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REGION II

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Enclosure 2

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 & 2
NRC Inspection Report 50-413/96-13, 50-414/96-13

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by regional reactor safety and reactor projects inspectors and reviews by a licensing project manager. In addition, the results of a maintenance inspection conducted by a regional reactor inspector during the week of July 8, has been included in Sections M2.3 and M7.

Operations

- Although a required 10 CFR 50.72 report was submitted late (Non-Cited Violation 50-414/96-13-01), communication conventions were consistently utilized, a timely decision regarding the initiation of the shutdown was made, and good command and control was exhibited during a forced Unit 2 shutdown. (Section O1.1)

- A procedure change to prewarm the Residual Heat Removal pump prior to placing it in service resulted in the unanticipated binding of a manual isolation valve, which rendered the system inoperable (VIO 50-413,414/96-13-02). (Section O1.2)

- The licensee was proactive in determining the source of the water on the ground surface in the vicinity of Nuclear Service Water System piping. The delay of Unit 2 startup until the source was identified and repaired demonstrated an appropriate focus on safe operation of the facility. (Section O1.3)

Maintenance

- The licensee's effort to determine root causes was thorough and adequate to ensure appropriate classification of safety significant motor failures. (Section M1.1)

- The decision to delay refueling until the 1A Residual Heat Removal Pump could be returned to an operable status was considered to be indicative of a conservative operational approach. The root cause evaluation of the motor failure was of an appropriate scope. (Section M1.2)

- The actions to repair damaged secondary contact blocks on the Unit 1 Reactor Trip Breakers (RTBs) and bypass RTBs were appropriate. Planned corrective actions also were appropriate. (Section M1.3)

- The licensee was actively monitoring and evaluating equipment reliability. Adverse trends were identified, and corrective actions were initiated. Actions reviewed by the inspectors addressed the concerns and were comprehensive in scope. (Section M2.1)

- The Maintenance self-assessment program was effective and well managed. The program identified a high number of rework items which were the result of poor work practices. (Sections M2.1 and M7.1)

- An inadequate procedure caused unanticipated component actuations that interfered with the dilution flow for a liquid radioactive release. (Violation 50-413,414/96-13-02). (Section M3.1)

- The licensee identified a violation (non-cited) involving the performance of Emergency Diesel Generator Head reassembly steps out of sequence (Non-Cited Violation 50-413/96-13-03). (Section M4.1)

Engineering

- An example of a violation for inadequate design control was identified in that Main Steam Isolation Valve (MSIV) solenoid valve nameplate rating was less than the instrument air maximum pressure (Violation 50-413,414/96-13-04). (Section E1.2)

- Actions to determine the root cause of the B main feedwater pump trip were timely and appropriate. Proposed corrective actions were adequate. (Section E2.1)

- Several Unit 1 modifications were implemented during the outage to resolve existing equipment problems and improve plant reliability. The modifications demonstrated appropriate control of the design control process at Catawba. The requirements of 50.59 were met for associated safety evaluations that were reviewed. (Section E2.2)

- The erosion/corrosion program was effective in identifying main feedwater pipe localized wall thinning. (Section E2.3)

- The 1995 revision of the Catawba UFSAR matched the provisions of 10 CFR 50.71 and was therefore in compliance with 10 CFR 50.71.(Section E3.1)

- Design input errors in Calculation 1223.04-00-0009 were not identified by the licensee on two occasions: first during the independent review of the calculation in November 1993, and again during the licensee's steam supply station (SSS) pre-inspection self-assessment in June 1996 (Violation 50-413,414/96-13-04). (Section E4.1)

Plant Support

- An unauthorized entry of an individual into the Radiation Control Area without appropriate dosimetry, training, or body burden analysis was identified as a violation of Radiation Protection Directive No. II-1, Radiation Area Access and Monitoring Devices (Violation 50-413,414/96-13-06). Corrective actions for a previous occurrence were not effective in preventing recurrence. (Section R1.1)

Report Details

Summary of Plant Status

Unit 1 was in a refueling/steam generator replacement outage for the duration of the inspection period.

Unit 2 was in a forced outage because of inoperability of both trains of the Control Room Ventilation System between August 3 and 12. The unit operated at or near 100% power throughout the remainder of the inspection period.

Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description signified the need for a special focus review that compares plant practices, procedures, and/or parameters to the UFSAR descriptions. While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters. No deficiencies were identified.

I. Operations

O1 Conduct of Operations

O1.1 Unit 2 Forced Shutdown

a. Inspection Scope (71707)

On August 3, 1996, Catawba Unit 2 entered Technical Specification 3.0.3 and was shut down when both trains of the Control Room Area Ventilation system became inoperable. During the forced outage, the inspectors observed control room activities, assessed equipment failures and reviewed reporting requirements.

b. Observations and Findings

Train B of the Control Room Area Ventilation system was out of service for planned maintenance. The system's A Train pressurization fan motor subsequently failed, and Technical Specifications (TS) required the unit to shutdown/cooldown (see section M1.1 of this report). While the unit was in Hot Shutdown (Mode 4) on August 4, a fan motor failure occurred on Train A of the Auxiliary Building Ventilation System (see section M1.1 of this report). This failure resulted in both trains of Auxiliary Building Ventilation being inoperable because Train B was out of service for planned filter testing. Subsequent problems encountered with establishing Residual Heat Removal flow on Train B (See section O1.2 of this report) required the use of Train A of the Residual Heat Removal system to take the unit to cold shutdown (Mode 5) at 12:58 p.m. on August 4.

The inspector observed control room activities during the forced shutdown and noted that communication conventions were consistently utilized, a timely decision regarding the initiation of the shutdown was made, and good command and control was exhibited.

The licensee identified a missed 10 CFR 50.72 report regarding the failure of the A Auxiliary Building Ventilation Filtered Exhaust Fan Motor. Prior to the failure, the B train was removed from service for filter testing and replacement. With both trains inoperable, a second condition existed that required entry into TS 3.0.3. On-shift personnel considered reporting of this second condition as having been accomplished by the previous report and did not make a second report regarding this failure. This condition was later recognized as reportable under 10 CFR 50.72(b)(2)(iii)(d) and a report was made. The report did not meet its associated timeliness requirements. The licensee initiated a Problem Investigation Process (PIP) Report for this occurrence (PIP 0-C96-2058). Corrective actions included a "read and sign" discussion of the occurrence for operations personnel and plans for including performance and assessment of reportability determinations in simulator training. This licensee-identified and corrected violation is characterized as Non-Cited Violation 50-414/96-13-01: Failure to Report Inoperability of Both Trains of Auxiliary Building Ventilation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

With the exception of a late 10 CFR 50.72 report, operators performed well during the forced shutdown in response to ventilation system failures.

O1.2 Residual Heat Removal Train B Inoperable During Unit 2 Forced Shutdown

a. Inspection Scope (71707)

On August 4 during the forced shutdown when TS 3.0.3 was entered after both trains of Control Room Ventilation were inoperable, control room operators were attempting to place the B train of the Residual Heat Removal (RHR) system in service. The 2B RHR heat exchanger inlet manual isolation valve, 2ND-53, was closed by procedure and became wedged in its seat. A stem to disc failure was incurred during attempts to open the valve. As a result, B train of RHR was inoperable during the Unit 2 cooldown from Mode 4 to Mode 5. The inspector interviewed plant personnel and reviewed procedures, system diagrams, and metallurgical analysis report #2032. The inspector also reviewed the licensee's root cause evaluation and associated recommendations.

b. Observations and Findings

Operators attempted to place B train RHR in service using OP/2/A/6200/04, Retype #13, Residual Heat Removal System, Enclosure 4.1, Startup of the RHR System During Normal Plant Cooldown. A recent procedure change directed operators to close valve 2ND-53 at step 2.6.29 and bypass flow around the heat exchanger. Flow was diverted through the heat exchanger bypass line and into the letdown system so that the 2B residual heat removal pump and associated suction and discharge piping could be slowly heated to within 50°F of reactor coolant system temperature before the pump was placed in service. The procedure change was designed to prevent thermal deformation of the pump casing and subsequent casing leakage. The procedure introduced the potential for thermally induced pressure locking of 2ND-53.

Step 2.6.46 of OP/2/A/6200/04 directed operators to open 2ND-53 to establish flow through the heat exchanger and place B train RHR in service. The valve could not be opened by normal use of a reach rod or direct, unassisted manipulation of the handwheel. A valve wrench was used to open the valve, and a stem to disc failure occurred but was not immediately recognized. As a result, the B train of the residual heat removal system was inoperable during unit cooldown from Mode 4 to Mode 5 and remained inoperable from 10:00 a.m. on August 4, 1996, until 4:00 p.m. on August 7, 1996. The A train of RHR was placed in service so that unit cooldown to Mode 5 could be achieved within the remaining time allowed by TS.

Valve 2ND-53 is a manual double disc gate valve, and it is located near (approximately 1.5 feet from) the heat exchanger bypass flowpath. The licensee concluded that the most likely cause of the valve binding was thermally induced pressure locking as RHR temperature increased.

The stem to disc failure occurred at a link that affixes the stem to the disc. According to metallurgical analysis report #2032, Catawba Linkage from 2ND-53, fracture of the 2ND-53 linkage was caused by a single overstress event, most likely attributable to attempts by plant personnel to free the stuck valve. No signs of pre-existing cracks or other material problems that might have made the linkage susceptible to premature failure were detected.

The inspector questioned the use of a valve wrench to open the valve and determined that Operations Management Procedure 2-33 allows for the use of a valve wrench if no more than normal force of a "large individual" is applied. The inspector determined that the requirements of this procedure were complied with.

The inspector reviewed the change to OP/2/A/6200/04 for prewarming the pump before placing the system in service, including the 10 CFR Part 50.59 evaluation. The inspector concluded that the potential for pressure locking and thermal binding was evaluated during the 10 CFR

50.59 review process. However, the evaluation was narrow in scope (limited to active valves), and the licensee concluded that, since 2ND-53 was a manual isolation valve, it would not be affected by these phenomena.

The licensee did not recognize that 2ND-53 was broken until flow could not be established through the heat exchanger, at which time the failure of 2ND-53 was self-disclosing. Because the binding and subsequent failure of valve 2ND-53 resulted in the inoperability of the B train of RHR, only one train of RHR was operable during the Unit 2 forced cooldown.

Incidentally, the inspector determined that the Unit 1 procedure for prewarming the RHR pumps had been changed before the refueling/steam generator replacement outage began. The change involved isolating the letdown piping from the RHR system to prevent water hammer in the letdown piping as RHR was placed in service and the RHR to letdown piping was rapidly pressurized. The same procedure change had not been made to Unit 2 procedures when the forced shutdown was initiated. The inspector considered implementation of procedure changes that were not unit specific on only one unit to be a poor practice. The licensee revised operation department guidelines to require simultaneous implementation of non-unit specific procedure changes in the future.

c. <u>Conclusions</u>

Procedure changes to OP/2/A/6200/04 were inadequate in that the procedure established conditions which caused thermally induced pressure locking of valve 2ND-53. The valve was damaged in attempts to open it, thereby extending the time that the B-train of RHR was inoperable. This issue is characterized as Example 1 of Violation 50-413,414/96-13-02: Inadequate Procedures.

O1.3 <u>Nuclear Service Water System Pipe Leak in Yard</u>

a. <u>Inspection Scope (40500 and 71707)</u>

On August 8, licensee maintenance technicians identified water bubbling up from the ground near the steam generator storage facility. The licensee was aware that nuclear service water (RN) system piping was buried in the general vicinity where the water was found and, concerned that an RN pipe was leaking, excavated the piping. A hole was found on the B train supply header, and a modification was implemented to repair the 42-inch pipe. The inspector reviewed the modification package, including the 10 CFR 50.59 evaluation, observed parts of the excavation, attended a PORC meeting, and reviewed the compensatory actions that were developed to ensure that, during the pipe repair, the seismic integrity of the RN piping was maintained and tornado missile protection could be reestablished within one hour of a tornado watch or warning notification.

b. Observations and Findings

The leak emerged from an external pit initiated from corrosion. The pit was approximately two inches in diameter on the outer surface of the pipe and roughly three-sixteenths of an inch in diameter on the inner pipe surface. The hole was temporarily plugged. Minor modification CNCE-8150 was developed to make permanent code repairs to the defect and other non-through wall pits in the vicinity. The pits appeared to be caused by localized damage to the protective coating while on the piping during initial installation. While the source of the water was being investigated and repaired, Unit 2 startup was delayed.

c. Conclusions

The inspector concluded that the licensee was proactive in determining the source of the water on the ground surface. Compensatory actions that were in effect during the pipe repair were appropriate. The delay of Unit 2 startup until the source was identified and repaired demonstrated an appropriately conservative focus on safe operation of the facility.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Follow-up of Ventilation Motor Failures

a. Inspection Scope (93702)

On August 3, 1996, Unit 2 entered TS 3.0.3 due to both trains of the Control Room Ventilation system being inoperable. The B train of Control Room Ventilation was inoperable due to Nuclear Service Water system work in progress. The A train became inoperable when the filter fan motor breaker tripped and would not reset. This resulted in both trains of ventilation being inoperable; thereby requiring entry into TS 3.0.3. During the shutdown the auxiliary building ventilation exhaust fan tripped on a ground fault. The inspector reviewed the failures of the ventilation system motors to determine if the failures were appropriately classified and adequate corrective actions completed or planned.

b. Observations and Findings

The inspector reviewed the failure of the Control Room Ventilation System Fan Motor 1CRA-PFT-1. The failure of this motor was determined to be an electrical failure due to a ground fault on the T3 phase winding. This failure was verified using a winding analysis test. The winding analysis test includes a winding resistance measurement, an insulation resistance (megger) test, a Hi-pot test, a polarization index test and a surge comparison test. The results of this test identified a ground fault with the megger indicating failure at 400 volts and the surge test revealing a 92% mismatch between two of the three phases. Further analysis was performed by the motor manufacturer, Reliance Electric, which confirmed the licensee's results. This motor was approximately 15 years old and had been in service since initial operation of the plant. A definitive root cause for the fault of the motor was indeterminate, but age related failure was suspected. The motor was replaced and the system returned to service prior to Unit restart.

Additionally, the inspector reviewed the failure of the Auxiliary Building Filtered Exhaust Fan Motor ABXF-2A. Initial failure investigation revealed a phase to ground fault on all three phases. This was determined by meggering. Bearing failure was suspected due to difficulty in rotation of the motor; however, after the motor was removed and taken to the shop for troubleshooting the cause of the rotation difficulty was determined to be melted copper from the damage caused by the fault. The inspector observed this inspection by the licensee and also reviewed the motor damage. The inspector concurred with the licensee's assessment during this preliminary investigation. The motor was subsequently shipped to a vendor troubleshooting and repair facility for further analysis.

The inspector reviewed the licensee's root cause effort to determine whether a common cause had initiated the failure of the two motors and possibly resulted in other motors being susceptible to failure. From this review the inspector determined that a common cause for these two motor failures had not been identified. The licensee's review for a common root cause was adequate to ensure that these two failures were random failures without a single initiating cause.

c. Conclusions

The inspector concluded that the licensee's effort to determine root cause was thorough and adequate to ensure appropriate classification of the motor failures.

M1.2 Followup of Residual Heat Removal Motor Failure

a. Inspection Scope (62703)

On August 31, the 1A Residual Heat Removal Pump tripped after approximately 6 hours of run time following installation. The inspector reviewed the operational impact and the root cause evaluation of the failure.

b. Observations and Findings

At the time of the failure, Unit 1 had no fuel in the core and preparations were underway to initiate refueling. Plant TS allow core alterations with one operable Residual Heat Removal pump and the refueling cavity filled. Based on questioning by operations personnel, the licensee chose to delay refueling until the 1A Residual Heat Removal Pump could be returned to an operable status. The inspector considered this decision to be reflective of a conservative operational approach.

Based on information provided by the licensee, the motor that failed had been refurbished by Westinghouse in 1994. The refurbishment was primarily a mechanical refurbishment to correct an out of tolerance condition on the upper bearing housing and improve vibration of the motor. Electrical testing indicated that the motor was in good condition. After storage in the contaminated warehouse on site at Catawba, the motor was installed in July, 1996. Electrical testing again indicated that the motor was in good condition at that time. Shortly after functional testing, the motor failed while in service. Initial cause investigation during disassembly indicated the fault was initiated by a turn-to-turn fault in the stator windings. The licensee root cause analysis was not complete at the end of the report period, but poor storage conditions in the contaminated warehouse was being investigated as a possible cause.

c. Conclusions

The licensee's decision to delay refueling until the 1A Residual Heat Removal Pump could be returned to an operable status was considered to be reflective of a conservative operational approach. The cause evaluation of the motor failure was of an appropriate scope.

M1.3 Reactor Trip Breaker Secondary Contact Blocks

a. Inspection Scope (62703)

In June 1996, the licensee identified cracked secondary contact blocks on the reactor trip breakers (RTBs) and bypass RTBs at the McGuire and Catawba Nuclear Stations. The issue is documented in NRC Inspection Report 50-413,414/96-10. In this inspection report period, the inspector reviewed work orders (WOs) to verify that all damaged secondary contact blocks on the Unit 1 RTBs and bypass RTBs were replaced with new blocks prior to unit restart from a refueling and steam generator replacement outage. The inspector also reviewed the procedure for handling RTBs and bypass RTBs, and reviewed the licensee's root cause evaluation and proposed corrective actions.

b. Observations and Findings

The inspector reviewed the task completion notes associated with WOs 96054700-01, 96019780-01, 96019781-01, and 96026725-01 and determined that the damaged RTB and bypass RTB secondary contact blocks were replaced with new blocks. The inspector also reviewed the root cause evaluation, which indicated that mishandling was the most likely cause for the damage to the secondary contact blocks. Based on the facts presented in the root cause, the inspector concluded that this root cause was the most likely. Proposed corrective actions include: (1) revise the standard procedure for breaker maintenance during refueling outages, SI/0/A/2410/001, Westinghouse DS-416 Air Circuit Breakers Inspection and Maintenance, to include a torque limit for the secondary contact block assembly mounting bolts; (2) to remove and inspect all secondary contact blocks on each breaker during each breaker PM; (3) add a caution statement to OP/0/A/6350/10, Operation of Station Breakers and Disconnects, to note the need for careful handling during breaker movement to avoid damage to secondary contact blocks and other breakable parts; and (4) provide two breaker hoists, each dedicated to a unit, versus the existing single shared hoist.

c. Conclusions

The inspector concluded that the licensee's actions to repair damaged secondary contact blocks on the Unit 1 RTBs and bypass RTBs were appropriate. Planned corrective actions were also appropriate.

M1.4 Maintenance Observations

a. Inspection Scope (62700)

The inspectors observed and reviewed portions of various licensee corrective and preventive maintenance activities to determine implementation of administrative controls, plant procedures, work instructions, industry codes and standards, Technical Specifications and regulatory requirements.

The inspectors observed portions of the following work activities:

- WO 96045006-01 Diesel Generator 1A:Pull 4 heads and pistons; measure and inspect liners and welds. Remove and replace 12 additional heads.

- WO 95053556-01 Component Cooling Water Pump 1A2 Corrective Maintenance.

b. Observations and Findings

The inspectors observed that the licensee had implemented the proper administrative controls in the performance of maintenance. For those periods of maintenance observed: cleanliness was maintained, tools were properly calibrated, inventory control logs were maintained, exclusion of foreign material was implemented, procedures were at the job and followed, Quality Control personnel were closely following the work, and procedure sign off was performed by both the craft and Quality Control personnel as steps were performed. Additionally, supervisory oversight was evident and personnel performing the maintenance were knowledgeable in their assigned tasks.

c. Conclusi ,

The ins ctors concluded that the licensee has developed and implemented adequate maintenance controls to assure reliability of equipment.

M2 **Maintenance and Material Condition of Facilities and Equipment**

M2.1 Equipment Performance and Availability Monitoring

a. Inspection Scope (62700)

The inspectors reviewed plant records and procedures to evaluate the licensee's activities to maintain equipment reliability. The licensee monitors equipment performance and availability in several ways. Some of these methods are:

- Component Failure Analysis Reports (CFAR) using the Nuclear Plant Reliability Data System (NPRDS) to compare Catawba performance with industry averages for specific equipment.

- Failure Analysis Trending System (FATS) using the Work Management System to obtain equipment maintenance history and maintenance work order data for trending system/component performance.

- Maintenance Assessments using maintenance rework items as a performance indicator to improve maintenance efficiency and equipment reliability.

- Self-Initiated Technical Audit (SITA) using a focused approach to highlight problems in a specific area. In this case the Diesel Generator Recovery Program.

- Problem Investigation Process (PIP) Reports used to document identified plant problems, proposed corrective actions and problem resolutions.

b. Observations and Findings

The inspectors reviewed portions of the above documents to evaluate the licensee's activities to monitor and maintain equipment reliability. The following was noted:

- CFAR results reported July 1996 indicated that 24 Catawba components were higher than the industry average. The licensee reviews the failure history of each of these components for cause and corrective action.

- The FATS quarterly report is the main method for establishing adverse equipment trends. In this report the equipment performance was evaluated over the previous 18 months to detect adverse trends and the previous 36 months to detect repeat failures. In the first quarter of 1996, adverse trends were identified for pressure switches and battery chargers in the electrical area and motors, HVAC chillers and diesel engines in the mechanical area. The report provided a description of the problem, problem significance, explanation of the trend, corrective action, PIP to track corrective action, Modifications if required, and the action plan. For instance, for the diesel generator, 19 specific actions were identified.

- Maintenance assessment of rework items was started in March 1995. Assessment for 1995 has identified problems in several areas. Of the 120 potential rework events assessed, 74 were confirmed as rework events. Of the 74 events, 41 or 55% of the total were due to poor work practices. These included inadequate self-checking, lack of independent verification, and skill based discrepancies. The assessment made detailed recommendations to improve these discrepancies and to focus management attention.

  The assessment also identified strengths in Steam Generator, HVAC, and Pipe Support maintenance where maintenance crews had recognized and corrected maintenance weaknesses.

  The Problem Investigation Process was used to track corrective actions.

- The Diesel Generator Recovery Program was initiated as a result of reliability and availability decrease in diesel performance. A SITA was performed to identify the problems and the recovery program developed to resolve the problems. Areas such as design basis, Maintenance, Operation, and trending were addressed.

- The inspector reviewed PIP 0-C96-0172, initiated for tracking the failure of Instrument Air Compressor D motor. The root cause was identified as a break down of insulation from loss of cooling due to dirt and oil deposits. Thorough corrective action was taken.

Actions included upgrading the insulation, check of insulation every 18 months, internal inspection every 36 months, installation of thermocouples and trending of temperature data.

c. Conclusions

Based on review of portions of the above documents and discussions with licensee personnel, the inspectors concluded that the licensee was actively monitoring and evaluating equipment reliability. Adverse trends were identified and corrective actions initiated. Those actions reviewed by the inspectors addressed the concerns and were comprehensive in scope.

M2.2 Safety-Related Carbon Filter Status

a. Inspection Scope (61726)

The inspector reviewed the status of the Unit 1 and Unit 2 safety-related carbon filters, including the Annulus, Auxiliary Building, Control Room, Fuel Pool, and Containment Purge Ventilation Systems.

b. Observations and Findings

On August 1, the 2B Auxiliary Building Ventilation carbon filter unit failed a TS required bypass leakage surveillance test. After troubleshooting for approximately three days the licensee replaced the carbon and surveillance testing was completed successfully. The inspector verified by reviewing methyl iodide penetration test results that safety-related filters in both units met TS requirements. Carbon filters such as the 2B auxiliary building unit which are operated continuously or have restrictive surveillance test acceptance criteria have been replaced more often than intermittent duty filters. Penetration test results showed consistent iodine adsorption ability relative to carbon age.

c. Conclusion

Safety-related carbon filters were found to meet TS requirements for methyl iodide penetration. The licensee was meeting carbon sampling requirements.

M2.3 Observation of General Material Condition

a. Inspection Scope (62703)

The inspector conducted a walkdown inspection of Unit 2 to examine general housekeeping conditions. In addition, the safe shutdown and auxiliary shutdown rooms and panels were examined to determine their material condition and identify any existing deficiencies. The main transformers and switchyard were also included in the walkdown. Also, portions of on-going maintenance work and test activities were reviewed that included: (1) installation of optical isolators; (2) control room area chiller test; and (3) air compressor motor alignment.

b. Observations and Findings

The housekeeping observed was adequate. The maintenance department was recently assigned housekeeping responsibility in 1996. In Unit 2, very few leaks were identified. The valve stems for MOVs were lubricated and in good condition. Not all the stems for manual valves and air operated valves were up to the same standards as the MOVs. The switchyard's relay building and battery rooms were in good condition. The switchyard disconnect switches were also in good condition as observed from the ground.

M3 Maintenance Procedures and Documentation

M3.1 Nuclear Service Water System Valve Realignments During Liquid Waste Release

a. Inspection Scope (61726)

On August 13 during Auxiliary Shutdown Panel (ASP) 1B testing, valve 1RN-58B, Nuclear Service Water Loop B Return to Standby Nuclear Service Water Pond Isolation Valve, and valve 1RN-843B, Nuclear Service Water to Conventional Low Pressure Service Water Isolation Valve, were inadvertently realigned to establish a flowpath to the Standby Nuclear Service Water Pond. A liquid radioactive waste release was initiated after the valves had realigned to the pond, and since RN was diverted to the pond, it was not available to carry the radwaste to the low pressure service water system for discharge to Lake Wylie. The inspector discussed the occurrence with plant personnel and reviewed procedures, system diagrams, the Off-site Dose Calculation Manual and liquid radiological release package #0336, and PIP 0-C96-2123.

b. Observations and Findings

The licensee initiated a root cause investigation to determine why the valves changed position during ASP 1B testing. The root cause investigation revealed that procedure PT/1/A/4700/14, Retype #0, Auxiliary Shutdown Panel 1B Functional Test, Enclosure 13.9, Control Room/Auto Closure of 1NI-65B and 1NI-88B, was inadequate. Specifically, the preparer of the procedure failed to recognize that valves 1RN-58B and 1RN-843B would be affected by the simulation of control transfer from the control room to 1ASPB. As a result, these valves were omitted from step 12.3.1 of PT/1/A/4700/14. Step 12.3.1 of PT/1/A/4700/14 listed eight affects of the manipulation of three transfer relays and directed the performer to verify that the listed effects would not adversely affect plant conditions. Since the effects on valves 1RN-58B and 1RN-843 were not listed, no such verification was made. As a result, the valves repositioned during the test, isolating flow to a portion of the Nuclear Service Water System that was in service to support a liquid radioactive release.

The inspector questioned the impact of the valve repositionings on the liquid radioactive waste release and determined the following:

- The concentrations of radionuclides in the waste stream were such that dilution flow was not required to comply with the limits stated in 10 CFR 20, Appendix B, Table 2, Column 2.
- Since flow was isolated to the Nuclear Service Water System discharge header to Lake Wylie, the liquid radioactive waste may have collected in the header until the system alignment was returned to normal. Had the radionuclide concentrations been higher, dilution flow requirement may not have been met. The licensee plans to evaluate process controls to ensure that Nuclear Service Water flow remains available throughout the duration of a release.

c. Conclusions

The inspector concluded that procedure PT/1/A/4700/14, Auxiliary Shutdown Panel 1B Functional Test, was inadequate in that it did not specify all components which would be affected by the test. This procedure inadequacy resulted in valve repositions in the Nuclear Service Water System which isolated flow to a portion of the system which was supporting a liquid radioactive release and is identified as Example 2 of Violation 50-413,414/96-13-02: Inadequate Procedures.

M4 Maintenance Staff Knowledge and Performance

M4.1 Emergency Diesel Generator Head Reassembly (62703)

During this inspection the licensee identified a failure to follow procedure problem during reassembly of the diesel generator cylinder heads per procedure MP/0/A/7400/009, Revision 10, 3/6/89, Diesel Engine Cylinder Head Removal And Replacement. MP/0/A/7400/009 is a "Reference Use" procedure for which, by Nuclear System Directive (NSD) 704, Technical Procedure Use and Adherence, Revision No. 3, 9/21/95, the steps must be followed in sequence unless a deviation is documented. NSD 704, paragraph 704.6, states that t is the intent that steps in "Continuous Use" and "Reference Use" procedures be performed sequentially where the procedure does not specify flexibility. Out-of-sequence steps are acceptable only if a deviation is allowed by the procedure or is made under the following conditions:

- The sequence deviation shall be reviewed by a knowledgeable supervisor.

- Out-Of-Sequence steps shall be reviewed and initialed by the performer and a knowledgeable supervisor prior to performing the steps.

- The supervisor shall ensure that a clarifying explanation of why the deviation was made is documented within the procedure or work order.

- The supervisor determination should take into account the necessity for a procedure change.

Steps 11.3.17 to 11.3.20 of MP/0/A/7400/009 deal with the installation of the intake elbow for the airline from the cylinder head to the air header intake manifold. The procedure specifically requires that the elbow be installed and torqued to the cylinder head, the head installed, the elbow aligned to the intake manifold by moving the head, and then torque head holddown nuts.

The licensee deviated from the sequence of the procedural steps by first installing and torquing the cylinder head before installing the elbows on 4 cylinders. When this was discovered the condition was corrected by removing the cylinder heads and installing the elbow per procedure.

The licensee stated that, although the machine could be reassembled either way, the purpose for this sequence of steps was to avoid the possibility of stressing the elbow while aligning it to a fixed head and intake manifold in a cramped space.

Investigation showed that the supervisor had directed the technician to install and torque the cylinder heads prior to installing the elbows on the heads for four cylinders. The technician and supervisor failed to annotate the procedure steps and the supervisor did not make a clarifying statement in the procedure as to why the deviation was necessary.

The inspector reviewed the circumstances and determined that the licensee had violated the requirements of NSD 704, paragraph 704.6 in that the deviation was not properly documented. The situation was identified by the licensee, was corrected immediately, and had minimal safety significance. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue is identified as Non-Cited Violation 50-413/96-13-03: Failure To Follow Procedure For Deviation Of Step Sequence.

M7 Quality Assurance in Maintenance Activities

M7.1 Implementation of Self-Assessment Programs

a. Inspection Scope (40500, 61726, and 62703)

The inspector reviewed the implementation of the new maintenance self-assessment program and portions of the work reduction program initiated in January 1996. The self-assessment program was reviewed in depth to determine the effectiveness of the licensee's controls in identifying, resolving, and implementing corrective action in the maintenance area.

b. Observations and Findings

Self-assessment was part of the licensee's Quality Assurance program and is described in Section 17.3.3 of the Duke-1 Topical Report. Corporate procedure NSD-607, Revision 2, Self-Assessments, was the controlling administrative procedure. Procedure MMP 1.14, Revision 0, Maintenance Self-Assessment Process Guideline, was approved February 29, 1996, for implementing the program.

The program was comprised of two categories. The first requires continuous assessment. The second requires assessment on an as-needed basis. The as-needed includes control of vendors, chemical control, pre-job briefings, staffing, and procedures used.

The self-assessment corrective actions are managed in four ways: (1) Key management issues are major concerns that have a maintenance manager assigned as a sponsor to oversee the corrective action; (2) Focus issues are concerns supervisors (foreman) follow for job observations and briefings; (3) Rework issues occurring within 90 days are identified in the rework program; and (4) Small scope items that have ownership under a certain individual or crew.

The first two quarter assessments identified several problem areas such as: (1) Work Practices - adherence to following technical procedures; (2) Communications - technical procedures have errors and administrative directives are numerous, overlapping, confused, and sometimes hidden; (3) Foreign Material Exclusion - housekeeping and foreign material entering system; (4) Misposition devices continued to be a problem; and (5) Rework with pumps, valves, and heat exchangers.

The inspector reviewed 10 Problem Investigation Process (PIP) reports to verify the licensee was implementing appropriate and timely corrective action for the problem areas identified above. Overall, there were: (1) four key management issues; (2) two focus items; (3) 16 rework items; and (4) 43 small scope items addressed in the PIPs listed.

The license's work order (WO) reduction program has been effective. The backlog of 1231 in January 1996, was reduced to 429. The backlog for WOs over six months old has been reduced from 279 to 99 and the WOs over one year have been reduced from 79 to 20 over the same time period in 1996.

c. Conclusion

The maintenance department has implemented an effective self-assessment program that is detailed and well managed. Problems such as poor work practices, foreign material exclusion and configuration control have been identified and management has supported implementing appropriate corrective action. The work order backlog has been significantly reduced during 1996.

III. Engineering

E1 Conduct of Engineering

E1.1 Review of Radiographs for Relief Request No. 95-01 (Weld No.1RHRB-W3)

a. Inspection Scope (57090)

On August 22, 1996, the inspectors reviewed the licensee's radiographic film for Weld No. 1RHRB-W3. This review was conduct because during the licensee's ultrasonic examination of Unit 1 residual heat removal heat exchanger flange-to-shell circumferential Weld No. 1RHRB-W3, two directional coverage as required by ASME Section XI, Appendix III and Section V, Article IV as modified by Code Case N-460, could not be obtained.

b. Observations and Findings

The causes of the scan limitation were part geometry and physical barriers. Where possible, a combination of angles and wave modes were used to maximize the coverage obtained. The weld and base metal at the component inside surface was covered from at least one direction with a minimum of one angle. The licensee provided NRC's Office of Nuclear Reactor Regulation (NRR) an ISI Limitation Report that gave the layout of Weld 1RHRB-W3. The layout showed flange geometry and bolting limited ultrasonic scanning; thus precluding examination of approximately 78% of the weld volume. The licensee proposed using radiography as an alternate volumetric examination method. However, a modification to the heat exchanger had to be completed to allow access to the ID surface for source positioning and the qualification of an acceptable radiographic technique. The radiographic examination was scheduled to be performed in the first refueling outage of the Second 10-Year Interval (End of Cycle 9). Although this examination would be performed after the close of the first inspection interval, it would enhance the 22% Code-acquired volumetric examination coverage achieved using ultrasonic techniques.

NRR Safety Evaluation Report (SER) for Relief Request No. 95-01 concurred with the licensee's proposed alternative examination method. NRR concluded that, based on the coverage obtained and the radiographic examination scheduled during the first outage of the second inspection interval, it was reasonable to conclude that degradation, if present, would be detected. Thus, reasonable assurance of continued inservice structural integrity would be provided.

The inspector's review of radiographic film for weld 1RHRB-W3 did not reveal any unacceptable indications. The inspector also concluded that the licensee had made the best attempt possible to examine the weld with radiography. However, 100% volumetric coverage was also not obtained with this method of examination. The licensee's "Limited Examination Coverage Worksheet" for this method of examination revealed that out of the 258.75 square inches in the inspection volume, a total of 149.15 square inches (58%) were examined with radiography. The examination limitation was due to component configuration, which resulted in a portion of the weld metal and 100% of the base metal on the flange side of the weld not being recorded.

c. Conclusion

Based on the licensee's best attempt with a combination of one directional ultrasonic examination of the weld and base material ID, as well as the additional radiographic examination coverage, the inspectors concluded that it was reasonable to assume that significant degradation, if present, would be detected. Thus, reasonable assurance of continued inservice structural integrity will be provided.

E1.2 Solenoid Valve Nameplate Rating Less than Instrument Air Design Pressure

a. Inspection Scope (37551)

The inspector reviewed the main steam isolation valve solenoid valve application as it related to maximum instrument air system design pressures.

b. Observations and Findings

During testing and troubleshooting of main steam isolation valve actuators discussed in Section E8.3, the licensee identified that the cause of a previous MSIV stroke time failure was associated with a malfunctioning solenoid exhaust valve. When an MSIV closure signal is generated, these solenoid valves function as pilot valves that operate by spring force to vent pilot air when the solenoid is deenergized. This in turn repositions a shuttle valve that exhausts air from the MSIV actuator and allows the MSIV to close. During replacement of the solenoid valves on the Unit 1 actuators, the licensee recognized that internal springs in the replacement solenoid valves were larger than the existing valves and concluded that the relatively low spring force available in the existing solenoid valves may have contributed to the previous stroke time failure.

Subsequent to this troubleshooting, the inspector compared the nameplate pressure ratings for the solenoid valves to the maximum design pressure of the instrument air system based on instrument air system relief valve settings (Flow Diagram CN-1605-1.1). On August 22, the inspector identified that the nameplate rating of the solenoid valves (100 psi) was less than the relief setpoints for main air receiver tanks located at the discharge of the main air compressors (115 psi). The inspector informed the licensee of this discrepancy and questioned whether normal operating pressures of the instrument air exceeded the design rating of the solenoid valve and if provisions existed for control room operators to detect an increase in instrument air pressure resulting from a malfunction of the instrument air system. At the time of identification this concern only applied to Unit 2 since Unit 1 was shutdown and the Unit 1 solenoid valves had been refurbished.

The licensee took actions to measure air pressures locally at the Unit 2 MSIVs and found air pressure at approximately 91 psi. Normal instrument air pressure at the discharge of the air compressors is approximately 100 psi. The pressure differential between the air compressors and MSIVs is attributed to air system losses. The licensee also initiated an increased surveillance of instrument air pressures because no high pressure alarms were available in the control room. The licensee performed additional bench testing of the old Unit 1 solenoid valves and determined that the solenoid valves would function properly above 115 psi with the exception of the solenoid valve assumed to have caused the 1SM-1 stroke time failure. The licensee also obtained vendor concurrence to operate the valves with air pressures up to 120 psi.

c. Conclusion

The licensee's initial and subsequent actions were adequate to resolve an NRC identified discrepancy where the nameplate design rating of the MSIV solenoid valves was less than the maximum design pressure of the instrument air system. This discrepancy is significant because it resulted in the unrecognized potential to degrade the ability of the main steam isolation valves to close in the event of an instrument air system malfunction. This issue is identified as Example 1 of Violation 50-413,414/96-13-04: Inadequate Design Controls (Selection of MSIV Solenoid Valves.)

E2 Engineering Support of Facilities and Equipment

E2.1 Main Feedwater Pump B Trip During Unit 2 Startup

a. Inspection Scope (37551)

On August 10, during the Unit 2 restart from a forced shutdown, the 2B main feedwater pump tripped on high discharge pressure while operators were attempting to place it in service. A Failure Investigation Process (FIP) team was formed to determine why the pump tripped. The inspector observed the initial meeting of the FIP team, discussed the issue with engineering personnel, and reviewed instrument details and Problem Investigation Process (PIP) report 2-C96-2110.

b. Observations and Findings

Several indication anomalies associated with the pump trip were noted during the pump startup and trip. Specifically, control room operators indicated that they did not receive an annunciator for high pump discharge pressure prior to the pump trip, nor did the control room indication for pump discharge pressure reach the high discharge pressure setpoint of 1385 psig. As a result, there was some confusion over the validity of the pump trip.

According to data obtained from the Operator Aid Computer (OAC), the 2B Main Feedwater pump discharge pressure closely approached and probably reached the pump discharge pressure high setpoint. This indicated that the trip was valid. To explain the anomalies observed by the control room operators, the licensee began to explore the pump discharge pressure instruments. The inspector reviewed drawing number CN-1499-CF1, Revision 8, Instrument Detail for Feedwater Pump Discharge Pressure and discussed the drawing with engineering personnel to understand how the indication and control instruments functioned.

Three pump discharge pressure switches perform a pump trip function on 2 out of 3 high discharge pressure signals. Two of these pressure switches sense process fluid directly. As such, these switches provide an instantaneous response to changes in pump discharge pressure. The third pressure switch is operated by a pneumatic transmitter. This pressure switch is not as responsive to changes in pump discharge pressure. In addition, the same pneumatic transmitter provides the signal to indicate pump discharge pressure on the control board and to the high pump discharge pressure annunciator. The OAC data was transmitted from an electronic transmitter which directly sensed process fluid.

The B Main Feedwater pump apparently tripped when a short duration pressure spike was sensed by the pressure switches which monitor the process fluid directly, thereby satisfying the 2 out of 3 trip logic. The OAC data were valid, but process limitations introduced a lag in the transmission of the pump discharge pressure information to the control board gauge and annunciator. As a result, the control indications were consistent with the conditions in the plant and the pump trip was valid.

The FIP team concluded that a combination of factors caused the B Main Feedwater pump discharge pressure to reach the pump trip setpoint. Steam for Main Feedwater pump operation while the associated unit is offline is typically provided from the other unit. Since Unit 1 was in a refueling/steam generator replacement outage, steam was provided by an auxiliary boiler. The FIP team concluded that the combination of supplying auxiliary steam from a single auxiliary boiler and relatively rapid increases in pump speed demand by the control room operator caused the speed to overshoot, causing the high discharge pressure.

The FIP has recommended that two auxiliary boilers be used to supply steam to the main feedwater pump turbines in future unit start-ups occurring when both units are shut down. An extended time for steam piping and turbine chest warming was also proposed. Operator monitoring of steam pressure at the low pressure steam admission valve to the main feedwater pump turbine during pump starts was identified as an additional potential corrective action.

c. <u>Conclusions</u>

The inspector concluded that the licensee's actions to determine the root cause of the 2B main feedwater pump trip, and evaluate the indication anomalies observed by the operators were timely and appropriate. Proposed corrective actions addressed the apparent cause identified.

E2.2 <u>Engineering Support of Facilities and Equipment - Modifications</u>

a. <u>Inspection Scope (37550)</u>

The inspector reviewed several Nuclear Station Modifications (NSMs) implemented during the current Unit 1 outage. The modification review included verification that design control requirements of Regulatory Guided 1.64 and ANSI N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants, and licensee procedures were implemented. Elements of the design process reviewed included post modification testing, procurement, procedure revision, training, 50.59 safety evaluation, and field verification of plant hardware changes as applicable. The following NSMs were reviewed:

- CN-11360, Diesel Generator Battery Charger Replacement
- CN-11375, Upgrade Allowable Temperature for Some Auxiliary Feedwater (CA) System Piping
- CN-11371, Deletion of CA System Flow Optimization and Run-out Protection Circuits

- CN-11372, Revise Run-out Setpoints for Component Cooling (KC) System Single Pump Operation

b. Observations and Findings

The following modifications were implemented to resolve long-standing equipment problems at Catawba:

- The DG battery chargers were replaced (CN-11360) to resolve a reliability concern with the previous chargers related to the impact of ambient temperatures on charger performance. The purchase specification required vender testing to verify the new chargers were not impacted by the anticipated DG room ambient temperature transients.
- Piping supports for portions of the Auxiliary Feedwater system were modified (CN-11375) to allow increasing the piping allowable temperature.
- The Auxiliary Feedwater flow optimization and run-out protection circuit deletion (CN-11371) was to compensate for the changed Auxiliary Feedwater operating system characteristics associated with the new steam generators.
- Future run-out protection was to be provided by mechanical stops on the Auxiliary Feedwater pump flow control valves.
- The Component Cooling water pump run-out setpoint change (CN-11372) was to permit single pump operation of the Component Cooling system for normal plant conditions. Single pump operation would allow the pumps to operate at an optimum condition with reduced vibration and impeller wear.

Post modification testing performed and scheduled was adequate to verify equipment and system function following the modifications. Appropriate procedures were revised and adequate training was scheduled or completed for these modifications. The licensee's 50.59 safety evaluations were detailed and adequately justified the conclusions. An outstanding issue from a previous NRC inspection remains open related to the 50.59 evaluation for the Auxiliary Feedwater piping temperature upgrade. Procurement documentation demonstrated that the appropriate quality level material was used for installed equipment and materials. Field verification for the Auxiliary Feedwater piping supports and the DG chargers demonstrated that equipment installation was consistent with the Nuclear Station Modification requirements.

c. Conclusion

Several Unit 1 modifications were implemented during the outage to resolve existing equipment problems and improve plant reliability. The modifications demonstrated appropriate control of the design control process at Catawba. For the safety evaluations reviewed, the requirements of 50.59 were met.

E2.3 Main Feedwater Piping Erosion/Corrosion

a. Inspection Scope (37551)

During the Unit 1 Steam Generator Replacement Outage, the licensee identified erosion/corrosion of a localized area in the main feedwater piping between the check valves and isolation valves in the doghouses. The licensee requested approval of ASME Code Case N-480 to allow for planned replacement of some of the affected piping during the next refueling outage. The inspector reviewed the erosion/corrosion inspection data and PIP 0-C96-1963.

b. Observations and Findings

With the approval of the ASME Code Case N-480, the licensee performed evaluations to support operation until the next refueling outage for two of the four feedwater lines on Unit 1. One line was degraded to the point that a repair was performed and the remaining line was acceptable "as is." During the forced outage on Unit 2 erosion/corrosion inspections of similar locations were performed with acceptable results. NRC approval to implement ASME Code Case N-480 was required prior to restart of Unit 1. This approval was received in a letter dated September 9, 1996.

c. Conclusions

The inspector concluded that the erosion/corrosion program was effective in identifying this issue and an appropriate decision was made to inspect Unit 2 for similar conditions at the first available opportunity.

E3 Engineering Procedures and Documentation

E3.1 1995 Revision to the Updated Final Safety Analysis Report

By letter dated May 28, 1996, the licensee submitted the 1995 revision to the Updated Final Safety Analysis Report (UFSAR) in accordance with 10 CFR 50.71. This regulation requires that this submittal shall contain all the changes necessary to reflect information and analyses submitted to the Commission by the licensee or prepared by the licensee pursuant to Commission requirement since the submission of the original FSAR or, as appropriate, the last updated FSAR.

a. Inspection Scope

10 CFR 50.71 provides that the updated FSAR shall be revised to include the effects of:

- "All changes made in the facility or procedures as described in the FSAR."

- "Safety evaluations performed by the licensee either in support of requested license amendments...." - Since this category clearly involves NRC staff approval of licensing basis changes, other changes that the staff approved (e.g., topical reports, reliefs to ASME Code sections, exemptions, etc.) but were not conveyed as amendments are also implied.

  "....or in support of conclusions that changes did not involve an unreviewed safety question" - These are evaluations performed by the licensee in accordance with the provisions of 10 CFR 50.59.

- "All analyses of new safety issues performed by or on behalf of the licensee at Commission request" - Examples include licensee actions as a result of generic letters, bulletins, etc.

b. Observations and Findings

The inspector reviewed the 1995 revision of the Catawba UFSAR in-office and met with licensee personnel on-site. The purpose of the review was to confirm if the changes made in the 1995 revision comply with the provisions of 10 CFR 50.71. The inspector reviewed the changed pages to confirm that all changes were appropriately addressed by licensing actions, 10 CFR 50.59 reports, or regional inspection activities.

The inspector traced the changes in the 1995 revision of the UFSAR to documents in the official NRC records such as amendments to the operating license, staff letters transmitting safety evaluations, annual 10 CFR 50.59 reports submitted by the licensee, inspection reports, or licensee letters. The inspector confirmed that the 1995 revision does not constitute a source of initial communication (to NRR) of these changes.

The inspector noted that some UFSAR changes made under 10 CFR 50.59 appeared to have not been reported in the periodic update submitted immediately after the changes were made. Examples include CN-50422, CN-50431, CE-3604, CE-3605, and CE-60212. The licensee should review the circumstances involved and determine the cause of the delayed update. The inspector noted that the licensee had performed the required analyses in accordance with 10 CFR 50.59 and concluded that the apparently late reporting of some changes was not a violation of regulatory requirements.

The inspector noted that UFSAR Section 13.1, regarding the licensee's nuclear organization, had been revised. The licensee had not performed an evaluation in accordance with 10 CFR 50.59, or sought prior staff approval. The inspector reviewed the changes and determined that the changes do not reduce the organizational resources committed to nuclear safety and are therefore acceptable. In an August 20, 1996, meeting, the licensee stated that it planned to institute an internal procedure to ensure that such changes receive sufficient evaluation in the future.

c. Conclusion

The inspector concluded that the 1995 revision of the Catawba UFSAR matched the provisions of 10 CFR 50.71, and is therefore in compliance with 10 CFR 50.71.

E4 Engineering Staff Knowledge and Performance

E4.1 Standby Shutdown System (SSS) Operability

a. Inspection Scope (92903)

The inspector reviewed the licensee's activity to resolve a recently identified issue related to the operability of the SSS.

b. Observations and Findings

During an inspection of the SSS on July 8-12, 1996, (NRC Inspection Report 50-413,414/96-10) an NRC inspector noted non-conservative assumptions/design inputs in calculation CNC 1223.04-00-0009, Standby Make-up Pump (SMUP) Sizing, dated November 1, 1993. Discussions with the licensee indicated these incorrect assumptions did not impact the calculation conclusion that the SMUP was operable for the required 72-hour period of an SSS event. Further review by the licensee after the inspection determined that the design input errors did impact the calculation conclusion, resulting in an operability concern for both Units 1 and 2 SSS. Problem Investigation Process Report (PIP) 0-C-96-1824 was initiated by the licensee on July 18, 1996, to address this issue.

The calculation included the following errors:

- Incorrect determination of Spent Fuel Pool (SFP) Inventory; boil off not included
- Incorrect pump speed
- Incorrect SFP (cycle specific) temperature

- Design minimum pump flow rather than actual flow used for SFP inventory reduction

The significant error was the temperature value used for the SFP which provided the water source for SMUP to the reactor coolant pump seals. The temperature was derived from a heat up rate based on pool loading of spent fuel that was specific to a past cycle on Unit 2. This temperature value would not be appropriate for any other pool loading. A calculation revision in November 1993 reviewed the SMUP suction pulsation dampener based on these past cycle conditions and concluded that the dampener (and SMUP) was operable for the required 72-hour period. The dampener's function is to assure adequate net positive suction head (NPSH) for SMUP operation. The licensee's recent evaluation, initiated by PIP 0-C-96-1824, determined that the dampener (and SMUP) operability could not be assured near the end of the 72 hour period.

At the time that the operability concern was identified, Unit 2 was at power and Unit 1 was in an extended outage for steam generator replacement. The licensee determined that the Unit 2 SSS was operable but degraded and Unit 1 SSS was inoperable. Unit 1 SSS was not required to be operable until entering mode 3.

The Unit 2 SSS degraded operability determination was based on analysis and imposition of more limiting SFP temperature requirements. The analysis was provided by Calculations CNC 1201.30-00-0019, Catawba Unit 2 SFP Decay Heat and Temperature Calculation for PIP 0-C96-1824, dated July 24, 1996, and CNC 1223.04-00-0069, Unit 2 Cycle 8 SMUP NPSH Requirements for PIP 0-C96-1824, dated July 24, 1996. The SFP decay heat calculation determined that with an initial SFP temperature of 125°F and the current Unit 2 SFP load, the SFP temperature would be approximately 181°F 72 hours after the initiation of an SSS event. The SMUP NPSH calculation determined that at 181°F, adequate NPSH was available to the SMUP, assuming the suction dampener was inoperable. The licensee established controls to assure that the SFP temperature was maintained less than 125°F. The SFP temperature alarm was reset to 115°F (included a 9°F instrument error) and increased operations surveillance for SFP temperature monitoring. The normal summer temperature range of the SFP was 100-105°F. The inspector reviewed the calculations and verified the correct design input values were used.

The above actions were immediate corrective actions to establish Unit 2 SSS operability for the current fuel cycle. Long-term corrective actions were being evaluated and will include resolution of the Unit 1 SSS operability prior to restart of the unit.

c. Conclusion

The licensee's immediate corrective actions were adequate to resolve present operability concerns on Unit 2. The licensee failed to identify the design input errors in Calculation 1223.04-00-0009 on two occasions: first during the independent review of the calculation in November 1993, and again during the licensee's SSS pre-inspection self-assessment in June 1996. This issue is identified as Example 2 of Violation 50-413,414/96-13-04, Inadequate Design Controls (Standby Shutdown System Make-up Pump Sizing Calculation.)

E8 Miscellaneous Engineering Issues

E8.1 Safety-Related Logic Circuits Testing Discrepancy

a. Inspection Scope (37551)

The inspector reviewed the licensee's response to their finding that the testing of the degraded voltage and undervoltage logic on the DG load sequencer had been insufficient. The licensee's finding was in response to the review of safety-related logic circuits required by Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits."

b. Observations and Findings

During the review of the safety-related logic circuits required by GL 96-01, the licensee discovered that part of the logic circuits for the degraded voltage and undervoltage relays for the emergency diesel generator load sequencer logic circuits were not being tested completely. This logic is a 2 out of 3 logic circuit. Portions of the logic circuit were not verified during surveillance testing in that not all possible combinations of logic were tested. This resulted in portions of circuitry not being verified operable during each surveillance cycle. The licensee documented this issue in PIP 0-C96-2015.

Both Units 1 and 2 were affected by this testing deficiency; however, both Units were shutdown at the time of discovery. The licensee's corrective action was preparation and completion of revised testing which would satisfy the testing requirements for the logic circuitry. Procedure IP/2/A/4971/075A, Logic Testing for Degraded Bus and Load Sequencer Voltage Circuits was completed to satisfy the testing requirements. The inspector reviewed this test procedure and found that it adequately resolved the testing concern. The licensee planned to complete this testing for both Units 1 and 2 prior to restart.

c. Conclusions

Licensee identification of this test deficiency met the intent of Generic Letter 96-01 and corrective actions were appropriate.

E8.2 Temporary Station Modification Audit Program (92903)

(Closed) Violation 50-413,414/94-30-01, Inadequate Corrective Action for Temporary Station Modification (TSM) Program Deficiency. This item addressed the licensee's failure to correct a TSM program deficiency related to periodic audits of active TSMs. The licensee identified that several monthly audits required by procedure were not performed. After the completion of the corrective actions, an NRC inspector reviewed the TSM program and identified approximately 30 active TSMs which were not included in the previous audit. This demonstrated that the licensee's original corrective actions were not adequate. The licensee's corrective action for the violation was to revise the TSM audit process to incorporate increased management oversight and increase guidance for the audit process. The inspector reviewed the June 1996 quarterly TSM audit and verified that all active TSMs were included. The inspector concluded that the licensee adequately resolved the TSM program deficiency related to periodic audits.

E8.3 Main Steam Isolation Valve 1SM-1 Reportability Evaluation (92903)

(Closed) Unresolved Item 50-413/96-02-05, Review of MSIV 1SM-1 Reportability Evaluation and In-Plant Review of PIP Initiation Performance. During this inspection period the licensee completed the Reportability Evaluation and troubleshooting for the stroke time failure of Main Steam Isolation Valve 1SM-1 (refer to PIP 1-C96-0751). Results of testing performed during the current 1EOC9 refueling outage determined that the cause of the stroke time failure was due to an intermittently malfunctioning B-train exhaust solenoid valve. Based on the test results, the licensee plans to submit an LER. The inspector reviewed the results of the licensee's in-plant review of PIP initiation during test activities (Report No. SA-96-41(CN) (SRG), PIP 0-C96-1759). The licensee's audit consisted of the review of approximately 150 completed test procedures and other records. The review concluded that PIPs are being initiated to assess systems/components that do not meet test acceptance criteria. The review recommended enhancements to NSD 208, Problem Investigation Process, to clarify references for PIP initiation. The inspector concluded from this review that the failure to initiate PIPs in response to test failures is not a programmatic concern.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Individual Escorted into Radiation Control Area

a. Inspection Scope (71750)

On July 19, 1996, a contractor employee escorted his spouse into the Radiation Control Area during a plant tour. A radiation protection technician in upper containment questioned their need to enter that area and requested that they leave. While exiting the Radiation Control Area a second radiation protection technician questioned the absence of appropriate dosimetry and recognized the unauthorized access. Problem Investigation Process (PIP) Report 1-C96-1837 was initiated to address the issue. A root cause analysis was performed by the licensee because station management recognized the similarity of this occurrence to an issue in October 1995. The inspector reviewed the PIP and its associated root cause, discussed the issue with the contractor employee, and reviewed the circumstances of the previous occurrence documented in NRC Inspection Report 50-413,414/95-22.

b. Observations and Findings

While in the Radiation Controlled Area, the individuals remained together, did not enter any high radiation areas, and had one electronic dosimeter which was operating. The electronic dosimeter registered no exposure during the entry.

The inspector noted that the previous occurrence was characterized as a non-cited violation (NCV 50-413,414/95-22-03) since it was identified by the licensee, was apparently an isolated case, and appropriate corrective actions were initiated.

The recent issue was also identified by the licensee and appropriate actions were taken by radiation protection personnel to question, identify, and document the occurrence. Appropriate sensitivity to the issue was demonstrated by the performance of a root cause evaluation which identified expanded proposed corrective actions.

c. Conclusions

The unauthorized entry of an individual into the Radiation Control Area without appropriate dosimetry, training, or body burden analysis is a violation of Radiation Protection Directive No. II-1, Radiation Area Access and Monitoring Devices. Since corrective actions for a previous, similar occurrence were not effective in preventing recurrence, this issue is identified as Violation 50-413,414/96-13-05: Repeat Radiation Control Area Entry Without Dosimetry.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 16, 1996. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Bhatnager, A., Operations Superintendent
Coy, S., Radiation Protection Manager
Eller, R., Licensing Specialist
Forbes, J., Engineering Manager
Funderburk, W., Work Control Superintendent
Hallman, W., Project Director, SGRP
Harrall, T., IAE Maintenance Superintendent
Kelly, C., Maintenance Manager
Kimball, D., Safety Review Group Manager
Kitlan, M., Regulatory Compliance Manager
Lowery, J., Compliance Specialist
McCollum, W., Catawba Site Vice-President
Nicholson, K., Compliance Specialist
Parker, R., Manager, Inage
Patrick, M., Safety Assurance Manager
Peterson, G., Station Manager
Propst, R., Chemistry Manager
Rogers, D., Mechanical Maintenance Manager
Rose, I., Manager, Workforce Processing
Self, T., Maintenance Supervisor
Tower, D., Compliance Engineer

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Problem Identification and Prevention
IP 57090:	NDE Procedure Radiographic Exam. Procedure Review
IP 61726:	Surveillance Observation
IP 62700:	Maintenance Program Implementation
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92903:	Followup - Engineering
IP 93702:	Onsite Response to Events

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-414/96-13-01	NCV: Failure to Report Inoperability of Both Trains of Auxiliary Building Ventilation (Section O1.1).
50-413, 414/96-13-02	VIO: Inadequate Procedures (Sections O1.2, M3.1).
50-413/96-13-03	NCV: Failure To Follow Procedure For Deviation of Step Sequence (Section M4.1).
50-413,414/96-13-04	VIO: Inadequate Design Controls for (1) Standby Shutdown System Make-up Pump Sizing Calculation, and (2) Selection of MSIV Solenoid Valves (Sections E4.1 and E1.2).
50-413,414/96-13-05	VIO: Repeat Radiation Control Area Entry Without Dosimetry (Section R1.1).

Closed

50-413,414/94-30-01	VIO: Inadequate Corrective Action for Temporary Station Modification Program Deficiency (Section E8.2).
50-413/96-02-05	URI: Review of MSIV 1SM-1 Reportability Evaluation and In-Plant Review of PIP Initiation Performance (Section E8.3).

LIST OF ACRONYMS USED

ANSI	-	American Nuclear Standard Institute
ASME	-	American Society of Mechanical Engineers
ASP	-	Auxiliary Shutdown Panel
CA	-	Auxiliary Feedwater System
CFAR	-	Component Failure Analysis Report
CFR	-	Code of Federal Regulations
CNS	-	Catawba Nuclear Station
CR	-	Control Room
DG	-	Diesel Generator
DPC	-	Duke Power Company
EOC	-	End of Cycle
°F	-	degrees Fahrenheit
FATS	-	Failure Analysis Trending System
GL	-	Generic Letter
HVAC	-	Heating, Ventilation, and Air Conditioning
IAE	-	Instrument and Electrical
ID	-	ID Inner Diameter
IFI	-	Inspector Followup Item
IR	-	Inspection Report
KC	-	Component Cooling
LER	-	Licensee Event Report
MOV	-	Motor Operated Valve
MSIV	-	Main Steam Isolation Valve
NDE	-	Non-Destructive Examinations
NPRDS	-	Nuclear Plant Reliability Data System
NPSH	-	Net Positive Suction Head
NSD	-	Nuclear System Directive
NSM	-	Nuclear Station Modification
OOS	-	Out-of-Service
PIP	-	Problem Investigation Process
PM	-	Preventive Maintenance
PORC	-	Plant Operations Review Committee
RG	-	Regulatory Guide
RHR	-	Residual Heat Removal
RN	-	Nuclear Service Water System
RTB	-	Reactor Trip Breaker
SFP	-	Spent Fuel Pool
SGRP	-	Steam Generator Replacement Project
SITA	-	Self-Initiated Technical Audit
SMUP	-	Standby Make-up Pump
SSS	-	Standby Shutdown System
TSM	-	Temporary Station Modification
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VC/YC	-	Control Room Ventilation and Chilled Water Systems
VIO	-	Violation
WO	-	Work Order

Enclosure 2