UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

Report Nos. 50-369/81-39

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

Facility Name: McGuire 1

Docket No. 50-369

License No. NPF-9

Inspection at McGuire site near Charlotte, North Carolina

Inspectors: A. J. Ignatonis for 1/29/82
P. R. Bemis Date Signed

D. Falconer 1/29/82
D. Falconer Date Signed

Approved by: A. J. Ignatonis for 1/29/82
J. C. Bryant, Section Chief, Division of Resident and Reactor Project Inspection Date Signed

SUMMARY

Inspection on November 23 to December 23, 1981

Areas Inspected

This routine, announced inspection involved 280 resident inspector-hours on site in the areas of operational safety, safety system challenges, maintenance, surveillance, and independent inspection.

Results

Of the five areas inspected, no violations or deviations were identified.

DETAILS

1. Persons Contacted

Licensee Employees

*M. McIntosh, Station Manager
*G. Cage, Operations Superintendent
R. Wilkinson, Superintendent of Administration
N. McGraw, Operations
*D. Sample, Projects and Licensing
D. B. Lampke, Project and Licensing
D. M. Franks, Quality Assurance
*C. M. Fish, Administration
D. B. Adkins, Security

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

Other Organizations

J. Roth, Westinghouse
D. Puryear, Westinghouse

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on December 23, 1981, with those persons indicated in paragraph 1 above and the results were acknowledged by the Plant Manager.

3. Licensee Action on Previous Inspection Findings

Not inspected.

4. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve noncompliance or deviations. A new unresolved item identified during this inspection is discussed in paragraph 6a.

5. Operational History

The unit was in cold shutdown to perform eddy current tests on the steam generator tubes at the beginning of the inspection period. When no detectable tube degradation was found, the plant proceeded towards power operation. On November 24, at 11:10 p.m. the unit went critical and proceeded towards 75% power for testing at that power level.

After the power ascension testing was completed at the 75% level, the unit was taken to 30% power to perform the loss of offsite power test. When the test was performed the turbine generator did not react as designed, the reactor tripped and a station blackout occurred. During the ensuing transient the generator hydrogen cooler was damaged which caused the unit to enter an extended outage. This transient will be discussed in more detail in a later paragraph.

While the unit was in mode 5, during the generator and hydrogen cooler repair, the integrated engineered safeguards features systems (ESF) test was run. There were many problems which occurred during this test; these will be discussed in more detail in subsequent paragraphs, but all the problems were satisfactorily resolved prior to the end of the outage.

The unit is presently in cold shutdown awaiting reassembly of the main electrical generator. Once the generator is ready the unit will be taken to 90% power, Technical Specification (TS) limit due to reactor coolant system flow, where power ascension testing at that level will be performed.

6. Operations Safety Verification

During the inspection interval the inspector observed operations and manning in the control room and throughout the plant. Control operator, SRO in the control room, key control, tagging, modification, and work request logs were reviewed. The status of instrument calibration, equipment tags, limiting conditions operation (LCO) log and annunciators were verified. Compliance with selected technical specification parameters was independently verified, where possible, during each mode of operation. Inspection of certain Unit 1 systems was performed to verify operability and system line up was verified in the control room and in the plant for the highhead (NV), intermediate head (NI) and low head (ND) safety injection system. In addition, the diesel startup and operation was observed.

Based on this review and verification, one unresolved, one open and two inspector followup items were identified and are discussed in more detail in paragraphs 6a through 6d.

a. High Head Centrifugal Charging Pump Discharge Pressure Discrepancy.

In March, 1981, Duke was notified by Westinghouse of a potential shaft torque problem due to locknut arrangement on NV centrifugal pumps with more than 500 hours of operation. NV 1A pump at McGuire had more than 500 hours of operation and was sent for required modification, which included a new shaft.

There was a spare NV pump at McGuire which had not been operated; therefore, the modification could be accomplished onsite and the spare shaft and impeller were installed in NV 1A pump. When the original NV 1A shaft and impeller were returned following modifications they were installed in NV pump 1B and the original NV 1B equipment was moved to an onsite warehouse.

In November of 1981, McGuire received Technical Bulletin Number NSD-TB-81-10 from Westinghouse stating, in part, that when an entire rotating assembly is to be repaired or replaced it shall be tested under all flow conditions to insure it does not exceed runout flow, or overpower the other pump. When the pump head curves were received from Pacific (the manufacturer) on the original spare pump (now installed in NV 1A) it was found that NV 1A would probably exceed the runout flow. As soon as this was determined, NV 1A was declared inoperable.

Technical Specification surveillance paragraph 4.5.2.h states that each ECCS subsystem shall be demonstrated operable by performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystem which alters the subsystem flow characteristics,in order to verify that each centrifugal charging pump meets both a minimum and maximum flow rate. After replacement of the NV 1A shaft and impeller in March 1981, the licensee performed a single point flow test at operating pressure and minimum flow, as required by IWP (inservice inspection code), with acceptable results. The licensee did not run a flow test at runout pressure, which would have given unacceptable results as shown by the pumphead curves. The licensee did not feel they had to follow the surveillance requirement quoted because they did not feel they had altered the flow characteristics and had satisfied the IWP requirement.

After declaring NV1A inoperable in November 1981, the licensee replaced the shaft and impeller with fully tested components, thus bringing the pump into compliance with requirement.

This will be carried as an unresolved item (369/81-39) until it is determined if operation of NV1A from March to November is a violation.

b. Overtime Requirements for Licensed Operators.

NUREG 0737, TMI Action Plan Items, requires that a licensed operator not work more than twelve consecutive hours in a licensed capacity. The clarification also states that if a licensed operator performs function other than licensed functions he should have a twelve hour break before assuming a licensed capacity. The licensee committed to the NRC that licensed operators would not work in a licensed capacity more than 12 hours without prior approval of the station management. On two consecutive days a licensed operator worked at least four hours in a non-licensed capacity then immediately assumed the shift as the operator at the controls and served in a licensed capacity for the twelve hours without management prior approval. Due to the wording in the licensee's station directive covering this item, there was a misinterpretation.

The licensee has put out a memo on this item and has committed to change the station directive such that no licensed operator may work more than twelve consecutive hours without a twelve hour break without

management approval. Until the station directive is changed this item will remain open (369/81-39-02).

c. Integrated ESF Test

During the outage caused by the ruptured hydrogen cooler on the electrical generator, the licensee ran the integrated ESF test required by Technical Specification. When the operators attempted to initiate Train A, Safety Injection phase A, and containment spray, as called for in the procedure, very few pieces of equipment required to respond did in reality move to their ESF position.

After a complete recheck of the systems to determine the cause of the improper response the licensee determined that the fault could only lie with the initiation buttons. Before rerunning train A, the initiation button were tested at least twenty times to insure a signal was being sent to the logic cabinets. When train A was retested it passed the acceptance criteria.

Since this test requires a twenty four hour run time on the diesel prior to the ESF actuation (and the train B diesel had been running almost constantly for three days due to interrupted test runs the licensee wanted to insure the train B initiation buttons would not cause the same problems as the train A buttons, therefore, they tested the signal generated by the initiation buttons prior to running the test. When the initiation buttons were tested, they failed eleven out of fifteen times, but the more the buttons were tested, the better they reacted until there were no failures. After many tests on the buttons and no failures, the train B actuation was performed and the test was successful.

Preliminary findings indicated that the problem could have been caused by particulate buildup on the contacts and the fact that the switches are in a 48 volt circuit. There is a large number of identical switches in use on the plant. These are all in 120 volt circuits and have never given any problem.

The failed switches came onsite already installed in the console and thus have been in place many years. There is no record of a prior failure. The licensee replaced all 14 similar switches in the console with new switches that have been sealed and environmentally protected since arrival onsite. This is regarded as a temporary fix until evaluations are complete. This is an Inspector Followup Item (309/81-39-03).

d. Loss of Offsite Power Test

The inspectors witnessed TP/1/A2650/05, Unit Load Transient test and TP/1/A/2650/12, Loss of Offsite Power test to verify that activities were being accomplished in accordance with Technical Specifications,

License requirements, and NRC requirements. While witnessing these tests no violations or deviations were identified.

However, the loss of Offsite Power acceptance criterion requiring the reactor and turbine not to trip was not met. Shortly after the transient was initiated, a reactor trip occurred on reactor coolant pump bus underfrequency when the turbine/generator did not maintain house load. The resolution of this test deficiency will be identified as an Inspector Followup Item. (369/81-39-04). The transient which ensued is discussed in paragraph 7a.

7. Safety System Challenges

During the reporting period there was a reactor trip and a safety injection. These will be discussed in detail in the following paragraphs.

a. Reactor Trip

At 9:36 p.m. on December 2, 1981 the Unit 1 reactor and turbine tripped on low reactor coolant (NC) pump frequency while a Loss of Offsite Power Test was being attempted. The test was initiated by opening the switchyard power circuit breakers (PCB) and isolating Unit 1 from the power grid. The turbine generator was expected to "run back" from its operating load of 30% (315 MWe) to the unit's auxiliary load of 46 MWe while maintaining a generating frequency within the reactor and turbine trip setpoints.

Immediately following the trip of the last PCB, generator frequency increased to 62 Hz as the overspeed protection controller took over and closed the governor and intercept valves. Frequency then dropped to 60 Hz and the intercept valves opened to maintain speed. Governor valves remained closed and the frequency again began to drop after hovering at 60 Hz for a short period. Frequency dropped to 58 Hz and then slowly drifted to 56 Hz. The governor valves never opened more than a crack before the reactor and all four NC pumps tripped on under frequency signals from 2 out of 4 NC pump motor busses. The NC system went into natural circulation cooling and the safety systems responded as designed.

Operators immediately began recovering offsite power and the 6900 volt busses were charged after verifying that major pump motor breakers on the busses were tripped. Power was restored to all four 6900 volt busses about two minutes after the blackout started. NC pump B was started at 9:40 p.m. and forced circulation of the primary system was reestablished. Within twenty minutes, NC pumps A and C were started; but, efforts to start NC pump D were unsuccessful because its number 1 seal was apparently cocked. No significant transient resulted from the trip.

Operators continued to recover the secondary side of the plant. The condensate (CM) system was started up using the appropriate condensate and feedwater system procedure. Hotwell pump (HWP) A was started about 10:12 p.m. but the strainer differential pressure rose rapidly so B HWP was started and A HWP was tripped. About ten or fifteen minutes later, a seal oil (LG) system trouble alarm was received. While investigating this problem, water was noticed coming from the turbine end of the main generator. Operations staff personnel attempted to keep the generator sealed by running the back up seal oil pump and controlling the system manually. Other operations personnel isolated the hydrogen cooler from the CM system and vented hydrogen to atmosphere. The LG system maintains an operating pressure 12 psig higher than the hydrogen pressure in the generator. When the operators reached the LG skid, the local gauge was pegged high (100 psig) due to the high hydrogen pressure. A large volume of water had leaked from the hydrogen cooler into the generator.

Investigation revealed that a water hammer or pressure surge resulting from the operations described above had pushed three tubes out of the tube sheet in the hydrogen cooler and partially separated several others, thus, water was introduced into the hydrogen system.

The Loss of Offsite Power test was the first test of the turbine control system in which turbine speed was controlled with a load on the generator. A severe drop in electrical load, from 315 MWe to 46 MWe, added to the difficulty of the test.

The turbine speed transient that ended in a reactor trip was the result of an improperly set up turbine control system. Damage to the generator hydrogen cooler was apparently caused by starting a HWP with a flow path through polisher demineralizer cells A, C and D.

As the CM system is currently designed, seven flow paths exist between the HWP discharge header and the generator hydrogen cooler. Four of the paths are through polishing demineralizer cells A, B, C and D. Two demineralizer bypass paths are controlled by valves 1 CM-422 and 1 CM-423. The seventh path is a line which connects the HWP discharge directly to the condensate booster pump suction and is controlled by valve 1CM-420. Valve 1 CM-420 is normally closed and opens only when a turbine runback is in progress. Valves 1 CM-422 and 1CM-423 operate from a single controller to limit differential pressure across the demineralizers when the controller is in automatic. When the controller is in manual the valves may be positioned as necessary by a manual loader in the control room.

Of the four valves involved with isolation of each demineralizer cell, 2 inlet and 2 outlet, 2 are operated by the demineralizer control logic and 2 may be positioned manually. If a cell is in service and flow drops below a preset limit, the corresponding "hold" pump starts and a "hold" valve opens to allow recirculation flow through the cell. This prevents loss of the filter coating material which covers the screens.

The demineralizer outlet valves do not automatically close on loss of flow through a cell in service, but maintain their operating positions unless repositioned by the cell control system.

Cells may be isolated by selecting the "hold" mode on the local control panel. Each cell has its own set of control switches and indication lights on the local panel. A set of switch modules is also located in the control room for controlling the operating modes of the cells. Each module, one for each cell, has a "hold" pushbutton and light, and a "filter" pushbutton and light. These switches are redundant to the switches on the local panel and are not normally used because station Chemistry personnel have responsibility for operating the cells.

During the event the control room operator called the chemistry technician on duty and asked the status of the polisher demineralizer cells. Based on the information he received he assumed all the cells were isolated, but, in fact, cells A, C and D were not isolated. Some of the misunderstanding between operations and Chemistry personnel might be attributable to what is meant by a cell being in "hold". A cell might be said to be in "hold" when the flow has dropped on a cell that was in service. The hold pump would be running and the water would be recirculating to protect the filter. This condition differs from the "hold" mode because the cell is not isolated and the "filter" status light is illuminated.

None of the seven flow valves have status lights in the control room. The demineralizer cell valves have status light on the local panel. Valve 1 CM-420 has a computer status point.

There are three interlocks which prevent starting the first HWP when all three pumps are tripped. If 1CM-420 or 1CM-422 is not closed, HWP starts are prevented (1CM-423 closes before 1CM-422). Pump start is also prevented if the controller for 1CM-422 and 1CM-423 is in automatic mode. No interlocks are installed on the demineralizer cell isolation valve to prevent HWP starts.

Inspection of the generator determined that no permanent damage had occurred other than damage to tubes at the exciter end of the cooler. The speed controls on the turbine generator will be readjusted by Westinghouse personnel to respond more quickly. Work is underway to replace the damaged hydrogen cooler with the cooler coil from Unit 2. The stator and rotor of the generator have been heated and dried out using fans, heaters, and specially constructed housing structures. Electrical leakage tests were conducted on the insulation to determine the residual moisture present during the drying process.

A task force has been formed to review this incident and to determine whether procedural or design changes are required.

The reactor trip and ensuing transient presented no danger to the NC system. Development of the capability for a unit to withstand a

separation from its electrical load and offsite power and yet continue to supply auxiliary loads will increase the safety and reliability of the station. The health and safety of the public was not affected by the incident.

The inspector followup on this incident has been mentioned in paragraph 6.d.

b. Safety Injection

While performing a surveillance test on the ESF logic cabinets an instrument technician caused a safety injection (S.I.) signal to be generated by low pressurizer pressure. The procedure that the technician was using contained a poorly worded note (not a step in the procedure) and when the technician was retracing his original steps to return the logic cabinet to service he skipped over the note, which required him to block the low pressure S.I. signal. Since the plant was in mode 5 (cold shutdown) when the cabinet was returned to service it sensed the low pressure and the S. I. signal was generated.

The licensee has committed to change the procedure so that this will not happen again. The inadvertent S. I. did not create a major problem because train B, which generated the signal, was already set up to run the integrated ESF test discussed in paragraph 6c, therefore, little water was injected into the reactor coolant system. The only problem was that the diesel generator shed the load that it was carrying for the test and this required the diesel to be run for another twenty four hours before the train B ESF test could be run.

Until the licensee corrects the deficient procedure this item will be carried as an inspector follow up item. (369/81-39-05)

8. Maintenance

Maintenance activities were observed in progress throughout the inspection interval. The inspector verified that these activities were accomplished by qualified personnel using approved procedures. Radiation controls, fire prevention measures, and QA/QC hold points were observed as appropriate. Test equipment used was verified to be calibrated, and data recorded were compared to those observed. The following maintenance activities were observed and reviewed in depth as were the work requests used to perform the maintenance.

(a) Reactor Building (VL) Air Handling units (AHU).

The B, C, and D VL AHU's required new or modified bearing mounts and "B" required bearing replacement. In order to perform and complete the required work the following documentation and procedures were used:

Work request: NSM 91443

MPO/B/7650/09	Permit for Cutting, Welding and Open Flame work with portable gas
SPD 4402-1	Request for Modification
SPD 4404-0	Design Summary
SPD-1001-2	Nuclear Safety Evaluation Checklist
MP/O/A/7650/74	Bearing Modification Data Sheets

(b) Repair 1A Centrifugal Charging Pump.

Discussion of the reason behind this repair is found in paragraph 6a. The following documentation and procedures were used:

WR: 106597

MPO/A/7150/16	Data Sheets
MPO/B/7650/09	Permit for Cutting, Welding and Open Flame work.
MPO/A/7650/44	Data Sheets
MP/O/A/7650/01	QC Inspection Sheets

Based on the above review and observation no violations or deviations were identified.

9. Surveillance

Surveillance activities were observed in progress throughout the inspection interval. The inspector verified that these activities were accomplished by qualified personnel using approved procedures. Test equipment used was verified to be calibrated and data recorded were compared to those observed where appropriate. Radiation controls were observed in effect. The following surveillance activities were observed in greater depth.

(a)	PTO/A/4600/14C	Source Range Neutron Flux Functional
(b)	PT1/A/4150/17	Pressurizer Heater Capacity Test
(c)	PTO/A/460102	Protection System Channel II Functional
(d)	PT1/A/4602/01A	K_f Pump 1A Performance Test

Based on this review and observation no violations or deviations were identified.

10. Independent Inspection

(a) On November 30, 1981 at 11:30 p.m. while under the surveillance requirements of T.S. 4.2.1.1, the licensee reduced power to below 50% prior to collecting 1 hour penalty deviation from the AFD target band during the previous 24 hours. This action met the LCO of T.S. 3.2.1. Subsequent discussions with the licensee concerning Action A.2 of T.S. 3.2.1 indicates that the licensee does not interpret Action A.2 to require the reduction of the Power Range Neutron Flux - High Trip setpoints to less than or equal to 55% RTP when the indicated AFD has been outside of the required target band for more than one hour penalty deviation cumulative during the previous 24 hours. The NRC interprets Action A.2 to require the reduction of the Power Range Neutron Flux - High Trip setpoints to less than or equal to 55% RTP when one hour penalty deviation has been accumulated in the previous 24 hours.

The review of operator logs to verify that the surveillance requirements of T.S. 4.2.1.1 were met is identified as inspector follow-up item (IFI/81-39-06).

(b) Security

During the period of this inspection the inspector noticed several times that security guards were stepping through the radiation monitors at the exit of the controlled area. This practice, even if approved under certain conditions, invites violation of health physics procedures. The licensee is in process of installing a monitor such that one cannot step through without being monitored. Until this partial monitor is installed the inspector will make further observations and the item will be carried as an inspector followup item. (369/81-39-07).