B: Unit 1 B Diesel Generator 24-Hour Run

This surveillance test was performed to verify that diesel generator 1B operates at 4300 KW to 4400 KW for two hours and then at reduced power, 3800 KW - 4000 KW for a period of 22 hours. After shutdown, the diesel was to be restarted within five minutes to prove hot restart capability. Applicable requirements by reference included TS 4.8.1.1.2e.8. Acceptance criteria included:

1. Accelerate to 95 percent speed ≤ 11.0 sec. (488 RPM)
2. Time from start to 4160 Volts, ≤ 11 sec.
3. D/G output between 374 to 458 volts
4. Frequency, 60 ± 1.2 Hz

The test-run began at 10:20 p.m. on December 14, 1995. The inspector observed the diesel during this test run, and noted that test parameters were consistent with procedural requirements. By review of test data during this time, and after the test, the inspector verified that the diesel met all the acceptance criteria delineated in the applicable procedure.

3.4 Performance Test PT/2/A/4206/01B: Safety Injection Pump 2B Performance Test

The purpose of this surveillance test procedure was to verify the operational readiness of safety injection pump 2B of Unit 2. Applicable acceptance criteria included TS 4.0.5 and 4.5.2, FSAR Section 6.3.2, 6.3.4 and ASME Code Section XI Subsection IWP, 1986 Edition.

The inspector reviewed the subject procedure for completeness, compliance with applicable code requirements and adequacy. On December 14, 1995, while the test was in progress, the inspector observed recording of inboard, outboard and axial vibration measurements, suction and discharge pump pressure readings, as well as pump flow rates. Associated instruments were noted for a review of calibration data. This review was performed and test results indicated the instruments were functioning within acceptance criteria. Test results were reviewed and found to be well within requirements. Trend data on previous tests were reviewed and it was determined that this pump has been operating well within the code acceptable range over the previous four years.

3.5 Maintenance Procedure MP/0/A/7150/44: Safety Injection Pump 1B Corrective Maintenance

The licensee completed replacement of the 1B Safety Injection pump rotating element. The original rotating element was removed from service and has been scheduled for disassembly and examination. The licensee performed this replacement in response to concerns identified in a 10 CFR Part 21 notification regarding a potential for pump failure as a result of inadequate heat treatment of pump components manufactured by the Pacific Pump Division of Dresser Industries (now Ingersoll-Dresser Pump Company) for Westinghouse, the vendor. The Part 21 addresses intermediate head injection pump components manufactured from 416 stainless steel that is susceptible to intergranular stress corrosion cracking in aqueous environments. Because of the importance of these pumps to plant safety, Westinghouse recommended that the affected pump components be replaced with parts currently recommended by Ingersoll-Dresser. Ingersoll-Dresser recommended replacing the components manufactured of 416 stainless steel with components manufactured of other series 400 stainless steel and having a hardness less than 40 Rockwell Scale C to reduce the susceptibility to stress-corrosion cracking.

The components affected by the Part 21 notification included the impeller locknut, pressure reducing sleeve locknut, and spacer sleeves. Rather than replacing the specific pump components affected by the Part 21 notification, the licensee decided to replace the entire rotating assembly in the intermediate head injection pumps. The replacement of the 1B rotating assembly completed the third of four scheduled replacements. The final rotating assembly replacement is currently scheduled for completion during the upcoming 2EOC10 outage.

The inspectors reviewed the controlling procedure MP/0/A/7150/44, Safety Injection Pump Corrective Maintenance, and witnessed portions of the rotating element replacement. Replacement of the pump rotating element was completed in accordance with the applicable procedure. Following the replacement, the inspectors witnessed the completion of PT/1/A/4206/15B, 1B Safety Injection Pump Performance Test. The pump performance was satisfactory and test acceptance criteria were met. The inspectors concluded that the new installation should improve safety injection system reliability.

3.6 Inservice Inspection (ISI) Unit 1

This was the 10th refueling outage for this Unit which is the third such outage of the second, 10-year interval. The inspector reviewed procedures and records indicated below, to determine whether ISI examinations had been conducted in accordance with applicable codes, procedures and regulatory requirements. Controlling documents for ISI activities included Technical Specifications 4.4.5.1-5 and The American Society of Mechanical Engineers Boiler and Pressure Vessel (ASME B&PPV)

Code,Section XI,1986 Edition. The licensee's Technical Support Group (TSG), was in charge of ISI examinations. Eddy-Current (ET), examinations of steam Generator (S/G) tubing was managed by the S/G Maintenance Group, assisted by TSG.

3.6.1 Review of NDE Procedures

The inspector reviewed the procedures listed below to determine whether they were consistent with applicable code requirements and regulatory commitments. The procedures were also reviewed in the areas of procedure approval, requirements for qualification of NDE personnel, visual acuity requirements and compilation of required records.

- Eddy Current Analysis Guidelines McGuire Station EOC-10
- Computer Data Screening Guidelines, Bobbin
- Resolution Analyst Guidelines
- MRPC Analysis Guidelines
- MRPC Plug Analysis Guidelines
- NDE-701 Rev.2 Multifrequency Eddy Current Examination of S/G Tubing at McGuire
- NDE-702 Rev.0 Eddy Current Data Screening Program
- NDE-703 Rev.4 Evaluation of Eddy Current Data for S/G Tubing
- NDE-707 Rev.2 Multifrequency Eddy Current Examination of Nonferrous Tubing Using a Motorized Rotary Coil
- NDE-708 Rev.2 Evaluation of Eddy Current Data for Nonferrous Tubing Using Motorized Rotating Pancake Coil (MRPC)
- NDE-713 Rev.1 Data Management Procedure and Responsibility in Support of Eddy Current Inspections
- NDE-714 Rev.0 Administrative Guidelines for Resolution of differences During Review of Eddy Current Data
- NDE-35 Rev.15 Liquid Penetrant Examination
- NDE-25 Rev.15 Magnetic Particle Examination Procedure and Technique
- NDE-680 Rev.1 (FC95-16) Ultrasonic Examination of Nozzle Inner Radius and Ferritic Pressure Vessels

- NDE-610 Rev.2 Ultrasonic Examination of Dissimilar Metal Welds and Austenitic Welds Using R/L Waves

3.6.2 Eddy Current (ET) Examination of S/G Tubing, Unit 1 Review and Evaluation of Data (73755)

As reported in previous Reports, 94-05 and 94-19, Unit 1 has experienced primary water stress corrosion cracking (SCC) of tubing in the rolled tubesheet region. This phenomenon is responsible for removing many tubes from service. Other causes include: tube wear, antivibration bar wear, SCC in the free span region on the cold leg, outside diameter SCC and circumferential SCC at the top of the tubesheet, in the rolled expansion region.

The scope of the ET examination of tubing in each of the four S/Gs was as follows:

Bobbin: 100% of the entire tube bundle, full length.

MRPC: 100% of tubing in the hot leg, 2" above and 3" below the top of the tubesheet.

20% of tubing in the cold leg 2" above and 3" below the top of the tubesheet.

100% of the U-Bend section, in rows 2 through 4

100% of all rolled Inconel 600 plugs on the cold leg and 10% of all rolled Inconel 690 plugs on the hot leg.

Data acquisition and analysis was performed in accordance with procedures identified earlier in this report. Regulatory Guide 1.83 July 1975, Code Cases N-401-1 and N-402 were applicable. Data acquisition was performed using the Zetec MIZ-30 data acquisition system.

By review of Analysis Guidelines and through discussions with cognizant licensee personnel the inspector ascertained that ET data was analyzed independently by primary analysts at McGuire. Secondary analysis was performed with aid of Zetec's computer data screening (CDS) system. CDS was performed and monitored by certified Level IIA or III analysts. Data analysis, resolution, management and administrative responsibilities were executed at McGuire. Other organizations, contracted to assist in primary and secondary analysis included Framatome, Rockbridge Technologies and Zetec. Examinations were performed using bobbin, MRPC and the relatively new Plus Point coil for detection of circumferential crack indications. The size of probes used varied with tube location, geometry and inspection scope.

A summary of tubes plugged during this outage by S/G and in total were as follows:

Steam Generator	Tubes Plugged	Total	%Plugged
A	49	819	17.52
B	88	805	17.22
C	70	898	14.93
D	100	945	20.22
Total	307	3267	17.47

Circumferential Cracking: Examinations on top of the tubesheet region using the MRPC and Plus Point coil probe revealed circumferential crack indications in the expanded roll region of the tubesheet. A total of 23 such indications were identified. Six indications were in S/G "A", 0 in S/G "B", 5 in S/G "C" and 12 in S/G "D". The licensee indicated that 19 of the 23 indications were visible during the previous (EOC-9) outage. Two of the remaining 4 indications were questionable and 2 were not visible during the last outage. One circumferential crack indication was in S/G "D", tube 36-93 and was located in a dent near the 8th tube support plate. The indication was contained within the dent which was approximately 1/4". The licensee evaluated this indication as not structurally significant. In addition, the inspector reviewed the final revision of the S/G Tube Repair List to verify that it had been reviewed and approved by appropriate personnel. Other documents reviewed for completeness and accuracy included receipt inspection reports and material certifications for Inconel 690 plugs and stabilizers assemblies.

3.6.3 Review and Evaluation of Visual, Surface and Volumetric ISI Data

Records of completed ISI examinations performed during this outage were reviewed for completeness and accuracy. Welds selected for this review included those requiring either surface, visual and volumetric examinations.

Item No.	Weld NO.	Examination	Coverage
B02.012.002	1PZR-9	UT	90%
B03.140.001	1SGA-Inlet	UT	75.93%
B03.140.002	1SGD-Outlet	UT	75.93%
B03.140.007	1CGD-Inlet	UT	75.93%
B05.040.002	1PZR-W2SE	UT	96.00%
B05.040.003	1PZR-W3SE	UT	90.00%
B03.140.008	1SGD-Outlet	UT	75.93%

B05.070.001	1SGA-Inlet	UT	48.6%
B05.070.002	1SGA-Outlet	UT	48.6%
B05.130.002	1NC1F-1-2	UT	48.6%
B05.130.003	1NCF-1-3	UT	48.6%
B09.011.053	1NCP-224-1	UT	<90%
B09.031.004	1NC47-WN8	UT	47.4%
B09.011.056A	1NC-128-2	PT	NRI
B09.011.058A	1NC-102-2	PT	NRI
B06.030.016-.019	RV Closure Studs	UT	100%
B06.031.019A	RV Closure Studs	MT	100%
B06.010.020	RV Closure Head Nuts	MT	100%
C05.011.012A	1ND133-1	PT	100%
C05.011.029A	1ND1F-87	PT	100%
C05.011.031A	1ND72-5A	PT	100%
B13.010.001*	1RPV-Interior	VT-3	100%

* This inspection completes the corrective action on the previously identified Violation 50-369/94-26-02, Missed VT-3 on Reactor Vessel Interior Surfaces. This violation was closed in NRC Inspection Report 50-369/95-09 based on review of corrective actions planned for the present outage.

In addition to this review the inspector reviewed certifications and calibration records for consumables and equipment used for surface and volumetric examinations. NDE personnel qualifications were reviewed for completeness and accuracy. Welds where the volumetric examination did not meet code minimum coverage were earmarked for code relief request as required by 10.CFR50.55a(g).

3.7 Temporary Low Voltage Power Disruptions During 1EOC10

During 1EOC10, unit 1 experienced several unexpected power losses to selected low voltage motor control centers and lighting circuits during preventive maintenance activities. In response, the licensee conducted a self assessment to evaluate the potential for an adverse trend in this area. A review of the outage schedule by the inspectors showed that

there were numerous preventive maintenance activities associated with 600 volt breakers that affected several load and motor control centers. This was a significant increase in the scope of electrical maintenance work over previous outages. The work scope change increased the potential for power losses to some of the essential plant loads. For example, while swapping the Unit 1 standby 600 VAC motor control center back to its normal supply after maintenance, a momentary loss of normal power to several important plant components occurred. Those components included station instrument air compressors, area radiation monitors, and control rod position indication. Also, refueling operations were halted because of actuation of the containment evacuation alarm when power was lost. Although a momentary power loss was expected, control room personnel were not aware of the overall effect of the temporary loss of power. An incomplete load analysis contributed to the operators' lack of awareness.

The licensees self assessment showed that although there was no adverse trend or common causes an increased attention to planning detail of electrical activities was warranted. The licensee has scheduled improvements in this area prior to the upcoming 2EOC10 outage. The inspectors determined that the licensee's self assessment was thorough and accurate and the recommended actions should eliminate recurrence.

3.8 Close Out Issues

3.8.1 (Closed) VIO 50-369,370/94-26-01: Failure to Provide Adequate Procedures and Administrative Controls for S/G Tube Repairs.

Corrective actions taken by the licensee on this violation were reviewed and documented in Report No. 369,370/95-09. In addition to the corrective actions reviewed, the inspector reviewed recommendations contained in an internal report issued by a Task Group formed to examine S/G maintenance activities. While most of the recommendations had been implemented, at the time of the review, a few required additional work before full implementation could be achieved. These items were documented in Report No. 369,370/95-09 and are identified in this report for record purposes. These items are as follows:

Item (PIP)Concern	Concern	Status
G94-0460	Corrective Action Process not Effective	Closed
G94-0459	Management Oversight of S/G Maintenance Activities not Effective.	Closed
94-0462	Procedure for SGM Needs Improvement	Closed

Documentation of corrective actions taken to address these concerns were reviewed and the actions taken were discussed in detail with cognizant personnel. These corrective actions were implemented in part during Unit 2 outage (2EOC9) and will be implemented in total during the present Unit 1 outage (1EOC10). This item is closed.

3.8.2 (Closed) LER 50-370/95-01: Past Inoperability of Unit 2 Containment Penetrations because of Equipment Failure Caused by Unanticipated Environmental Interaction.

Corrective actions taken in response to this item were reviewed during a previous inspection performed by another inspector. Results and findings of that work effort are as follows:

LER 50-370/95-01 concerned the degradation of component cooling (KC) system piping inside containment and the potential impact on containment integrity. Stress corrosion cracking was discovered in Unit 2 KC system piping welds in the cooling water supply and return lines for the excess letdown heat exchanger. The penetrations for these lines, M218 and M217, contain only one outside isolation valve for each penetration, KC-305B and KC-315B respectively. The design for these penetrations presumes that the KC piping provides one isolation boundary and the valve is the second isolation barrier. As part of the review the inspector reviewed the actions taken to assure Unit 1 containment integrity.

Investigation of the stress corrosion cracking problem indicated that pipe weld cracking would be corrected before cracks reach a critical size which would impact the validity of seismic structural integrity analysis. Additionally, evaluation of the system indicates that there is enough water in the KC system to seal the potential inleakage of containment atmosphere for 30 minutes. In the event of a seismic event or a phase A/phase B containment isolation signal, administrative controls provide two barriers for M-218 and M-217.

The LER delineated eight corrective actions associated with identification, repair and evaluation of the stress corrosion cracking condition and assurance of containment integrity. The inspector reviewed these actions with licensee personnel and determined that the remaining action to be performed is the ultrasonic examination of KC system pipe welds associated with Unit 1 excess letdown heat exchanger inside containment. This action is scheduled for the upcoming Unit 1 refueling outage. Previously, it was determined that the subject LER would remain open pending a review of the ultrasonic examination results. However, during this inspection, the inspector revisited this area with cognizant licensee personnel and discussed the scope of the

ultrasonic examination to be performed on Unit 1 heat exchanger and excess letdown piping. The welds scheduled for examination were as follows:

12 pipe welds inside the heat exchanger room.
16 pipe welds in the pipe chase.
2 pipe welds in the annulus area.
2 pipe welds in the auxiliary building between the isolation valve and the supply and return line.

This activity will be performed under Work Order 95008358 Rev 0. A total of 183 pipe welds have been examined in the KC system. Three welds exhibited cracking. Results from the present weld sample will be reviewed on a routine basis on a future inspection.

During the week of January 15, the licensee inspected the above welds. This piping is made mostly of 3"diameter schedule 40 thickness material. The inspection effort included material thickness measurements and UT examination for cracks in the base metal near the weld. A total of 35 welds were examined at this time and no evidence of crack indication were identified. This examination concluded the NDE sampling program which was intended to determine the extent of cracking in this system. Based on this evaluation, this LER is considered closed.

3.8.3 (Open) IFI 50-369,370/95-09-01 Limited Access Weld Examination

This was a followup to determine the licensee's efforts in obtaining the calculated percentage of coverage for welds where a code minimum 90% of the weld could not be UT examined, see Report 95-09 for details. During this inspection, the inspector met with the licensee's cognizant engineer to discuss their progress in obtaining calculated percentages on these welds. As stated earlier in this report, percentage of weld coverage is now calculated on a case to case basis and where necessary requests for code relief are prepared. However, because of a breakdown in communications between the licensee and the contractor, percentage calculations for previously examined reactor vessel welds and nozzle welds had not been completed as anticipated. The licensee stated that following discussions with the contractor, Framatome, they determined that a schedule for providing the required information would be ready for review by the end of March, 1996. The inspector agreed to meet at that time to review the data and map out a target date for completing this effort.

4.0 ENGINEERING (NRC Inspection Procedure 37551)

On-site engineering activities were reviewed to determine their effectiveness in preventing, identifying, and resolving safety issues.

4.1 Removal of Thermo-Lag Fire Barrier Material

During the Unit 1EOC10 outage, the licensee began implementing activities to eliminate Thermo-Lag fire barrier material at the station. There is approximately 115 square feet of the material protecting cable trays and approximately 160 square feet in all other applications. The material is located in three areas of the plant for the purpose of providing a 3-hour rated fire barrier to protect redundant systems or components necessary for safe shutdown per the requirements of 10 CFR Part 50, Appendix R. The areas are as follows:

1) Unit 1 auxiliary building pipe chase;
2) Unit 2 motor driven auxiliary feedwater pump room; and
3) Unit 1 B train switchgear room.

In accordance with Nuclear Station Modification (NSM) 12455, fire barrier material was removed from the Unit 1 nuclear service water supply to turbine driven auxiliary feedwater pump cross connect valves, 1CA161 & 1CA162, and check valves were installed downstream of the valves. The modification provided a means to credit the availability of the Safe Shutdown Facility supply of water to the turbine driven auxiliary feedwater pump in the event of an Appendix R Safe Shutdown fire event. The installation of these check valves allows the operators to open the cross-connect valves during a safe shutdown fire event to ensure a flow path to the turbine driven auxiliary feedwater pump. The check valves prevent the loss of condensate grade water from the upper surge tank and the auxiliary feedwater condensate storage tank through the nuclear service water system because of elevation differences.

An enable/disable switch was also installed in the Unit 1 Safe Shutdown Facility Control Panel to allow operators to isolate the 250 VDC feeder power to these valves to prevent inadvertent closure subsequent to their opening. Operational Appendix R Safe Shutdown procedures are also scheduled to be revised to direct operators to manually open the cross-connect valves and disable the 250 Vdc feeder power within a 10 minute window. By assuring the availability of emergency feedwater to the turbine driven auxiliary feedwater pump, the reliance on the fire barrier is alleviated.

To eliminate the reliance on fire barrier material protecting Unit 1 "A" train cables routed through the Unit 1 B train switchgear room, the licensee implemented modification NSM-12456. The modification replaced the original A train cables with mineral insulated cables qualified to the requirements of ASTM E119 and designed to withstand the temperatures produced by the postulated safe shutdown fire.

The removal of the material is expected to be completed during the upcoming 2EOC10 outage, scheduled to be completed during the second quarter of 1996. The licensee has committed to continue hourly fire watches in the affected areas until the modifications can be completely

implemented and the affected procedures can be revised. The inspectors reviewed the licensee completed and proposed actions and determined them to be acceptable.

4.2 Reactor Coolant Pump Seal Modification - Unit 1

The licensee implemented minor modifications MGMM-7183 and MGMM-7883 to the 1A and 1B reactor coolant pump seal housings, respectively. The modification added a seal stop to the current seal housing design. The original configuration had two seal stops. The additional stop was added to provide stability during pump starts and to reduce the likelihood of the No. 2 seal ring lodging or binding in the upper seal housing.

The modification required that holes be drilled and tapped in the upper seal housing outer ring to allow the stops to be equally spaced and to ensure that the stops would not interfere with other components in the seal assembly. Westinghouse, the seal manufacturer, was contacted for guidance prior to implementation of the modification. Westinghouse evaluated the modification with respect to clearance within the assembly, obstruction of the No. 1 seal leak off line, and impact on the Code analysis. Westinghouse confirmed that the modified seal configuration should not adversely affect the operation and reliability of the reactor coolant pump.

The inspectors witnessed portions of the modification, discussed the modification with the responsible engineer, and reviewed documentation from the vendor. The maintenance personnel involved with the activity were familiar with the assigned task and engineering support was adequate. No unreviewed safety question was identified. Reassembly of the pump seal was conducted in accordance with the controlling procedure, MP/0/A/7150/39, Reactor Coolant Pump Seal Removal and Installation.

4.3 Design Basis Documentation Program

The McGuire Station has completed the Design Basis Documents (DBD) program. The DBDs are a compilation of the current licensing design bases and criteria for a specific plant structure or system. Plant DBDs provide design requirements and the provisions for complying with these requirements for multiple structures, systems and equipment. Examples of Plant DBDs include Environmental Qualification, Single Failure and Seismic Design. System DBDs consists of two parts: Design Basis Specification and Test Acceptance Criteria drawings. System DBDs include both specific and generic system design criteria, and equipment design criteria. The program produced a total of 88 DBDs that typically consists of design requirements, required operating modes, system descriptions and NRC Commitments. Although the DBDs do not replace the FSAR, intended uses of the DBDs include design input for modifications and calculations, operability evaluations, 10 CFR 50.59 evaluations,

principle design input to station testing programs, and training. The DBDs are considered living documents and are routinely updated using NSMs, audits, inspections and self assessment results.

The inspectors concluded that the Design Basis Document program should significantly improve the licensee's ability to ensure that the design basis of specific plant and system components is maintained.

5.0 PLANT SUPPORT (NRC Inspection Procedures 71750, 81070 and 83750)

Plant support activities were observed and reviewed to ensure that programs were implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. Activities reviewed included radiological controls, physical security, emergency preparedness, and fire protection.

5.1 Physical Security

In the area of Personnel Access Control, Section 6.2.2. of the licensee's NRC approved Physical Security Plan provides that all persons requiring escort into the protected area will be escorted by a person or persons allowed unescorted access. In addition, the licensee denotes the escort ratio shall not exceed one to ten for protected area access.

The inspector reviewed Security Procedure EXAO, "Security Badging Program," Revision 57, dated December 7, 1995, which denotes escort requirements. Also, the inspector evaluated Site Directive 950, "Security Program," Revision 0, dated June 3, 1993.

All visitors and their respective escorts are verbally advised of their responsibilities by the Primary Access Point (PAP) officer and questioned to determine if they understand their responsibilities before being admitted to the protected area. Currently the escort and visitor(s) sign a visitor badge/escort authorization form which outlines the responsibilities of both parties. Additional training for escorts is contained in the licensee's General Employee Training (GET), which is required for all individuals requiring access. When a visitor requires an escort change, it will be recorded on an escort change form denoted as the Security Visitor Badge Access Log.

The inspector reviewed random badge/escort authorization forms for the years 1991 and 1993 to verify visitors were escorted in accordance with the licensee's procedures for those time periods. The inspector also toured the protected area and questioned visitors and escorts, to include canteen workers, as to their knowledge of their respective responsibilities. All visitors and escorts observed by the inspector were escorted in accordance with the licensee's procedures and the approved Physical Security Plan.

Based on observation, review of licensee procedures, and interview of licensee representatives, the inspector concluded that escorts and visitors were knowledgeable of their responsibilities and the licensee was in compliance with their procedures and Section 6.2.2 of the approved Physical Security Plan.

5.2 Radiation Protection

5.2.1 Planning and Preparation

This program area was reviewed to assess the adequacy of staff planning and preparation efforts in meeting applicable requirements for protection against ionizing radiation and utilizing radiation protection principles to achieve radiation doses that are ALARA.

The inspection focused on planning activities for the ongoing refueling outage, review of records, discussion of planning activities with licensee representatives, and observation of on-going work.

Planning elements reviewed included RP staffing levels, equipment levels, shielding, ALARA implementation, management involvement and monitoring, level of management support in RP activities, use of engineering controls and incorporation of lessons learned.

The inspector determined that the licensee was adequately planning and preparing for work involving exposures to radioactive materials.

5.2.2 External and Internal Exposure Controls

This program area was reviewed to evaluate the adequacy of licensee radiation protection controls for internal and external radiation hazards and to verify individual radiation doses did not exceed the dose limits described in Subpart C of 10 CFR Part 20.

The review included:

Use of RWPs;

Administrative controls for maintaining individual external and internal radiation exposures below regulatory and administrative limits;

Use of personnel monitoring dosimeters;

Radiological controls for observed work;

Security of locked high radiation areas; and

Use of process and engineering controls to limit exposures to airborne radioactivity.

The licensee reported the following maximum doses (Rems) for individuals in 1995 and 1996:

Year	TEDE	Skin	Extremity	Lens-Eye
1995	0.962	1.013	1.456	0.962
1996	0.695	0.695	0.790	0.695

No individual internal exposures were reported for 1995 and the highest individual internal dose for 1996 was 47 mrem CEDE and 780 mrem CDE.

Through review of licensee procedures and reported dose information, the inspector concluded the licensee was implementing adequate radiation protection controls and monitoring individual occupational radiation exposures in accordance with the requirements and that all individual doses reported were within 10 CFR Part 20 limits.

5.2.3 Posting Radiological Hazards

10 CFR Part 20.1003, "Definitions" defines a radiation area as an area, accessible to individuals, in which radiation levels could result in an individual receiving a dose equivalent in excess of 0.005 rem (5 mrem) in one hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates.

10 CFR Part 20.1902, "Posting Requirements," describes posting requirements for a radiation area in paragraph (a) which states; The licensee shall post each radiation area with a conspicuous sign or signs bearing the radiation symbol and the words "Caution, Radiation Area."

During the inspector's performance of radiation surveys in the licensee's Auxiliary Building, the inspector found three radiation areas on the 750 foot elevation that were not posted in accordance with the regulatory requirements. Each radiation area was within a separate and shielded cubical or room and equipped with individual doors. The inspector measured the following radiation levels within these rooms:

- Room 733, "RHR and Containment Spray Heat Exchangers 1A," having radiation levels of at least 12 mrem/hour at 30 centimeters from a high radiation area boundary;

- Room 732, "RHR and Containment Spray Heat Exchangers 1B," having radiation levels of at least 10 mrem/hour at 30 centimeters from a high radiation area boundary; and

- Room 812, "Boron Injection Surge Tank," having radiation levels of at least 22 mrem/hour at 30 centimeters from a radiation source.

None of the rooms were posted as a radiation area. Inside rooms 733 and 732 the licensee had established high radiation boundaries that were properly posted.

Access to the general area outside these cubicles was through unsecured gates. These gates were posted with the radiation symbol and no other identification. Licensee RP personnel were promptly notified of the inspectors findings and the areas were immediately posted.

The inspector stated that failure to properly post the three radiation areas appeared to be a violation of NRC requirements and will be identified as NCV 50-369,370/95-29-01: Failure to post radiation area boundaries. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

Part of the licensee's problem in the posting violation concerned over-posting the general area outside the individual rooms as a radiation area. At approximately 1:00 a.m., on January 10, 1996, a shift RPT conducting a routine survey of the area outside the rooms did not identify a radiation area outside the rooms and removed the radiation area posting on the two gates entering the area. The technician was unaware of the un-posted radiation areas within the individual rooms. The most proper posting would have been a radiation area posting on each of entry points to the individual rooms.

In addition to posting access to the radiation areas, the licensee entered the posting problem in the licensee's corrective action program, generating PIP 1-M96-0077. Other corrective measures included: adding the problem in the RPT continuing training program for 1996; issuance of a memorandum addressing posting responsibilities to the RP staff concerning the posting problem; and a review of the recent activities performed by the RPT removing the postings.

No additional radiological posting concerns were identified. No deviations were identified.

5.2.4 Control of Radioactive Materials and Contamination, Surveys and Monitoring

This area was reviewed to evaluate the licensee's control of radioactive and contaminated material.

Based on direct observation, discussion and review of records the inspector concluded the licensee was adequately controlling contamination and radioactive material. Housekeeping within containment and containment access needed additional attention to eliminate clutter. Some improvement in housekeeping outside the lower entrance to containment was noted during the inspection.

5.2.5 Maintaining Occupational Exposures ALARA

This program area was reviewed to determine the status and effectiveness of ALARA program initiatives in reducing collective dose for the EOC10. Areas reviewed included goals and objectives, radiation source reductions, and the collective dose results.

A summary of recent collective dose and goals for the site is shown below.

Collective Personnel Exposures (Person-Rem)

Year	Annual Dose Actual	Annual Dose Goal	Title	Outage Dose Actual	Outage Dose Goal	Days
1993	463.0	502.0	U1-EOC-8	208.5	249.9	95
			U2-EOC-8	161.4	222.0	75
			U1-S/G	43.8	-	58
			U2-S/G	18.3	-	19
1994	397.0	412.0	U1-EOC-9	170.5	205.0	69
			U2-EOC-9	183.4	182.0	37
			U1-S/G	45.7	-	34
1995	135.0	174.9	U2-EOC-9-continued			12
			U1-EOC-10	130.0	167.0	17
			U1-Diesel	1.0	-	7
			U2-NV-840	2.5	-	7
			U2-Head	2.2	-	9
1996	30.0	284.8	U1-EOC-10-continued			25
			U2-EOC-10	-	159.7	46

Notes:

1995 dose information includes DAD information for the fourth quarter.

The total dose and goal for U2-EOC-9 and projected dose and goal for U1-EOC-10 are shown in first year of the outage.

Outage length projections are shown in 1996.

The information showed that the collective doses continued to decrease as the outage length decreased and the licensee was implementing effective ALARA measures. At the time of the inspection the licensee was basically on schedule in the Unit 1 EOC-10 outage and the radiological collective dose was below the projected dose for the period. The collective dose as projected would be the lowest refueling outage collective dose in the facility's history. With the exception of Unit 2 EOC-9 outage, the licensee has seen decreasing collective doses on both units for all refueling outages following the EOC-5 outages.

The inspector verified that the licensee had conducted a successful crud burst during reactor shutdown. The licensee utilized crud burst

guidelines recently developed and tested for effective source term reductions. Since the Unit 1 EOC-7 outage, the licensee had seen decreases in average dose rates in the EOC 8 and 9 refueling outages. However, the average dose rates for the Unit 1 EOC-10 refueling outage was higher than the dose rates measured during EOC-9 outage. The licensee believed the EOC-9 average dose rates were much lower due to the outages in cycle 9 prior to EOC-9 outage. With the exception of auxiliary building the average dose rates in EOC-10 outage were still lower than EOC-8 outage by about 10 percent.

Based on direct observation, discussion, and review of records, the inspector concluded the licensee was utilizing ALARA techniques and making progress in reducing collective doses for the staff.

5.3 Emergency Preparedness

5.3.1 Emergency Plan Licensing Review

In April 1995, the licensee issued Revision 95-2 to the Emergency Plan. The NRC's licensing review of this Plan revision identified a need for specific additional information before a determination could be made regarding the acceptability of certain changes. This information was requested in a June 2, 1995, letter to the licensee. Although the licensee responded to the request for additional information in a letter dated August 8, 1995, certain aspects and implications of the subject Plan change were still unclear. The areas of NRC concern were confined to Section J.6, and were related to the requirements for members of the ERO to be respirator-qualified and to the intended use of respirators during an actual emergency.

On January 25, a Region II inspector visited the McGuire site to review and inspect the licensee's implementation of selected facets of Revision 95-2 of the Emergency Plan. Cognizant licensee employees were interviewed, applicable documentation was reviewed, and selected equipment was inspected. The inspector determined that the licensee had not actually implemented the changes in the respirator-qualification program which were allowed by Revision 95-2. Specifically, the licensee had not discontinued the program requirement that all personnel assigned to the TSC were to be respirator-qualified, although the inspector noted that program supervision continued to be less than fully effective, with approximately 18% of the TSC personnel qualifications for respirator use found to be expired (see also Paragraph 6 of NRC Inspection Report 50-369,370/93-10). Additionally, the inspector determined that the licensee did not intend that the discontinuation of the respirator-qualification requirements would apply to members of the ERO other than those assigned to the TSC (approximately 100 persons). Licensee management expressed willingness to resubmit Section J.6 of the Plan with clarifications to this effect.

During the exit interview for the subject inspection, licensee management was informed that a potential violation of 10 CFR 50.54(q) had occurred because the changes made in the ERO respirator-qualification program decreased the effectiveness of the approved Emergency Plan. However, further review of the inspection details by Regional management determined that a violation of regulatory requirements did not occur, principally because the licensee decided not to implement the changes delineated in Section J.6 of Revision 95-2 of the Emergency Plan. The final disposition of this matter will be addressed in separate correspondence with the licensee.

6.0 Other NRC Personnel on Site

None

7.0 EXIT

The inspection scope and findings were summarized on January 26, 1996, with those persons indicated by an asterisk in paragraph 1. Interim exits were conducted on January 12, 18, and 25, 1996. The inspectors described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
VIO	50-369,370/94-26-01	Closed	Failure to Provide Adequate Procedures and Administrative Controls for S/G Tube Repairs, (paragraph 3.8.1)
LER	50-370/95-01	Closed	Past Inoperability of Unit 2 Containment Penetrations because of Equipment Failure Caused by Unanticipated Environmental Interaction, (paragraph 3.8.2)
IFI	50-369,370/95-09-01	Open	Limited Access Welds (paragraph 3.8.3)
NCV	50-369,370/95-29-01	Closed	Failure to Adequately Post Radiation Areas Within the Licensee's Auxiliary Building (paragraph 5.2.3)
NCV	50-370/95-29-02	Closed	ESF Actuation After the Loss of Auxiliary Steam Due to

			Inadequate Procedure (paragraph 2.8.1)
LER	50-370/95-04	Closed	Manually Initiated Actuation of Both Unit 2 Motor-Driven Auxiliary Feedwater Pumps Due to Loss of Auxiliary Steam Supply to the Main Feedwater Pump Turbine (paragraph 2.8.1).
IFI	50-369,370/94-30-01	Closed	Refueling Issues (paragraph 2.8.2)
IFI	50-369,370/95-29-03	Open	MSSV Testing While the Plant is in Mode 1 (paragraph 3.2)

8.0 ACRONYMS

ALARA	As Low As Reasonably Achievable
ANSI	American National Standards Institute
ASME	American Society for Mechanical Engineers
ASTM	American Society for Testing and Materials
CDE	Committed Dose Equivalent
CDS	Computer Data Screening
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
DBD	Design Basis Document
EOC	End Of Cycle
ERO	Emergency Response Organization
ESF	Engineered Safety Feature
ET	Eddy Current
FSAR	Final Safety Analysis Report
GET	General Employee Training
IFI	Inspector Followup Item
ISI	Inservice Inspection
LER	Licensee Event Report
MRPC	Magnetic Rotating Pancake Coil
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NI	Safety Injection
NSM	Nuclear Station Modification
NRC	Nuclear Regulatory Commission
NSRB	Nuclear Safety Review Board
PAP	Primary Access Point
PORC	Plant Operations Review Committee
RPT	Radiation Protection Technician
RWP	Radiation Work Permit
SCC	Stress Corrosion Cracking

S/G	Steam Generator
TSC	Technical Support Center
TSG	Technical Support Group
VIO	Violation