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

Report No. 50-369/82-03

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

Inspector: A. J. Signature for P. R. Bemis — 2/22/82 Date Signed

Approved by: J. C. Bryant, Section Chief, Division of Resident and Reactor Project Inspection — 2/23/82 Date Signed

SUMMARY

Inspection on December 24, 1981 - January 22, 1982

Areas Inspected

This routine, announced inspection involved 160 resident inspector-hours on site in the areas of maintenance, surveillance, safety system challenges, organization and administration, and the onsite Review Committee.

Results

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

DETAILS

1. Persons Contacted

Licensee Employees

*M. McIntosh, Plant Manager
G. Cage, Operations Superintendent
*R. Wilkerson, Administrative Superintendent
*D. Adkins, Technical Specialist
*D. Lampke, Engineer
T. McConnell, Technical Services Superintendent
R. Ryder, Mechanical Maintenance Engineer
L. Weaver, I&E Engineer
*M. Sample, Projects and Licensing Engineer
T. Keene, Station Health Physicist
R. Michael, Station Chemist
M. Pasetti, SRG Chairman

Other licensee employees contacted included shift supervisors, technicians, shift technical advisors, operators, engineers, mechanics, security force members and office personnel.

Other Organizations

D. Roth, Westinghouse

NRC Resident Inspector

*P. R. Bemis

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on January 19, 1982 with those persons indicated in paragraph 1 above. Additional findings were summarized with the plant manager on January 22, 1982. The plant manager acknowledged the findings and agreed to furnish further information as to the rewriting of the instrument procedures.

3. Licensee Action on Previous Inspection Findings

Not inspected.

4. Unresolved Items

Unresolved items were not identified during this inspection.

5. Operating History

At the beginning of the inspection period the unit was in mode 5 due to the leak in the hydrogen coolers in the main electrical generator. The hydrogen cooler and generator head were removed from Unit 2 to replace the damaged Unit 1 equipment while the generator was being dried out. Prior to the unit commencing startup, a few items which failed to meet acceptance criteria during the integrated ESF test had to be repaired. Each of the items was repaired and tests were performed to insure operability; on December 30, 1981 at 3:48 a.m. hours the unit entered mode 4 in preparation for startup.

At 4:49 a.m. on January 2, 1982, the reactor went critical, and at 7:39 a.m. the turbine-generator was tied to the grid and the unit entered mode 1 for the purpose of escalating to 90% power to perform testing at that level. The licensee was also given permission by NRR to operate above 90% power for 48 hours in order to perform tests at that level.

During the interval of this inspection report the unit experienced two safety injections and four additional reactor trips. Each of the protection system challenges will be discussed in more detail in paragraphs 9.a. and 9.b. The unit is presently at 50% power and the licensee intends to operate at this level until February 15, 1982, when the unit will enter a projected 16 day outage for steam generator(S/G) eddy current testing and the installation of internal monitoring instrumentation into one S/G.

6. Operational Safety Verification

Throughout the inspection interval the inspector observed operational activities in the plant and the control room. The following activities were reviewed and/or observed as possible on a daily basis: Shift turnover; control room and shift manning; control room and other vital area access; control room and plant operators use and adherence to approved procedures for ongoing activities; instrumentation and recorder traces important to safety for anomolies; operator understanding of alarmed control room annunciators to include initiation of corrective action in a timely, as required manner; operator response to computer alarms; valve and electrical alignment for emergency safeguards features (ESF) and reactor protection system (RPS) inputs in the control room in compliance with Technical Specification (T/S) requirements; shift supervisor, control operator, tag out, and operators' work request logs; access and egress from the protected area in compliance with requirements of the security procedures; and egress controlled by radiological monitoring equipment required by the health physics plan.

Also during the inspection period the inspector observed, reviewed and/or verified as possible the following: Status of instrument calibration, equipment tags and radiation work permits; the operability of boron injection tank portion of the ESF; results of selected liquid and gaseous samples. The inspector toured the accessible areas of the plant to make an assessment of the following: Plant and equipment conditions; areas which

could be fire hazards; interiors of selected electrical and control panels; proper personnel monitoring practices; housekeeping and cleanliness practices; and radiation protection controls. The inspector performed a complete walk down of the high head S.I. system to insure operability.

Based on this review and observation, two open items were identified and are discussed below.

a. Definition of Boundaries of Control Room

On January 19, 1982 at approximately 5:30 p.m. the inspector entered the control room to observe plant operation. The inspector noted at approximately 5:50 p.m. that there was not a licensed SRO in the control room, as required by Technical Specifications. When the Unit coordinator entered the control room at approximately 6:00 p.m. the inspector questioned him as to this apparent discrepancy. The unit coordinator referred the inspector to station directive 3.1.4, figure 1, dated 11/20/81 which defined the boundaries of the control "complex" (McGuire Term) where a SRO had to be present. This figure was generated after discussions with and apparent approval by the previous resident inspector. The areas that were added to the control room by the new boundary definition included areas outside of the vital area access; there were two SRO's located in the boundaries defined in the station directive.

After discussions with NRR and Region II it was determined that areas outside the control room vital area could not be considered as part of the control room for purposes of SRO location. The licensee has committed to change the station directive to delineate only areas inside the vital area as control room boundary. Until the licensee changes the station directive to reflect the corrected boundaries this will be carried as an open item. (369/82-03-01).

b. Vital Area Access Control During Degraded Operation

On January 19, 1982, while observing personnel entry and egress through the vital areas, the inspector determined that a problem exists with regard to access controls. The matter has been referred to the region physical security specialists, and will be followed up during a subsequent inspection.

7. Maintenance

Maintenance activities were observed in progress throughout the inspection interval. The inspector verified that the following activities were accomplished by qualified personnel using approved procedures, radiation controls, fire prevention and safety 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; required administrative approvals and tagouts were obtained prior to initiating the work; limiting

conditions for operation (LCO) were met while maintenance was being performed; replacement parts and materials used were properly certified; and testing and calibration as necessary were completed prior to returning the equipment to service. The inspector reviewed portions of outstanding work orders for safety-related systems to insure the licensee is performing maintenance in a timely manner and that an excessive backlog is not developing. The inspector examined the procedures used in the following paragraphs for technical adequacy and the work orders for completion.

The following maintenance activities were observed and reviewed in depth.

a. Repair of "B" NI Pump Inboard Mechanical Seal.

1B NI pump (Intermediate Head SI pump) seal was discovered leaking and a work request was issued and the following work was observed:

(1) Tension on the mechanical seal to determine if set screw adjustment on the shaft was correct.

(2) Disassembly of mechanical seal, inspection of sealing surfaces and shaft sleeve "O" rings, check sealing surface face alignment.

(3) Rebuild seal

(4) Reinstall seal and align motor and check coupling alignment.

The following paper work was reviewed:

Work request 104450 OPS

PT/1/A/4206/01B Safety injection pump 1B performance

MP/0/A/7150/44 Safety Injection Pump Corrective Maintenance

MP/0/B/7650/09 Permit for cutting, welding, open flame safety

b. Replacement of 1A NV Pump Shaft and Impeller

Report 369/81-39 discussed reason for the replacement of 1A NV (High head SI) pump shaft and impeller unit with equipment from 2A NV pump. The inspector witnessed major portions of this maintenance and the following documentation was examined for adequacy:

Work request II 106597 OPS

MP/0/A/7650/44 Hanger removal and replacement

MP/0/A/7150/16 Centrifugal charging pump corrective maintenance

MP/0/A/7650/01 Flange gasket removal and replacement

MP/0/A/7650/74 Coating Procedure

MP/0/B/7650/09 Cutting welding and open flame safety

PT/1/A/4150/18 CCP 1A pump head verification

QCI-1A NDE inspection report revision 4

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

8. Surveillance

Surveillance activities were observed in progress throughout the inspection period. The inspector reviewed and/or verified that procedures used conformed to technical specification requirements and had received proper licensee review and approval; that test instrumentation was properly calibrated; that the systems were removed from service and restored to service per procedure; test prerequisites and acceptance criteria were met; test data were accurate and complete; completed tests were properly reviewed and discrepancies were rectified; and tests were performed by qualified individuals. The following surveillance activities were observed in greater depth.

a. NV Head Curve Verification

After replacement of the shaft and impeller, discussed in paragraph 7b the licensee was required to insure NV pump 1A was operable. This operability requirement was met by performing PT/1/A/4150/18 NV Head Curve Verification

b. Portions of the following surveillances were observed and the data were reviewed for adequacy:

(1) TP/1/A/1200/03C Safety injection pumps and flow adjustment functional test

(2) PT/1/A/4400/01J Fire protection system weekly inspection

(3) PT/1/A/4200/09A ESF actuation periodic test

(4) PT/1/A/4450/03B (Purge blower subsystem) VE train B operability test

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

9. Safety System Challenges - Plant Trips

During the inspection period the plant incurred two S.I.'s and four additional reactor trips. In each case the plant systems responded as required and the health and safety of the public was not compromised. The inspector reviewed the licensee's response to each challenge as well as applicable followup by the safety review group and plant staff. Each challenge will be discussed in more detail in paragraphs 9a and b.

Based on this review and observation one inspector follow up item was identified and will be discussed in paragraphs 9a and b.

a. Safety Injections

(1) At 0900 on December 24, 1981 an I&E technician initiated a S.I. while working in the solid state protection system (SSPS) on pressurizer pressure. The initiation was due to a procedure deficiency. The technician was using the approved most recent change of IP/0/A/3000/09/K, Pressurizer Pressure Control Calibration. Step 10.1.3 required the technician to place all protection channels in test at the same time. When the second channel was placed in test, P-11, which blocks the low pressure SI. signal when deliberately going below 1900 psig, was automatically removed. The reactor was in mode 5 with pressure approximately atmosperic; therefore, when the SI signal was unblocked an SI signal was generated because the pressure was less than 1845 psig. All safety systems responded as required.

This was the third challenge, 2 SIs and one reactor trip, in less than a month due to a deficient procedure. In RII report 369/81-39, this item was addressed as an open item. Due to the repetitive nature of the problem this item was addressed in the exit with the licensee. The inspector was given a firm commitment by the licensee to review and change the format of the I&E procedures as expediently as possible.

(2) At approximately 12:00 noon on January 11, 1982, the unit was at 75% power when it experienced a SI initiated by low steam line pressure. The SI signal was generated when two of three steam line pressure transmitters failed due to freezing of sensing lines. The unit had been having single transmitters failing all night long the previous evening due to the coldest weather experienced in many years. All safety systems operated as required and water was injected thru the Boron injection tank (BIT) for approximately eight minutes before termination of the S.I.

After injecting through the BIT for eight minutes, the concentration was reduced from approximately 21000 ppm boron to approximately 4000 ppm boron. T/S 3.5.4 requires the BIT concentration to be between 20000 and 22500 ppm boron. Before the

unit could be restarted the concentration had to be raised to the T/S value, which would require approximately 2-3 days.

The licensee had in his possession two analyses purchased from Westinghouse which showed the BIT concentration could be lowered to 2000 ppm or removed altogether and not compromise the plant safety. The licensee had planned to submit a request for a T/S change, but had not done so when the S.I. occurred. Since there was a desparate need for electricity in the area due to the extreme cold, the licensee submitted a request for an emergency temporary T/S change that would allow the plant to operate for seven days with BIT concentration greater than 2000 ppm. This emergency change was approved until the permanent change could be further analyzed and unit was back on line the same day.

The licensee has taken temporary action to prevent freezing of instrument lines in the future and is determining a permanent solution. Until the permanent solution is instituted this will be carried as an inspector followup item. (369/82-03-03).

b. Reactor Trips

(1) At 5:32 p.m. January 3, 1982, with the unit at 85% power, a reactor trip was received due to lo-lo S/G level. The RPS signal was initiated due to a 1MXH breaker trip. This breaker is one of two main feeders of power to the plant. When the power to the motor control center (MCC) fed by 1MXH was lost, power to approximately one half the plant was lost. Feedwater pump 1A was caused to lose control and it ran back to minimum speed. When this happened, feedwater flow could not keep up with steam flow, causing level in the S/G to go low giving a reactor trip signal.

The reason for the trip of 1MXH has not been determined, but will be as soon as the unit is shut down for the next outage (to work on 1MXH, the unit must be shutdown). The plant is presently feeding the MCC normally fed by 1MXH by the emergency feeder breaker (which is authorized) until the next outage.

(2) At 9:02 a.m. on January 5, 1982, while at approximately 90% power, the unit experienced a reactor trip. The first out panel showed the trip was caused by the intermediate range (I.R.) high flux trip. The computer printout verified that the trip was due to I.R. high flux with power range (PR) high flux, lo setpoint immediately (20 milli seconds) behind. This was very unusual because both of these trips are, and were, blocked at approximately 10% power.

After investigation it was found by the inspector and the licensee that the trip was caused because of an instrument procedure error. When the unit is undergoing power ascension the operator is allowed to block both the I.R. and P.R. range trips when the unit

is above 10% power if there are no problems, and we must block the trips before 25% power since that is the trip setpoint. These trips had been blocked by the operator, but due to an error in the order of steps in the instrument procedure being used by an I&E technician to perform surveillance on the SSPS, the trips were unblocked and because the unit was above the trip setpoint a trip signal was generated.

As mentioned in paragraph 9a(1) the problems in the I&E procedures were addressed in the exit interview and a firm commitment was given by the licensee to change and review procedure format.

(3) At 2:35 p.m. on January 9, 1982, while at 75% power, the unit experienced a reactor trip due to a turbine trip. The unit had been experiencing problems with the turbine digital electro hydraulic (DEH) control system signal to the governor valves "hunting" while in the automatic mode of operation. An I&E technician was performing some checks on the DEH and he had not grounded the instrument he was using. When the DEH went to ground through his instrument a turbine trip was generated which tripped the reactor (automatically occurs when power is above 48%).

Steps have been taken to reinforce in the procedure and to the individuals the need for grounding instruments and a long term fix is being considered.

(4) At 8:42 a.m. on January 15, 1982, while at 50% power, the unit experienced a reactor trip due to loss of a reactor coolant pump (NCP). The unit operator received a hi-hi vibration alarm on "B" NCP, and tripped the pump according to procedure. It was determined that the alarm was due to a faulty instrument rather than high vibration; therefore, the pump and reactor were restarted.

10. Organization and Administration

The inspector verified the licensee's onsite organizational structure is as described in the facility T/S; that personnel qualifications are in conformance with NRC regulations and licensee commitments; that lines of authority and responsibilities meet T/S requirements; and that organizational changes addressed in T/S are submitted to the NRC.

Based on this review no violations or deviations were identified.

11. Onsite Review Committee

The inspector attended a meeting of the onsite safety review committee on January 22, 1981, as a nonparticipant only. The inspector observed the conduct of the meeting to ascertain that provisions of T/S dealing with membership, review process, frequency, and qualifications were satisfied. The inspector later reviewed the meeting minutes to confirm decisions and

recommendations were reflected and that recommended corrective actions were completed.

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