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

Report Nos.: 50-413/93-34 and 50-414/93-34

Licensee: Duke Power Company
422 South 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: December 5, 1993 - January 8, 1994

Inspectors: W. Holmes Jr. For 1/31/94
R. J. Freudenberger, Senior Resident Inspector Date Signed
P. C. Hopkins, Resident Inspector, Catawba
J. Zeiler, Resident Inspector, Catawba
C. Yates, Intern

Approved by: MSLesser 2/1/94
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 follow-up of previously identified items. Backshift inspections were conducted on December 5, 10, 17, 18, 19, 31, and January 7.

Results: In the operations area, good communication was noted during refueling activities (paragraph 3.a). A violation was identified involving a mode change with the turbine driven auxiliary feedwater pump steam supply isolated due to confusion regarding documented guidance. (VIO 50-413/93-34-01, paragraph 3.b). NRC inspection of the condition of Unit 1 lower containment identified no discrepancies (paragraph 3.c). The licensee's assessment of the Unit 2, January 2, runback identified appropriate actions to improve unit response (paragraph 3.d).

In the maintenance area, activities observed were performed in a satisfactory manner in accordance with procedural requirements.

In the engineering area, a violation was identified involving delayed corrective actions for high vibrations on Unit 1 Residual Heat Removal pump No. 1A. (VIO 50-413/93-34-02, paragraph 5.c).

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Informal activities to monitor the pump were being conducted without sufficient management oversight. Clear direction and acceptance criteria was not established.

As a result, with the plant in a reduced inventory condition, immediate corrective action was not initiated when excessive vibrations rendered the pump inoperable. Two days later the pump was secured, as vibration levels continued to increase, and action to replace it was initiated.

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 in the End of Cycle 7 Refueling Outage. The reactor was brought critical on December 29, and placed on line December 31, following Zero Power Physics Testing. The Unit reached full power prior to the end of the report period.

b. Unit 2 Summary

Unit 2 operated at full power for the duration [illegible] the report period with the exception of a runback to 50 percent power on January 2, as described in paragraph 3.c.

c. Inspections and Activities of Interest

During the week of December 13, a specialist inspection of the licensee's program for the control of safeguards information was conducted. Results of this inspection are documented in NRC Inspection Report 50-269, 270, 287/93-32, 50-369, 370/93-31 and 50-413, 414/93-35.

During the week of January 3, a specialist inspection was conducted concerning the steam generator replacement project, primary to secondary leakage monitoring, and grafitization of sections of the turbine driven auxiliary feedwater pump steam supply piping. Results of the inspection are documented in NRC Inspection Report 50-413, 414/94-01.

3. **OPERATIONS** (NRC Inspection Procedures 71707, 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, 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 Refueling Activities

On December 5, 1993, Unit 1 entered Mode 6, and refueling of the reactor core commenced using PT/0/A/4150/22, Total Core Reloading. Prior to commencing refueling, the control room operators received a Tailgate briefing provided by the Reactor Engineering group. The inspector reviewed the Tailgate Package and noted that it provided the operators with detailed guidance of what plant parameters to monitor during the activity and expected control board alarms. The inspector reviewed portions of PT/0/A/4150/22, and verified a sample of the prerequisites. The inspector witnessed aspects of the refueling activity from the control room, containment, and the fuel building. The inspector periodically verified that proper plant conditions were maintained as required by Technical Specifications to support these activities, that radiological controls were being observed, and that proper housekeeping and material exclusion controls were met in the Reactor and Fuel Buildings. The inspector noted good communication existed between personnel at each of these locations. By December 8, the core was completely reloaded without incident.

b. Mode Change with Turbine Driven Auxiliary Feedwater Pump Steam Supply Isolated

On December 25, at 3:46 p.m., the plant entered operational Mode 3, Hot Standby, when the operators increased average reactor coolant system temperature to greater that 350°F. Prior to changing operation mode, the operators completed procedure OP/1/A/6100/01, Controlling Procedure for Unit Startup, Enclosure 4.4, which is intended to ensure Technical Specification requirements for entry into Hot Standby are met. The operators were aware of an outstanding equipment Removal and Restoration order associated with Valves 1SA1 and 1SA4, manual isolation valves in the auxiliary steam supply to the turbine driven auxiliary feedwater pump turbine. Although the work associated with the Removal and Restoration order was complete, Instrument and Electrical technicians had informally requested that it remain in place while they performed troubleshooting of a discrepancy unrelated to the Work Order for which the Removal and Restoration order had originally been placed. The operators, including at least 2 Senior Reactor Operators, misinterpreted the procedure and a licensee's Technical Specification Interpretation in authorizing the operational mode change to Hot Standby, with the turbine driven auxiliary feedwater pump steam isolation valves closed. On the morning of December 26, the Shift Manager, listening in on the Unit Supervisor's turnover, questioned the information discussed regarding the status of the Removal and Restoration order associated with the turbine driven auxiliary feedwater pump steam isolation valves. A review of pertinent information revealed that the valves should have been opened prior to entering Hot Standby to comply with Technical Specification 3.7.1.2. Also, no work was ongoing which necessitated that these valves be closed. Valve 1SA1 was opened at 7:56 a.m., and Valve 1SA4 was opened at 7:58 a.m., on December 26. A Problem Investigation Process report (Number 1-C93-1158) was initiated by the Unit 1 Supervisor on December 26.

In order to assess this issue, the inspector reviewed the Problem Identification Process Report 1-C93-1158; Operating Procedure OP/1/A/6100/01, Controlling Procedure for Unit Startup; Design Basis Specification for the Main Steam to Auxiliary Equipment System (SA) and Feed Water Pump Turbine Exhaust System (TE); Removal and Restoration Number 13-2980; plant computer historical data; Technical Specification 3/4.7.1.2; and the licensee's written interpretation of Technical Specification 3/4.7.1.2. This issue was also discussed with appropriate plant personnel.

Based on this review, the inspector determined that the safety significance of entering Hot Standby with the steam supply to the turbine driven auxiliary feedwater pump was reduced for the following reasons:

- The Unit Supervisors were aware of the status of the valves and could have initiated actions to open them should it have

been necessary, within the time available to maintain the steam generators available;

- the valves were opened as the main steam system reached normal operating pressure;

- both motor driven auxiliary feedwater pumps were operable; and

- substantial margin existed in the steam generator secondary inventory to provide decay heat removal by steaming to atmosphere, without makeup.

The inspector noted that the licensee's Technical Specification Interpretations contributed to operator confusion regarding this issue and informal implementation of the Removal and Restoration process contributed to its cause.

The licensee planned corrective actions include the submission of a Licensee Event Report, communication to licensed operators through an operator update and other training, and revision to the Technical Specification interpretation. The corrective actions initiated appeared to address the relevant issues. However, the mode change with the steam supply to the turbine driven auxiliary feedwater pump isolated is a violation of Technical Specifications 3.0.4 and 3.7.1.2. Violation 50-413/93-34-01: Mode Change with Turbine Driven Auxiliary Feedwater Pump Steam Supply Isolated.

c. Unit 1 Lower Containment Cleanliness

On December 22, 1993, with preparations being completed for entering Mode 4, the inspector conducted a walkdown of Unit 1 lower containment to verify adequate cleanliness. Of particular concern was sources of fibrous material or other debris that could migrate to the lower containment ECCS sump screens, potentially causing blockage of the screens. At the time of this walkdown, the licensee had not yet performed their containment cleanliness procedure, but the inspector confirmed that this activity was appropriately scheduled to be performed prior to Mode 4 entry when the ECCS sump was required to be operable. Although a thorough cleaning of lower containment had yet to be conducted, the inspector observed that the licensee had identified and already removed a majority of the sources of debris and fibrous material. The inspector verified that the licensee had removed the Containment Air Charcoal Filter Units' pre-filter and High Efficiency Particulate Air filter which were used during the outage. In response to NRC Bulletin 93-02, Debris Plugging of the ECCS Suction Strainers, the licensee committed to removing this material in order to reduce the possibility of this source of this fibrous material from plugging the strainers. Since the licensee had already cleaned the screens and ECCS suction piping, the inspector examined the condition of these items. Some minor

residue was found but was judged to have no impact on the system. The inspector determined that the area had been adequately cleaned.

d. Unit 2 Runback

On January 2, Unit 2 experienced a runback from full power to approximately fifty percent load. At 5:18 p.m. protective relaying detected a fault associated with Power Circuit Breaker 23, resulting in an isolation of the "B" offsite power tie line including opening of one of the two generator output breakers. An automatic runback was initiated to reduce unit load to within the capability of the remaining generator output circuit. The "B" train normal incoming breakers opened and tie breakers closed as designed.

When the automatic runback terminated at a turbine impulse pressure of approximately 385 psig., (approximately 63% power), an annunciator for generator output breaker "A" overcurrent in alarm remained. Plant operators reduced load further (to approximately 56% power) to clear the overcurrent alarm condition and stabilized plant conditions. Reactor engineering personnel utilized applicable portions of PT/0/A/4150/02, Reactor Trip Investigation, to analyze the runback.

Shortly after the runback, a Unit 1 ventilation system particulate radiation monitor alarmed. A sample confirmed the activity and the ventilation system was placed in the filter mode. Licensee investigation for the source of the activity identified no primary coolant leakage. The licensee initiated PIP 1-C94-0002 and actions to identify the cause of the increased particulate activity in the ventilation system. The licensee's investigation determined that at the time of the Unit 2 runback, letdown was aligned to the "B" Recycle Holdup Tank. Unit 2 was operating with elevated activity as a result of known fuel leakage. Due to the runback, additional letdown was diverted to the holdup tank. Along with reduced capacity of the waste gas system due to an out of service compressor, a loop seal between the gas space of the holdup tank and the ventilation system was breached, allowing a flow path for gaseous activity to the ventilation system. The gases decayed to particulate daughters which were detected by the radiation monitor. The inspector reviewed the licensee's cause analysis and dose assessment of the release and discussed the issue with appropriate plant personnel. The inspector noted that the licensee's analysis was effective in identifying an inconspicuous cause and the calculated dose from the release was negligible, well within regulatory limits.

The inspector attended the licensee's Abnormal Plant Event meeting conducted on January 6, to review the assessment of the plant response and corrective actions for the runback. The licensee's evaluation of the runback identified that the automatic runback

had stopped based on the programmed turbine impulse pressure. The programmed pressure was slightly high, therefore the overcurrent condition on the remaining generator output breaker did not clear, necessitating operator action. The cause of the slightly high programmed impulse pressure was determined to be the result of the slightly non-linear relationship of impulse pressure to unit load.

Action items identified by the licensee included: determination of the root cause of the failure of the instrument transformer; evaluation of the feasibility of the development of a procedure, similar to the reactor trip procedure, for assessment of runbacks and other plant transients; and evaluation of the use of turbine impulse pressure in control systems represent plant load for adjustments.

The inspector concluded that the licensee's assessment of the runback identified appropriate actions to improve unit response. The inspector considered that the corrective actions associated with the radiological release described above would have added to the completeness of the discussion.

Within this area, one violation was 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 Technical Specification requirements were appropriately implemented.

In addition, the inspector observed maintenance activities to verify that correct equipment removal and restoration orders were in effect; work orders and fire prevention work permits, as required, were issued and being followed; quality control personnel performed inspection activities as required; and Technical Specification requirements were being properly implemented.

a. Diesel Generator 1A Periodic Test

On December 7, the inspectors witnessed the performance of portions of surveillance test PT/1/A/4350/15A, Diesel Generator 1A Periodic Test. The purpose of this test was to verify that Diesel Generator 1A would: reject a load of 825 KW while maintaining a voltage of 4160 V and a frequency of 60 Hz; reject a load of 5600 KW without tripping and without allowing diesel speed to exceed 500 RPM; trip on all automatic trip functions; receive fuel from each of the two fuel storage tanks by operation of the fuel transfer valve; not start if barring device was engaged or maintenance mode lockout feature activated; start on an auto-start signal; and carry a load of 5600-5750 KW for 24 hours. The

inspectors witnessed this test from Diesel Generator Room 1A. No discrepancies were noted.

b. Control Rod Drop Timing Test

On December 27, the inspector witnessed portions of the rod drop timing test and reviewed IP/0/B/3220/01, Control Rod Drop Timing Test on Unit 1. The purpose of this test was to determine the drop time of the Rod Cluster Control Assemblies and to establish data for future rod drops. The Rod Cluster Control Assembly Movement Test, PT/1/A/4600/01, was performed in conjunction with the control rod drop timing test. The purpose of this test was to periodically test Rod Cluster Control Assembly operation under actual operating conditions, or prior to startup. To perform the control rod drop timing test, a bank of control rods were selected and stepped to the full withdrawal position. The individual drop time for each rod in the bank was then determined by pulling the selected Control Rod Drive Mechanism's moving and stationary gripper coil fuses, and recording the voltage profile induced by the Rod Cluster Control Assembly drive shaft dropping through the coils of the Digital Rod Position Indication detector. The maximum allowable rod drop time per Technical Specification 3.1.3.4 was 2.2 seconds. The inspector reviewed Work Request No. 93053729-01, Rod Cluster Control Assembly Drop Time Summary, and the control rod drop time traces. The slowest Rod Cluster Control Assembly drop time was 1.64 seconds. No discrepancies were noted.

c. Approach to Criticality

On December 29, the inspector witnessed the approach to criticality and reviewed PT/0/A/4150/19, 1/M Approach to Criticality as part of the Zero Power Physics Testing for Unit 1 EOC7 outage. The purpose of this procedure was to ensure that criticality was achieved in a safe and orderly manner. A tailgate meeting was held with the operators to address configuration control and the impact on technical specifications. Potential difficulties and test termination criteria regarding startup physics testing and the approach to criticality were also addressed. The inspector verified the operability of the rod control system by observing that the demand position and actual (digital) position indications were within +/-12 steps of each other. The inspector witnessed operator verification of proper control bank overlap, and proper annunciator response to assure that the reactor went critical above the Rod Insertion Limit. The calculation for determining the estimated critical rod position was accurate in predicting conditions for criticality. The inspector considered the approach to criticality orderly, and well conducted. The inspector also noted that communication between operators and reactor engineers was good.

d. General Warning Alarm For B Train Solid State Protection System

On January 4, the control room received a general warning alarm for B train Solid State Protection System (SSPS). The licensee's investigation found that one of the redundant B train power supplies had failed. It should be noted that the SSPS was fully operable with one power supply. The SSPS receives signals from various Nuclear Process and Control Instrumentation throughout the plant. The SSPS conditions these signals and develops logic sequences for the protection of the Reactor. Technical Specification 3.3.2 allows bypassing of one channel for up to two 2 hours for surveillance testing per Specification 4.3.2.1, provided the other channel is operable. Because the Operations and Instrument and Electrical Organizations had a high level of confidence in the ability to replace the power supply in less than 2 hours, B train SSPS was placed in test, the appropriate action statement was entered, and the failed power supply was replaced. Contingency plans were made for returning B train SSPS to normal in the event that unexpected problems occurred with the power supply replacement. The inspector witnessed replacement of the power supply and reviewed IP/2/A/3200/02B, Solid State Protection System (SSPS) Train B Periodic Testing, and IP/0/A/3890/01 Controlling Procedure for Troubleshooting and Corrective Maintenance. No discrepancies were noted.

Overall, surveillance and maintenance activities observed and discussed above were performed in a satisfactory manner in accordance with procedural requirements and met the requirements of the Technical Specifications.

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

Degradation of Residual Heat Removal Pump during Reduced Reactor Coolant System Inventory Operations

a. Background

On December 11, 1993, day 43 of the Unit 1 End of Cycle 7 outage, operators drained the reactor coolant system to reduced inventory conditions following refueling to allow reinstallation of the reactor vessel head, removal of steam generator nozzle dams and replacement of the "A" and "D" reactor coolant pump seals. The estimated time to core boil following a loss of decay heat removal, starting with reactor coolant system level at midloop, was approximately forty-five minutes. The licensee's administrative controls, delineated in Site Directive 3.1.30, Unit Shutdown Configuration Control, established the following plant status prior to entering reactor coolant system reduced inventory conditions:

- Containment Closure: The equipment hatch was installed, the personnel hatches were operating with interlocks active, and

penetrations were closed. Two penetrations were temporarily sealed with foam (qualification tested to 17 psig) to support outage equipment.

- Electrical Power Sources: Two offsite power sources were available. Administrative controls for switchyard and transformer yard access were implemented and areas in the vicinity of major power distribution components were posted. One emergency diesel generator was operable, the other was available.

- Reactor Coolant System Inventory Sources: Gravity feed was available from the Fueling Water Storage Tank; one charging pump and one safety injection pump were operable; and one charging pump and one safety injection pump were available (tagged out with breaker racked out for low temperature overpressure protection).

- Decay Heat Removal: Both trains of the Residual Heat Removal System (with separate connections to the reactor coolant system) were operable. Vibration of the "A" pump upper motor bearing was in the alert range following the installation of a rebuilt motor and pump rotating assembly.

- Reactor Coolant System Level Instrumentation: Two trains of wide and mid range differential pressure instruments referenced to containment atmosphere were operating and in agreement. Two trains of ultrasonic level indications which indicate level in hot legs were set to alarm if they came on scale (level at top of hot leg). A sight glass with video display in the control was in operation.

- Reactor Coolant System Temperature Instrumentation: Prior to reactor vessel head installation, Residual Heat Removal temperatures were available for reactor coolant system temperature monitoring. Within two hours after head installation, two core exit thermocouples were placed in service.

- Containment Sump: Sump screens were in place and uncovered. Material in containment was not judged to be sufficient to block screens. Therefore the sump was considered available for recirculation.

Although not controlled by shutdown administrative procedures, the following plant conditions existed which may have impacted a potential loss of shutdown cooling scenario.

- Steam Generators: Steam Generators were in wet layup with atmospheric dump valves available.

- Ice Condensers: The ice condensers were unavailable, the lower inlet doors were blocked closed.

b. Sequence of Events

Nov. 23 Unit Status: Core offloaded, 1A RHR pump repair

Radiation Protection personnel initiated actions to have lead shielding installed on the 1A RHR pump inlet and discharge piping located in the RHR pump room in order to reduce the radiation exposure to maintenance personnel while they replaced the pump/motor assembly. Engineering approved the use of shielding and provided instructions for its location and the installation of two travel stops on piping supports. Engineering indicated that the RHR pump was inoperable while the temporary shielding and travel stops were installed.

Nov. 26 Unit Status: Core offloaded, ECCS flow balance testing

Scheduled repairs for a mechanical seal leak on 1A RHR pump were completed. Scope of repairs involved replacing the pump/motor assembly with a spare that had been removed from 2B RHR train and rebuilt. Replaced as a unit were the motor, motor support, casing cover, mechanical seal, and impeller.

Lead shielding and spring can support travel stops on the pump inlet and discharge piping were not removed.

Nov. 30 Unit Status: Core offloaded, ECCS flow balance testing

1A RHR pump was operated at miniflow recirculation and fullflow conditions during ECCS flow balance testing. Vibration measured at the upper motor bearing location (top of the motor), in the East/West horizontal direction, was approximately 0.35 inches/second. Since this was higher than expected, further vibration data was planned to be taken. Vibration measured at the same location while the pump operated at full flow was 0.596 inches/second.

Dec. 2 Unit Status: Core offloaded, ECCS flow balance testing

Inservice Testing was conducted on the 1A RHR pump in order to verify operability following replacement of the pump/motor assembly. Pump operating parameters were measured and recorded with the pump operating in miniflow recirculation condition with suction from the FWST. Vibration at the upper motor bearing location was measured to be 0.42 inches/second which was within the Alert Range of between 0.325 and 0.7 inches/second. The pump was considered operable but testing frequency increased in

accordance with IST requirements. Besides vibration, all other operating parameters measured were within acceptable limits.

Dec. 2-8 Unit Status: ECCS flow balance testing and core reload

Vibration monitoring, conducted during various operating conditions, results indicated higher than desired vibration. (varied but within alert range - 0.325 to 0.7 inches/second) No indications present to support bearing degradation. Based on history, suspected resonant conditions.

Dec. 6 Unit Status: ECCS flow balance testing and core reload

Meeting held between Operations, Systems and Component Engineering personnel, including management, to discuss the 1A RHR pump vibration results. It was concluded that there was confidence in reliability of 1A RHR pump. A recommendation was made to replace the pump/motor assembly following Engineered Safety Features testing on December 19. Decided to obtain additional vibration data in the interim.

Dec. 8 Unit Status: Cavity flooded, Core reload completion

Lead shielding was removed from 1A RHR piping in preparation for draining refueling cavity and declaring the 1A RHR pump operable, however, the spring can support travel stops were overlooked.

Vibration testing involving excitation with known force to identify resonant frequencies ("hammer test") performed.

Dec. 9 Unit Status: Reactor Upper Internals Installation

1A RHR pump declared operable.

Dec. 10 Unit Status: Cavity flooded, 1A RHR pump operating

After lead shielding removed from piping adjacent to 1A Residual Heat Removal pump, vibration reduced but still in Alert range.

Refueling cavity drained to reactor vessel flange.

Dec. 11 Unit Status: Transition to Reduced Inventory

Reactor coolant system drained to reduced inventory condition (8.5%, approximately two inches above top of hot leg junction with reactor vessel). Reactor vessel head set in place after significant vent path established through "B" hot leg steam generator manway. Reactor coolant pump "A" and "D" seal replacements initiated.

Dec. 12 Unit Status: Reduced Inventory, 1A RHR pump operating

Vibration data indicated upper motor bearing vibration in Action Range, greater than 0.7 inches/second. No supporting indication of degradation. Frequency of vibration monitoring increased to twice per day.

"B" hot leg manway installed. Reactor coolant system vented through reactor head vent sized for low temperature overpressure protection. On loss of residual heat removal, inventory makeup from pumps only (gravity feed unavailable due to pressurization following core boil).

Dec. 13 Unit Status: Reduced Inventory, 1A RHR pump operating

1A RHR spring can support travel stops were discovered and removed from 1A RHR pump inlet and discharge piping.

Vibration measurements trended slightly upward.

Dec. 14 Unit Status: Reduced Inventory, 1A RHR pump operating

1A Residual Heat Removal pump declared inoperable based on increasing vibration trend (> 0.9 inches per second) and harmonic indications. Controlled swap of residual heat removal train in operation performed. Plans developed for optimal methods to place unit in lower risk condition.

Dec. 15 Unit Status: Reduced Inventory, 1B RHR pump operating

Reactor coolant pump seal work completed. Conventional fill and vent of reactor coolant system initiated.

Seal replaced on motor and pump rotating assembly removed from 1A residual heat removal pump earlier in the outage and prepared for reinstallation. Pump isolated for replacement.

Dec. 17 Unit Status: RCS filled and vented, 1B RHR pump operating

Steam generators became operable for decay heat removal with natural circulation.

1A residual heat removal pump replaced, filled and vented, ready for testing.

Dec. 18 Unit Status: RCS filled and vented, ESF test preparations

1A RHR pump replacement and testing complete, declared operable.

c. Residual Heat Removal Pump Vibration

The inspector reviewed the circumstances leading to the licensee declaring the 1A RHR pump inoperable on December 14, 1993, due to high vibration. This resulted in a reduction in the level of safety due to having only one operable RHR pump with the unit in Mode 5, while the Reactor Coolant System (RCS) was in reduced inventory conditions, at 8.5 percent level.

As shown in the sequence of events, vibration data was collected on the 1A RHR pump periodically from November 30, when higher than expected vibration was first detected, until December 14, at which time the pump was declared inoperable. On December 6, after evaluating the vibration data collected up to that time, the Component Engineer responsible for evaluating vibration on rotating equipment concluded that there may be a structural resonance problem that was amplifying the pump vibration levels. Previous resonance problems were thought to have been experienced on RHR pumps at Catawba, and were known to have been experienced at other nuclear plants utilizing similar vertically mounted RHR pumps. In these instances, high vibration levels were caused by the pump/motor assembly natural frequency in resonance with the pump operating speed frequency. On December 8, a hammer test on the 1A RHR pump was performed to determine if any resonant frequencies existed. Licensee analysis of the results indicated resonant vibration frequencies were within the amplification region of the pump running speed frequency.

While a resonance vibration problem appeared to have been evident from the data collected, the inspector considered that the licensee placed too much reliance in having identified the problem and did not adequately pursue other potential causes of the high vibration prior to draining the RCS on December 10. This determination was based on several factors. First, vibration was unstable during the entire period, having approached the Required Action limit on December 2. Second, the pump had been replaced with a spare rebuilt from a pump/motor assembly that had experienced high vibration. Insufficient consideration was given to the possibility that in addition to the resonance problem, a pump mechanical problem may have been causing the high vibration. The preliminary results of a failure analysis being conducted by Westinghouse on the 1A pump indicated that the high vibration may have been caused by the improper installation of the upper bearing runner during the pump rebuild. Third, the recommendations from the pump manufacturer after reviewing portions of the vibration data may not have been given adequate consideration. Specifically, after reviewing the vibration data, the manufacturer did not recommend continued operation of the pump.

In addition to the above, the licensee's evaluation of the high vibration was complicated by the failure to control lead shielding and spring can support stops from the inlet and discharge piping

of the pump. On December 10, vibration was measured for the first time after removing the lead shielding. Although still in the Alert range, vibration reduced to 0.42 inches/second. At that time, the licensee believed that the shielding may have contributed to the high vibration indications.

The inspector reviewed the events of December 12, when vibration at the upper motor bearing increased to 0.76 inches/second, entering the IST Required Action Range. Based on pump noise and stable bearing temperatures, the Component Engineer determined that the bearings did not appear to be degrading or to be in distress. The Component Engineer believed that this higher vibration was being caused, in part, by the lower suction pressure that the pump was operating under due to the RCS being at reduced inventory level. The impact of reduced suction pressure when in reduced inventory conditions had not been previously evaluated. When vibration had been measured last on December 10, the RCS had been slightly less than 23 feet above reactor vessel flange, therefore, the suction pressure of the operating 1A RHR pump was higher. Noting no supporting indications of pump degradation, such as elevated bearing temperatures or noise, the Component Engineer still believed that the source of the high vibration was structural resonance. The Component Engineer recognized the data as exceeding the IST Program Action Range but did not recognize actions required. Therefore, the operations Shift Supervisor, Shift Manager, nor management personnel were notified. Vibration measurements frequency was increased to twice daily.

The inspector discussed the results of the licensee's pump meeting conducted on December 6 between Operations, Systems and Component Engineering personnel. Although it was decided that additional vibration data needed to be obtained until the pump could be replaced, there was no formal plan developed for conducting this activity nor contingencies established should vibration increase. In addition, there were apparently no provisions setup for communicating the results to management or appropriate IST personnel responsible for determining overall pump operability. The vibration readings were being taken informally, without procedural direction and clear acceptance criteria. While it is clear that increased attention was appropriate, the inspector considered management oversight and direction was lacking.

The inspector determined that adequate corrective actions were not implemented when vibration entered the Action range on December 12. Appropriate operations or management personnel were not notified of the vibration test results nor the conclusions of the Component Engineer. Although the Component Engineer apparently understood that 0.7 inches/second was the Action range limit, a clear understanding of the IST required actions was lacking when this value was reached. As a result, an operability evaluation for vibration entering the Action range was not performed.

The licensee's Pump and Valve Inservice Testing Program required that with pump parameters within the Required Action Range, the pump be declared inoperative until the condition is corrected or an analysis to demonstrate that the condition does not impair pump operability is performed.

As noted above, on December 12, 1993, unit 1 was in operational mode 5 with reactor coolant loops not filled. Technical Specification 3.4.1.4.2 requires two residual heat removal loops operable when in operational mode 5 with the reactor coolant loops not filled. With less than two loops operable, immediate initiation of corrective action to return the required residual heat removal loops to operable status as soon as possible is required. Measured vibration of the 1A Residual Heat Removal Pump motor upper bearing casing was in excess of 0.7 inches per second. This deviation with the Required Action Range established by the Pump and Valve Inservice Testing Program was not promptly identified as a condition adverse to quality. As a result, actions to assess the operability of the pump were not promptly implemented and the pump was not declared inoperable until 2:00 p.m. on December 14, 1993. This issue was identified as a violation of the requirements of 10 CFR 50, Appendix B, Criterion XVI and is documented as Violation 50-413/93-34-02: Delayed Corrective Actions for High RHR Pump Vibration.

d. Control of Lead Shielding Installations

The inspector reviewed the circumstances associated with the licensee's failure to adequately control the removal of lead shielding and two spring can support travel stops from the 1A RHR inlet and discharge piping. As a result of this review, the following observations were considered noteworthy.

- The inspector determined that this material may have contributed to the inconsistent and higher than normal vibration of the 1A RHR pump. Following the removal of the lead shielding, vibration decreased slightly.

- When WO No. 93085459-01 for installation and removal of the shielding and travel stops was generated, the planner indicated in the Task Description that the shielding needed to be removed prior to Mode 4. Since TSs require two RHR loops be operable in Mode 6 when water level above the reactor vessel flange is less than 23 feet, this was the incorrect plant condition requiring the shielding and travel stop removal. Based on discussions with the licensee during the inspector's review of this issue, it was noted that the planner did not review the engineering Temporary Load Request for Shielding data sheet when the Mode 4 determination was made. The data sheet showed that the 1A RHR pump was inoperable while the shielding and travel stops were installed. If this information had been reviewed by

the planner, it would have been evident that the material needed to be removed prior to RCS draindown.

- During the outage, the licensee used the Plant Condition/Mode Change (PCMC) data base for ensuring that all WOs impacting equipment required for certain plant conditions, e.g., No Mode to Mode 6, Mode 6 to 5, as well as, Refueling Canal Less Than 23 Feet, were completed prior to entering the condition. Prior to the outage, the Operations Planning Group coded all pre-defined outage related WOs based on a determination of which plant condition the WO needed to be completed by. During the outage, new WOs generated were similarly coded. The inspector learned from discussions with the licensee that WO No. 93085459-01 was coded in PCMC as a Mode 4 item. This activity should have been coded for Refueling Canal Less Than 23 Feet. The inspector determined that the WO was not adequately reviewed when this determination was performed. Most likely, this error was caused by the WO incorrectly stating that the material should be removed prior to Mode 4.

- Besides the PCMC data base, the operations shutdown procedure, OP/1/A/6100/02, Controlling Procedure for Unit Shutdown, also contained controls for ensuring that shielding was removed prior to draining the refueling canal to less than 23 feet. The inspector reviewed Enclosure 4.3, Unit Shutdown From Mode 5 to Mode 6/No Mode and Returning to Mode 5, which was completed prior to the draindown on December 10. In Section 2.10, engineering signed off on December 10 that all shielding requests were reviewed to ensure that there were no outstanding requests that could adversely impact systems required for draining the RCS to less than 23 feet above the flange. Due to lack of adequate verification, this step was completed even though the spring can support stops had not been removed.

Based on review of this issue, the inspector determined that multiple weaknesses in the licensee's execution of work controls for this activity, resulted in the shielding and spring can stops not being removed at the appropriate time. The licensee initiated PIP No. 1-C93-1117, to investigate the failure to adequately control the removal of the spring can support travel stops prior to reducing RCS level less than 23 feet below the reactor vessel flange. As part of this PIP, Engineering performed a past-operability evaluation to determine the impact that the travel stops had on the operability of the 1A RHR pump during the period, December 9 through 13, when the pump was required by TSs to be operable. The results indicated that the pump was not rendered inoperable during this period. The inspector discussed these results with engineering and concluded that the licensee had adequately evaluated the impact on the RHR system. The inspectors

plan to review the licensee's corrective actions for this issue upon completion of the PIP.

e. Shutdown Configuration Control

The inspector reviewed the implementation of licensee administrative controls for shutdown operations delineated in Site Directive 3.1.30, Unit Shutdown Configuration Control, during the period of operation with reduced reactor coolant system inventory described above. As previously noted in NRC Inspection Report 50-413,414/93-27, the administrative requirements included in Site Directive 3.1.30 were assessed as providing the basis for a strong shutdown risk management program. The review included assessments of the implementation of the reactor coolant system vent path and level instrumentation requirements and management involvement in the implementation of shutdown configuration control to assess the significance of the degradation and eventual inoperability of the 1A RHR pump.

Reactor Coolant System Vent Paths:

The inspector reviewed the implementation of controls for reactor coolant system vent paths. Licensee analysis of the configuration of Catawba's reactor coolant systems, with a pressurizer surge line which enters the side of the reactor coolant loop piping, has shown that only vent paths through steam generator hot leg or cold leg manways, (hot leg preferred) are adequate to prevent reactor coolant system pressurization from a boiling core. The inspector noted that work activities were well coordinated to provide for a hot leg manway vent path prior to setting the reactor head. After completing valve maintenance activities which required the reactor coolant system to be in reduced inventory, the last hot leg manway was closed and the reactor coolant system considered intact. A reactor head vent sized to mitigate low temperature overpressure scenarios had been opened. This vent path was not sufficient to prevent reactor coolant system pressurization on a loss of decay heat removal that resulted in core boiling, therefore, gravity makeup from the fueling water storage tank was not considered available. The inspectors discussed this with NRR. This was determined to be acceptable based upon redundant sources of makeup from ECCS pumps. The inspector noted that additional safety margin could have been gained by installing the last hot leg manway nearer to the end of the planned reduced inventory period to maintain this inventory makeup path available and level indication accurate following core boiling.

Reactor Coolant System Level Instrumentation:

The inspector reviewed the implementation of controls for reactor coolant system level indication. Redundant and diverse indication was provided by two trains of two channels (wide and mid ranges)

of differential pressure instruments and ultrasonic indication of level within the hot leg (narrow range). Review of the configuration of the differential pressure instruments identified that a modification was recently performed to change the reference side of the transmitters from a common, wet leg reference, shared with pressurizer level instruments to individual vents referenced to the containment atmosphere, when the RCS was vented. The inspector reviewed Minor Modification CE-3862, which implemented the change mentioned above. It was noted that the safety evaluation did not consider the effects of core boiling following a loss of shutdown cooling and the associated reactor coolant system pressurization which would cause inaccurate indication as the reactor coolant system pressurized. The inspector questioned this configuration and the instrumentation response following a loss of shutdown cooling leading to core boiling.

With a hot or cold leg steam generator manway vent path or the reactor head removed, no RCS pressurization occurs with a boiling core, therefore, no concern was identified. However, with the reactor head vent open, an insufficient vent path to prevent RCS pressurization with a boiling core exists. Therefore, the differential level indication would be inaccurate.

Based on a review of licensee analyses, the inspector noted that a similar condition would exist with the indication aligned to the pressurizer reference due to slugging of water and flow restriction in the pressurizer surge line. The licensee had considered this limitation of differential pressure instrumentation and relies on installed the narrow range ultrasonic instrumentation. Also, abnormal operating procedure AP/1/A/5500/19, Loss of Residual Heat Removal System, directs operators to control inventory addition to the RCS following a loss of RHR based core exit temperature, regardless of level. The Inspectors could not determine the acceptability of this condition. This will be identified as Inspector Followup Item 50-413/93-34-03: RCS Level Instrument.

Management Involvement:

The inspector reviewed management involvement in the implementation of shutdown configuration administrative controls. Prior to entering reduced inventory operation, plant management was aware of the above normal vibration of the 1A RHR pump. As discussed in paragraph 5.c, above, the licensee apparently placed too much reliance on having identified the problem and did not adequately pursue other potential causes of the high vibration prior to draining the RCS to reduced inventory conditions. A multidisciplinary review of available information regarding the degraded component and its impact on risk during reduced inventory operations was not initiated. This placed responsibility for assessment of the condition of the component on a single individual with specialized skills. The inspector observed that a

multidisciplinary review of the available information may have been appropriate.

After concluding that the 1A residual heat removal pump was inoperable on December 14, personnel from operations and engineering were gathered to evaluate approaches available to establish a redundant decay heat removal means. Based on input from both groups, the licensee determined that the best course of action was to pursue preparations for replacement of the 1A residual heat removal pump while the installed pump remained available and actions to initiate a conventional fill and vent of the reactor coolant system were pursued. With the reactor coolant system filled and vented and the secondary side of the steam generators filled, the steam generators would be available for decay heat removal via natural circulation. A conventional fill and vent of the reactor coolant system involves raising the level and performing a series of reactor coolant pump starts to sweep air to the reactor head for venting. For the last several outages, the licensee has used a vacuum refill method which involves draining to midloop, drawing a vacuum on the reactor coolant system, then filling. This method reduces the number of reactor coolant pump starts required and shortens the evolution. Since only one residual heat removal pump was operable, the licensee choose not to use the vacuum refill method to avoid entering midloop conditions. The inspector considered that once management became involved, the correct actions were taken.

Within this area, one violation was identified.

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

a. (Closed) VIO 414/92-24-02, Failure to Follow Scaffolding Erection Procedures.

The licensee responded to this violation by letter dated December 3, 1992. To prevent recurrence Component Engineering evaluated the procedure requirements for the erection and removal of scaffolding. Procedure MP/0/A7650/115, Erection and Removal of Scaffolding, was enhanced and the requirements of this procedure were re-emphasized with appropriate maintenance personnel. Station Directive 3.8.12, Installation of Temporary Shielding and Scaffolding, was revised to provide better guidance for the installation/removal of scaffolding. Also, this procedure has been reissued as Site Directive 3.8.12. The inspectors verified that the licensee's corrective actions were complete.

b. (Closed) LER 413/93-010: Missed Technical Specification Surveillance

This LER was submitted as a corrective action associated with a violation issued in NRC Inspection Report 50-413,414/93-26, VIO

413, 414/93-26-02: Failure to Submit LER on TS 6.8.4 Violation and ESF Actuation. Corrective actions regarding this issue will be reviewed and assessed in conjunction with review of the violation.

c. (Closed) LER 414/93-004: Ice Condenser Door Opened due to Residual Heat Removal System Transient

This LER was submitted as a corrective action associated with a violation issued in NRC Inspection Report 50-413,414/93-26, VIO 413, 414/93-26-02: Failure to Submit LER on TS 6.8.4 Violation and ESF Actuation. Corrective actions regarding this issue will be reviewed and assessed in conjunction with review of the violation.

d. (Open) IFI 413/93-31-01, Resolution of Emergency Diesel Generator Outage Issues (Part A, Turbocharger High Vibration)

On December 3, 1993, Diesel Generator 1B tripped on high vibration on left bank turbocharger during the first and second attempted operability runs. During its third run, the high vibration trip was bypassed and the engine was allowed to continue running although the turbocharger vibration trip annunciated. A troubleshooting plan was not developed for implementation during the operability runs; however, based on conditions observed, the licensee chose to replaced the turbocharger. This issue is discussed in Inspection Report 50-413,414/93-31 and documented as an Inspection Followup Item. It should be noted that the high vibration engine trip is a non-emergency trip, and the 1B Diesel Generator would not have been prevented from operating following an emergency start. The inspector followed up by reviewing Problem Investigation Process Report 1-C93-1054, Diesel Generator 1B tripped on high left bank turbocharger vibration, which documented the turbocharger vibration trips and the licensee's subsequent root cause investigation. The inspector also reviewed the following:

WR 93088612-01	Inspect/Rebuild Left Bank Turbocharger
WR 93087560-01	1B Diesel Generator Trip on High Vibration
WR 93029364-01	Inspect Diesel Generator 1B Turbocharger.
MP/0/A/7400/040	Diesel Engine Turbocharger Corrective Maintenance Dismounted/Mounted
MP/0/A/7400/38	Diesel Engine Intercooler Removal, Replacement, and Corrective Maintenance
MP/0/A/7400/42	Turbocharger Removal and Replacement

Also, a special report was submitted to the NRC to report the three invalid failures. Licensee investigation identified the following potential root causes of the high vibration trips:

(1) The turbocharger itself
(2) The vibration monitor on the turbocharger
(3) The "load swings" observed on the engine kilowatt meter

During the root cause analysis on the turbocharger. A representative from Elliott Co., the turbocharger manufacturer, visited Catawba to observe the disassembly of the turbocharger. The turbocharger's journal bearing clearances and axial thrust were found to be in satisfactory condition. However, the rotor assembly was sent to Elliott for an evaluation of its balance condition. It was determined that the rotor was slightly out of balance, requiring minimal correction. The licensee determined that the out of balance condition was not sufficient to cause the vibration problem.

The licensee's evaluation of the vibration monitor determined that the switch had functioned properly before and after the incidents and it was unlikely that a spurious switch actuation caused the high vibration trips. The diesel generator also experienced a load swing pattern during these trips, which continued after replacement of the turbocharger. The cause of this load swing pattern is still unknown. The inspector will continue to monitor licensee actions regarding this issue.

The licensee proposed instituting two programmatic changes in the short term:

1) Increase vibration monitoring frequency to monthly.
2) Inspect the blower end of the turbocharger at the completion of monthly surveillance testing runs.

The inspector's evaluation of the root cause revealed the licensee's troubleshooting efforts to be unstructured. Following the initial engine trip, the diesel generator was started and run twice without planned actions, such as vibration measurements with portable equipment to validate operation of the installed vibration switches. The inspector also noted that the load swing pattern (on the order of 50 kilowatts) existed after replacement of the turbocharger, indicating the root cause of the issue may not be resolved. Therefore, this item remains open.

7. EXIT INTERVIEW

The inspection scope and findings were summarized on January 11, 1994, 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
LER 50-413/93-34-01	Mode Change with Turbine Driven Auxiliary Feedwater Pump Steam Supply Isolated. (paragraph 3.b)

VIO 50-413/93-34-02	Delayed Corrective Actions for High RHR Pump Vibration. (paragraph 5.c)
IFI 50-413/93-34-03	RCS Level Instrumentation (paragraph 5.e)

8. ACRONYMS AND ABBREVIATIONS

CNS	-	Catawba Nuclear Station
DPC	-	Duke Power Company
ECCS	-	Emergency Core Cooling System
ESF	-	Engineered Safety Feature
FWST	-	Fueling Water Storage Tank
IAC	-	Instrument and Electrical
IST	-	Inservice Testing
LER	-	Licensee Event Report
MMP	-	Maintenance Management Procedure
NCV	-	Non-Cited Violation
NLO	-	Non-Licensed Operator
OP	-	Operating Procedure
PIP	-	Problem Investigation Process
PT	-	Periodic Test
R&R	-	Removal and Restoration (Tagging Order)
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RO	-	Reactor Operator
SG	-	Steam Generator
SRO	-	Senior Reactor Operator
SSPS	-	Solid State Protection System
TS	-	Technical Specifications
TSM	-	Temporary Station Modification
URI	-	Unresolved Item
WO	-	Work Order
WR	-	Work Request