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

Report Nos.: 50-413/94-04 and 50-414/94-04

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

Docket Nos.: 50-413 and 50-414 License Nos.: NPF-35 and NPF-52

Facility Name: Catawba Nuclear Station Units 1 and 2

Inspection Conducted: January 9, 1994 - February 5, 1994

Inspectors: W. H. Miller Jr. 2/22/94
for R. J. Freudenberger, Senior Resident Inspector Date Signed
P. C. Hopkins, Resident Inspector
J. Zeiler, Resident Inspector
C. Yates, Intern

Approved by: M Lesser 2/22/94
Mark S. Lesser, Chief Date Signed
Projects Section 3A
Division of Reactor Projects

SUMMARY

Scope: This resident inspection was conducted in the areas of review of plant operations, maintenance, engineering, plant support and followup of previously identified items and Licensee Event Reports. Backshift inspections were conducted on January 10, 15, 18, 19, 20, 21, 24, 25, 26, 27, 28, 30, 31, and February 1, 2, and 3.

Results: In the operations area, the operators handled two separate events, a reactor trip and turbine trip, satisfactorily, utilizing applicable emergency and abnormal procedures to control the plant. Discrepancies attributed to operator attention to detail were noted during the response to both events (paragraphs 3.a and 3.b). Licensee responses to cold weather protection deficiencies were considered to be thorough (paragraph 3.d). NRC inspection of the alignment of the Unit 2 high head safety injection system found it to be properly maintained (paragraph 3.e).

In the maintenance area, personnel inattention to detail and improper procedure usage caused a hydrogen analyzer to not be properly returned to service following maintenance (paragraph 4.a). Similarly, observations of Standby Shutdown Facility diesel

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generator maintenance identified weakness in usage and periodic review of a calibration procedure (paragraph 4.d). NRC inspection of the on-line leak repair of drain valve 2CA-169 noted good preplanning and coordination (paragraph 4.b). A Technical Specification surveillance for Low Power Reactor Trip channel test was missed due to the failure to recognize the operational mode that the surveillance was required. An Unresolved Item was identified to determine whether this surveillance was required during normal shutdown prior to decreasing to less than 10 percent power (paragraph 4.f). Procedural deficiencies and lack of detailed vendor information contributed to the inadequate rebuild of a Residual Heat Removal pump motor (paragraph 4.g).

In the engineering area, an Unresolved Item was identified regarding the adequacy of the licensee's review of the potential impact of Thermal Barrier Heat Exchanger Component Cooling Water check valve failures (paragraph 6).

In the plant support area, the NRC's tour of the Emergency Operations Facility indicated that equipment and facilities were being well maintained (paragraph 7).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

S. Bradshaw, Shift Operations Manager
J. Forbes, Engineering Manager
T. Harrall, Safety Assurance Manager
J. Lowery, Compliance Specialist
*W. McCollum, Station Manager
W. Miller, Operations Superintendent
*K. Nicholson, Compliance Specialist
*D. Rehn, Catawba Site Vice-President
*Z. Taylor, Compliance Manager

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

NRC Resident Inspectors

*R. Freudenberger, Senior Resident Inspector
*P. Hopkins, Resident Inspector
*J. Zeiler, Resident Inspector
C. Yates, Intern

* Attended exit interview.

Acronyms and abbreviations used throughout this report are listed in the last paragraph.

2. **PLANT STATUS**

a. Unit 1 Summary

Unit 1 began the period at full power. On January 10, after measuring reactor coolant system flow rate to be less than the required technical specification value for 100 percent power operation, reactor power was restricted to less than 98 percent power. On January 12, a reactor trip occurred due to a turbine trip. The turbine trip was caused by a loss of condenser vacuum when a two inch extraction steam drain line to the condenser failed, creating an opening from the condenser to the atmosphere. Details pertaining to this reactor trip are contained in paragraph 3.a. Reactor startup commenced the following day and the unit was placed on line. The unit reached 97 percent power on January 14 and operated at this power for the remainder of the report period.

b. Unit 2 Summary

Unit 2 began the period at full power. On January 12, a turbine runback and associated reactor runback to 56 percent power occurred when the "B" main generator breaker opened due to corroded contacts in the breaker's motor operated disconnect circuitry. Approximately 1 hour and fifteen minutes later, a turbine trip occurred due to loss of condenser vacuum. The reactor did not trip since the unit was below 69 percent power. Details pertaining to these two events are contained in paragraph 3.b. The unit remained in Mode 2, Startup, until the following day when the unit was placed on line. The unit reached full power on January 15 and operated at essentially full power for the remainder of the report period.

c. Inspections and Activities of Interest

Inspections were conducted by specialist inspectors from the NRC Region II office as follows:

Report	Dates	Subject	Lead Inspector
94-02	02/07-11	EOP Review	Bartley
94-03	01/10-14	Plant Effluents	Jones
94-05	01/24-28	Generic Letter 89-10	Hunt
94-06	02/07-11	Security	Thompson

In addition, on January 25, S. Israel of the NRC Office for Analysis and Evaluation of Operational Data conducted a site visit to discuss with the licensee the circumstances related to an event reported in LER 414/93-04.

3. **OPERATIONS** (NRC Inspection Procedures 71707, 71710, 71714, 40500, 93702)

Throughout the inspection period, facility tours were conducted to observe operations and maintenance activities in progress. The tours included entries into the protected areas and the radiologically controlled areas of the plant. During these inspections, discussions were held with operators, radiation protection, and instrument and electrical technicians, mechanics, security personnel, engineers, supervisors, and plant management. Some operations and maintenance activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections confirmed Duke Power's compliance with 10 CFR, Technical Specifications, License Conditions, and Administrative Procedures.

a. Unit 1 Reactor Trip due to Loss of Condenser Vacuum

On January 11, at 10:58 p.m., Unit 1 tripped from full power due to a loss of condenser vacuum. The loss of condenser vacuum tripped the turbine which resulted in a reactor trip since power was greater than P-9 (69% power). The reactor trip resulted in a main feedwater isolation on low average reactor coolant system temperature coincident with the reactor trip signal. Also, steam generator shrink reduced level to the lo lo level setpoint causing an auto start of the motor driven auxiliary feedwater pumps. These automatic system responses were considered normal by the inspector.

While operators were stabilizing the plant, the steam dump system was transferred to the pressure control mode as directed by the reactor trip response procedure. When the transfer was accomplished, one bank of the condenser dumps opened reducing reactor coolant system temperature to approximately 547°F. Operators took manual control and closed the valves. Licensee investigation identified that although steam header pressure remained below the steam dump actuation setpoint of 1090 psig throughout the transient, the pressure instrumentation which provided input to the condenser steam dumps when in the pressure mode was indicating higher than actual pressure. As a result, although the steam header pressure deviation indication on the main control board indicated no deviation, input to the condenser steam dump pressure controller was greater than the setpoint for approximately four minutes. This caused the integral function of the pressure controller to increase steam dump demand. The demand was indicated on the main control board controller, contradicting the steam header deviation indication. Operators, including the Senior Reactor Operator directing the trip response, recognized the demand indicated on the controller and chose to make the transfer to the pressure controller. This action had minimal safety impact on the reactor trip recovery. Nonetheless, the inspector considered it to be indicative of a lack of attention to detail on the part of the operators.

The loss of condenser vacuum resulted in operation of the atmospheric steam dumps for approximately twenty minutes, until temporary patches could be installed on a sheared extraction steam drain line. The inspector verified there was no detectable activity in the secondary system while the atmospheric dumps were operated, therefore no release occurred.

Licensee investigation of the cause of the loss of condenser vacuum identified it to be the failure of an unisolable two inch diameter drain line near the "A" condenser. The affected drain line was downstream of valve 1HB-08, a "B" extraction steam drain valve which cycles automatically to divert collected moisture to the condenser. The line sheared due to outside diameter initiated fatigue in the heat affected zone of a socket weld adjacent to an elbow. The fatigue appeared to be the result of movement of the "field routed" piping during normal operation and excessive cycling of drain valve 1HB-08. Prior to restart, the licensee had completed penetrant examinations of approximately eleven accessible locations with similar operating conditions. No similar conditions were identified. Licensee evaluation and development of long term corrective action to prevent similar failures in the future were continuing at the end of the report period. The inspector plans to review these actions during the review of the LER associated with the reactor trip.

b. Unit 2 Runback and Turbine Trip

On January 12, at 8:30 a.m., a runback from full power to approximately 56 percent generator load occurred on Unit 2 due to the unexpected opening of one of the two main generator output breakers. Following the runback, main condenser vacuum abnormally decreased. At approximately 9:30 a.m., the operators observed vacuum decreasing. In accordance with the abnormal procedure for loss of condenser vacuum, the operators began reducing load and coordinating actions for placing the standby vacuum pump in service. At 9:47 a.m., before the standby vacuum pump could be aligned and placed in service, vacuum reached 23.5 inches Hg resulting in an automatic turbine trip. Since reactor power was less than the P-9 setpoint (69 percent power), an automatic reactor trip did not occur. Following the turbine trip, the operators decided to reduce generator load further and to enter Mode 2 while stabilizing the plant. Mode 2 was entered at 9:55 a.m. Vacuum began increasing after the turbine trip, and by 9:57 a.m., it had recovered whereby the condenser became available for steam dump operation in order to maintain reactor coolant system temperature at the reference temperature.

The temporary loss of condenser vacuum resulted in operation of the atmospheric steam dumps for approximately three minutes. The inspector verified there was no detectable activity in the secondary system while the atmospheric dumps were operated, therefore, no release occurred.

At approximately 10:20 a.m., while the operators were maintaining the unit in Mode 2, the inspector noted that reactor thermal power, as indicated by the Operator Aid Computer digital readout, was above 5 percent power. When this was brought to the attention of the operators, they began to manually insert rods to reduce power. The Operator-at-the-Controls indicated that he had been monitoring Power Range NIS and based on this, power had not exceeded approximately 4.5 percent. The inspector questioned whether a mode change had occurred (from Mode 2 to Mode 1) based on exceeding 5 percent thermal power. The inspector later reviewed a licensee calculation that subtracted decay heat from the indicated thermal power during this period. Based on the results of this review, the inspector determined that reactor power had remained below 5 percent, as defined in the Technical Specification for operational modes, thus, a mode change had not occurred. The inspector considered that the operators had not exercised conservative judgement by relying solely on the NIS for reactor power indication versus using all indications available, such as thermal power indication, and operating to the most conservative of these two in order to ensure that Mode 2 was maintained.

The inspector reviewed the licensee's investigation into the cause of the opening of the A generator breaker and discussed the issue with appropriate plant personnel. The breaker opened due to electrical arcing across the terminals of a microswitch in the breaker motor operated disconnect circuitry. This arcing essentially configured the breaker to its "safe" position causing it to trip. The licensee determined that corrosion found on the microswitch terminals resulted in the arcing. The switches are located in electrical compartments outside the turbine building and, although the compartments are heated and insulated, the licensee believed that the outside environment may have induced the corrosion. This and one other slightly corroded switch on the opposite unit was replaced. The licensee planned to include inspections of the microswitches for corrosion in a preventive maintenance program. The inspector noted that the licensee's analysis was effective in identifying the root cause and correcting the problem.

The inspector monitored the licensee's efforts to determine the root cause of the loss of vacuum which resulted in the turbine trip. The licensee investigated several areas that could have caused the vacuum loss including: 1) low steam pressure to the steam jet air ejectors, 2) degraded turbine steam seals, 3) introduction of non-condensible gases that may have accumulated in the steam dump piping, and, 4) air inleakage from main steam valve packing. The inspector noted that the licensee expended considerable effort to investigate the vacuum loss, however, they were unable to conclusively determine the cause.

Although the cause of the loss of vacuum was not determined, the inspector noted that the licensee exercised good judgement in implementing contingency actions for early detection of a vacuum problem during power escalation the following day. Among these actions included: 1) providing the operators with details of the previous vacuum problem, 2) special monitoring of vacuum pressure and installation of temporary alarms on decreasing vacuum, 3) monitoring of condenser steam jet air ejector off-gas flow rates at various power levels for early detection of a problem, and, 4) expediting activities to start a standby vacuum pump if needed. The unit was returned to full power with no further vacuum problems.

c. Unit 1 Reactor Power Restriction

On January 10, the licensee performed a precision heat balance test in order to calculate RCS flow rate. This precision heat balance is used to calculate RCS flow based on gross steam generator thermal output divided by the enthalpy difference across the reactor vessel as measured by the RCS hot and cold leg RTDs. Once RCS flow is determined, the cold leg elbow tap flow coefficients are adjusted to match the RCS flow indication with the calculated flow measurement. The licensee performed three separate flow measurements. The average of these measurements resulted in a total RCS flow rate of 379,285 gpm which was less than the minimum allowed limit of 382,000 gpm required under Technical Specification 3.2.5 for 100 percent power operation. Based on these results, on January 11, in accordance with the Technical Specification Action Requirements, reactor power was reduced to less than 98 percent.

While steam generator tube plugging during the previous refueling outage accounted for a small amount of the flow loss, the licensee believed that the majority of the loss was due to uncertainty in the RCS hot leg temperature as indicated by the RTDs, a phenomenon that the industry has referred to as hot leg streaming. This phenomenon involves the assumption that a temperature gradient exists in the hot leg piping and based on the location of the RTDs, the average hot leg temperature may be biased higher than the actual bulk temperature of the water. Based on the heat balance method, a higher hot leg temperature results in a lower calculated value of RCS flow.

On January 10, the licensee submitted a proposed Technical Specification revision to the NRC to change the method of measuring the reactor coolant flow rate. The precision heat balance was adopted due to a perceived improvement in accuracy. As a result of the problems encountered with this method, the licensee proposes to return to the method, using the cold leg elbow tap indication of RCS flow. This Technical Specification is currently being reviewed by the NRC. In accordance with Technical Specifications, Unit 1 will remain at less than 98 percent power until this flow problem is resolved.

d. Cold Weather Preparation and Operations

During the week of January 10 unusually cold weather was experienced at the facility. The inspector reviewed the effects of the weather on operation of plant systems and licensee activities to identify and correct deficiencies.

Instrumentation sensing lines associated with several plant systems were inadequately protected for the weather conditions which existed. The instrumentation affected included; fire pump pressure switches, the non-safety related service water header pressure impulse line, the condensate storage tank level, and the filtered water storage tank level. These deficiencies were promptly identified by operations personnel. The licensee initiated corrective maintenance in a timely manner.

The inspector judged the deficiencies to have insignificant impact on safe operation of the facility. None of the deficiencies resulted in entry into Technical Specification action statements. Freezing of the instrument lines associated with the fire pump was was reviewed in detail.

Licensee investigation of an inadvertent start of the fire water system pumps showed that sensing lines, located adjacent to the fire pumps at the intake structure had frozen. The sensing lines were associated with pressure switches which start the fire pumps on low fire water header pressure. With the pumps running the fire water system remained capable of performing its function. To minimize operation of the pumps with low flow in the recirculation mode, the licensee installed a temporary station modification that bypassed the affected switches in the fire pump start circuitry and temporarily replaced them with an alternate set of switches. The alternate switches were located inside the service building and monitored fire water header pressure.

Licensee investigation of the cause of the frozen fire pump sensing lines identified that the heat trace had failed. The failure was caused by a small hole in the impulse line (stainless steel tubing) of one of the pressure switches. The hole was the result of a short and arcing of the heat trace wiring to the tubing. The heat trace was apparently damaged by personnel stepping on the tubing tray which carried the instrument lines.

The licensee initiated a permanent modification to install self-regulating heat tracing that will provide more heat capacity over larger surfaces of the tubing. The modification also provided for better protection of instrument lines in the tubing trays.

Licensee review of the other instrumentation affected revealed that installed heat tracing was operating, but was not providing sufficient heat capacity to meet existing conditions.

Component engineering tracked the deficiencies identified to determine actions for resolution through modifications and/or incorporation into an annual preventive maintenance work order, WO 91004266, Heat Trace System.

In summary, the licensee responded appropriately to the cold weather protection deficiencies encountered during the report period. The deficiencies were judged to have insignificant impact on safe operation of the facility.

e. Walkdown of Unit 2 High Head Safety Injection System

During this report period, the inspector conducted a walkdown of accessible portions of both trains of the Unit 2 High Head Safety Injection System to verify the proper status of the ECCS function of the system. The walkdown verified that the lineup procedures for this system conformed to the plant drawing and as-built configurations. Equipment conditions and items that might degrade plant performance were also reviewed. These included verifying that hangers and supports were properly installed; acceptable housekeeping and the control of combustibles and other fire hazards were being maintained; components of the systems were properly labeled; and no system leakage existed. Each accessible valve in the ECCS flowpath was visually inspected to verify that the valve was in the position specified by the lineup procedure and that the valves were appropriately locked where required. The following procedures and drawings were referenced during this walkdown inspection:

- Procedure OP/2/A/6200/01, Chemical and Volume Control System, Enclosure 4.17, Valve Checklist, and,
- Drawing Nos. CN-2554-1.6, CN-2554-1.7, and CN-2562-1.0

The inspector determined that the ECCS function of the High Head Safety Injection System was well maintained, in conformance with the drawings and aligned in accordance with the lineup procedures.

f. Problem Investigation Process Corrective Action

The inspector, while performing a review of Problem Investigation Process (PIP) 2-C93-0879, took the opportunity to observe the corrective actions that were initiated. The PIP addressed a licensee identified component mispositioning issue associated with valve 2NW-62, the assured source of water from the nuclear service water system to the containment valve injection system.

There was minimal safety significance associated with this event. While valve 2NW-62 was closed, the "B" train containment valve injection system was inoperable. The condition was identified and corrected within one day, well with in the seven day action statement for the containment valve injection system Technical Specification. Also, the "A" train remained operable while the "B" train was not.

During the review of the PIP, the inspector noted that it did not contain enough detailed information to understand the sequence of events nor the full scope of corrective actions performed.

Examples of discrepancies noted by the inspector were as follows:

1) The PIP did not discuss that valve 2NW-62 was normally locked open and that it is an assured source of water from the nuclear service water system to the containment valve injection system,

2) The corrective action for the PIP did not provide enough detail to exactly understand what was being revised in the Operations Management Procedure (OMP). The PIP did not address all issues which were discussed during shift briefings.

Individuals involved in the mispositioning performed training of their peers to increase the sensitivity to the types of errors which led to the mispositioning. This training included role playing and was observed by the inspector as it was presented to four of the operating shifts. The inspector considered the training to be effective.

No violations or deviations were identified.

4. **MAINTENANCE** (NRC Inspection Procedures 62703, 61726, 40500 & 93702)

Surveillance tests were observed to verify that approved procedures were being used; qualified personnel were conducting the tests; tests were adequate to verify equipment operability; calibrated equipment was utilized; and TS requirements appropriately implemented.

In addition, the inspector observed maintenance activities to verify that correct equipment clearances were in effect; work requests and fire prevention work permits, as required, were issued and being followed; quality control personnel performed inspection activities as required; and TS requirements were being followed.

The following items were reviewed in detail.

a. Improper Restoration of Hydrogen Analyzer

On January 11, following the completion of a quarterly channel calibration of the Unit 2, B train containment atmosphere hydrogen analyzer, the hydrogen analyzer failed to be returned to standby alignment. The analyzer is inoperable when not in this alignment. At 8:40 p.m. that same evening, during the performance of routine auxiliary building rounds, a NLO discovered that the analyzer was not in its standby alignment mode. By 10:40 p.m., the analyzer was returned to standby alignment and the necessary operating temperature was reached for operability.

The inspector reviewed the completed Work Request (93092087-01) package for the activity and procedure IP/2/A/3176/01, Calibration Procedure Containment Hydrogen Monitor, that was used to perform the quarterly channel calibration. In section 10.5 for restoring the analyzer to service following calibration, the last step, 10.5.5, required that the analyzer be placed in the standby condition. The inspector considered that this step was missed by the technicians due to lack of attention to detail and not performing proper self-checking techniques. The inspector noted that this was the only restoration step in the procedure that did not require a signoff by the individual performing the step. This human factors procedural weakness may have contributed to the technicians not performing the step.

The inspector determined that this incident had no safety significance in that the A train hydrogen analyzer remained operable during the short time period that the B train analyzer was out of its standby alignment. In addition, TSs allow one analyzer to be inoperable for up to 30 days prior to requiring shutdown of the unit. The inspector reviewed PIP No. 2-C94-0042 that was initiated by the licensee to address the problem. The inspector determined that the licensee's proposed corrective actions adequately addressed the problems associated with this incident.

b. Leak Repair of Nonisolable Auxiliary Feedwater System Drain Valve

The inspectors observed the production and implementation of Work Order 93031604-02, Repair of Valve 2CA-169. The valve is a one inch drain valve in the auxiliary feedwater line to the 2D steam generator and is unisolable with the unit in power operations. PT/2/A/4200/013, CA Valve Inservice Test, was utilized to perform the work observed on valve 2CA-169.

The valve had seat leakage which developed into a steam leak on the threaded connection of a schedule 160 nipple and pipe cap downstream of the valve. The leak had been discovered by a non-licensed operator on daily rounds. The condition of the leaking valve and pipe cap was surveyed by licensee personnel. It was decided to temporarily repair the leak by injection of the cap with leak sealant. Due to the configuration of the components and concerns associated with leak repairs of this type, the vendor designed a strongback clamp to restrain the pipe cap during the procedure and to control the pressure relief of the piping. The strongback was designed to handle the operating parameters of 1400 psig and 600°F. Actual system pressure was 955 psig and 437°F.

A detailed prejob briefing was held to inform operations of the nature of the repair effort and possible actions that may had been necessary by the operating crew.

The vendor installed the strongback clamp and drilled the pipe cap to relieve the pressure. The leakage was evaluated and the pipe cap removed. A one inch Modified Thread Injection Cap was installed, but could not be used because of a lack of thread engagement with the pipe nipple. As the injection cap internal pipe seating plug was adjusted, its threads became galled. The first injection cap was removed and another installed successfully. The injection cap was then injected with sealing material which stopped the steam leak.

The inspector observed portions of the entire repair effort. It was noted that job planning preparations, operations briefings and safety preparations were of high quality and contributed to a successfully completed job. Also, procedural restrictions established by the licensee to control implementation of the leak seal repair process, including the use of a strongback in this case reflected positively on the licensee's maintenance program.

c. Auxiliary Feedwater Valve Inservice Test

On January 25, the inspector witnessed the performance of surveillance test PT/1/A/4700/13E, Auxiliary Feedwater Valve Inservice Test, for Valve 1CA-60. The purpose of this test procedure was to satisfy the requirements of Section XI of the ASME Boiler and Pressure Vessel Code with regard to the measurement of valve stroke time, valve operability and valve position indicator verification as required by the Catawba inservice testing program.

Valve 1CA-60 is an air operated auxiliary feedwater flow control valve to the 1A steam generator. The "normal" and "fail safe" position for the valve 1CA-60 is open. The valve is controllable from the control room, and opens on an auxiliary feedwater autostart signal.

On December 27, 1993, Work Order 94003008-01 was issued for seat leakage past valve 1CA-60 which was identified during auxiliary feedwater system flow balance testing. During the flow balance, proper flow through valve 1CA-60 was verified with the valve in the full open position. While performing work on the valve to correct seat leakage and Operator Aid Computer closed indication, the valve positioner was found out of calibration such that the valve was going 90% closed with a full closed (0% demand) signal present. The positioner was calibrated, and functionally tested satisfactorily, including Operator Aid Computer indications. An inservice test was then completed with the valve stroke time of 1.6 seconds, well below the allowed stroke time of 10 seconds. This stroke time represented a significant increase from previous testing. However, the out of calibration valve positioner indicated the valve was not previously stroked from the full closed position. Calibration of the positioner accounted for an increased valve stroke time.

The inspector observed a short prejob briefing just prior to the performance of the surveillance PT/1/A/4700/13/E, Auxiliary Feedwater Valve Inservice Test. The operator asked the technician performing the test about the scope of the maintenance which had been performed prior to the test. Initially, he did not receive a satisfactory answer to demonstrate the technician was knowledgeable of the work which had been performed to support assessment of the test results. The operator delayed performance of the test until appropriate information was provided. The inspector noted this to be indicative of good control of plant activities by the operator and insufficient preparation on the part of the maintenance technician.

d. Safe Shutdown Facility Diesel Generator Maintenance

On January 31, at 4:00 a.m., the SSF diesel generator was removed from service to conduct routine preventative maintenance. After completing this maintenance, the diesel generator was started for post-maintenance functional testing. During this testing, the diesel tripped on overspeed and in later starts, load was observed to be swinging between 60-80 kilowatts. On February 2, IAE technicians with support from Component Engineering personnel, began troubleshooting the cause of the erratic diesel operation. That same day, the magnetic speed sensor pickup was cleaned, the fuel actuator was replaced, and the electric governor was calibrated. While diesel operation reportedly improved, the load swings continued. On February 3, Component Engineering determined that the cause of the erratic operation was most likely due to a problem in the electric governor controls. Several of the governor control unit circuitry boards were replaced and the diesel was operated. While the diesel operated properly unloaded, when synchronized to the test buss, it continued to exhibit load swings. Component Engineering personnel suspected that the "droop" mode control, which helps maintain stable operation when parralleled to the test buss, was not operating properly. On February 4, another governor control unit was obtained from McGuire Nuclear Station and installed. When started, the diesel operated properly and after calibrating the new control unit, post-maintenance testing was performed. This testing was successfully completed and the diesel was returned to service later that same day.

The inspector monitored portions of the troubleshooting activities and noted good technical support from Component Engineering personnel. WR 94003763-01 and procedure IP/0/A/3890/01, Controlling Procedure for Troubleshooting and Corrective Maintenance, was used to accomplish the troubleshooting. The inspector reviewed the WR package at the job site while troubleshooting was in progress. IP/0/A/3890/01 was used to control the removal and installation of governor control boards. The inspector noted that while troubleshooting was accomplished satisfactorily and without incident, a detailed action plan was not developed in order to conduct the activities in a more efficient manner. The WR task description only instructed the investigation into the cause of the diesel running rough and to repair and recalibrate the diesel governor as necessary. The inspector considered that if such a plan had been developed, the root cause of the diesel erratic operation may have been identified sooner and without having to perform maintenance on components such as the speed sensor and fuel actuator unnecessarily.

The inspector also witnessed portions of the calibration of the replaced governor control unit and reviewed the IAE instrument guide procedure IG/0/B/3691/02, SSF Diesel Generator American Bosch Electric Governor System, used to perform the calibration. The inspector noted that the procedure was last revised on September 2, 1983. This was in excess of the 5 year periodic review frequency for instrument guides as prescribed by MMP 4.0, Development, Approval, and Use of Instrument Technician Guides (IGs), approved October 25, 1991. At the 5 year review point, MMP 4.0 indicated that Instrument Technician Guides should be upgraded to Instrumentation Procedure. In addition, when the inspector visited the job site on February 4, following the second governor control unit replacement, it was observed that the technicians were not using this calibration procedure. However, the activity was being monitored and supervised by Component Engineering personnel. After discussing the calibration process with the Component Engineering personnel, and reviewing the calibration steps provided in vendor documentation supplied with the replacement governor unit, the inspector determined that the governor was being adequately calibrated. Upon further review the inspector determined that this was an isolated case where an overdue IG was used for TS equipment. Nonetheless, the inspector considered the examples described above regarding periodic review and revision of the procedure and procedure usage practices for work on the Technical Specification related Safe Shutdown Facility equipment to represent a weakness in maintenance practices.

e. Residual Heat Removal Pump 1A Spring Can Stop Left Installed

On February 1, the licensee discovered that a spring can support stop, that was supposed to have been removed from the suction side of the RHR pump 1A piping, was still installed. The spring can stop was immediately removed. Due to the possible affect on the RHR pump vibration, an Inservice pump test was performed to ensure that vibration had not increased. The results of this testing showed no change in pump vibration or other operating parameters. The licensee also inspected a total of 74 spring can supports on the other ECCS pump piping. No further spring can support stops were found installed.

This spring can stop along with a second stop on the RHR 1A pump discharge piping was installed during replacement of the pump on December 15. Both stops were supposed to have been removed under WR 93085459-01, after completing the pump replacement. However, only the stop in the discharge piping was removed. The suction piping stop was discovered during a routine review of the WR package by Quality Assurance personnel. The licensee initiated

PIP 1-C94-0106 to address this incident. Weaknesses involving the licensee's control of lead shielding and spring can stops for this maintenance activity were discussed in NRC Inspection Report 50-413, 414/93-34. The inspectors plan to review the licensee's corrective actions for this issue upon completion of the PIP.

f. Review of Unit 2 Missed Technical Specification Surveillance

On February 3, the licensee discovered that the monthly ACOT for Power Range Low Power Setpoint Reactor Trip and Intermediate Range Neutron Flux Reactor Trip were not performed while Unit 2 operated less than 10 percent reactor power following the turbine trip at 9:47 a.m. on January 12, 1994. Shortly after the turbine trip, Mode 2 was entered in order to stabilize the plant. The unit was maintained in Mode 2 for repairs and investigation of the trip until 1:30 p.m. the following day, at which time, Mode 1 was entered. Shortly thereafter, power escalation commenced above 10 percent. The licensee later determined that the ACOT for Intermediate Range Neutron Flux Reactor Trip had been performed within the previous 30 days, therefore, a missed TS surveillance had not occurred. The licensee planned to submit an LER for the missed TS surveillance for the Power Range Low Power Setpoint Reactor Trip. The inspector will review the licensee's corrective actions during normal followup of this LER.

The inspector reviewed TS surveillance 4.3-1, Item 2.b., for Power Range Low Power Setpoint Reactor Trip. This ACOT for verifying operability of the trip setpoint is required to be performed monthly when the unit is in Mode 1 less than 10 percent power or in Mode 2. During discussions with the licensee concerning past performance of the surveillances, the inspector learned that the surveillance is performed during plant startups prior to entering Mode 2 from Mode 3, however, the surveillances have not been performed during plant shutdown prior to decreasing below 10 percent power nor before Mode 3 is reached. Based on the licensee's current method of performing the surveillance, it takes 2-3 hours for each of the four channels to be tested due to its complexity. The inspector considered it impractical to expect the licensee to perform the surveillance in the short time period (normally 1-2 hours) operating between 10 percent power and Mode 3 during a normal plant shutdown. However, in those abnormal circumstances where extended time is spent in this operational mode, as in the case with the Unit 2 turbine trip on January 12, the surveillance is required to be performed.

Since it appears impractical to perform the surveillance between 10 percent power and Mode 3 during a normal plant shutdown, the inspector questioned whether this and the intermediate range surveillance needed to be performed prior to decreasing below 10 percent power. The general surveillance guidance contained in TS 4.0.4 requires that surveillance requirements shall be current prior to entry into the operational mode for which they are required. An exception is allowed if the mode change is being directed by a TS action statement. It was not clear to the inspectors what the intent of the surveillance is during shutdowns. Accordingly, this issue will be carried as an URI pending completion of this review. This item is documented as URI 50-413, 414/94-04-01: Review of Reactor Trip Surveillance Requirements.

g. Residual Heat Removal Pump 1A Motor Rebuild Deficiency

On November 30, 1993, during the Unit 1 refueling outage (1EOC7), the RHR pump 1A motor assembly was replaced with a rebuilt pump/motor assembly due to a seal leak. When this rebuilt pump/motor assembly subsequently experienced high vibration during reduced reactor coolant system inventory conditions, it was declared inoperable and the original pump/motor assembly, which had been rebuilt, was installed. Details pertaining to this incident were discussed in detail in NRC Inspection Report 50-413, 414/93-34.

During this inspection report period, the inspector reviewed the Westinghouse failure analysis of the cause of the high vibration and the licensee's Work Request package for rebuilding the pump/motor assembly installed on November 30.

The Westinghouse failure analysis indicated that the excessive vibration was caused by a loose upper bearing runner. Apparently when the upper runner was installed, the locknut was not tightened sufficiently to compress the preload springs under the bearing. This allowed excessive movement of the shaft causing high vibration at the top of the motor. Westinghouse uses a special tool to help ensure that the locknut is installed properly. Until the motor was taken to Westinghouse for evaluation, the licensee was unaware that such a tool was available. The licensee plans to obtain this tool for future pump/motor rebuilds. Other licensee corrective actions include: 1) constructing a motor test stand to allow pre-installation testing of motor rebuilds in order to identify problems prior to installation, and, 2) procedural enhancements including measurements of the upper bearing fit on the shaft prior to and after reassembly. The inspector determined that the licensee's planned corrective actions should help assure that pump/motor rebuilds are assembled correctly in the future.

WR 93041018-01 and procedure MP/0/A/2002/01, Motor Inspection and Maintenance, approved June 6, 1988, was used to perform the rebuild of the RHR 1A pump/motor assembly that was installed on November 30, 1993. The inspector reviewed this WR and procedure. The inspector noted that this maintenance procedure lacked detailed instructions to ensure that the upper motor bearing was reassembled properly. A single step stated that the motor be reassembled in the reverse order of disassembly, and if necessary, refer to the manufacturer's drawings and instruction manual. The licensee has developed a new procedure for the RHR pump motors following the RHR 1A rebuild. This new procedure, IP/0/A/4974/15, Residual Heat Removal Motor Inspection and Maintenance, was approved October 12, 1993. The inspector reviewed this procedure. The inspector noted that this procedure was an improvement from the earlier version, in that it included much more detailed instructions and provided tolerances for critical motor assembly parameters.

The inspector reviewed CNM 1201.05 - 0318, the manufacturer's (Westinghouse) vendor manual for the RHR 1A pump motor. The inspector noted that the manual did not provide any information, neither in the form of descriptions nor disassembly/reassembly, for the type of upper bearing (ball bearing) that is installed on the RHR pump motors. Based on discussions with appropriate Component Engineering personnel, the licensee is attempting to obtain this documentation from Westinghouse. The Containment Spray pump motors are also involved since they have a similar upper bearing design. The inspector considered that this information may be needed to ensure that the licensee's procedures are adequate to perform the level of maintenance (rebuilds) of this safety-related equipment. Pending further review of the effectiveness of the licensee's pgrogram to incorporate vendor information into maintenance procedures this is identified as unresolved Item 413/50-94-04-03; RHR Pump Maintenance Procedure.

No violations or deviations were identified.

6. **ENGINEERING** (NRC Inspection Procedures 71707, 37828 & 40500)

Thermal Barrier Heat Exchanger Component Cooling Water Check Valves

The Component Cooling Water check valves located in the supply lines to the reactor coolant pump thermal barrier heat exchangers were evaluated for a potential operability concern. The concern was the result of a concern identified at Sequoyah Unit 2, in November 1993, after radiography revealed that seven check valves were failed in the open position and the eighth had an internal piston installed incorrectly. These valves are normally open to provide cooling water to the reactor coolant pump thermal barrier heat exchanger and must close to prevent gross diversion of reactor coolant from a ruptured thermal barrier cooling coil from entering the Component Cooling nonessential Reactor Building supply header. If a thermal barrier was to rupture and the check valve failed to close, the Component Cooling piping upstream of the check valve could fail due to over pressurization and result in an unisolable intersystem loss of reactor coolant.

The inspector determined that the eight check valves which perform a similar function at Catawba are two inch self-actuating Kerotest check valves, a different design than those which failed at Sequoyah. These check valves were not included in the inservice test program nor were they included in a preventive maintenance program. The inspector questioned the licensee's actions in response to NRC Information Notice 89-54, Potential Overpressurization of the Component Cooling Water System, and the reliability of the check valves. This question was not resolved by the end of the report period and is identified as an unresolved item. URI 50-413, 414/94-04-02: Thermal Barrier Heat Exchanger Check Valve Reliability.

No violations or deviations were identified.

7. **PLANT SUPPORT** (NRC Inspection Procedures 71707)

Emergency Operations Facility Tour

On January 11, the inspector accompanied the NRC Region II Emergency Preparedness Coordinator, and the Catawba Emergency Planning Manager on a tour of the licensee's Emergency Operations Facility located in Charlotte, North Carolina. The facility was dedicated to the emergency response function, therefore no activities to set up the facility are necessary to activate it during emergencies. The facility was well maintained. Current revisions of reference material were available and equipment was in good working order.

No violations or deviations were identified.

8. **PREVIOUS INSPECTION FINDINGS AND LICENSEE EVENT REPORTS** (NRC Inspection Procedures 92700 and 92702)

a. (Closed) LER 50-413/92-07: Technical Specification Violation Due to Missed Surveillance on the Upper Containment Personnel Air Lock

On July 3, 1992, the licensee discovered that the Unit 1 upper containment air lock had not been leak rate tested in accordance with technical specifications. Technical specifications require air lock leak rate testing within 72 hours of closing the air lock in order to verify its continued operability. On June 29, 1992, at 10:15 a.m., an entry into upper containment was performed thereby requiring testing of the air lock within 72 hours (not including the 25 percent TS grace time). Due to inadequate communications between personnel in the Operations Support Group responsible for conducting this testing, the licensee failed to perform the required testing within the TS allowable time frame. Testing was not completed until July 3, 1993, at 9:40 a.m., at which time the upper air lock was found operational.

The inspectors reviewed the licensee's corrective actions which included the development within the Operations Support Group a formal surveillance verification method to assure that TS surveillances with infrequent intervals are completed as required.

In November 1993, the responsibility for performance of this TS surveillance was changed from the Operations Support Group to the operations shift personnel. The shift now performs this surveillance every 72 hours during shutdown regardless of whether a containment entry has been made. In addition, a computer program was developed to track and record the date and time that the test was last performed and when it is next required to be performed. The inspector determined that an adequate surveillance verification method was developed to ensure that the TS surveillance was completed as required.

b. (Closed) LER 413/93-01 Control Room Ventilation System Entry Into Technical Specification 3.0.3

While the licensee was performing OP/0/A/6450/11, Control Room Area Ventilation/Chilled Water System, the control room differential pressure dropped from 0.45 to 0.10 inch water gauge. Consequently, the units entered TS 3.0.3 because the requirements of TS 3.7.6, Control Room Area Ventilation System, which requires two control room ventilation systems operable, were not met.

While the train "B" intake was isolated for testing, a spurious "High Chlorine" alarm closed the "A" intake isolation valve. With both intake isolation valves closed, control room differential pressure decreased to less than the TS limit. Control room operators took immediate action by opening the intake isolation valves after identifying the defective chlorine detector. This was accomplished in less than six minutes. Corrective maintenance was performed in accordance with Work Order 93003944. The electrode and a faulty printed circuit card were replaced. The inspector reviewed the work order and the maintenance history associated with the chlorine detectors. The chlorine detectors have not exhibited a high failure rate as identified by this review.

c. (Closed) LER 50-413/93-12, Unit 1 Entered Mode 3 with Inoperable Auxiliary Feedwater Pump.

The event described in this LER was the subject of Violation 50-413/93-34-01, as documented in NRC Inspection Report 50-413/93-34 paragraph 3b. Corrective actions associated with this event will be reviewed in conjunction with the review of the licensee's response to the violation.

d. (Closed) LER 50-414/92-05: Technical Specification Violation Due to Containment Temperature Below Limits

On November 29, 1992, during Unit 2 startup, Mode 1 was entered with containment upper compartment temperature less than allowed by technical specifications. Technical specifications require that containment average air temperature be maintained between 75 and 100°F. Prior to entering Mode 1, an operator completed a surveillance check of containment temperature and incorrectly read a computer printout that indicated containment upper compartment temperature was 73.8°F. Immediately following the reactor being taken critical, a computer alarm was received indicating that temperature was low. The operators failed to properly respond to the alarm and subsequently Mode 1 was entered 27 minutes later with temperature less than 75°F. Twenty-five minutes after entering Mode 1, the operators recognized the computer alarm and immediate action was then taken to restore temperature within its limit. Approximately four and one-half hours later, average temperature had increased above 75°F.

This issue was the subject of NCV 414/92-29-03, which was documented in NRC Inspection Report 50-413,414/92-29.

The inspectors reviewed the licensee's corrective actions which included changing the operations procedure to require the operators to enter the actual temperature when performing the surveillance check, and, enhancing the control room computer alarm system to provide alarms every 5 minutes for alarms not acknowledged. The inspector considered that adequate corrective action had been implemented.

9. EXIT INTERVIEW

The inspection scope and findings were summarized on February 9, 1993, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

Item Number	Description and Reference
URI 50-413, 414/94-04-01	Review of Reactor Trip Surveillance Requirements (paragraph 3.f).
URI 50-413, 414/94-04-02	Thermal Banner Heat Exchanger Check Valve Reliability (paragraph 6).
URI 50-413/94-04-03	RHR Pump Maintenance Procedures (paragraph 4.g.)

10. ACRONYMS AND ABBREVIATIONS

ACOT - Analog Channel Operational Test
ASME - American Society of Mechanical Engineers
CFR - Code of Federal Regulations
ECCS - Emergency Core Cooling System
EOP - Emergency Operating Procedure
IAE - Instrument and Electrical
IG - Instrument Technician Guide
gpm - gallons per minute
Hg - Mercury
IP - Instrumentation Procedure

LER	-	Licensee Event Report
MMP	-	Maintenance Management Procedure
NIS	-	Nuclear Instrumentation System
NLO	-	Non-Licensed Operator
OP	-	Operating Procedure
PIP	-	Problem Investigation Process
psig	-	pounds per square inch
PT	-	Periodic Test
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
R&R	-	Removal and Restoration (Tagging Order)
RTD	-	Resistance Temperature Detector
SSF	-	Standby Shutdown Facility
TS	-	Technical Specification
URI	-	Unresolved Item
WO	-	Work Order
WR	-	Work Request