U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
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Enclosure

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/99-04, 50-414/99-04

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection, as well as the results of announced inspections by regional reactor safety inspectors. [Applicable template codes and the assessment for items inspected are provided below.]

Operations

- A Notice of Enforcement Discretion was granted to allow replacement of the failed 1B chemical and volume control system centrifugal charging pump on June 10, 1999. (Section O1.2; [NOED - 2A, 4C])

- Operators took appropriate actions following failure of the 1B charging pump to ensure that the plant was stabilized. (Section O1.2; [POS - 1A])

- During the repair of the 1B charging pump, plant personnel breached the pump room ventilation boundary for approximately 15 hours without taking proper actions to address Technical Specification requirements for the auxiliary building ventilation system. An unresolved item was opened to track the breached ventilation boundary and the Notice of Enforcement Discretion. (Section O1.2; [URI - 1A, 2B])

- Walkdowns of the Unit 1 residual heat removal system found: valves, breakers, switches and controllers appropriately positioned; associated instrumentation properly functioning; and, with minor exceptions, components properly labeled. Material condition and general housekeeping were good, with the exception of the residual heat removal heat exchanger rooms. (Section O2.1; [POS - 1A, 2A])

- The licensee had appropriate procedures, plant systems and equipment, and control room indications available to aid in the detection and mitigation of flooding events. Drains, sumps, and associated equipment were in good material condition. The Catawba station was properly addressing potential generic implications from a March 1999 auxiliary feedwater pump room flood event at the McGuire Nuclear Station. (Section O2.2; [POS - 1A, 1C, 2A])

- A non-cited violation was identified regarding a non-compliance with Technical Specification 3.4.7 due to an inadequate work sequence that rendered a residual heat removal train inoperable while in Mode 5. (Section O8.1; [NCV - 1A, 2B])

- The NRC identified a non-cited violation for failing to properly make Technical Specification Action Item Log entries when four channels of reactor coolant system average temperature instrumentation were inoperable during refueling outages from 1995 to 1997. Operations performance was inadequate to prevent Technical Specification 3.0.3 conditions during cross-calibrations of the four channels. The licensee's root cause for the TS 3.0.3 entries did not address the operator performance issues. (Section M8.2; [NCV - 1A; NEG - 5B])

Maintenance

- The licensee's maintenance and surveillance programs for the residual heat removal system appears to be properly focused on surveillance testing and preventive maintenance to establish and maintain equipment operability, rather than reacting with corrective maintenance in response to equipment failures. (Section O2.1; [POS - 2B])

- Review of completed inservice testing procedures for the Unit 1 residual heat removal system pumps and selected valves revealed that the test procedures had been performed satisfactorily, properly documented, and met applicable upper tier component test performance requirements. (Section O2.1; [POS - 2B])

- The NRC identified a non-cited violation concerning a non-compliance with Technical Specification Surveillance Requirement 3.5.2.2 due to a failure of the associated surveillance procedure to require position verification of valves ND27 and ND61 every 31 days. (Section O2.1; [NCV - 2B])

- A limited review of other residual heat removal surveillance procedures found them to be well written and appropriate for implementing the applicable surveillance requirements. (Section O2.1; [POS - 2B])

- An unresolved item was identified pending further NRC review of the exclusion of safety-related sump pumps from the licensee's in-service testing program. (Section O2.2; [URI - 2B])

- A non-cited violation was identified regarding inadequate surveillance testing of residual heat removal system valve response times due to incorrect acceptance criteria in test procedures. (Section M8.1; [NCV - 2B; POS - 5A])

- A non-cited violation, with two examples, was identified regarding a non-compliance with Technical Specification 5.2.2.e, for failure to comply with overtime control requirements. (Section O8.2; [NCV - 3C, 5A])

Engineering

- Reviewed industry-related residual heat removal issues were properly captured under the Duke corporate industry operating experience program, with associated corrective actions effectively implemented. The use of forms similar to a problem identification process report for tracking these issues to completion was considered a strength of the Duke industry operating experience program. (Section O2.1; [POS - 5A, 5C])

- Engineering involvement in the analysis and resolution of technical issues was generally effective. Analyses of technical issues and evaluations of operability demonstrated an appropriate understanding of plant design. (Section E2.1; [POS - 4B, 5B])

- Design changes and modifications reviewed were implemented in accordance with regulatory guidance. The design and licensing bases were appropriately updated to reflect plant changes. (Section E2.2; [POS - 4A, 4C])

- Two instances were noted where there was a lack of documented analysis to support design changes. (Section E2.2; [NEG - 4A])

- The licensee demonstrated good management of engineering work and control of work backlogs. Substantial improvements in this area had been made in 1999 and more were planned. (Section E2.3; [POS - 4B])

- The quantity and quality of licensee audits and assessments of engineering activities during the last year were good. The audits and assessments identified many deficient conditions which were appropriately entered into the corrective action system and also identified many recommended improvements. (Section E7.1; [POS - 5A])

- A non-cited violation was identified regarding a failure to update the Final Safety Analysis Report to reflect the iodine removal function of the auxiliary building ventilation. (Section E8.1; [NCV - 4A]

Plant Support

- The licensee's performance during an annual emergency preparedness exercise on June 9, 1999, was adequate with the appropriate focus on maintaining plant and personnel safety. Only minor concerns were noted in the area of command and control in the Emergency Operations Facility. (Section P1.1; [1C - POS])

- The Unit 1 residual heat removal heat exchanger rooms were maintained as contaminated areas, were poorly lighted, and had dirty floors that appeared to be stained by rusty water. The inspector also observed system components with damaged lagging, as well as tygon tubing and rope on the floors and tied off to the walkway handrails. The licensee indicated that the residual heat removal rooms were maintained in their present condition due to efforts to maintain personnel radiation exposures as low as reasonably achievable; therefore, time and dose would not be expended on further improvement in these rooms. (Section O2.1; [MISC - 2A, 1C])

Report Details

Summary of Plant Status

Unit 1 began the inspection period operating at 100 percent power. On June 8, 1999, operators commenced a power reduction per Technical Specification (TS) 3.0.3 after declaring both chemical and volume control (NV) system centrifugal charging pumps inoperable. This followed a failure of the 1B pump coincident with operators determining that the 1A pump was inoperable due to ongoing maintenance on the 1A train of the nuclear service water system. After restoring the nuclear service water system (and hence the 1A NV pump) to operable status within one hour, the shutdown was halted with the reactor at 97.5 percent power. Reactor power was restored to 100 percent on the morning of June 9, 1999. On July 15, 1999, reactor power was reduced to 97 percent to facilitate testing of the 1C steam generator power-operated relief valve (1SV-7). The same day, following valve testing, the reactor was restored to 100 percent power, where it remained for the duration of the inspection period.

Unit 2 began the period shutdown in Mode 4 due to ongoing repairs of the main turbine generator. The main generator reassembly was completed and a unit heatup to Mode 3 performed on June 13, 1999. A reactor startup was commenced on June 14, 1999. The unit was synchronized to the electrical grid on June 14, 1999, with the reactor reaching 100 percent power on June 15, 1999. The unit remained at full power for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness and effective communications, and adherence to approved procedures. The inspectors: (1) attended operations shift turnovers and site direction meetings to maintain awareness of overall plant status and operations; (2) reviewed operator logs to verify operational safety and compliance with TS; (3) periodically reviewed instrumentation, computer indications, and safety system lineups, along with equipment removal and restoration tagouts, to assess system availability; (4) reviewed the TS Action Item Log for both units daily for potential entries into limiting conditions for operation (LCO) action statements; (5) conducted plant tours to observe material condition and housekeeping; and (6) routinely reviewed Problem Identification Process reports (PIPs) to ensure that potential safety concerns and equipment problems were resolved. The inspectors identified no major problems from the above reviews.

O1.2 Unit 1B Centrifugal Charging Pump Failure and Resultant Notice of Enforcement Discretion (NOED 99-2-002)

a. Inspection Scope (71707, 93702, 40500)

The inspectors reviewed the circumstances involving the failure of the 1B charging pump on June 8, 1999. This included a review of plant data, discussions with control room operators and engineering personnel, and observation of the licensee's Plant Operations Review Committee meeting, during which the licensee discussed a proposed NOED request to extend the TS allowed outage time to allow pump replacement.

b. Observations and Findings

On June 8, 1999, at approximately 8:45 p.m. with Unit 1 in Mode 1 at 100 percent power, operators noticed that pressurizer water level was decreasing and that the NV system flow control valve was indicated as full open. Operators placed the flow control valve from automatic to manual mode in an unsuccessful attempt to increase charging flow to the reactor coolant system (RCS) and restore pressurizer level, which had dropped from 53 percent to approximately 49 percent. With these indications, and after local verification that valves in the charging flowpath were operating correctly, operators suspected a failure of the 1B NV pump and placed the 1A NV pump in service. All charging and level indications returned to normal. The operators secured the 1B pump and declared it inoperable at 11:20 p.m. At the time, the 1A nuclear service water (RN) system was inoperable for scheduled maintenance and testing, which required operators to consider TS LCO 3.0.3 and TS LCO 3.8.1 [emergency diesel generator (EDG) specification], Required Action B.2. Although TS 3.8.1 allowed four hours from the time of discovery to declare the redundant 1A NV pump inoperable (since its emergency power supply was the 1A EDG, which was inoperable because of the 1A RN train), operators conservatively considered both NV pumps inoperable at 11:20 p.m. and entered TS 3.0.3. As a result, within one hour operators began a power reduction in preparation for placing the unit in Mode 3. The shutdown was stopped within one hour with the unit at 97.5 percent power after testing of RN Train 1A was successfully completed and the system was declared operable. The 1A NV pump was declared operable, the TS 3.0.3 entry was cleared, and reactor power was restored to 100 percent by 3:00 a.m. on June 9, 1999. The conservative TS 3.0.3 entry was discussed in PIP 1-C99-2422, in which the licensee concluded that this aspect of the event was not NRC-reportable per 10 CFR 50.73. The inspectors concurred with the licensee's determination. The inspectors also concluded, from discussions with operations personnel on shift that day, that a better operator understanding of the improved TS requirements (implemented in January 1999) for cascading from one system to another's TS LCO action statements would have prevented the TS 3.0.3 entry.

The licensee later determined that the 1B NV pump replacement effort would require more than the 72 hours allowed by TS 3.5.2, the governing specification for having one pump inoperable. The licensee requested a NOED from the NRC on June 10, 1999, to extend the allowed inoperable period to seven days from the time of initial inoperability. In addition, the licensee requested discretionary enforcement of TS 3.7.12, which required both trains of the safety-related auxiliary building ventilation filtered exhaust (VA) system to be operable. The VA system's operability would be impacted during the 1B NV pump repair effort because replacement crews needed to remove a ceiling hatch cover in the pump room to facilitate the removal and installation of the old and new pumps and other heavy equipment. In addition, to provide worker comfort, licensee personnel intended to route temporary flexible ductwork from outside air conditioning units into the room through propped-open doors. The ability of the VA system to draw the required negative pressure on the NV pump room with the hatch removed and the access doors propped open (particularly with air conditioning units blowing into the room) would be compromised. The licensee's basis for determining that discretionary enforcement was appropriate in this case was supported, in part, by a risk analysis and a number of compensatory actions that the inspectors independently verified were being properly implemented. The NRC granted the NOED on June 10, 1999, and the licensee successfully replaced and tested the 1B NV pump by June 14, 1999, at which time the TS LCO actions for both the NV and VA systems were exited.

Prior to the NOED being issued, the inspectors observed portions of the licensee's repair efforts on June 10, 1999, and noticed that the pump room access doors were already blocked open with two cooling ducts routed through them and the associated air conditioning units operating. The inspectors informed licensee personnel who immediately closed the doors and later determined that they had been open continuously for approximately 15 hours (since about 12:00 a.m. that morning) without the system having been declared inoperable and appropriate TS actions taken. With both trains of the VA system incapable of drawing a negative pressure on the NV pump room, TS 3.0.3 required that actions be initiated within one hour to place the unit in Mode 3 (within seven hours) and Mode 4 (within 13 hours). Following the pump replacement, the licensee initiated a root cause investigation into the premature door opening and TS non-compliance. The licensee reported the TS 3.7.12/ TS 3.0.3 noncompliance, as well as the TS 3.5.2 allowed outage time being exceeded (albeit with discretion) during the pump replacement, in Licensee Event Report (LER) 50-413/99-08. Because the root cause of the TS 3.7.12 compliance issue had not been developed yet, the LER contained only an abstract of the event. The licensee planned to supplement the LER when the root cause and safety significance determinations were completed after the close of this inspection period.

The inspectors determined that further NRC review was warranted to address the premature opening of the 1B NV pump room doors and assess regulatory and safety significance. This review will be conducted under Unresolved Item (URI) 50-413/99-04-01: VA System Potentially Inoperable due to Premature Opening of ECCS Pump Room Ventilation Boundary Doors During Pump Replacement. This URI will also track the NOED that was granted on June 10, 1999.

c. Conclusions

A Notice of Enforcement Discretion was granted to allow replacement of the failed 1B NV centrifugal charging pump on June 10, 1999. Operators took appropriate actions following failure of the pump to ensure that the plant was stabilized. However, during the pump repair effort, plant personnel breached the pump room ventilation boundary for approximately 15 hours without taking proper actions to address TS requirements for the VA system. An unresolved item was opened to track the breached ventilation boundary and the NOED item.

O2 Operational Status of Facilities and Equipment

O2.1 Inspection of Unit 1 Residual Heat Removal (RHR) System

a. Inspection Scope (71707, 62707, 61726)

This was a vertical slice inspection of the Unit 1 RHR system, up to and including related boundary valves with interfacing systems (i.e., containment spray, component cooling water, safety injection, chemical volume control, and refueling water). It involved detailed system walkdowns and reviews of system operation, maintenance, and surveillance.

b. Observations and Findings

System Walkdowns

The inspectors conducted walkdowns of the accessible mechanical and electrical portions of the Unit 1 RHR system. Encompassing the applicable areas of the control room, standby shutdown facility, annulus, and auxiliary building (including the auxiliary shutdown panel rooms), the walkdowns verified that valves, breakers, switches and controllers were appropriately positioned. Associated instrumentation was found to be properly functioning. With minor exceptions, which were promptly captured in the licensee's problem identification process for correction, components were properly labeled. Overall, material condition and general housekeeping were considered to be good, with the exception of the RHR heat exchanger rooms. These rooms were maintained as contaminated areas, were poorly lighted, and appeared dirty. The inspector observed damaged lagging, as well as tygon tubing and rope on the floors and tied off to the walkway handrails. The floors were dirty and appeared to have been stained by rusty water. The licensee indicated that these rooms were maintained in their present condition due to efforts to maintain personnel radiation exposure as low as reasonably achievable (ALARA); therefore, time and dose would not be expended on further improvement in these rooms.

Equipment History

RHR system PIPs for the last three years and the maintenance history for approximately 40 RHR system components were reviewed to determine the extent of testing and preventive maintenance performed as opposed to corrective maintenance following component failures. Summarized by component type, the results of the inspectors' review are as follows:

- Motor Operated Valves - The maintenance and surveillance program included vendor recommended actuator preventive maintenance (PMs), repacking PMs, Generic Letter 89-10, Motor-operated Valve, testing, VOTES testing, and TS testing. As a result, very few valve failures were noted.

- Check Valves - All check valves reviewed had been subjected to testing. Some of the valves had been subjected to open and inspection type PMs. No failures were observed.

- Instrumentation - All of the instrumentation reviewed had been calibrated within the past three years. Very few failures were observed.

- Relief Valves - All relief valves reviewed had been refurbished and the setpoints were checked within the last three years.

- Pumps - The RHR pumps received a motor replacement on a five refueling outage frequency due to vendor recommended thrust bearing wear analysis. PMs were established for cleaning the seal housing and vibration analysis was routinely performed. TS testing was also being performed. Only minor problems were noted in the maintenance history.

Based on the above findings, the licensee's maintenance and surveillance programs for the RHR system appeared to be focused on surveillance testing and preventive maintenance in order to establish and maintain equipment operability, rather than reacting with corrective maintenance in response to equipment failures.

TS Surveillance Requirements (SR)

As reflected in LER 50-413/99-002 (addressed in Section M8.1), there were instances in which TS SRs were not properly reflected or accomplished by an implementing test procedure. Accordingly, the inspectors reviewed implementing test procedures for selected portions of the following RHR TS related SRs: 3.3.2.2, 3.3.2.4, 3.3.2.7, 3.3.2.9, 3.3.2.10, 3.4.14.2, 3.5.2.1, 3.5.2.2, 3.5.2.4, 3.5.2.5, and 3.5.2.6. Overall, except for SR 3.5.2.2, the associated test procedures were found to be well written and appropriate for implementing the applicable surveillance requirements.

Technical Specification SR 3.5.2.2 required that a verification be made every 31 days to ensure that each emergency core cooling system (ECCS) manual, power operated, and automatic valve in the flow path, that was not locked, sealed, or otherwise secured in position, was in the correct position. To accomplish this surveillance requirement, the licensee implemented procedure PT/1(2)/A/4200/006B, ECCS Valve Lineup Verification, on a specified 31-day frequency. A review of this procedure by the inspectors revealed that ECCS automatic valves ND-27 and ND-61 (bypass for RHR heat exchanger A and B, respectively) were not included in the associated valve lineup checklist, even though they were in the flow path and required to be closed to prevent bypassing their respective RHR heat exchanger during the ECCS recirculation mode of operation. Although modulated open during plant cool down, these air operated control valves, which were remotely operated from the control room, were normally aligned shut in Modes 1 - 3 and fail closed upon receipt of a safety injection signal. The inspectors confirmed that the subject valves were in their correct positions and that the licensee captured this issue in their corrective action program as PIP 0-C99-2505. Accordingly, this failure to verify the position of valves ND-27 and ND-61 every 31 days is a Severity Level IV violation that is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. It is identified as NCV 50-413,414/99-04-02: TS 3.5.2.2 Non-Compliance Due to Failure of Surveillance Procedure to Require Position Verification of Valves ND27 and ND61 Every 31 Days

Inservice Testing (IST)

Completed IST procedures for both RHR pumps and 34 select RHR valves were reviewed to determine whether the intended test functions were satisfactorily accomplished and whether component performance values delineated in these procedures met the Updated Final Safety Analysis Report (UFSAR), the American Society of Mechanical Engineers (ASME) Code (Section XI, 1989 Edition) requirements, Duke Energy Design Criteria and NUREG 1248, Guidelines for Inservice Testing at Nuclear Power Plants. The reviewed IST procedures, which included the corrected procedures addressed in Section M8.1, were found to meet the test requirements and performance criteria (i.e., time, flow, capacity, actuation, and leak test requirements). Overall, the inspectors determined that the selected IST procedures had been performed satisfactorily, properly documented, and met applicable upper tier component test performance requirements.

Industry Issues

One Generic Letter and five Information Notices were selected for review in order to assess the licensee's incorporation of industry experience into the operation, maintenance, and surveillance of the RHR system. These items were found to be captured under the Duke corporate Industry Operating Experience (IOE) program. The inspectors determined that corrective actions to address the associated industry issues were effectively implemented and considered the use of forms similar to a PIP for tracking these issues to completion was a strength of the Duke IOE program.

c. Conclusions

Walkdowns of the Unit 1 RHR system found: valves, breakers, switches and controllers appropriately positioned; associated instrumentation properly functioning; and, with minor exceptions, components properly labeled. Material condition and general housekeeping were good, with the exception of the RHR heat exchanger rooms.

The Unit 1 RHR heat exchanger rooms were maintained as contaminated areas, were poorly lighted, and had dirty floors that appeared to be stained by rusty water. The inspectors also observed system components with damaged lagging, as well as tygon tubing and rope on the floors and tied off to the walkway handrails.

The licensee indicated that the residual heat removal rooms were maintained in their present condition due to ALARA considerations; therefore, time and dose would not be expended on further improvement in these rooms.

The licensee's maintenance and surveillance programs for the RHR system appear to be focused on surveillance testing and preventive maintenance in order to establish and maintain equipment operability, rather than reacting with corrective maintenance in response to equipment failures.

An NCV was identified concerning a non-compliance with TS SR 3.5.2.2 due to a failure of the associated surveillance procedure to require position verification of valves ND27 and ND61 every 31 days. A limited review of other RHR surveillance procedures found them to be well written and appropriate for implementing the applicable surveillance requirements.

Review of completed IST procedures for the Unit 1 RHR system pumps and selected valves revealed that the test procedures had been performed satisfactorily, properly documented, and met applicable upper tier component test performance requirements.

Reviewed industry-related RHR issues were properly captured under the Duke corporate IOE program, with associated corrective actions effectively implemented. The use of forms similar to a PIP for tracking these issues to completion was considered a strength of the Duke IOE program.

O2.2 Inspection of Catawba's Drainage Systems and Readiness to Withstand Internal Flooding Events

a. Inspection Scope (71707)

The inspectors reviewed the Catawba plant's vulnerability to internal floods, and assessed its readiness to mitigate such events. This included a review of the facility's Probabilistic Risk Analysis (PRA); UFSAR; Design Basis Specifications; Selected Licensee Commitments (SLC); system operating, maintenance, and testing procedures; and plant and instrument drawings. The inspectors also reviewed completed instrument calibration procedures, work orders, and outstanding clearances. This review specifically addressed the groundwater drainage system, the turbine and auxiliary building sump systems, and the liquid waste system. The inspectors also interviewed various individuals from the engineering and operations organizations and conducted multiple plant tours to observe the material condition of drainage systems.

b. Observations and Findings

The inspectors found that, in general, plant equipment designed to mitigate flooding events was in good working order and material condition. While no flood response procedures were in place to direct operations following identification of one, there were procedures in place for handling the loss of safety equipment that would most likely be affected during a flood. Alarm response procedures were in place for indications of abnormal sump pump operation caused by high building sump levels. Operators were familiar with these procedures. The inspectors considered this approach to mitigating flood events reasonable. The licensee was addressing the need for specific flood response procedures in PIP 0-C99-2628. This PIP also addressed other generic issues related to a flood of one of the auxiliary feedwater pump rooms at the McGuire plant earlier this year. The inspectors determined that the licensee was adequately addressing related issues for the Catawba facility and concluded, given the design of the auxiliary building, the layout of the sumps and associated safety-related sump pumps, and the piping systems routed through the area, that the likelihood of a similar flood in that room causing the failure of all three auxiliary feedwater (CA) pumps was minimal.

The inspectors identified minor discrepancies related to the monitoring of groundwater sump levels and configuration control for one set of groundwater sump pumps. These discrepancies were appropriately addressed in the licensee's corrective action program.

The licensee has designated sump pumps in the groundwater drainage system, the auxiliary building sump system, and the liquid waste system as safety-related. The inspectors reviewed the licensee's IST program, which implements ASME Code, Section XI requirements, to determine if the safety-related sump pumps were included. The inspectors found that no pump performance or vibration testing was being performed for the following safety-related pumps: the A1 and B2 groundwater drainage sump pumps, the Unit 1 and Unit 2 A and B containment spray/RHR pump sump pumps, the Unit 1 and Unit 2 A and B motor-driven CA pump sump pumps, and the Unit 1 and Unit 2 A and B turbine-driven CA pump sump pumps. The inspectors were particularly concerned about the exclusion of the turbine-driven CA pump's sump pumps from the program. These sump pumps are required to maintain water level in the sump (and ultimately the pump room) below that which might impact the turbine-driven pump's capability to perform its design basis functions. The turbine-driven CA pump sumps receive continuous component cooling water flow from the discharge of the CA pump's oil cooler, as well as condensate from the CA pump's turbine exhaust. Engineering personnel indicated that an analysis had been performed that bounded the flow into the sump; they suggested that a large factor-of-safety existed between the sump pumps' design and what their actual flow requirements would be during an event. The licensee currently declares the turbine-driven pumps inoperable (and the standby shutdown facility in degrade) when the sump pumps are inoperable. The inspectors determined that further inspection was warranted to review the licensee's justification for not including these pumps, along with the other safety-related sump pumps, in its in-service testing program. This item will be tracked as Unresolved Item (URI) 50-413, 414/99-04-03: Review of Licensee's Justification for Excluding Safety-Related Sump Pumps from the IST Program.

c. Conclusions

The licensee had appropriate procedures, plant systems and equipment, and control room indications available to aid in the detection and mitigation of flooding events. Drains, sumps, and associated equipment were in good material condition. The Catawba station was properly addressing potential generic implications from a March 1999 auxiliary feedwater pump room flood event at the McGuire Nuclear Station. An unresolved item was identified pending further NRC review of the exclusion of safety-related sump pumps from the licensee's in-service testing program.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) LER 50-413/99-007: Operation Prohibited by TS 3.4.7 Caused by an Inoperable Train of RHR due to Inadequate Work Sequencing

Initially discussed in Inspection Report 50-413,414/99-03, this LER concerns a non-compliance with TS 3.4.7 for approximately 28 hours while Unit 1 was in Mode 5 with RHR loop A in operation. Specifically, while in Mode 5, TS 3.4.7 requires one RHR loop be in operation, and either one additional RHR loop operable or the secondary side water level of at least two steam generators (S/Gs) be greater than or equal to 12 percent narrow range. (This TS requires immediate action be taken to restore a second RHR loop to operable status or the required S/G secondary side water levels to within limits.) The subject non-compliance was due to secondary side water levels in the S/Gs being reduced to less than 12 percent narrow range and a disabled interlock between valves 1ND-36B (RHR Train B RCS loop C outboard suction valve) and 1NI-136B (RHR-to-safety injection pump supply valve) rendering the B train of RHR inoperable. The logic for the interlock had been unknowingly affected by an unrelated safety injection system tag out that removed power from 1NI-136B; thereby preventing the realignment of RHR train B from the refueling water storage tank (via valve 1FW-55B) to its associated RCS loop by precluding the opening of valve 1ND-36B.

The non-compliance with TS 3.4.7 was identified on April 26, 1999, following solid plant crud burst activities. Without consideration of the associated valve interlock(s), the newly developed work plan directed the aforementioned safety injection system tag out to be established upon entry into Mode 5. In addition, it maintained the alignment of RHR train B to the refueling water storage tank (RWST) [1FW-55B open and 1ND-36B (along with its in-line counterpart 1ND-37A) closed] until after crud burst activities were complete.

An RCS level reduction to 17 percent pressurizer cold calibration level was in progress when operators noted that the level decrease had stopped around 58 percent. Further investigation revealed that static head differences was allowing water from the RWST to gravity flow to the RCS via RHR train B. Approximately 6,000 gallons of water was drained from the RWST before operators recognized the problem and shut 1FW-55B. However, when an attempt to realign RHR train B to RCS loop C failed [i.e., valve position of 1ND-37A indicated intermediate (determined later to be a limit switch problem) and 1ND-36B would not open], operations declared RHR train B inoperable. Subsequent investigation identified the interlock problem, resulting in power being restored to 1NI-136B and the opening of 1ND-36B.

This event had minimal safety significance, in that: (1) RHR train A remained in operation; (2) secondary side water level in two S/Gs, though below 12 percent narrow range, remained above the tubes; (3) the chemical and volume control system and RHR train B were available for core make-up and RCS heat removal via injection from the RWST; and (4) the licensee's estimate for restoring RHR flow utilizing AP1/A/5500/19, Loss of RHR System, was approximately 45 minutes (i.e.,15 minutes prior to boiling). However, this event did reflect a lack of thoroughness in planning new evolutions, which in turn revealed procedural weaknesses and a weak working knowledge of the associated valve interlocks. The effect of the associated valve interlocks and leaving RHR train B aligned to the RWST could have been realized and accounted for: (1) at the time the new work plan was developed; (2) during the safety injection system tag out process; or (3) during system alignment discussions (between operations, engineering, and regulatory compliance) prior to commencing solid plant crud burst activities on April 23, 1999.

The inspectors' review of the planned corrective actions (captured under PIP 1-C99-1497) found that they appropriately address the apparent root causes for this event. They include such activities as changing the outage sequencing ties for establishing the subject tag out; evaluating other valve interlocks, procedures, and pre-existing system tag outs for similar interlock problems; making improvements to various operating procedures to ensure RHR operability and TS compliance; and providing appropriate training to the work groups involved. Concerned with the potential safety impact that maintenance could have on the many interlocked RHR interface valves, the inspectors also confirmed that the licensee's post-maintenance processes ensure interlock integrity is restored. Accordingly, this Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. It is identified as NCV 50-413/99-04-04: Non-Compliance With TS 3.4.7 due to Inoperable RHR Train.

O8.2 (Closed) Inspector Follow-up Item (IFI) 50-413,414/97-08-03: Overtime Control Program Limitations.

This item was opened to allow for a review of the licensee's program for monitoring and controlling the use of overtime by persons performing work on safety-related equipment. The inspectors reviewed Nuclear System Directive (NSD) 200, Overtime Control, Revision 6, to determine if enhancements to administrative controls had been made since the item was opened. The inspectors determined that more restrictive controls had been incorporated into the procedure to ensure that fitness-for-duty assessments were made within four hours of the onset of overtime.

The inspectors performed a timesheet review to identify instances whereby overtime limits had been exceeded. The timesheets of 34 maintenance employees were reviewed for the period between April 19 and May 16, 1999. The inspectors identified a violation of TS 5.2.2, in that overtime limits were exceeded without authorization on nine occasions involving four employees performing maintenance activities on safety-related plant equipment. Because of the number of unauthorized uses of overtime, the inspectors concluded that the violation was not an isolated case of non-compliance. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP 0-C99-2940. The violation is the first example of the licensee's failure to follow the requirements of TS 5.2.2 and it is identified as NCV 50-413,414/99-04-05: Failure to Comply With Overtime Requirements Specified in TS 5.2.2.e. The inspectors were not aware of any equipment problems or adversely impacted plant operations as a result of the unauthorized use of overtime. The licensee indicated that a management tool is being considered by supervisory staff to assist them in monitoring the work hours of their employees, thereby enhancing management oversight of overtime.

Technical Specification 5.2.2.e requires the licensee to include controls in administrative procedures such that individual overtime shall be reviewed monthly by the Station Manager or his designee to ensure that excessive hours have not been assigned. The licensee's administrative procedure (NSD 200) required the performance of monthly audits of overtime authorization sheets to ensure that (1) they were being completed as required by NSD 200 and (2) overtime work was not excessive. The inspectors verified that these audits were being performed and documented in memoranda to the Human Resources Manager. The audits were limited to reviews of authorized work hour extension forms and did not involve a review of timesheets to determine the extent of overtime usage. Since the inspectors determined that overtime was being used without the required documented authorization, the inspectors determined that station management's review of overtime was not adequate to ensure that assigned overtime (whether authorized or not) was not excessive. The inspectors discussed this observation with station management. The licensee agreed that the reviews did not include all assigned overtime and initiated a PIP to address the concern. This violation of TS 5.2.2.e requirements, is a Severity Level IV violation and is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP 0-C99-3281. It is identified as example number two of NCV 50-413,414/99-04-05: Failure to Comply With Overtime Requirements Specified in TS 5.2.2.e.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on the Conduct of Maintenance and Surveillance Activities (62707, 61726)

The inspectors observed all or portions of the following maintenance and surveillance activities:

- IP/0/A/3091/001, Revision 023, Calibration Procedure For WZ Groundwater Drainage System

- IP/0/B/3091/003, Revision 014, Calibration Procedure For WZ Groundwater Drainage System
- MP/0/A/7150/016A, Revision 026, Centrifugal Charging Pump Corrective Maintenance
- PT/1/A/4200/007B, Revision 50, Centrifugal Charging Pump 1B Test
The above maintenance and surveillance activities were generally conducted with proper adherence to procedures and appropriate adherence to equipment calibration and radiation protection requirements.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER 50-413/99-002: Three Residual Heat Removal Valves Did Not Meet Their Engineered Safety Features Response Time Requirement due to a Procedural Deficiency

As previously discussed in Inspection Report 50-413,414/99-01, the licensee determined on February 25, 1999, that the surveillance test procedures associated with RHR valves 1(2)ND-26 and -60, RHR Heat Exchanger (HX) A and B Outlet Control Valves, and valves 1(2)ND-27 and -61, RHR HX A and B Bypass Control Valves, referenced incorrect engineered safety feature (ESF) response time criteria. This discrepancy was identified during a programmatic review of ESF response time test criteria in the UFSAR Table 7-15. The UFSAR table specified a safety injection response time of 12 seconds (normal power). However, the ESF test procedures indicated that response time criteria for these valves were not applicable. The ASME Code, Section XI, valve stroke (IWV) tests for these valves were used to implement the surveillance requirements, and these IWV test procedures incorrectly specified 15 seconds as the response time acceptance criterion. As a result, the licensee failed to recognize that three valves (1ND-27, 1ND-60 and 2ND-26) did not meet the 12-second ESF response time criterion during IWV tests performed in the Unit 1 End-Of-Cycle (EOC) 10 and Unit 2 EOC 9 outages and actions to correct unacceptable valve stroke times were not taken. The licensee determined that these valves had, at some point been in their non-accident positions since the unrecognized test failures occurred and were, therefore, inoperable during those times. The licensee immediately verified that all the valves, including those that failed the stroke time tests, were in their accident positions and actions were taken to administratively control the valves in their accident positions until (1) procedure changes could be completed to correct the errors and (2) response time testing for the three valves with excessive stroke times could be performed to the correct acceptance criteria. The inspectors reviewed the corrective actions delineated in LER 50-413/99-002, as implemented in PIP 0-C99-0747, and found them to be satisfactory. Valve response times for inservice tests performed in April 1999 for valves 2ND-26, 1ND-27, and 1ND-60 were satisfactory.

The Improved Technical Specification (ITS) 3.3.2 and UFSAR Table 7-15 specify the maximum response times for various engineered safety features components. For containment pressure-high safety injection, the maximum response time is 12 seconds when normal offsite power is available. In addition, TS Table 3.3-5 (where the ESF response times were listed prior to implementation of ITS) had always specified this response time as 12 seconds. Neither of the two test procedures which were used to verify the response time of the above valves (i.e., PT/1(2)/A/4200/013D, ND Valve

Inservice Test and PT/1(2)/A/4200/009A, Auxiliary Safeguards Test Cabinet Periodic Test) had never specified the 12 second response times. This failure to adequately conduct TS required surveillance testing is a Severity Level IV violation that is being treated as a NCV, consistent with Appendix C of the NRC Enforcement Policy. It is identified as NCV 50-413,414/ 99-04-06: Inadequate Surveillance Testing of ESF Response Times Caused by Deficient Test Procedures.

M8.2 (Closed) LER 50-413/97-012: RTD and Incore Thermocouple Cross Calibrations Being Performed Inconsistent with Technical Specification Requirement

On December 31, 1997, the licensee determined that on four occasions, compliance with former TS 3.3.2, Table 3.3-3, Functional Unit 18.c, Low-Low T-average (Tavg), P-12 [now in ITS 3.3.2, Table 3.3.2-1, Function 8.c, Tavg - Low Low, P-12] was not maintained. These four incidents occurred during refueling outages 1EOC8, 1EOC9, 2EOC7 and 2EOC8 when IP/1(2)/A/3222/095, Procedure for RTD and Thermocouple Cross Calibration by AMS, was performed. Former TS 3.3.2, Table 3.3-3 required a minimum of three channels of Low-Low Tavg, P-12 interlock [nominally set at 553 degrees Fahrenheit (F) RCS average temperature (Tavg)] be operable in Modes 1-3. Table 3.3.-3 Action 20 required, with less than the minimum channels operable, that plant personnel determine by observation of the associated permissive status light(s) that the P-12 interlock is in its required state for the existing plant condition within one hour or apply Specification 3.0.3. During the four occasions mentioned, all four channels of Tavg were taken out of service simultaneously while in Mode 3, and the interlock was not observed to be in its required state nor was it recognized by the licensee that a TS 3.0.3 condition existed. The licensee generated PIP 0-C98-0567 to track its investigation of this issue.

The licensee determined that a similar event had happened on April 9, 1990, in which an unexpected ESF actuation occurred during performance of procedure IP/1/A/3231/01, Incore Thermocouple and RTD Cross Calibration Testing. The licensee documented this ESF actuation with LER 50-413/90-25, which was the subject of NRC Violation 50-413/90-09-01 for an inadequate test procedure. During that test, but unrelated to the ESF actuation, the licensee identified that all four channels of Tavg had been inoperable simultaneously; however, they were returned to service within one hour and a TS 3.3.2 non-compliance was avoided. In order to prevent potential non-compliances with TS 3.3.2, and as a response to the issued NRC violation for the ESF actuation, a commitment was generated by the licensee to modify the testing procedure to ensure that only one channel of Tavg would be removed from service at a time.

In 1995, a new method for performing the cross-calibration procedures became available, which provided faster data acquisition and analysis. This new method was developed into new procedures and the older procedures were deleted. During this transition, the 1990 commitment to remove only one channel of Tavg from service at a time was dropped. Between March 1995 and April 1997 during refueling outages 1EOC8, 1EOC9, 2EOC7 and 2EOC8, the new cross-calibration procedures were performed, which simultaneously removed all four Tavg channels from service without plant personnel realizing the need to perform a P-12 status verification within one hour or enter TS 3.0.3.

The licensee determined the root cause of this issue to be an inadequate process for identifying commitments. As a result, its corrective actions were focused solely on the improvements to the commitment management process. This suggested that the licensee relied on a commitment tracking system as the principle barrier to prevent a TS non-compliance in this case. The inspectors questioned the roles of operations personnel during these tests and whether or not they were aware that four protective channels of Tavg had been removed from service when required to be operable by TS. The inspectors identified that the test procedures included signed steps notifying control room operators that all four channels were being placed in the test condition. Licensee management indicated that, although the test procedures notified control room personnel of the configuration change, the licensee has shifted the focus of maintaining TS compliance from the control room to the work control center (WCC). The licensee normally has continuous manning of the WCC by a licensed senior reactor operator. The inspectors concluded that operations performance during these tests was deficient in that control room personnel neither drew the nexus between the configuration change and TS requirements, nor did they notify WCC personnel. This aspect was not developed in the licensee's root cause determination, which the inspectors concluded was narrowly focused.

In assessing the regulatory significance of this event, the inspectors determined that the LER lacked clarification in two areas. The LER mentioned that the potential to violate TS 3.0.4 existed in that the test was conducted at three different temperature plateaus: 350, 450, and 530 degrees F and all four Tavg channels may have been removed from service before heatup to 350 degrees (Mode 3) was achieved. TS 3.0.4 stated entry into an operational mode or other specified condition shall not be made when the conditions for the limited condition for operation are not met and the associated action requires a shutdown if they are not met within a specified time interval. Because at least three channels of T-avg were required to be operable in Mode 3, the inspectors questioned whether a TS 3.0.4 violation had occurred since the LER did not further address specific incidents of this potential non-compliance. The inspectors' review of documents related to the tests from the four subject refueling outages determined that it was inconclusive as to whether a TS 3.0.4 violation had actually occurred. This was because it was indeterminate as to whether the channels were placed in test prior to or after a heatup to Mode 3 conditions. This was based on the fact that the licensee did not record actual times that the channels were removed from service in its procedures or in its Technical Specification Action Item Log (TSAIL) program. The licensee has since adopted the practice of annotating in procedures the actual times that steps are completed. [The failure to make TSAIL entries for the inoperable channels is the subject of the enforcement action discussed in the paragraph below.]

The second area that was not developed in the LER was whether or not TS 3.0.3 was violated. The inspectors were provided with data obtained during the RTD cross-calibration testing. This data suggested that the four channels of Tavg were out of service for each iteration of the tests for little more than an hour. The inspectors concluded that the licensee did not violate TS 3.0.3. The inspectors were unable to determine the exact times that TS 3.3.2, Action 20 was entered for three of the outages because licensee personnel failed to make Technical Specification Action Item Log (TSAIL) entries for the inoperable Tavg channels. Operations Management Procedure (OMP) 2-29, TS Action Item Log, stated in Section 7.1, item D, that all inoperabilities shall be logged in TSAIL. The failure to log TSAIL entries for each temperature plateau when all four channels of Tavg were inoperable is a Severity IV violation that is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation was added to the licensee's corrective action program under PIP 0-C97-4330.

It is identified as NCV 50-413,414/99-04-07: Failure to Make Technical Specification Action Item Log Entries for Inoperable Tavg Protective Channels.

The inspectors' concerns about the LER quality were discussed with licensee management who acknowledged the noted deficiencies as areas of improvement in LER development.

Finally, the inspectors reviewed electrical wiring diagrams and the test procedures to determine whether simultaneously calibrating all four channels presented a safety challenge to the plant, specifically with respect to the P-12 interlock and its impact on the steam dump system. The purpose of the low-low T-average, P-12 interlock is to remove the arming signal to the steam dump system to prevent an excessive cooldown of the RCS. The inspectors determined that placing all four of the T-average channels in the test position would not alter the required two-out-of-four logic, which would still block steam dump valve actuation as needed. Based on this determination, the inspectors concluded that the licensee's current cross calibration methodology, which still removes all four channels of Tavg from service simultaneously, was safe. To address the TS 3.3.2 Action 20 compliance issue, precautions have been added to the test procedure to ensure that the interlock is verified to be in its required state within one hour. This LER is closed.

M8.3 (Closed) Unresolved Item (URI) 50-413,414/98-08-01: Failure to Establish RPS and ESFAS Trip Setpoints in Accordance with TS Limits.

This URI was opened pending further NRC review of the licensee's ESFAS and RPS setpoint calibration practices and procedures. The NRC completed its review of this issue and determined that the licensee practices were not in compliance with TS Tables 2.2-1 and 3.3-4. This non-compliance with the TS constituted a violation of minor significance and is not subject to formal enforcement action.

The licensee has initiated corrective action to change the trip setpoint values specified in ITS to nominal values, thereby rendering their calibration procedures and practices in compliance with ITS requirements. This corrective action is documented in station PIP 0-C98-1186. The TS amendment request was submitted to the NRC on March 25, 1999, and is currently under review by the NRC. The URI is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Resolution of Technical Issues

a. Inspection Scope (37550)

The inspectors reviewed the extent and quality of engineering involvement in the resolution of technical issues identified in the previous year. These issues were documented in PIPs. This review included an assessment of engineering's understanding of plant design as demonstrated by the investigation and resolution of identified problems.

b. Observations and Findings

The technical issues described in approximately 30 PIPs that were reviewed were generally resolved effectively. The problem descriptions and relationship to the system design function and required operability evaluations demonstrated an appropriate understanding of plant design. Operability evaluations were generally conservative and focused on system safety function.

There were several PIPs associated with repeated failures of Valcor solenoid valves in the containment valve injection system to properly operate or indicate position during periodic testing. This trend was initially identified in June 1998 (PIP 0-C98-2141). Engineering involvement in the root cause investigation has been ongoing and included technical involvement by the vendor and an independent investigation contractor. The investigation has been hampered by the inability to repeat the failures in controlled conditions and to isolate the event when the failures occur. Interim actions were to increase valve testing and to provide guidance for isolation of the equipment following failure. Although not resolved, this issue demonstrated engineering's plant support in the resolution of a technical issue. The quarterly system health report described the issue and provided information on the current status to licensee management.

The inspectors noted one instance of lack of timeliness in addressing an issue with risk importance. In PIP 0-C99-0606, an action item had been assigned to operations to revise the surveillance procedures for daily determination of the total accumulated RCS leakage. The total accumulated RCS leakage value included identified leakage plus unidentified leakage plus reactor coolant pump seal leak off. This value was limited to a maximum of 20 gallons per minute (gpm), to ensure the operability of the standby shutdown facility (SSF) standby makeup pump. While the SSF was not classified as safety-related and was not addressed in the TS, it was shown by the PRA to have risk importance. However, the PIP action item had not scheduled the surveillance procedure revisions to be completed promptly, but instead had scheduled them to be completed in six months. Licensee personnel told the inspectors that the PIP computer automatically allowed six months to accomplish action items. In response to this issue, licensee management initiated PIP 0-C99-2935 and also initiated prompt changes to the surveillance procedures. In addition, the licensee verified that the total actual RCS leakage had remained less than 12 gpm on each unit during 1999.

c. Conclusions

Engineering involvement in the analysis and resolution of technical issues was generally effective. Analyses of technical issues and evaluations of operability demonstrated an appropriate understanding of plant design.

E2.2 Design Changes and Modifications

a. Inspection Scope (37550)

The inspectors reviewed design changes and modifications installed in 1998 and 1999 to determine if the plant design was maintained consistent with the original design bases and modifications were implemented in accordance with regulatory requirements. This review included the adequacy of design development, post-modification testing, independent review, 10 CFR 50.59 safety evaluations, and updating of the design and licensing bases. The inspectors also inspected the completed modifications in the plant.

b. Observations and Findings

In the 11 modifications reviewed, post-modification testing was adequate to verify the function of the equipment modified. Design requirements were translated correctly into vendor specifications. Plant design was maintained consistent with the design bases and the design and licensing bases were updated to reflect the changes. Several calculations associated with modifications were reviewed and were verified to be revised consistent with the design change. Where applicable, affected procedures and drawings were revised. Changes to the UFSAR related to modifications were entered into a database of approved changes awaiting the next UFSAR revision submittal. The station 10 CFR 50.59 procedure required review of this database in the development of safety evaluations.

The inspectors noted examples of good engineering analyses, including an evaluation of the need for better fast transfer breakers to increase the reliability of offsite power to safety-related busses. The fact that a problem was identified and a solution was designed and implemented demonstrated a management commitment to resolve issues and increase reliability.

Inspectors also noted a good practice of post-implementation reviews. The review of a Unit 1 modification (CN-11391) to provide an assured air supply to the auxiliary feedwater flow control valves identified ALARA improvements which were then implemented in the schedule for a similar Unit 2 modification.

However, inspectors noted a lack of documented analysis on the following modifications related to EDG replacement batteries and non-safety offsite power supply breakers:

1) Modification NSM-21388, which installed new Unit 2 safety-related EDG batteries, did not include sufficient documented analysis for a reviewer to conclude that the batteries were seismically qualified. The modification stated that the new cells were seismically qualified by similarity to the old cells, which had been seismically tested. However, the analysis did not specifically address cell structure differences; i.e., the new cells were heavier and taller and had a thinner jar wall. These differences could potentially reduce the ability of the new cells to withstand a seismic event. Additionally, the analysis did not address potential aging effects on the seismic qualification. The analysis did note two offsetting factors: 1) the old batteries had passed the seismic testing with substantial margin, and 2) the seismic testing was conducted without cell spacers, which the licensee had since installed to increase the seismic rigidity of the batteries.

   An additional element of the battery qualification not specifically addressed was the battery lifetime. The licensee's commercial grade item evaluation for NSM-21388 stated that the new EDG batteries had an expected life of 20 years. However, inspector review of the manufacturer's information on the batteries noted that the 20-year expected life was based on operation at a temperature of 77 degrees F. The inspectors noted that temperatures in the EDG room were higher than 77 degrees F, which would result in a shorter expected life than 20 years. The licensee stated that their battery testing program was adequate to detect expected battery deterioration due to aging before it would fall below the required capacity. In response to inspector questions, the licensee initiated PIP 0-C99-2939 to address documentation deficiencies related to the seismic qualification and testing to identify aging degradation of the new EDG batteries.

2) Modification NSM-21379 installed faster non-safety offsite power supply circuit breakers to improve the reliability of offsite power. However, the inspectors noted that the faster circuit breakers needed a higher short-circuit current interrupting capability, and that factor was not assessed within the design package. In response to inspector questions, licensee engineers provided an analysis which showed that the new circuit breakers had adequate interrupting capability.

c. Conclusions

Design changes and modifications reviewed were implemented in accordance with regulatory guidance. The design and licensing bases were appropriately updated to reflect plant changes. The inspectors noted instances of a lack of documented analysis to support design changes, however, the licensee provided sufficient information to the inspectors to support that the modified equipment was within the design basis.

E2.3 Engineering Work Management and Backlogs

a. Inspection Scope (37550)

The inspectors assessed the management and backlogs of engineering work.

b. Observations and Findings

The inspectors noted that the licensee had initiated improvements in engineering work management in early 1999. These included structured daily meetings and additional management reports. The inspectors attended one daily meeting and reviewed many of the management reports. Inspectors noted that the daily meeting and reports reviewed were well organized and demonstrated good internal communication of issues and status. To effect further improvements, the licensee was implementing plans for a computerized engineering work management process to be installed early next year.

The inspectors noted that engineering work backlogs of design changes and corrective action items were being maintained at reasonable levels. Backlogs of needed drawing changes had been substantially reduced and overdue drawing changes, which had been a problem, had been essentially eliminated.

c. Conclusions

The licensee demonstrated good management of engineering work and control of work backlogs. Substantial improvements in this area had been made in 1999 and more were planned.

E7 Quality Assurance in Engineering Activities

E7.1 Licensee Assessments and Audits of Engineering Activities

a. Inspection Scope (37550)

The inspectors reviewed licensee assessments and audits of engineering activities performed during the last year. The inspectors assessed the quantity and quality of the assessments and audits and their findings. In addition, the inspectors verified that the findings had been appropriately entered into the corrective action system.

b. Observations and Findings

The inspectors reviewed 12 assessments and audits that were completed during the last year and one that was in progress. Two comprehensive efforts were performed primarily by offsite personnel: (1) a self-initiated technical audit of the transformer yard, and (2) an assessment of the surveillance requirements in the ITS and Selected Licensee Commitments and their related implementing procedures. During the performance of the assessments and audits, the licensee identified many findings, some of which resulted in LERs. For each of the findings, the licensee identified corrective actions and recommendations for improvements. The other self-assessments, which were generally focused on particular performance areas, also included worthwhile findings and recommendations. The findings from the audits and assessments were appropriately entered into the corrective action system. In addition, the inspectors noted that the licensee was planning to begin a large audit of engineering within a month, to be performed primarily by offsite personnel.

c. Conclusions

The quantity and quality of licensee audits and assessments of engineering activities during the last year was good. The audits and assessments identified many deficient conditions which were appropriately entered into the corrective action system and also identified many recommended improvements.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Inspector Followup Item (IFI) 50-413,414/98-01-04: Assess the Licensee's Dose Analysis Calculation For ECCS Leakage Outside Containment

This IFI was opened to (1) address an ongoing revision of the licensee's offsite dose analysis, and (2) address inconsistencies between the licensee's current post-accident dose analysis of record and a statement in the UFSAR, Section 15.6.5.3, indicating that no credit was taken in the analysis for iodine removal by the safety-related auxiliary building ventilation (VA) system carbon filters. The licensee, in fact, does credit the VA system for processing the maximum credible emergency core cooling system leakage outside containment (caused by a postulated pump seal failure). The inconsistency between the UFSAR statement and what was assumed in design calculations had been identified by the licensee in 1995 and documented in PIP 0-C95-1938. The licensee was planning to correct the UFSAR when its ongoing revision of offsite dose calculations was completed. The schedule for completion, originally planned for 1996, has slipped and is now projected for the end of 2000. The licensee has recognized the need to correct the

UFSAR and now plans to delete the discrepant sentence in Section 15.6.5.3 prior to that time.

The inspectors reviewed the design basis of the VA system, as described in design basis document CNS-1577.VA-01-0001, Auxiliary Building Ventilation System (VA) Design Basis Specification; and TS 3.7.12 and associated bases. These documents described the iodine-removal function of the VA system. The inspectors also reviewed the Catawba Safety Evaluation Report (NUREG 0954 dated February 1983), Section 15.4.5.2, which described the maximum credible ECCS leakage outside containment and the fact that this leakage would be processed through an engineered safety feature-grade emergency filtration system (the VA system), thus limiting the release of untreated radioactive materials to the environment. All of these statements were inconsistent with the statement in the UFSAR and supported the licensee taking credit for the iodine removal function in its offsite dose calculations.

10 CFR 50.71(e) requires, in part, that licensees shall update periodically the final safety analysis report (FSAR) to assure that the information included in the FSAR contains the latest material developed. The licensee's failure to include the latest information pertaining to crediting the VA system for its iodine-removal capability in offsite dose calculations was contrary to that requirement. However, this failure did not have a material impact on safety or licensed activities. The inspectors also determined that the licensee's plans to complete its revision of the offsite dose calculations are in its corrective action program under PIP 0-C95-1938. Accordingly, this Severity Level IV violation is being treated as a NCV, consistent with Appendix C of the NRC Enforcement Policy. It is identified as NCV 50-413,414/99-04-08: Failure to Update FSAR to Reflect the Iodine Removal Function of the VA System.

IV. Plant Support

P1 Conduct of Emergency Preparedness (EP) Activities

P1.1 Annual EP Exercise - General Comments (71750)

The licensee conducted its annual EP exercise on June 9, 1999. The inspectors observed activities from the plant-specific control room simulator, the Technical Support Center, and the Emergency Operations Facility (EOF). The exercise scenario involved a damaged spent fuel assembly and ultimately a loss of both 4160 volt essential electrical busses. No excessive offsite radiological effluent releases were simulated. The maximum emergency action level challenged during this event, by plan, was a Site Area Emergency. The inspectors concluded that overall licensee performance during the exercise was adequate with the appropriate focus on maintaining plant and personnel safety. Minor items for management consideration were noted in the area of command and control in the EOF. These items were discussed with and acknowledged as areas of improvement by licensee management after their own drill critique following the exercise.

V. Management Meetings

X1 Exit Meeting Summary

The inspector presented the inspection results to members of licensee management at the conclusion of the inspection on July 22, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

X2 Escalated Enforcement Results

On July 12, 1999, a predecisional enforcement conference regarding EA Case Number 99-094 was held in the regional office with the licensee in attendance. At this conference, Apparent Violation (EEI) 50-413,414/99-10-01, involving the inoperability of the standby shutdown system, was discussed.

On July 22, 1999, a Notice of Violation (NOV) was issued. Based on this NOV being issued, EEI 50-413,414/99-10-01 is closed and the violation identified in the NOV will be tracked as VIO EA 99-094-01013: Failure to Comply with Technical Specification 3.7.13 with the Standby Shutdown System Inoperable due to Mispositioned Breakers.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Beagles, Safety Assurance Manager
M. Boyle, Radiation Protection Manager
S. Bradshaw, Safety Assurance Manager
G. Gilbert, Regulatory Compliance Manager
R. Glover, Operations Superintendent
P. Grobusky, Human Resources Manager
P. Herran, Engineering Manager
R. Jones, Station Manager
R. Parker, Maintenance Superintendent
G. Peterson, Catawba Site Vice-President
F. Smith, Chemistry Manager

NRC

C. Casto, Region II

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-413,414/99-04-01	URI	VA System Potentially Inoperable due to Premature Opening of ECCS Pump Room Ventilation Boundary Doors During Pump Replacement (Section O1.2)
50-413,414/99-04-02	NCV	TS 3.5.2.2 Non-Compliance Due to Failure of Surveillance Procedure to Require Position Verification of Valves ND27 and ND61 Every 31 Days (Section O2.1)
50-413,414/99-04-03	URI	Review of Licensee's Justification for Excluding Safety-Related Sump Pumps from the IST program (Section O2.2)
50-413/99-04-04	NCV	Non-Compliance With TS 3.4.7 due to Inoperable RHR Train (Section O8.1)
50-413,414/99-04-05	NCV	Failure to Comply With Overtime Requirements Specified in TS 5.2.2.e. (Section O8.2)
50-413,414/99-04-06	NCV	Inadequate Surveillance Testing of ESF Response Times Caused by Deficient Test Procedures (Section M8.1)
50-413,414/99-04-07	NCV	Failure to Make Technical Specification Action Item Log Entries for Inoperable Tavg Protective Channels (Section M8.2)
50-413,414/99-04-08	NCV	Failure to Update FSAR to Reflect the Iodine Removal Function of the VA System (Section E8.1)
EA 99-094-01013	VIO	Failure to Comply with Technical Specification 3.7.13 with the Standby Shutdown System Inoperable for Nearly Two Weeks (Section X2)

Closed

50-413/99-007	LER	Operation Prohibited by TS 3.4.7 caused by an Inoperable Train of RHR due to Inadequate Work Sequencing (Section O8.1)
50-413,414/97-08-03	IFI	Overtime Control Program Limitations (Section O8.2)
50-413/99-002	LER	Three Residual Heat Removal Valves Did Not Meet Their Engineered Safety Features Response Time Requirement due to a Procedural Deficiency (Section M8.1)

50-413/97-012	LER	RTD and Incore Thermocouple Cross Calibrations Being Performed Inconsistent with Technical Specification Requirement (Section M8.2)
50-413,414/98-08-01	URI	Failure to Establish RPS and ESFAS Trip Setpoints (Section M8.3)
50-413,414/98-01-04	IFI	Assess the Licensee's Dose Analysis Calculation For ECCS Leakage Outside Containment (Section E8.1)
50-413,414/99-10-01	EEI	Standby Shutdown System Inoperable in Excess of TS Limits Due to Mispositioned Circuit Breakers (Section X2)

LIST OF ACRONYMS USED

ALARA - As Low As Reasonably Achievable
ASME - American Society of Mechanical Engineers
CA - Auxiliary Feedwater
CFR - Code of Federal Regulations
EA - Enforcement Action
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EEI - Escalated Enforcement item
EOC - End-of-Cycle
EOF - Emergency Operations Facility
EP - Emergency Preparedness
ESF - Engineered Safety Feature
ESFAS - Engineered Safety Feature Actuation System
F - Fahrenheit
FSAR - Final Safety Analysis Report
GPM - Gallons Per Minute
HX - Heat Exchanger
IFI - Inspector Followup Item
IOE - Industry Operating Experience
IST - Inservice Testing
ITS - Improved Technical Specification
IWV - ASME Valve Stroke Testing
LCO - Limiting Conditions for Operation
LER - Licensee Event Report
NCV - Non-Cited Violation
NOED - Notice of Enforcement Discretion
NOV - Notice of Violation
NRC - Nuclear Regulatory Commission
NSD - Nuclear System Directive
NV - Chemical and Volume Control
OMP - Operations Management Procedures
PIP - Problem Identification Process
PM - Preventive Maintenance
PRA - Probabilistic Risk Assessment
RCS - Reactor Coolant System
RN - Nuclear Service Water

RWST	-	Refueling Water Storage Tank
RHR	-	Residual Heat Removal
RTD	-	Resistance Temperature (or Thermal) Detector
RWST	-	Refueling Water Storage Tank
S/G	-	Steam Generator
SLC	-	Selected Licensee Commitment
SR	-	Surveillance Requirement
SSF	-	Standby Shutdown Facility
Tavg	-	RCS Average Temperature
TS	-	Technical Specification
TSAIL	-	Technical Specification Action Item Log
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VA	-	Auxiliary Building Ventilation System
VIO	-	Violation
WCC	-	Work Control Center