UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

Report Nos.: 50-369/84-11 and 50-370/84-09

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

Docket Nos.: 50-369 and 50-370

License Nos.: NPF-9 and NPF-17

Facility Name: McGuire Nuclear Station Units 1 and 2

Inspection at McGuire site near Charlotte, North Carolina

Inspectors: A. J. Ignatonis for W. Orders — 6/20/84 Date Signed

A. J. Ignatonis for R. Pierson — 6/20/84 Date Signed

Approved by: Virgil Brownlee — 6/21/84 Date Signed
V. L. Browhlee, Section Chief
Division of Reactor Projects

SUMMARY

Inspection on February 20 - April 20, 1984

Areas Inspected

This routine, unannounced inspection involved 320 inspector-hours on site in the areas of operations, safety verification, surveillance testing and maintenance activities.

Results

Two violations were identified - use of two procedures for Engineered Safety Features test in which one was inadequate and the other procedure was not followed resulting in inadvertent Train A blackout (50-369/84-11-03); and failure to perform required testing resulting in loss of containment integrity (50-369/84-11-02 and 50-370/84-09-03).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*G. Cage, Superintendent of Operations
*T. McConnell, Superintendent, Technical Services
*M. McIntosh, Station Manager
*M. Pacetti, MSRG
*D. Rains, Superintendent of Maintenance
*M. Sample, Project Engineer
*B. Travis, Operations Engineer
*G. Vaughn, Manager, Nuclear Station
*L. Weaver, Superintendent, Station Services

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

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on April 27, 1984, with those persons indicated in paragraph 1 above. The licensee expressed cognizance of the issues discussed. The two violations as described in paragraphs 10 and 11, involved use of an inadequate procedure and failure to follow another procedure for the Engineered Safety Features test, and failure to verify containment integrity by not testing the Reactor Vessel Level Indication System penetrations. Those violations were discussed in detail.

3. Licensee Action on Previous Enforcement Matters

Not inspected.

4. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. New unresolved items identified during this inspection are discussed in paragraphs 5 and 11.

5. Plant Operations

The inspector reviewed plant operations throughout the report period, February 20 - April 20, 1984, to verify conformance with regulatory requirements, Technical Specifications and administrative controls. Control room logs, shift supervisors' logs, shift turnover records and equipment removal and restoration records were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel on day and night shifts.

Activities within the control rooms were monitored during shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in the Station Directives. The complement of licensed personnel on each shift met or exceeded the minimum required by technical specifications. Operators were responsive to plant annunciator alarms and appeared to be cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a systematic basis. The areas toured include but are not limited to the following:

Turbine Buildings

Auxiliary Buildings

Units 1 and 2, Electrical Equipment Rooms

Units 1 and 2, Cable Spreading Rooms

Station Yard Zone within the Protected Area

Unit 1 Reactor Building

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

McGuire Unit 1 began the reporting period at 95% power, in an elevated Tavg mode of control. Power was restricted due to an inoperable main turbine governor valve (discussed in previous reports). Power was maintained at 95% until Friday, February 24, 1984, when the unit was shutdown for the unit's first refueling outage.

On Friday, March 16 at 3:00 p.m., core alterations commenced and continued until Tuesday, March 20, 1984, when at 4:21 p.m. core off-load was completed.

On March 30, 1984, a successful 24-hour diesel generator test run was completed followed by an Engineered Safety Features Actuation test which was also completed satisfactorily.

The core remained unloaded until April 1, 1984, 12:45 a.m., when core reload commenced. During core reload, a significant number of bowed fuel assemblies were encountered. The licensee and Region II personnel are evaluating applicable core data to ascertain the significance, if any, of these bowed assemblies. Core alterations were complete at 10:50 a.m., April 8, 1984. The unit entered Mode 5 at 9:30 a.m. Friday, April 13, 1984 and was maintained in Mode 5 through the duration of the reporting period.

McGuire Unit 2 began the report period, decreasing power to Mode 2 to facilitate maintenance on a pressurizer spray valve which was leaking and causing excessive pressurizer heater actuation. Following the completion of that work, the unit was placed on line at 10:00 p.m. and was subsequently escalated to 100% power. The unit operated virtually unencumbered until 10:06 p.m. on March 3, when power reduction to 50% power was commenced in order to facilitate a containment entry, to seek the source of a secondary system leak. At 12:48 a.m., March 4, the unit began decreasing power toward 10-05/814/ amps to facilitate the security of a steam generator blowdown valve - the source of the leak. The unit was taken on line at 5:52 a.m. that morning and entered Mode 3 at 9:45 a.m. At 6:55 a.m., the following morning, the unit entered Mode 2 and was placed on line at 8:50 a.m. with subsequent ascension to full power. The unit operated virtually trouble free until March 14 at 11:30 a.m., when it was determined that certain penetrations in the Unit 2 containment had not undergone required testing and as such, containment integrity was unverified (see paragraph 11 of this report for a detailed discussion). Resultantly, pursuant to Technical Specification (TS) 3.6.1, at 12:19 p.m. that afternoon, unit shutdown commenced at a rate of 20% per hour. At 4:35 p.m., testing of those penetrations was complete, power reduction was terminated and the unit returned to full power operation. Unit 2 operated at virtually 100% power until March 19 when at 3:00 p.m., the reactor tripped on low-low steam generator water level caused by a failed power supply in a process control cabinet.

The unit was subsequently restarted and reached criticality at 3:53 a.m. on Tuesday, March 20, 1984. The unit was paralleled to the grid at 6:11 a.m. that morning and operated at or about 100% power until 10:46 a.m. on Thursday, April 19, 1984, when the reactor tripped from 100% power as detailed below.

While preparing to perform PT/1/A/4350/05, the 6.9 KV Normal Auxiliary Power Automatic Transfer Test, #2 SMXT was being transferred to its alternate power supply. The "B" main feedwater pump (MFP) controller de-energized and reduced the speed of the MFP, such that it was not feeding the steam generator and then failed to recover following re-energization after the power transfer. The subsequent feedwater transient caused the "C" steam generator to reach its low-low level setpoint and resulted in a reactor trip. All systems responded normally.

It should be noted that when the "B" MFP backed down, the operator in an effort to preclude a unit trip, was attempting to trip the "B"MFP which would have initiated a unit runback. However, the operator mistakenly tripped the "A" MFP instead which only complicated the event. The inspector in evaluating the operator's actions, detected that there is no procedure for the loss of one MFP. Regulatory Guide 1.33, Rev. 2, 1978 recommends procedures for not only loss of feedwater transients, but also feedwater system failures. Pending resolution of this issue, it will be maintained as an unresolved item (50-370/84-09-01).

Failure of the MFP controller was found to be due to a plugged orifice. It was subsequently repaired and the unit achieved criticality at 12:32 a.m. on Friday, April 20, 1984, and reached 100% power at 1:00 p.m. that afternoon. The unit finished the reporting period operating at 100% power.

6. Surveillance Testing

The surveillance tests categorized below were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy.

The completed test procedures examined were analyzed for embodiment of the necessary test prerequisites, preparations, instructions, acceptance criteria, and sufficiency of technical content.

The selected tests witnessed were examined to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration completed and test results were adequate.

The selected procedures perused attested conformance with applicable TS and procedural requirements, they appeared to have received the required administrative review and they apparently were performed within the surveillance frequency specified.

Three cases of deficiencies encountered during surveillance testing are detailed in paragraphs 8, 9, and 10.

Procedure	Title
PT-1-A-4200-02B	Cold Shutdown Containment Integrity
PT-1-A-4200-06B	Boron Injection Valve Lineup
PT-1-A-4200-19	ECCS & NS Valve Lineup
PT-1-A-4200-02C	Containment Integrity During Core Alterations
PT-1-A-4450-01	Preparation for Refueling
PT-1-A-4206-01B	NI Pump 1B Performance Test
PT-1-A-4550-07	Total Core Reload
PT-1-A-4450-04B	Hydrogen Recombiner A&B Performance
PT-2-A-4209-01B	NV Pump 2B Performance Test
PT-2-A-4252-01	T/D Auxiliary Feed Pump Test
PT-2-A-4252-01B	M/D B Auxiliary Feed Pump Test
PT-2-A-4206-01A	NI Pump A Performance Test
PT-2-A-4206-01B	NI Pump B Performance Test
PT-2-A-4401-01A	KC Train A Performance Test
PT-1-A-4403-01B	RN Pump 1B Performance Test
PT-1-A-4350-15B	D/G Pump 1B Performance Test
PT-1-A-4209-01B	NV Pump 1B Performance Test
PT-1-A-4252-07	Auxiliary Feedwater System Performance

7. Maintenance Observations

The maintenance activities categorized below were analyzed and/or witnessed by the resident inspection staff to ascertain procedural and performance adequacy.

The completed procedures examined were analyzed for embodiment of the necessary prerequisites, preparation, instruction, acceptance criteria and sufficiency of technical detail.

The selected activities witnessed were examined to ascertain that they were applicable, current written approved procedures were available and in use, that prerequisites were met, equipment restoration completed and maintenance results were adequate.

The selected work requests/maintenance packages perused attested conformance with applicable Technical Specifications and procedural requirements and appeared to have received the required administrative review.

WORK REQUEST	EQUIPMENT
115620	Loose Parts Monitor
023865	UHI Piping
85495	NI 358A
029774	EVCA
00023	EDGA
28524	Main Electrical Generator
23225	D/G 1B
54902	SSF D/G
118007	SSF Batteries
118009	1A D/G

8. Destruction of Charging Pump 2B Speed Changer

On the morning of February 23, 1984, McGuire Unit 2 was operating at 100% power. At 9:15 a.m. that morning, an Instrument and Electrical (I&E) technician removed thermometer 2MNVTH9340 from the speed changer on Centrifugal Charging (NV) Pump 2B for calibration. This resulted in a loss of lubrication to the speed changer which led to serious damage to the bearings.

Due to the loss of the speed changer, NV Pump 2B and NV Train 2B were declared inoperable, pursuant to Technical Specifications (TS) 3.5.2, 3.1.2.2, and 3.1.2.4. These specifications require that both trains of NV be operable in Modes 1, 2, and 3. NV Pump 2A was operable and was started to maintain charging flow.

The speed changer was then repaired and the pump returned to service at 6:07 a.m. on February 26, within the TS allowed 72 hour period.

A review of this incident revealed the following apparent deficiencies:

1) A review of the procedure employed to facilitate this work, IP-0-B-3201-02, Calibration Procedure for Ashcroft B. Metal Thermometers, indicated that the guidance offered in the procedure for removal of the instruments from their associated equipment were general in nature: Step 5.2 of the procedure, under Limits and Precautions, states:

> "Thermometers may or may not be installed in a well. Some reducer fittings resemble a well in appearance, and removal of a thermometer in direct contact with the process may be hazardous, both to the equipment and personnel. If you suspect the thermometer is NOT in a well, isolate and tag as appropriate before removing the thermometer from the process."

In addition, as a special caution note, just prior to Step 10.2 of the body of the procedure, the step in which the instrument is removed, a warning is declared stating:

CAUTION:

> BEFORE REMOVING THERMOMETER FROM PROCESS, NOTE PRECAUTION OF SECTION 5.2.

It is the intent, that procedures, in general, be sufficiently detailed such that qualified personnel might perform those functions without direct supervision. The simplicity of removing the thermometer is such that it is felt a more detailed procedure may not have been required. Further, the instructions offered in the procedure, Steps 10.2 and 5.2, appeared to be adequate in terms of warning personnel of possible equipment damage or personnel injury. Information in LER 370/84-08 reveals that the technician believed that the reducer employed to correct the thermometer to the piping was a well. (The precaution warns of this.) If the technician was unsure as to the existence of a well, his qualifications and the procedural precautions should have been adequate to preclude this occurrence.

2) The thermometer was mislocated, in that it should have been located on the thrust bearing of the pump as opposed to the speed changer. Although, this is a consideration, it is equally imprudent to remove any instrument from a dynamic process, therefore, the above argument remains valid.

It is concluded that, the procedure, had it been prudently implemented would have been sufficient for the task.

Having failed to heed the precautions of the procedure constitutes a failure to follow procedure which in turn is in violation of TS 6.8.1 which requires the implementation of current written approved procedures to facilitate plant maintenance/testing, on safety related equipment.

Pursuant to the provisions of 10 CFR 2, Appendix C, IV.A, a notice of violation will not be issued for this violation in as much as the event meets the criterion therein.

9. Reactor Trip - Operator Error - Pressurizer Pressure

PT/2/A/4150/01A, Reactor Coolant System Leak Test, is performed prior to reactor start-up if the Reactor Coolant System has been opened during unit shutdown. The system is pressurized to 2350-2400 psig, and an inspection is performed to verify leak tightness of the system.

During performance of this test on January 22, 1984, a reactor trip occurred at 2324 when pressurizer pressure exceeded 2385 psig, the setpoint for the pressurizer high pressure reactor trip. At the time, Unit 2 was in Mode 3 with the shutdown rod banks withdrawn.

As stated above, PT/2/A/4150/01A, Reactor Coolant System Leak Test, is performed routinely after the Reactor Coolant System has been closed following refueling or maintenance which required opening the system. The test requires increasing Reactor Coolant System pressure to 2350-2400 psig with system temperature 520°F and with the pressurizer power-operated relief valves blocked (OPEN-CLOSE-AUTO switch turned to CLOSE). A visual inspection is then conducted to verify leak tightness of the system.

Since the pressurizer high pressure reactor trip setpoint is 2385 psig, the test is normally performed with the reactor trip breakers open and all rods inserted. In this manner, the test pressure (2350-2400 psig) does not challenge any safety functions. The status of the reactor trip breakers was not, however, stipulated as a procedure prerequisite.

In this case, the procedure was performed with the reactor trip breakers closed and the shutdown banks withdrawn to expedite plant start-up. The Control Operators who were performing the test were cognizant of the trip setpoint. They chose to maintain Reactor Coolant System pressure at ≈2370 psig (±2 psig), a range they considered to be sufficiently low to avoid a pressurizer high pressure reactor trip during fluctuations in system pressure.

The operators did not consider instrument accuracy or trip logic channels when they determined the 2370 psig target pressure or when they selected computer point A-0826 (Reactor Coolant System Wide Range Pressure) to monitor pressure. This analog computer point receives a signal from pressure transmitter 2NCPT5140, located on the "C" hot leg. The instrument range is 0-3000 psig with a ±0.5% (±15 psig) calibration tolerance. It can be seen that an observed 2370 psig could correspond to an actual pressure of 2355 psig to 2385 psig, the trip setpoint for pressurizer high pressure.

Computer point A-1118 (pressurizer pressure channel I) would have been the appropriate choice for monitoring Reactor Coolant System pressure. This point receives a signal from pressure transmitter 2NCPT5160, located on the pressurizer, which provides one signal for the 2 out of 4 pressurizer high pressure trip logic. The instrument range is 1700-2500 psig with a calibration tolerance of ±0.5% (±4 psig). An observed pressure of 2370 psig could correspond to an actual pressure of 2366 psig to 2374 psig.

The target pressure of 2370 (±2) as indicated by computer point A-0826 (Reactor Coolant System Wide Range Pressure) was maintained for ^{2}1 minute prior to the reactor trip. At that time, A-0826 was indicating 2372 psig and computer point A-1118 (pressurizer pressure channel I) was indicating 2390 psig. It should be noted that the procedure did not specify the instrumentation which should be monitored during system pressurization.

It is concluded that two conditions contributed to the event:

1) a. inadequate procedure in failing to specify appropriate prerequisite conditions

   b. inadequate procedure in failing to specify instrumentation which should be observed during system pressurization.

2) personnel error in that the operators failed to determine the correct instrumentation to monitor

It appears that the overriding factor is the inadequate procedure in failing to provide sufficient detail.

TS 6.8.1.a requires written approved procedures be employed in the performance of surveillance tests for NSSS pressurization and leak detection. Regulatory Guide 1.33, February 1978, Appendix A, 8.b.(1)(s) identifies this test as a typical safety-related activity that should be covered by written procedures. Implicit in that requirement is the requirement that the procedure entail sufficient specificity to facilitate the successful completion of the task. This procedure did not entail adequate detail, and as such constitutes a violation of TS 6.8.1.a.

Pursuant to the provisions of 10 CFR 2, Appendix C, IV.A, a notice of violation will not be issued for this violation in as much as the event meets the criterion therein.

10. Inadvertent ESF Blackout Initiation

On the afternoon of April 20, 1984, McGuire Unit 1 was in Mode 5 when performance personnel were attempting to perform Step 12.5.A.21 of PT/1/A/4200/09A Change 54. This step tests the blackout response of valve 2RN 43A, an 'A' train isolation valve separating essential nuclear service water header 2B from essential header 2A and the non-essential header. This valve will close on receipt of an Engineered Safety Features (ESF) actuation signal from either unit. Completion of this step had been precluded by plant conditions during earlier ESF periodic testing which was done over several days during the present refueling outage of February through April 1984. To prevent ESF actuation of previously tested components, a procedure modification was written to allow actuation of 2RN43A while electrically isolating the remaining ESF circuitry. This was to be accomplished by opening sliding links which would electrically isolate the portion of the circuit affecting the actuation of 2RN43A from the rest of the ESF actuation circuitry. The procedure incorrectly listed sliding link B13 to be opened vice B14, and as a result 2RN43A was also electrically isolated. The technician attempted to actuate 2RN43A by energizing relay LRA1 (CA) which shuts contacts providing power to the relay which picks up 2RN43A. Consequently, 2RN43A did not actuate when link B13 was opened which was in the current path to the relay that picks up 2RN43A. Because the technician could not actuate 2RN43 by pulling the toggle which makes switch contacts in the magnetic device, the procedure was modified to allow direct energization of relay LRA1 (CA). When the relay which picks up 2RN43A still failed to function, the technician began to troubleshoot the circuit. While troubleshooting, the lead wire was disconnected from relay LRA1 (CA) and inadvertently connected to the power supply instead of to the terminate on LRA1(CA).

The procedure step for appropriate wiring connections required independent verification in the modified procedure, but the discrepancy was not noticed until the disconnected lead was energized. This lead is connected in parallel to relay LRA2 (DA) which trips normal and standby incoming power giving the ESF circuitry the indication of a blackout. Consequently, when LRA2 (DA) was energized, the ESF circuitry responded correctly and initiated. Train "A" blackout load sequence initiation including starting of the train "A" diesel generator.

In assessing this incident, several items of concern were noted:

a) the procedure PT/1A/4200/09A Change 54 incorrectly specified that link B13 be opened vice link B14. If link B14 had been opened with B13 remaining closed, then the test should have worked providing the remainder of the procedure was correctly followed.

b) During performance of the modified procedure PT/1A/4200/09A Change 57, the power supply was incorrectly connected to the lead which had been disconnected from LRA1 (CA) vice the terminal on LRA1 (CA) as specified in the procedure. Although this step required independent verification, the error was not noticed until the incorrect relay LRA2 (DA) was energized.

TS 6.8.1 requires that current written approved procedures be established, implemented and maintained covering applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978 which includes, "surveillance testing of safety-related equipment" and that this testing should be properly pre-planned and performed in accordance with written procedures, documented instructions appropriate to the circumstances. In that the procedure was incorrect in specifying the correct link to be opened and was subsequently incorrectly implemented as detailed above, constitutes a violation of TS 6.8.1. (50-369/84-11-03). Similar violations on failure to follow the requirements of the procedure and using a procedure which contained an incorrect step while performing functional testing of safety related equipment have been identified in inspection report numbers 50-369/83-33 and 50-369/83-47.

11. Containment Penetration Testing

On March 14, 1984 at approximately 11:30 a.m., it was determined that there was a possible lack of containment integrity involving the Reactor Vessel Level Indication System (RVLIS) on Units 1 and 2. The licensee's Quality Assurance (QA) review revealed that the welds connecting the tubing together and the welds connecting the tubing to the containment penetration fitting had not been tested on Unit 2. The condition on Unit 1 existed from March 1981 to June 1982 with the unit entering Mode 4 which required containment integrity, up to a power level of 90% and on Unit 2 from July 1983 to March 1984 with the unit operating in Modes 1 - 4 at power levels up to 100%.

Containment integrity was verified on Unit 1 on June 29, 1982, with a pressure test performed by Westinghouse. Unit 2 containment integrity was verified when performance personnel performed a leak test on RVLIS on March 14, 1984.

As previously stated, on March 14, 1984, a QA review of Unit 2 RVLIS revealed that the welds connecting the tubing and the welds connecting the tubing to the containment penetration fittings had not been tested. Since the welds had not been tested, containment integrity could not be verified. This condition existed on Unit 2 for approximately eight and a half months. Upon investigation, it was also revealed that this condition had previously existed on Unit 1 for approximately fifteen months. The QA review also revealed that RVLIS on both units was not installed under the proper QA program, even though the system drawings indicated that the entire system was QA Condition One. Further, it was determined that the tubing employed was not of the standard required for safety-related systems.

Failure to perform the test did not affect the health and safety of the public. Although the penetrations were not properly tested prior to entering Mode 4, their integrity was assured by the tubing and bellows in the Containment Vessel and Auxiliary Building. It was shown by the pressure test, performed by Westinghouse on the Unit 1 RVLIS, and the leak test on Unit 2 RVLIS that the penetrations would have maintained containment integrity in a design event.

10 CFR 50, Appendix J, IV.A, requires that any major modification, replacement of a component which is part of the primary containment boundary or resealing a seal welded door, performed after the preoperational leakage rate test, shall be followed by either a Type A, B, or C test as applicable.

Having failed to test the penetrations as required by 10 CFR 50, Appendix J, Section IV, Special Tests, led to the violation of TS 3.6.1.1 which requires containment integrity in Modes 1-4. Further, in inspection report numbered 50-369/83-20 and 50-370/83-27, detailed is a previous example in which a required test (TS 4.6.1.2.f, soap bubble) was not performed - a test to confirm containment integrity/containment leakage rate. This is a violation (50-369/84-11-02 and 50-370/84-09-03).

The issues of the RVLIS systems not having been installed under the proper QA program and that the tubing is not traceable will be carried forward as an unresolved item (50-369/84-11-01 and 50-370/84-09-02).