U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Power Company
Facility:	McGuire Generating Station, Units 1 & 2
Location:	12700 Hagers Ferry Rd. Huntersville, NC 28078
Dates:	April 26 - June 15, 1996
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Enclosure 2

EXECUTIVE SUMMARY

McGuire Generating Station, Units 1 & 2
NRC Inspection Report 50-369/96-04, 50-370/96-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by a regional specialist and regional inspectors.

Operations

- An inadequate procedure results in an Engineered Safety Feature actuation (Section O1.2).

- Operations and engineering response and failure investigation was good for an automatic Rx Trip resulting from the failure of the Unit 1B RCP stator. (Section O1.3).

- Inadequate maintenance practice coupled with lightning strike results in partial loss of offsite power (Section O1.4).

- Scheduling of surveillances has resulted in recent near misses of TS required surveillance. A violation was identified in this area (Section O3.1).

- Operators demonstrated capability to perform safe shutdown activation tasks to meet the criteria related to reactor coolant pump seal water supply during normal control room activities. However, an inspector followup item was identified concerning verification that the safe shutdown could be met during an actual emergency plan drill (Section O.4.1).

- A thorough self-assessment was conducted to determine what long term corrective actions should be taken to reduce the overall number of site significant events (Section O7.1).

Maintenance

- A concern was identified in Unit 2 containment when a large amount of handwritten identification was observed on the containment walls (Section M1.2).

- The inspector found that the piping NDE portion of the ISI program was well documented and that deviations from the planned scope of inspection were technically justified (Section M1.3).

- The licensee used conservative plugging criteria during the Unit 2 EOC 10 SG examinations. The Unit 2 SGs will be replaced during the EOC 11 refueling outage, and the licensee determined that conservative plugging would reduce the chances of a mid-cycle SG outage (Section M1.4).

- The material condition of the standby shutdown system was considered to be adequate (Section M2.1).

Engineering

- The 10 CFR 50.59 review process being implemented by the licensee provided adequate controls to allow potential 10 CFR 50.59 items to be reviewed, documented, and submitted to the NRC where applicable (Section E2.1).

- An Unresolved Item was identified concerning examples of FSAR inconsistencies (Section E7.1).

- The DBD process included a review of the FSAR and should have identified any FSAR discrepancies. Based on the NRC findings documented in NRC IR 50-369,370/96-01, some FSAR discrepancies were identified on the Spent Fuel Cooling System and were not identified and corrected by the DBD review. The licensee has a new program, currently not implemented, that will perform additional evaluations of the FSAR to assure its accuracy. The licensee's initiative to perform additional validations of the FSAR was considered a strength and should resolve concerns regarding the accuracy of the FSAR and DBD (Sections E7.2 and E3.1).

- A Non-cited Violation was identified concerning inadequate design review during a Unit 1 emergency diesel generator modification (Section E8.1).

- The inspectors reviewed the licensee actions to verify, monitor and maintain the capabilities of the Standby Shutdown System as described in the licensing basis, Supplement 6 of Safety Evaluation Report (SSER 6). The Standby Shutdown System (SSS) was adequately maintained. Time critical tasks of SSS activation were adequately demonstrated for the normal control room command structure. However, time critical activation tasks were not accomplished with the altered command structure implemented during a recent Emergency Plan drill which included an SSS activation. The root cause was being evaluated and an additional EP drill with an SSS activation was planned for August 1996. Calculations reviewed were of good quality. The licensee's pre-inspection self-assessment in this area was comprehensive. This included review of licensee activities in operations, maintenance, and engineering (Sections O4.1, M2.1, E1.3 and E7.3).

- Quality Assurance performance in the area of engineering self-assessment of the standby shutdown system was good (Section E7.3).

Plant Support

- Good Housekeeping and worker radiation protection awareness was observed. Significant reductions were also noted in potentially contaminated floor space and in the number of catch containers within the radiation control areas (Section R1.1).

- Licensee emergency preparedness training activities were evaluated and found to be aggressive and focused on exercises (Section P1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power and remained at full power the inspection period.

Unit 2 was in a scheduled refueling outage (2 EOC10) until May 11 when the unit entered Mode 3 at 0636. The unit was returned to power operation on May 13 after completing a record refueling outage that lasted only 39 days. The inspectors noted that licensee work activities identified as critical were successfully completed during the outage. However, on May 22, 1996, at 4:25 a.m., a low flow reactor trip from 99 percent power occurred when reactor coolant pump 2B tripped from an electrical fault. The reactor trip proceeded normally, with all systems functioning as required. Investigation identified a fault in the 2B RCP motor stator windings. The unit was cooled down to facilitate repairs. Pending the extent of repairs, Unit 2 is expected to be shutdown until approximately July 1.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Inadvertent ESF Actuation of Auxiliary Feedwater Supply Valves

a. Inspection Scope (93702)

While removing the Unit 2 B Train motor driven auxiliary feedwater pump from service, the assured supply valves to the auxiliary feedwater pumps, 2RN162B and 2CA18B, opened after suction pressure at the valves dropped to the ESF actuation logic setpoint. The valves opened to ensure an adequate supply of water was available from the nuclear service water system (assured source) to the auxiliary feedwater system. Operations personnel immediately re-established suction pressure to the pump via the normal flow path and closed 2RN162B and 2CA18B.

b. Observations and Findings

The inspectors reviewed the operating procedure and determined that the procedure steps were not incorporated to ensure that the assured source valves were closed and power had been removed. The same procedural omission was identified during a review of the Unit 1 Auxiliary Feedwater Block Tagout Procedure, OP/1/A/6800/07B. The licensee made notification to the NRC in accordance with 10 CFR 50.72. However, the

notification was retracted after further review by the licensee. The licensee noted that since the auxiliary feedwater pump had been removed from service prior to the actuation, this event was not reportable under 10 CFR 50.72.

c. Conclusions

The inspectors reviewed the circumstances of this occurrence and determined that the inadvertent ESF actuation was due to inadequate procedural guidance. Based on the licensee's immediate and subsequent corrective actions to realign the valves and revise the procedure, coupled with the low safety significance of this event, this licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. This item will be identified as Non-Cited Violation 50-369,370/96-04-03, Inadvertent ESF actuation due to inadequate procedural guidance.

O1.3 Unit 2 Automatic Reactor Trip - Low Reactor Coolant Flow (93702 and 71707)

On May 22, with Unit 2 operating at 99 percent power, an automatic reactor trip occurred on low reactor coolant flow following a trip of the 2B reactor coolant pump. The licensee determined that an electrical fault had been sensed and reactor coolant pump protection relays actuated as expected.

a. Observations and Findings

The unit was taken to cold shutdown to investigate the cause for the reactor coolant pump trip. The licensee evaluated the RCP power supply and safety breakers, power cables, and penetrations. An electrical fault at the 2B reactor coolant pump motor was identified as the apparent cause for the reactor coolant pump trip. Additional motor resistance testing identified that one of three phases had shorted to ground causing significant damage to the motor stator windings. The licensee determined that prolonged vibration of stator windings had resulted in stator insulation breakdown. Since no replacement motors or stators were available, the failed 2B stator was transported offsite for repair/rewind.

The licensee also reviewed maintenance records for each of the remaining Unit 1 and Unit 2 RCP motors. As a result, the licensee removed from service and transported the Unit 2 "C" and "D" RCP motor stators to the vendor for refurbishment to ensure equipment reliability. Unit 1 RCP motor stators were determined to be adequate for continued operation. The Unit 2 "A" motor was refurbished during the 2EOC10 refueling outage (see Inspection Report 50-369,370/96-03 for details).

The licensee had recognized the stator insulation breakdown and had undertaken a program to refurbish at least one RCP motor during each

scheduled refueling outage. However, only three of the four Unit 1 RCP motors and one of the four Unit 2 motors had been refurbished. The refurbishment included improving the structural support of the stator windings to reduce the rate of insulation breakdown. Each stator winding end turn was secured to the stator support ring. Also, the licensee stated that an evaluation of current predictive maintenance practices would be performed to identify necessary improvements.

b. Conclusion

The inspectors responded to the site and evaluated plant and licensee response to the transient. No discrepancies were noted. The licensee performed a detailed failure investigation process and effectively determined the cause of the transient. The inspectors also discussed the condition of the remaining RCP motors with the licensee and concluded that the licensee's decision to complete refurbishment of the Unit 2 C and D motors was conservative and should improve motor reliability.

O1.4 Inadvertent ESF Actuation

a. Inspection Scope (93702)

On May 24, with Unit 2 in Mode 5 (Cold Shutdown), with the B train of residual heat removal in service, and both Unit 2 EDGs operable, a momentary degraded voltage condition was sensed on 2ETA, the Unit 2 essential Train A power bus. The Unit 2 A EDG autostarted but did not load. The degraded voltage condition resulted from a lightning strike on a feeder line to the Unit 2 offsite high voltage switchyard. The fault cleared as expected by the opening of two PCBs (57 & 58). When the lightning strike occurred, PCB 52 had been removed from service for preventive maintenance. The PCB had been electrically isolated from the system and intentionally grounded on both sides of the breaker during the previous day. One phase of the MOD poles was left closed, creating a potential electrical path between the ground points.

The lightning strike was sensed at PCB 52 causing an automatic separation from one of the offsite power sources. According to licensee information, the strike was discharged to ground and then traveled through the installed ground loop that had been created by the maintenance activity. This de-energized the 2A main transformer causing a partial loss of offsite power condition. Since residual heat removal was supplied through the B train, shutdown cooling was not affected. Following a detailed investigation, normal power system alignment was re-established.

b. Observations

The licensee initiated an investigation to determine the cause for the EDG autostart. An electrical fault in the station switchyard caused the

loss of the A Train offsite power source. The licensee determined that PCBs 58, 59, and 62 had opened in the switchyard. A lightning strike was the suspected cause. No major damage was reported. The PCBs were subsequently realigned to re-establish the offsite power supply to Unit 2.

c. Conclusion

The inspectors concluded that the practice of leaving the system in such a condition was not conservative and could have potentially resulted in a significant operational event. Although only one offsite power source was required per TS, appropriate precautions were not established to prevent such an event. Had the initiating strike occurred on a different feeder line (such as Train B), a significant safety system challenge could have occurred. Corrective actions to prevent recurrence include always leaving the PCB poles open at the end of the work day or isolating the current transformer relays during maintenance.

03.1 Operational Testing Prior to Mode Changes

a. Inspection Scope (71707, 60710)

During refueling operations on April 29, 1996, Operations ceased fuel handling activities after discovery that PT/2/A/4350/03A had not been performed within the required interval for Mode 6 requirements to meet the TS surveillance requirement. The licensee completed the PT and resumed refueling activities.

b. Observations and Findings

Prior to entry into Mode 6 during the 2EOC10 RFO, the licensee failed to adequately complete the requirements of Procedure OP/2/A/6100/SU-1, Mode 6 and Core Alterations Checklist. This procedure requires operations personnel verify that all performance tests (PTs) required for Mode 6 are within their surveillance interval. Performance Test PT/2/A/4350/03A, Electrical Power Source Alignment Verification, is used to verify proper breaker alignment and power availability for switchgear, load centers, and 120V Vital AC and 125 V DC Vital Buses. The PT is performed to meet the surveillance requirements of Technical Specifications 4.1.8.2, 4.8.2.2.1, and 4.8.3.2 for Modes 5 and 6.

Subsequent investigation by the licensee identified that the intended TS surveillance requirements were met by other verifications and signoffs. The licensee reviewed data points from round sheets and alarm summaries which verified that the power source requirements for Mode 6 as required by TS were available.

Problem Investigation Process (PIP) 0-M96-0656 identified a TS surveillance that was not performed within the required time frame as required for TS 3/4.11.2.6 for verification activity level within the

Waste Gas Decay Tanks. This missed surveillance was discovered when investigating another PIP 0-M96-0600 which documented the same surveillance missed on another occasion.

Additionally, PIPs 2-M96-0228 and 2-M96-1344 were initiated to investigate two examples where work practices could have resulted in missed testing or missed surveillance.

c. Conclusion

The inspectors reviewed this failure to properly perform the Mode 6 checklist requirements and recent weaknesses in other missed or near miss TS surveillances. The Mode 6 checklist does not list all procedures required for Mode 6. The Mode 6 checklist was not performed when it came due because the Unit was defueled. The licensee work scheduling process did not identify that this procedure would need to be performed prior to Mode 6 if it was not performed during defueled conditions. The licensee identified that operators must rely on experience to ensure all required procedures are performed and that due to the experience level all operators might not be aware of all the surveillances required for a mode change. The inspectors considered this reliance on operator memory and experience to ensure all procedures are performed to be a weakness in the licensee's work process. The licensee plans an assessment in the "missed surveillance" area.

The inspector concluded that the failure to perform a PT required for Mode 6 as required by the Mode 6 checklist was a violation. This failure to follow procedure will be identified as Violation 50-369,370/96-04-01: Surveillance not performed as scheduled.

04 Operator Knowledge and Performance

04.1 Operator Knowledge and Performance - SSS Activation

a. Inspection Scope (93801)

The inspectors reviewed the licensee's actions to assure the time critical tasks of the standby shutdown system (SSS) activation were consistently accomplished. In particular, this applied to the criteria to provide seal water to the reactor coolant pumps (RCPs) within ten minutes of loss of all AC power.

b. Observations and Findings

Assurance of time critical tasks was provided by performance of Job Performance Measures (JPMs) incorporated in operator training. The JPM performance documentation indicated that Operations could consistently activate the SSS within ten minutes with the normal control room command structure. The licensee had not demonstrated the desired ten minute SSS activation time with the expanded operations command structure which

occurred during implementation of the Emergency Plan (EP). Technical Support Center (TSC) delays in dispatching operators to activate the SSS on loss of all AC power during the EP practice drill of May 29, 1996, resulted in exceeding the desired ten minute activation time. This performance problem was identified by the licensee during the drill and was addressed by PIP 0-M96-1576. Four previous EP drills in 1995 and 1996 included SSS activation; however, the ten minute SSS activation time was not included as a drill objective.

c. Conclusion

The licensee adequately demonstrated operator capability to perform SSS activation tasks to meet the time criteria related to NCP seal water supply during normal control room conditions. The current level of individual operator training in this area was good. However, the capability to perform these time critical tasks during SSS activation in conjunction with EP evolutions has not been verified. The licensee indicated that an EP drill would be conducted in August 1996 following evaluation and corrective actions for the performance problems identified during the recent drill. This issue is identified as Inspector Follow-up Item 96-04-05, Verification of SSS Activation Time during Emergency Plan Drill.

07 Quality Assurance in Operations

07.1 Licensee Self-Assessment Activities (40500)

a. Inspection Scope (40500)

The inspectors reviewed and evaluated a recent self-assessment that was conducted in response to concerns that were expressed at the Duke Power February, 1996 Nuclear Safety Review Board (NSRB) meeting.

b. Observations and Findings

The self-assessment was documented in PIP-0-M96-1693 and was referred to as Self-Assessment SA-96-69 (All) (OEA). The PIP was written for the Safety Review Group (SRG) to determine what site investigation/actions should be taken. On March 26, 1996, the Assessment Team met to conduct the evaluation. The team, identified as the "Common Cause Assessment Team," evaluated each of the events that were identified as industry significant. The records showed that the Duke sites experienced four of these events in 1994, six in 1995, and two in 1996.

The Common Cause Team reviewed the applicable documents such as: The Duke Significant Event Investigation Team (SEIT) reports, LERs, Significant Event Reports (SERS), and Significant Event Notifications (SENs). A table top discussion followed the event reviews and the common causes were established to try and identify the root causes. The team findings were categorized as follows: Operational Focus and

Control, Management Expectations and Standards, Procedure Quality, Use of Operating Experience, and Clear and Complete Communications.

c. Conclusions

The inspectors determined that the self-assessment was thorough and detailed. Also, the findings should be useful for the SRG in determining what, if any, long-term corrective actions should be taken to reduce the overall number of Significant Events.

08 Miscellaneous Operations Issues (92700)

08.1 (Closed) LER 50-370/95-03: Loss of Containment Integrity. Containment integrity was momentarily lost when the Auxiliary building door seals of the upper personnel airlock unexpectedly deflated while the reactor building door was open for normal ingress of station personnel.

The licensee promptly responded by immediately closing the reactor building door. In addition, the licensee identified a failure of a linear actuating cylinder as the cause for the auxiliary building seal deflation. The actuating cylinder was replaced and tested satisfactorily. The licensee also evaluated the condition of other personnel airlock doors, with emphasis on the actuating cylinder, to identify and correct any potential discrepancies. No notable concerns were identified.

The inspectors concluded that the licensee response to the equipment failure was adequate. This item is closed.

08.2 (Closed) LER 50-369/95-05: Manual Reactor Trip as a Result of Equipment Failure. On September 27, 1995, Main Steam Line A Isolation Valve moved to the closed position. Operators attempted to reopen the valve from the control room but were unsuccessful. The operators manually tripped the reactor.

The licensee conducted investigations to identify the reason for the valve closure but were unsuccessful in determining the exact mode of failure for the equipment. Since no cause for the valve closure was identified, the licensee conservatively replaced the associated fuses, solenoid valve coils, wiring terminations, and relays to eliminate potential intermittent problems associated with these components.

The inspectors determined that operator response to the event was adequate and that licensee investigation of the event cause was adequate. The inspectors concluded that appropriate measures had been taken by the licensee to eliminate potential causes for the MSIV closure. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726 and 62703)

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

a. **Inspection Scope**

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

- PT/2/A/4200/09: ESF Actuation Periodic Test
- PT/2/A/4200/08: Reactor Coolant Pressure Isolation Valve
- PT/2/A/4200/12: Accumulator Valve Leakage Test
- PT/2/A/4255/03A & B: Main Steam Train A & B Isolation Valve Stroke Timing
- PT/2/A/4255/03C: MSIV Functional Test and Closure Verification at Full Temperature and Pressure

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

M1.2 Unit 2 Containment Cleanliness Walkdown (62703)

Near completion of the Unit 2 refueling outage, the inspectors performed a containment cleanliness inspection of the reactor building. The walkdowns of the upper and lower reactor building areas included inspections of the ice condenser, containment sump, pipe chase, and refueling canal.

No fibrous material was identified that could have potentially prevented adequate residual heat removal performance during the

recirculation phase of emergency core cooling system injection phase. Insulating material had been adequately secured and tools and other temporary outage equipment had been removed.

The inspectors noted an inordinate amount of identification numbers handwritten on the walls for both mechanical and electrical equipment and penetrations. Although no licensee personnel were observed using these markings, the inspectors concluded that the use of these markings could result in the inadvertent manipulation of equipment and may result in subsequent system or plant transients. Therefore the inspectors considered the potential use of such non-official markings as a concern. The concern was communicated to station management.

M1.3 Inservice Examination Review, Unit 2

a. Inspection Scope (73753)

The inspector reviewed documents and records related to the inservice inspection (ISI), non-destructive examination (NDE) of Unit 2 piping pressure boundary welds. Unit 2 was in the second outage of the second ten-year ISI inspection interval. The review included 70 ultrasonic test (UT), liquid penetrant test (PT), and magnetic particle test (MT) records for piping and component, pressure boundary, and support welds.

b. Observations and Findings

The inspector found each of the NDE records to be appropriately completed, reviewed and approved by the licensee, and otherwise in accordance with the requirements of ASME Section XI, 1986 edition.

During review of the examination records for emergency core cooling system (ECCS) piping systems, the inspector determined, through discussions with responsible licensee personnel, that the potential for thermal fatigue cracks such as those described in NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems" had been considered.

c. Conclusions

The inspector found that the piping NDE portion of the ISI program was well documented and that deviations from the planned scope of inspection were technically justified.

M1.4 Steam Generator Eddy Current Examination

a. Inspection Scope (73753)

The inspector reviewed the eddy current (ET) examination results for the steam generator (SG) tubes which were taken out of service by plugging during the current outage. The results of the current ET examinations

were compared with the results of the December 1994 examination, which was the last time that the SGs were inspected.

b. Observation and Findings

McGuire 2 has Westinghouse Model D3 SGs which were placed in commercial operation in March 1984. There were 180 tubes plugged in Unit 2 SGs during the 1996, end-of-cycle-10, (EOC 10) outage, bringing the total percentage of tubes plugged to 12.53%, as shown in the tables below.

Table 1. Percentages Plugged

SG	EOC 10	Total	% Plugged
A	42	591	12.64%
B	51	631	13.50%
C	32	533	11.40%
D	55	587	12.56%
Total	180	2342	12.53%

Table 2. Summary of Mechanisms for Plugging

SG	Hot Leg Tubesheet	Hot Leg Support	Cold Leg Freespan	Other *	Total
A	27	4	2		42
B	28	10	6		51
C	15	13	0	4	32
D	26	18	5	6	55
Total	96	45	13	26	180

* Other includes Ubend, Hot Leg Freespan, Wear, Etc

The inspector noted that eight of the SG tubes showed significant, pluggable indications in areas that were recorded as "no detectable degradation" (NDD) during the December 1994 examinations. Two of these tubes, SG A tube R27C98 and SG B tube R10C68, contained volumetric indications (approximately 40% trough-wall) in the free span above the 5th support plate. The other six tubes: SG B tubes R11C68, R12C69, R47C45, & R48C57; SG C tube R5C100; and SG D tube R5C88 contained indications at a support plate.

The inspection results for the eight tubes discussed above, were reviewed during conference calls between the inspector, NRR, and the licensee on May 22 and May 28, 1996. During these discussions, the licensee explained that the free span indications had been present as absolute drift indications during previous examinations and had been

dispositioned as manufacturing marks. They also explained that the indications at support plates could not be reliably sized using fully qualified techniques, so they were assigned a conservative depth size by the bobbin coil analysts.

c. Conclusions

The licensee used very conservative plugging criteria during the Unit 2 EOC 10 SG examinations. The Unit 2 SGs will be replaced during the EOC 11 refueling outage and the licensee determined that conservative plugging would reduce the chances of a mid-cycle SG outage.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Maintenance and Material Condition of Facilities and Equipment - Standby Shutdown System (SSS)

a. Inspection Scope (93801)

The inspectors reviewed the maintenance history and condition of critical SSS equipment. The following equipment was reviewed:

Standby Make-up (SMU) pump and associated pulsation dampeners
SSS containment isolation valves, check valves, and relief valves
Turbine Driven Auxiliary Feedwater Pump
SSS Diesel Generator (SSS-DG)
SSS Instrumentation

b. Observations, Findings, and Conclusions

Equipment histories as indicated by maintenance work orders and PIPs demonstrated adequate equipment performance. Reliability and unavailability values for SSS equipment indicated maintenance was adequate to assure SSS capability; SSS DG reliability was 100 percent, system unavailability was less than the 5 percent goal. Equipment walkdowns identified no detrimental material conditions.

M7 Quality Assurance in Maintenance Activities

M7.1 Review of FSAR - Inservice Inspection Activities

a. Inspection Scope (73753)

The inspectors reviewed the FSAR during preparation for inspections documented in this section.

b. Observations and Findings

During the preparation for the ISI inspections, discussed in paragraphs M1.3 and M1.4, the inspector noted that Chapter 5 of the FSAR contained a Table 5.31, Tentative Inservice Inspection Schedule. This table was not referenced by the text of Chapter 5 and is not current with the approved ISI plan for either McGuire unit. The table describes a sample ISI plan for the first ten years of commercial operation while both of the McGuire units have been in the second ten years of commercial operation for over two years. The licensee initiated Problem Investigation Process (PIP) form 0-M96-1295 to update the FSAR. This FSAR inconsistency is documented as one of the items associated with the URI in section (E7.1).

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Inspector Followup Item (IFI) 50-369,370/95-09-01, Examination of Limited Access Welds. This item was opened in response to the NRC's denial of a generic request for relief by the licensee. The relief requested was from the requirement to provide identification of individual welds which had received less than 90% inspection coverage during ISI inspections in individual relief requests. The licensee initiated PIP 0-G95-0268, on March 28, 1995, to document the investigation and correction of the problem. During this inspection, the inspector determined that the problem had been identified, and that corrective actions were essentially complete. The NRC will therefore close this IFI, while the licensee completes the necessary actions to close out PIP 0-G95-0268.

M8.2 (Closed) LER 50-369/95-06: Automatic Reactor Trip Due to Equipment Failure. On October 1, 1995, Unit 1 reactor tripped due to low reactor coolant system flow. Both the motor supply and protection circuit breaker tripped on high ground fault current. Ground resistance checks identified a faulted surge capacitor as the cause for the coolant pump trip. The licensee replaced the failed capacitor and tested the associated motor control circuits and equipment. Each reactor coolant pump motor is equipped with three surge capacitors, one for each phase. The capacitors had been periodically tested and no concerns had been identified.

The inspectors concluded that the licensee's response to the equipment failure was adequate and no violations of NRC requirements were noted. This LER is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Framatome Cogema Fuels (FCF) Rod Control Cluster Assembly Oxidation

a. Inspection Scope (37551)

During the performance of the fuel assembly insert shuffle verification in the spent fuel pool, an unusual substance was identified on the control assemblies near the interface between the guide tubes at the top of the fuel assembly. The material was present only on reload fuel assemblies with newly installed FCF RCCAs. The licensee completed sampling of the material and determined that the residue was an iron oxide. This conclusion was confirmed by the vendor. The oxide was determined to be a result of the ion nitrating process used by the manufacturer for hardening the outer diameter of the stainless steel cladding. The new FCF RCCAs had been placed in the reload assemblies in the spent fuel pool for approximately 48 hours prior to the discovery of the residue.

b. Observations, Findings and Conclusions

The licensee, using an underwater vacuum in the spent fuel pool, removed significant amounts of the loose residue from each newly installed RCCA. To preserve reactor coolant pump seal life, the licensee also used one micron reactor coolant letdown filters during Mode 5 cleanup. Once the demineralizers were returned to service, filtration of remaining residue was provided. The licensee has planned to monitor suspended solids in the reactor coolant system for any changes during the operating cycle.

The inspectors discussed RCCA operability concerns with the licensee and were informed that the presence of residue would not prevent the RCCAs from meeting the TS operability requirements. The licensee determined that the residue would not adversely affect the RCCA life expectancy. Dose contribution from activation products were also expected to be minimal.

The inspectors reviewed the RCCA specifications and determined that the RCCAs were to be passivated prior to shipping to reduce the probability of accelerated oxidation flaking in the fuel pool and reactor.

E1.2 Engineering Calculations and Analysis For the Standby Shutdown System

a. Inspection Scope (93801)

The inspectors reviewed PIPs generated by the licensee on the SSS and the following calculations:

Reactor Vessel Head Vent Line Orifice Sizing, MCC-1223.03-00-0006, May 31, 1996.

Reactor Coolant Pump Seal Water Flow Requirements for Standby Makeup Pump, MCC-1223.04-0010, June 22, 1990.

Standby Makeup Pump Sizing, MCC-1223.04-00-0011, January 4, 1994.

PIP 95-1956 addressed a concern related to SSS DG minimum fuel requirements for 3.5 days of operation.

b. Observations, Findings and Conclusions

The inspectors noted that quality of the reviewed calculations was good. Calculation MCC-1223.03-00-0006 was revised due to a previously identified licensee concern that the orifice was not sized to permit adequate let-down during an SSS event. The engineers revised the calculation to take credit for the present NCP seal leakoff rate and determined that the orifice was adequately sized.

Calculation MCC-1223.04-00-0011 was revised to address a concern with the out of specification condition of the SMU pump suction pulsation dampener. The net positive suction head for the pump was re-calculated to include an acceleration head that was a result of the dampener. A review of the calculation and the vendors manual indicated that there was no SMU pump operability concern related to the out of specification condition for the dampener nitrogen pressure.

The SSS DG was run on May 23, 1996, to check fuel oil consumption and verify sufficient fuel oil was available for at least 3.5 days of diesel operation when the storage tank level is at the minimum allowable level of 4 feet. The inspectors reviewed an informal calculation performed in conjunction with the testing of the SSF diesel which indicated that adequate fuel was available for 3.5 days. The minimum level was not met on August 20, 1994, (non-cited violation 50-369,370/94-15-02). No additional occurrences were identified, indicating that the corrective actions for this problem were effective.

The inspectors noted that the method of hot short protection provided for the residual heat removal Train A isolation valves was not consistent with the method described in Supplement 6 of the Safety Evaluation Report (SSER 6). Administrative controls placed the valves in the shutdown position and removed power from the valves during operation in lieu of the control cable separation described in SSER 6. An NRC letter to Duke Power Company dated April 30, 1985, related to fuse\breaker coordination, stated that power removal was an acceptable method for satisfying Appendix R spurious signal concerns.

E2 Engineering Support of Facilities and Equipment

E2.1 Review Of 10 CFR 50.59 Items

a. Inspection Scope (37550 and 37551)

The inspector reviewed Nuclear System Directive 209, 10 CFR 50.59 Evaluations, Revision 3, implemented October 1, 1995. This procedure defines the process to be used in meeting the requirements of 10 CFR 50.59. The inspectors' review determined the procedure was modeled after NSAC-125 (Nuclear Safety Analysis Center) "Guidelines for 10 CFR 50.59 Safety Evaluations." The inspector verified, among other things, that the procedure required NRC approval prior to implementation of changes, involving an USQ or requiring a Technical Specification Change.

b. Observations, Findings, and Conclusions

As part of the 10 CFR 50.59 review, the inspector reviewed ongoing field modifications being made to the facility and selected one of these activities to evaluate the 10 CFR 50.59 process. The inspector attended the daily maintenance meeting and selected a specific modifications package, TN/2/A/2455/00/M, for review.

This modification installs 8 inch check valves (2CA221) and a 1 inch vent valve (2 A222) downstream of 2CA161C. As part of this modification, the Operational Appendix R safe shutdown procedure will require revision to direct the Operator to manually open the RN/CA cross connect valves, and to further disable the valve control power via new switches within the allotted 10 minutes.

- Documentation Reviews

  The inspectors review of the modification package identified in Section E3.1.b determined the package provided a cover sheet that indicated a 10 CFR 50.59 screening review for this modification was required and performed. For this modification, the licensee determined the modification did not constitute an USQ and did not affect the Technical Specifications. The inspector reviewed the 10 CFR 50.59 checklist and noted the licensee had adequately described the basis for the modification as not being an unreviewed safety question.

  The inspector performed field inspections and observed the check valves were installed and operational on Unit 1 and valve installation work was in-process on Unit 2. The inspector also inspected the SSF and noted the disable/enable switches were installed on both units. The emergency procedures were also reviewed and it was noted that Unit 1, presently operating, contained the required instructions to open the subject valves and disable the control switch in the event of an Appendix R fire.

Revision to the Unit 2 procedure is planned before the unit goes operational. The inspector had no further questions on this issue.

- Review Of Minor Modification Packages

The inspector selected 5 minor modification packages for 10 CFR 50.59 review. The packages were reviewed to assure the licensee had performed an adequate screening process for 10 CFR 50.59, including adequate written justification that the criteria of 10 CFR 50.59 was considered. The packages reviewed were:

Work Order 94071509 - Fabricate and attach a new platform to the polar crane to provide safe access to the upper containment ventilation units.

The inspector concluded from this review that this modification was adequately reviewed for 10 CFR 50.59 applicability and the modification did not affect Technical Specifications nor result in an USQ.

Work Order 94062781 - Replace existing corroded valves with flow restrictors. The inspector noted the attached justification indicated the flow restrictors satisfied the requirements as a code class change from ANSI (Nuclear Power Piping) B31.7, Class III to non-safety related piping. To verify this and other assumptions used in the 10 CFR 50.59 screening evaluation, the inspector reviewed calculation MCC-1223.24-00-0061, Revision 0. The calculation supported and the licensee concluded that:

- Use of the flow restricting devices sized by the calculation will not result in any problems with regards to insufficient NSW flow rate capacity in the Essential Pump Discharge Headers.

- The use of two flow rate restrictors in any Diesel Generator room will not result in a flooding concern in the event of a double ended rupture of non-safety NSW piping for the Diesel Generator (VG) system.

- The use of both supply and return header flow rate restrictors will not result in a loss or significant restriction of the design cooling water flow to the VG system.

The inspector concluded from this review that this modification was adequately reviewed for 10 CFR 50.59 applicability and the review found this modification did not affect Technical Specifications nor result in an USQ.

Work Order 95017310 - Install a new opening/closing mechanism for the ice condenser lower personnel access door. This modification did not affect Technical Specifications nor result in an USQ.

Work Order 95033775 - Change hard seat material to soft seat material on Kerotest valve. The inspector noted a minor problem with the documentation in that the screening block was not checked either yes or no. This was determined to be an administrative oversight and did not affect the documentation adequacy in that adequate justification was contained in the document showing evaluations were performed. This modification did not affect Technical Specifications nor result in an USQ.

Work Order 95032852 & 95037855 - Change all Bussman FNQ fuses in the control circuit that are associated with the fuel oil transfer pump and level controls and replace them with the Littelfuse FLQ fuses. This modification did not affect Technical Specifications nor result in an USQ.

The inspector found adequate screening reviews were done on all minor modification packages reviewed.

- Review of 10 CFR 50.59 Reports

The inspector selected one report that the licensee determined was an USQ that required approval from the NRC prior to implementing the change. The USQ was submitted to the NRC by letter dated March 4, 1996, and has not yet been approved by the NRC. The issue dealt with the present requirement to shut down the reactor in the event an earthquake is seen, heard, or felt. The reason for this action is that the airborne particulate monitoring equipment is not seismic qualified.

The licensee's proposed modification would revise the plant response procedure for earthquakes to remove the requirement to immediately trip the reactors if the effects of an earthquake are seen, heard, or felt and rely on seismic instrumentation and data obtained from a post-event plant walkdown to determine if a plant shutdown is required.

The inspector reviewed procedure RP-0-A-5700-07 "McGuire Nuclear Station Earthquake" and verified the procedure still required plant trips whenever an earthquake is seen, heard, or felt. The inspector determined the licensee had not implemented the proposed change prior to NRC approval of the USQ. Within the area reviewed, no violations or deviations were identified.

E3 Engineering Procedures and Documentation

E3.1 Review of Design Basis Document (DBD)

a. Inspection Scope (37550 and 37551)

The inspector reviewed the applicable procedure that controls the DBD process to determine the scope and process for the DBD. For detailed review, the inspector selected Volume 5 of the DBD, Section MCS-1465.00-00-0008, paragraphs A.2, Fire Hazard Analysis, C.9.6 Fire Retardant Wrapping, and C.31.12 Nuclear Service Water Pump for review to determine the licensee's process of collecting, evaluating, collating, and documenting the adequacy of design. Additionally, the inspector reviewed plant modification documents and performed field inspection to determine the as-built condition of the facility compared to the DBD.

b. Observations and Findings

- Procedure Review

  The inspector reviewed Engineering Directives Manual EDM-170 dated March 30, 1995. This document controls the Design Basis Document and identifies that the DBD process may not include a complete reconstitution of design bases. The document further identifies that in some cases where documentation does not exist, cannot be reconstructed, or cannot be found, a partial reconstitution may be required. The procedure indicates that DBD's are not intended to replace any existing licensing documents nor are they intended to be used as the licensing basis. The document also requires that during the development of DBDs, if it is discovered that as-built conditions may be or are in violation of design bases or criteria, then a problem investigation process shall be invoked. The inspector noted the licensee does not plan to complete several of the original planned DBD activities. For example missiles, cable tray supports, pipe supports, equipment qualification, and incore instrumentation are some examples that were not reconstituted as part of the DBD on the basis that not enough information would be generated to be cost effective and design basis information pertaining to the subjects can be found in existing calculations, specifications, and correspondence files, etc. This document is not a regulatory required document and was generated by the licensee to assist in daily work activities.

- DBD Documentation Review

  The inspector reviewed Volume 5 of the DBD to assure the document does not contribute to any potential reduction in nuclear safety.

  - A.2 Fire Hazard Analysis

The inspector reviewed the modification activities in process for installing two check valves downstream of valves CA161C and CA162C. The inspector noted the DBD discussed these valves in DBD, Volume 5, Paragraph A.2 (b) by stating "to insure SSS capability, valves 2CA161C and 2CA162C with associated cabling have been wrapped with a 1-hour fire retardant blanket in Fire Area 3."

The inspector performed field inspections of fire retardant installations as part of the DBD review to assure items such as fire wrap installed during the construction phase, shown in paragraph A.2 of the DBD, are still valid. The inspector noted the licensee had removed the previously installed Thermolag fire wrap.

A change to the DBD was in process by the licensee that would modify Paragraph A.2 discussed above to read: "To insure SSS shutdown capability, the SSF start-up procedures require the opening of valves 2CA161C and 2CA162C and then the removal of electric power via a disable/enable control switch located in the SSF within the 10 minute allotted start-up time." The inspector had no further questions on this item.

- C.9.6 Fire Retardant Wrapping

The DBD indicates that fire blankets which provide 1/2 hour fire barriers are installed on instrumentation and control cables for the turbine driven auxiliary feedwater pump in the motor driven auxiliary feedwater pump room. As determined from the field inspections, the licensee removed this fire blanket when the modifications for installing the SSF was installed. The licensee indicated that the need to have the fire blanket installed was eliminated when the SSF became operational. The SSF was installed and operational before the DBD commenced in 1989, indicating an oversight of the DBD process to identify the corrective actions had changed and fire blankets were no longer required or installed. The inspector concluded this oversight had no adverse impact on the design or safe operation of the facilities. The licensee initiated a PIP to address the deficiency.

- C.31.12 Nuclear Service Water Pumps

The DBD indicates that fixed water sprinklers are provided over the NSW pumps and extend twenty feet north to the station GG locator line to cover heavy cable concentration. Curbs are provided to control sprinkler discharge.

The inspector performed a field inspection and noted the curbs and required sprinklers were installed as specified in the DBD. The inspector had no questions on this item.

- Review Of Minor Plant Modifications

  The inspector selected one minor modification package performed by the licensee in 1994 to evaluate the adequacy of updating the DBD. The modification selected was work order 94062781. The work activity was to remove two severely corroded check valves and replace the check valves with flow restricting couplings. The old check valves were shown in Volume 7 of the DBD. On September 22, 1995, the DBD was updated to reflect the check valves had been deleted. The inspector determined the DBD had been updated to reflect the current design in a timely manner. The inspector had no questions on this issue.

c. Conclusion on Engineering Procedures and Documentation

The inspector's review of the DBD determined the licensee's objective in conducting the DBD process was not to do a reconstitution of the original design, but rather to assemble the existing design basis into a set of design documents for ready reference when performing 10 CFR 50.59 reviews and other daily functions. The inspector determined the licensee did some field validations during the DBD process. The inspector noted one discrepancy in the DBD as discussed above and noted the licensee has on occasion identified some other discrepancies. When discrepancies are noted, the licensee corrects the discrepancies through the PIP process.

The DBD process included a review of the FSAR and the licensee indicated the DBD process should have identified any FSAR discrepancies. However, based on the NRC findings documented in NRC IR 50-369,370/96-01, some FSAR discrepancies were identified on the Spent Fuel Cooling System and apparently were not identified and corrected by the DBD review.

The inspector noted the licensee has a new program, currently not implemented, that will perform additional evaluations of the FSAR to assure its accuracy as discussed in Section E7.2. This licensee initiative to perform additional validations of the accuracy of the FSAR was considered a strength and should resolve concerns regarding the accuracy of the FSAR and DBD. The inspector's review did not identify any deficiencies that would have any adverse effect on the safety functions of plant modifications or operations.

E7 Quality Assurance in Engineering Activities

E7.1 The inspectors reviewed the FSAR items that were documented in Inspection Report 50-369,370/96-01, paragraph 6.0 and section M7.1 of this report. The inspectors determined that the following FSAR inconsistencies may be in non-compliance with 10CFR50.71(e), and will be identified as an Unresolved Item 50-369, 370/96-04-02: FSAR Inconsistencies.

- FSAR 9.1.4.3.4 stated that the manipulator cranes contain positive stops which prevent the top of the fuel pellets in a fuel assembly from being raised to within ten feet of normal water level. Actually, the upper limit switches on the cranes limit height but do not ensure ten feet of water cover.

- FSAR Chapter 5 contained Table 5.31, concerning an ISI schedule, that was not referenced in the text of Chapter 5 and was not current with the approved ISI plan for the McGuire site.

- FSAR 9.1.2.3 stated that the highest level above the fuel racks that the fuel assembly can be dropped is 3 feet, two inches. The re-rack modification changed the height of the fuel racks such that the highest level would be 3 feet, six inches.

- FSAR 9.1.2.3.6 stated that spent fuel cask lifting height was limited to 12 inches if the cask shock absorbing cover is not installed. There were no administrative limits or physical restrictions on the crane to ensure this limit. This 12 inch limit is used in the drop analysis.

- FSAR 9.1.4.1 stated that fuel lifting and handling devices were capable of supporting maximum loads under Safe Shutdown Earthquake (SSE) conditions. No documentation was available to validate this seismic capability.

- FSAR 9.1.4.3.1 stated that the reactor manipulator crane was designed to prevent disengagement on a fuel assembly from the gripper in an SSE. No documentation was available to support this seismic capability.

- FSAR 9.1.3.1.1 stated that decay heat of spent fuel was analyzed for a twelve month refueling cycle. Current analysis addressed refueling cycle of greater than twelve months.

- SER Supplement 6, Section 3.3 stated that the long term SFP makeup sources included the reactor makeup water storage tank (RMWST) and the refueling water storage tank (RWST), both at 2000 ppm boron. The RMWST was not a borated water source.

- FSAR 9.2.4.2 implies that two component cooling water system pumps are necessary during normal plant operation. Unit 1 was operated for an extended period following the 1EOC10 outage with only one component cooling water pump in service.

- The calculation to determine the number of fuel assemblies affected by a post accidental drop of a fuel pool weir gate did not address the more diversely spaced fuel storage provided by fuel pool re-racking.

E7.2 Final Safety Analysis Report Review Team

The licensee's Regulatory Compliance Group has chartered a working crew to examine the FSAR Update process to come up with recommendations that would ensure the accuracy, completeness and quality of the FSAR. Additionally, the group was tasked to assess the more immediate need to develop a plan for an in-depth review and audit of the current FSAR for technical adequacy, quality, and completeness relative to the current licensing basis.

The group established 3 phases to address the issues and provide recommendations to management. The objective of Phase 1 is:

- Review the FSAR update process and all feeder processes for ways to improve the quality and accuracy of the FSAR.

- Determine the accuracy of the current FSAR based on identified deficiencies, NRC inspection reports, SITA reports, or other sources.

- Evaluate the completeness of the FSAR against regulatory requirements.

The objective of Phase 2 is:

- Develop necessary procedure changes to incorporate the short term recommendations from Phase 1.

The objective of Phase 3 is:

- Evaluate the administrative processes, including software, used for FSAR production against maintenance, production, and distribution requirements.

The projected completion date for Phase 3 is February 1, 1997.

The inspector considered this self-initiated review a strength that should provide better on-site control in keeping the FSAR current and technically correct. The inspector had no questions on this issue.

E7.3 Quality Assurance in Engineering Activities - Self Assessment

a. Inspection Scope (93801)

The inspectors reviewed the licensee's engineering self-assessment of the Standby Shutdown System (SSS) which was performed in preparation for the NRC inspection.

b. Observations, Findings, and Conclusions

The self-assessment identified findings in the areas of procedures, testing, documentation, and equipment which indicated a comprehensive review of the SSS. The findings were appropriately identified in the problem investigation process (PIP) for resolution. Proposed corrective actions adequately addressed the identified problems and provided potential enhancement of the SSS capability at the station. Overall performance in the SSS self-assessment was good.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) LER 50-369/94-07-01: Inadvertent Diesel Generator Starts Due to Unanticipated Interaction of Components. On October 24, 1994, during the performance of a routine 1B diesel operability test, the diesel generator autostarted when control power was restored to the engine. An immediate verification was performed to ensure that no ESF actuation system signal had been received. No signal had been received and the diesel was subsequently shutdown. Investigations were conducted to identify the cause for the autostart but none was identified. The diesel was subsequently retested and declared operable. On December 13, 1994, the 2A diesel generator experienced the same type of inadvertent start when the control power was restored.

The licensee conducted detailed investigations of the diesel generator start circuits and determined that the inadvertent starts were caused by inadequate design review prior to installation of modifications to the start circuitry. Additional solenoid valves had been included in the circuitry; however, the valves were installed without voltage suppression devices across the coils. The lack of suppression resulted in electrical surges when the control power was restored. These surges were of a magnitude that caused previously installed relays to actuate and initiate a diesel generator start. The licensee modified the diesel generator control circuitry to eliminate the potential for recurrence.

The inspectors determined that the licensee failed to perform an adequate review of the change prior to installation constituting a violation of 10 CFR 50 Appendix B Criterion 3 "Design Control." This licensee identified and corrected violation is being treated as a Non-Cited Violation 50-369, 370/96-04-04, Inadvertent Diesel Generator Starts, consistent with Section VII.B.1 of the NRC Enforcement Policy.

E8.2 (Closed) LER 50-370/96-01-00 and 96-01-01: Unit 2 Refueling Water Storage Tank Level Instrumentation Inoperability During Cold Weather Conditions

(Closed) LER 50-369,370/96-02: Past Inoperability of Emergency Diesel Generator 2B Due to Low Lube Oil Pressure Caused By Unanticipated Interaction of Systems and Components

Based on the identification of both of the conditions as NOVs in Report 50-369,370/96-02, these two LERs are closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Tour of Unit 1 and 2 Radiologically Protected Areas (RCA)

a. Inspection Scope (83750, 71750)

The inspectors accompanied an RP technician on a tour of the Unit 1 and Unit 2 RPA and outside areas to observe and discuss radiological control practices. The inspectors also reviewed the most recent radiological event reports, and evaluated the use of catch containers, and observed the status of the RCA contaminated floor spaces.

b. Observations and Findings

Radiological housekeeping practices and worker awareness of radiological hazards were generally good. The RP technician verified various Radiation Area and High Radiation Area boundary postings. No discrepancies were observed.

The inspectors evaluated the licensee's controls as they relate to the use of catch containers and contaminated floor spaces within the RCA. They observed that in July 1994 there were at least 50 catch containers that were being used to restrict and direct potentially contaminated liquids into waste liquid tanks and/or containers. By contrast, the inspectors observed that in May 1996 only 16 catch containers were installed in the RCA, and the RCA floor space considered to be contaminated was significantly reduced.

c. Conclusions

A tour of Unit 1 and 2 radiologically controlled areas revealed generally good radiological housekeeping and worker RP awareness. Also, a significant reduction in the number of catch containers and potentially contaminated floor space within the RCA has been noted. This reduction is considered a strength.

P1 Conduct of EP Activities

P1.1 Operational Status of the Emergency Preparedness Program

a. Inspection Scope (82701)

The inspector reviewed day-to-day routine operations and program initiatives to assess the effectiveness of the licensee's

implementation of their Emergency Plan in meeting the regulatory requirements of emergency preparedness. The following routine areas were reviewed:

- changes to the Emergency Plan and Implementing Procedures
- maintenance of selected emergency equipment and supplies
- review of the independent audit report conducted since the last inspection.

The inspector observed the following emergency preparedness training being conducted to assess the effectiveness of the training and some innovative initiatives being taken during training to enhance their overall emergency preparedness program:

- requalification training for reactor operators
- a table-top exercise for the technical support center, the operational support center, and the emergency operations facility
- a simulator driven training exercise that included participation by some of operations shift "d", the technical support center, the operational support center, the emergency operations facility, the near-site media center, and limited participation by the joint information center.

b. Observations and Findings

The inspector observed that changes made to the Emergency Plan or procedures were properly done. The Emergency Planning Manager had initiated the use of two forms, an initial screening checklist and a more detailed site 10 CFR 50.54(q) review to ensure any changes that would decrease the effectiveness of the Emergency Plan would not be implemented without prior NRC approval.

During the table-top and training exercises, the inspector observed selected activities in the TSC and OSC. In both facilities it was observed that the layout and equipment supported emergency response, and all emergency equipment was operational. Another equipment area reviewed by the inspector, focused on the availability data of the radiation monitors that provide input to the emergency action level scheme. The monitors were included in a Technical Specifications average availability of 98.24 percent for the period June 1, 1995, to June 1, 1996. The inspector also reviewed the operability data of the 57 sirens that provide the early warning to the populace within the 10 mile plume exposure

pathway zone. The operability rate was 97.9 percent as reported in the 1995 Siren Availability Report for the Federal Emergency Management Agency.

The inspector also reviewed the Regulatory Audit SA-95-54 Emergency Preparedness report. The report was adequate for the scope of the audit. A review of the file for the June 28, 1995, Notification of Unusual Event revealed a proper classification and timely notifications.

The inspector found the training performed in support of emergency preparedness to be professional and thorough. There were ample opportunities provided to improve skills by instruction that focused on emergency preparedness requirements as well as lessons learned. The scenario used for the training exercise was designed to challenge the operators in an area not previously tested, and it was effective in accomplishing that objective. While observing the exercise, the inspector noted the effectiveness of the new teleconferencing system the licensee used between the primary emergency response managers in the TSC, OSC, and EOF.

c. Conclusions

The inspector found the emergency preparedness program, including the Emergency Plan, facilities, emergency equipment, audits, and training to be maintained or conducted in a manner that supported good emergency response in the event of an accident.

P1.2 Temporary Instruction 2515/131, Licensee Offsite Communication Capabilities

Information gathered in support of this temporary instruction is documented in an attachment to this report.

G. Conclusion/Assessment

The emergency preparedness program was being maintained in a state of operational readiness.

S1 Conduct of Security and Safeguards Activities

S1.1 Replacement Steam Generator Project Security

On June 12 the licensee received the first of eight replacement steam generators at the McGuire site. The generator was transported by rail car to the site. The inspectors observed security personnel performance. The licensee established an isolation area and the rail car was thoroughly searched prior to entry into the protected area. The inspectors noted good security coverage during the entire delivery evolution. No discrepancies were noted.

A steam generator laydown area has been established to allow the licensee to complete pre-installation maintenance on each of the replacement generators. The inspectors noted adequate security support and concluded that overall security performance during replacement steam generator receipt and storage was good.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 18, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Boyle, J., Manager, Safety Assurance (Acting)
Byrum, W., Manager, Radiation Protection
Curtis, T., Manager, Mechanical/Nuclear Systems Engineering
Geddie, E., Manager, McGuire Nuclear Station
Herran, P., Manager, Engineering
Jones, R., Superintendent, Operations
Manoocheer, N., Superintendent, Maintenance
McMeekin, T., Vice President, McGuire Nuclear Station
Sample, M., Manager, Steam Generator Maintenance Group
Snyder, J., Manager, Regulatory Compliance
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical/Civil Equipment Engineering
Tuckman, M., Senior Vice President, Duke Power Company

NRC

G. Maxwell, Senior Resident Inspector, McGuire
S. Shaeffer, Senior Resident Inspector, McGuire
M. Sykes, Resident Inspector, McGuire
S. Rudisail, Project Engineer, RII

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60710:	Refueling Activities
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73753:	Inservice Inspection
IP 82701:	Operational Status of the Emergency Preparedness Program
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
IP 93801:	Regional Initiative
TI 2515/ 131:	Temporary Instruction for Licensee Offsite Communication Capabilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

369, 370/96-04-01	VIO	Surveillance not performed as required by procedure (Section 3.1)
369, 370/96-04-02	URI	FSAR Inconsistencies (Section E7.1)
369, 370/96-04-05	IFI	Verification of SSS Activation Time during Emergency Plan Drill (Section O4.1)

Closed

369, 370/96-04-03	NCV	Inadvertent ESF actuation due to inadequate procedural guidance (Section O1.2)
369, 370/96-04-04	NCV	Inadvertent diesel generator starts (Section E8.1)
369,370/95-09-01	IFI	Examination of limited access welds (Section M8.1)
370/95-03	LER	Momentary loss of containment integrity (Section O8.1)

370/96-01-00 and 96-01-01	LER	Unit 2 refueling water storage tank level instrumentation inoperability during cold weather conditions (Section E8.2)
370/96-02	LER	Past inoperability of emergency diesel generator 2B due to low lube oil pressure caused by unanticipated interaction of systems and components (Section E8.2)
369/95-05	LER	Manual trip initiated as a result of equipment failure (Section O8.2)
369/95-06	LER	Automatic reactor trip occurred due to equipment failure (Section M8.2)
369/94-07-01	LER	Inadvertent starts of 1B and 2A EDG due to inadequate engineering review (Section E8.1)

Items Discussed

None

LIST OF ACRONYMS USED

AC	alternating current
DBD	Design Basis Document
DG	diesel generator
ECCS	emergency core cooling system
EDM	Engineering Directive Manual
EOC 10	end-of-cycle 10
EOF	Emergency Operating Facility
EP	Emergency Plan
ET	eddy current
FSAR	Final Safety Analysis Report
IFI	inspector followup item
IR	Inspection Report
ISI	inservice inspection
JPM	job performance measure
MT	magnetic particle test
NCP	reactor coolant pump
NDD	no detectable degradation
NDE	non-destructive examination
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation, NRC
NSAC	Nuclear Safety Analysis Center
NSW	Nuclear Service Water
OSC	Operations Support Center
PIP	Problem Investigation Process
PT	liquid penetrant test
SG	steam generator
SMU	standby makeup pump
SSER	Supplemental Safety Evaluation Report
SSF	Standby Shutdown Facilities
SSS	Standby Shutdown System
TSC	Technical Support Center
UFSAR	updated final safety analysis report
USQ	Unreviewed Safety Question
UT	ultrasonic test

Attachment to Integrated Inspection Report 50-369/96-04 and 50-370/96-04

The following information is provided as requested by Temporary Instruction 2515/131, Licensee Offsite Communication Capabilities

1. Communication circuits that the licensee would rely on to notify offsite agencies of emergency events or plant status.

   a. The Selective Signaling System is the primary means of communication.

   b. Standard telephone lines serve as a backup means of communication.

   c. A radio system can be used for communication among off-site monitoring teams, counties, the control room, TSC and EOF. Communications by radio with the State's headquarters (i.e. SERT) can be achieved either by using the Duke Network (using portable radios) or by using the State's Radio Network.

2. The following additional information is provided regarding the above means of communication.

   The Selective Signaling is on the Duke microwave system tied to short lines leased from the local telephone company. This circuit allows intercommunication among the EOF, TSC, control room, counties, and States.

3. The Control Room, TSC, and EOF all have transmission and reception capability of the three systems listed in paragraph 1 above.

4. The relay of an event notification via an intermediate offsite organization could occur if both the Selective Signaling System and standard telephone lines could not be used. In this instance the licensee could use a radio relay from the counties to the States.

5. A review of the FSAR listed the following external hazards to which the plant may be susceptible (hurricane, wind and snow loading, tornados, flooding, and earthquake).

6. All means of communications share a common cable run/conduit external to the plant except the external telephone lines.

7. Primary and first back-up communications systems would be susceptible to design basis external hazards as they are routed through the main communications building which is not designed to withstand all design basis external hazards. However, the third

means of communication, the radio; would be available from the Control Room. Also, the telephone transmission lines on site are buried. The wind load rating of the microwave tower at the site is 90 mph wind load with 1/2 inch ice loading.

8. The power supply for the Selective Signaling System is 24V DC. The radios have both AC and battery (12V) backup as a power supply. None of the communications systems would be disabled by a loss of all offsite power or a station blackout. Only the Control Room and TSC Selective Signaling share a common power supply so that a loss of power would affect more than one circuit. For those systems with battery-powered backup power supplies, the communication circuit is the only load served by the battery.

9. Notification circuits listed in i above would potentially be cluttered with traffic in the event of a general emergency with the exception of the Selective Signaling System which is a dedicated line.

10. The licensee does not have a communication contingency procedure as referenced in paragraph 04.02 of the TI. The licensee does maintain spare parts onsite in its communication building for use in restoring communication capability.