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 50-413/99-07, 50-414/99-07

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 four regional inspectors. [Applicable template codes and the assessment for items inspected are provided below.]

Operations

- The licensee's preparations for cold weather were initiated in a timely manner and in accordance with their administrative program. (Section O2.1; [POS - 1C, 2A, 2B])

- A non-cited violation was identified for failure to verify correct breaker alignment and indicated power availability for each offsite circuit required by Technical Specification 3.8.1 with the 2B emergency diesel generator inoperable on July 27, 1999. (Section O8.1; [NCV - 1A])

- Licensed operators did not properly implement plant procedures and Technical Specification requirements associated with removing the 1B emergency diesel generator (and hence the 2B emergency diesel generator) from service. Similar operator performance weaknesses have been noted in the past related to removing Technical Specification equipment from service. These human performance weaknesses have not been developed in the licensee's root cause determinations for the associated reportable events. (Section O8.1; [NEG - 1A, 5B])

Maintenance

- Emergency diesel generator 1B experienced successive test failures following maintenance on November 16, 1999. To allow further troubleshooting and repair efforts to continue with Unit 1 operating in Mode 1, the NRC granted a Notice of Enforcement Discretion on November 19, 1999, prior to the end of the Technical Specification allowed outage time. (Section M2.1; [NOED - 1C, 2A, 4C])

- As a result of the failures of the 1B emergency diesel generator during the week of November 15, 1999, several concerns were identified related to: procedural adherence during heim joint replacement, the common-mode failure determination process for the 1A diesel generator, and Technical Specification 3.7.8 compliance related to the B train nuclear service water system and the 2B emergency diesel generator. An unresolved item was opened to track the followup of these items. (Section M2.1; [URI - 1A, 2A, 3A])

- Inservice inspection procedures and documentation met the requirements of applicable codes and regulations. (Section M3.1; [POS - 2B])

- The NRC identified a non-cited violation concerning continued Unit 1 operation in Mode 1 with the auxiliary building filtered ventilation exhaust system inoperable for 15 hours due to the 1B charging pump room door being blocked open. The licensee event report documenting this violation contained errors related to the time the system was inoperable. (Section M8.1; [NCV - 3A, 3B, 5B])

- A non-cited violation was identified for having inadequate procedures to conduct Technical Specification surveillance testing of the overpower delta temperature circuitry and the containment isolation Phase B signal actuation of the manual purge and exhaust isolation function. These issues were initially identified by the licensee in 1996, but they failed to recognize them as Technical Specification violations until 1999. (Section M8.2; [NCV - 2B, 4B, 5B])

- A non-cited violation with two examples was identified for failing to take adequate corrective actions to resolve Technical Specification surveillance requirement discrepancies. The first example related to a requirement to manually actuate the auxiliary building filtered ventilation exhaust system when it can only be actuated automatically. (Section M8.2; [NCV - 4C, 5A, 5C])

Engineering

- The licensee's exclusion of safety-related sump pumps from the in-service testing program was determined not to be a violation of NRC requirements. These pumps were conservatively classified as Quality Class C (American Society of Mechanical Engineers Class 3) components by the licensee. (Section E8.1; [MISC - 2B, 4C])

- Catawba Unit 1 and Unit 2 designs make each unit susceptible to a reactor coolant system draindown/loss of emergency core cooling system pump common suction header event. However, established administrative controls and corrective actions from a previous draindown event are in place to prevent such an incident from occurring. (Section E8.2; [MISC -1C, 4A, 5C])

- A non-cited violation with two examples was identified for failing to take adequate corrective actions to resolve Technical Specification surveillance requirement discrepancies. The second example involved a failure to request an amendment to Technical Specification Surveillance Requirement 3.6.16.2 to correct the acceptance criteria for the containment annulus drawdown time in a timely manner. (Section E8.3; [NCV - 4C, 5A, 5C])

- A non-cited violation was identified for failure to install an interlock on the containment spray and residual heat removal sump pumps as described in the Updated Final Safety Analysis Report. (Section E8.4; [NCV - 4A, 5A])

- A non-cited violation was identified for inadequate testing of a containment valve injection water system valve which resulted in Train B of the Unit 1 system being inoperable for approximately 18 months. (Section E8.5; [NCV - 2A, 4C, 5C])

Plant Support

- The licensee was maintaining radioactive waste process systems and monitoring radiological effluents to maintain offsite doses from radioactive waste effluents as low as reasonably achievable. (Section R1.1; [POS - 1C])

- Licensee personnel were knowledgeable of radioactive material transportation requirements and procedures. Reviewed radioactive material transportation documentation met regulatory requirements. The inspector concluded that the verification and validation of vendor computer software capabilities and established quality controls on the use of the computer program were acceptable. (Section R1.2; [POS - 1C, 3B])

- The licensee was effective in reducing the total amount of solid radioactive waste generated. The volume of solid radioactive waste generated at Catawba continued to decline. (Section R1.3; [POS - 1C])

- A non-cited violation was identified for the licensee's failure to comply with 10 CFR Part 20 and licensee survey requirements for sampling the release of the turbine building sump on August 20, 1999. The licensee's control room logs reviewed during the inspection did not accurately reflect all of the communication and testing associated with liquid releases from the turbine building sump. (Section R1.4; [NCV - 1C, 1A])

- The radiation protection personnel were effectively utilizing the corrective action program to make program improvements and correct identified program deficiencies or non-compliances. (Section R7.1; [POS - 5B, 5C])

Report Details

Summary of Plant Status

Unit 1 began the inspection period at approximately 100 percent power. On November 11, 1999, a power reduction to approximately 50 percent was initiated to allow the replacement of contact fingers on motor operated disconnects 1AT and 1BT, which are associated with the main generator. Reactor power was stabilized at 50 percent on November 12, 1999. Following the completion of this work, reactor power was increased to 100 percent on November 15, 1999, where it remained for the duration of the inspection period.

Unit 2 operated at or near 100 percent power during 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, 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 Technical Specifications (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 (TSAIL) 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.

O2 Operational Status of Facilities and Equipment

O2.1 Cold Weather Protection Program Implementation

a. Inspection Scope (71714)

The inspectors reviewed administrative procedures governing the licensee's freeze protection program; reviewed work orders and work requests to determine which preparations had been completed; and performed visual inspections of equipment in the field that is particularly vulnerable to freezing conditions.

b. Observations and Findings

The inspectors reviewed the licensee's cold weather protection program, as defined by Nuclear System Directive 317, Freeze Protection Program, and discussed with cognizant engineering personnel, completed, ongoing, and planned actions to prepare vulnerable safety-related and important-to-safety equipment for adverse weather conditions. The inspectors also performed inspections of selected risk-significant level instrumentation associated with the refueling water storage tank (FWST) to verify that: (1) transmitter cubicles were dry and well-insulated; (2) cubical space heaters were functioning; and (3) insulation and heat trace installed on sensing lines were in good material condition. The inspectors also reviewed selected work orders associated with the performance of periodic maintenance and functional verification of the electrical heat trace system, area space heaters (particularly in the main steam doghouses, the nuclear service water pump house, and the standby shutdown facility), instrument box heaters, and power cubicle potential transformer space heaters to verify that these annual seasonal activities were performed.

The inspectors also verified that the main steamline doghouse curtains had been lowered to shield vulnerable equipment from freezing temperatures and retain the warmth generated by the area space heaters. Several work items to correct equipment problems identified during the programmatic checks remained outstanding at the end of the inspection period. These items were being tracked to completion by the cold weather protection program coordinator.

c. Conclusions

The inspector concluded that the licensee's preparations for cold weather were initiated in a timely manner and in accordance with their administrative program.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-414/99-005-00: Missed Emergency Diesel Generator Technical Specification Surveillance Concerning Verification of Availability of Offsite Power Sources Resulted from Defective Procedure

On July 27, 1999, the licensee determined that TS 3.8.1 (AC Sources - Operating) had not been properly implemented. TS LCO 3.8.1.Condition B required that with one emergency diesel generator (EDG) inoperable, Surveillance Requirement (SR) 3.8.1.1, be accomplished within one hour and once per eight hours thereafter. This surveillance required verification of correct breaker alignment and indicated power availability to each offsite circuit. This surveillance requirement was not performed within one hour of the 2B EDG becoming inoperable.

The 1B EDG had been declared inoperable to support planned maintenance activities on July 27, 1999. Licensed operators removed the 1B EDG from service in accordance with OP/1/A/6350/002, Revision 111, Enclosure 4.16, Removing (Returning) D/G 1B From (To) Service. Step 2.7 of this enclosure provided an option of either aligning the emergency power supply for 2EMXH, 600 volt alternating current (AC) essential motor control center, to the 2B EDG, or declaring the B train of the nuclear service water system (NSWS), auxiliary building ventilation (VA), and control room area ventilation/chilled water (VC/YC) inoperable on both units. Bus 2EMXH, normally aligned to receive emergency power from the 1B EDG, provides normal power to the above mentioned B train loads, which are shared between Unit 1 and Unit 2, and other less significant loads. With this bus not aligned to receive emergency power, these loads must be declared inoperable because of their anticipated loss of function during a loss of offsite power event. Bus 2EMXH also provides normal power to the B train NSWS swapover valves. These valves automatically align the B train NSWS pumps to the assured suction source, the standby nuclear service water pond (SNSWP), when Lake Wylie level is less than that required to support continued pump operation. Without this auto-swap function, B train NSWS is inoperable on both units. In addition to the above mentioned affected loads, the 2B EDG is rendered inoperable.

Plant operators decided to use the second procedure option by declaring the B trains of NSWS, VA and VC/YC inoperable on Unit 2 and making appropriate TSAIL entries. The operators did not recognize that the inability for NSWS pumps to swap suction to the SNSWP rendered the 2B EDG inoperable. The operators failed to declare the 2B EDG inoperable and perform SR 3.8.1.1. This oversight was recognized by the oncoming operations shift during the turnover process a few hours later. Operators immediately performed the offsite power availability verification for Unit 2, realigned 2EMXH to the 2B EDG, and documented the missed surveillance in PIP 2-C99-03033.

The licensee determined the root cause of this event to be a deficient procedure, in that the 2B EDG was not specifically listed as a component to be declared inoperable if 2EMXH was not swapped to an operable emergency power source. The inspectors observed that the 2B EDG was not listed in OP/1/A/6350/002 as a component to be declared inoperable. However, the inspectors reviewed procedure enclosure 4.16, step 2.7, and concluded that it clearly stated that the B train of NSWS should be declared inoperable. In addition, step 2.5 (which required operator initials signifying performance) stated, "Comply with action statements of TS 3.7.8 (Nuclear Service Water System)". Technical Specification 3.7.8, Nuclear Service Water System (NSWS), Condition A (one NSWS train inoperable), Required Action A.1, Note 1, stated, "Enter applicable conditions and required actions of LCO 3.8.1, 'AC Sources - Operating', for emergency diesel generator made inoperable by NSWS." The inspectors concluded that had the operators adequately followed the procedure as written, and adequately referenced TS 3.7.8, the appropriate TS actions could have been performed for the 2B EDG.

The inspectors determined that this event had minimal actual impact on plant safety because the scenario required a design basis accident with a simultaneous loss of Lake Wylie, which would require the swapover to the SNSWP. Nevertheless, the inspectors were concerned that the operators did not properly follow procedures or implement TS when removing the 1B EDG from service. Two other events (LERs 50-413/97-012 and 50-413/99-001) recently documented in inspection reports involved operators' failures to properly implement TS requirements when removing safety-related equipment from service. All of these events could have been prevented if licensed operators had adequately referenced TS requirements or followed procedures when disabling the subject equipment. Operator performance aspects have not been developed in the licensee's root cause statements for any of the above LERs. The inspectors have expressed concern to licensee management regarding this lack of development of human performance aspects of these issues.

The inspectors performed a review of Unit 1 EDG inoperabilities logged in TSAIL over an approximate two-month period and identified five more occasions in which a Unit 1 EDG was declared inoperable without the 600 volt essential motor control center being swapped, the same train Unit 2 EDG being declared inoperable, or SR 3.8.1.1 being performed for the inoperable Unit 2 EDG. These occurrences constituted additional non-compliances with TS 3.8.1, in that SR 3.8.1.1 was not performed as required. These additional examples were not specifically mentioned in the LER, although a statement was included that it was likely that other identical events of this type had occurred previously in Catawba's operating history. The inspectors concluded that the licensee's extent-of-condition review to determine additional TS non-compliances was not thorough in this case.

The licensee's failure to perform SR 3.8.1.1 for the 2B EDG within one hour of it becoming inoperable was a violation of TS 3.8.1. Accordingly, this Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. The violation is in the licensee's corrective action program as PIP 2-C99-03033. It is identified as NCV 50-414/99-07-01: Failure to Perform SR 3.8.1.1 Within One Hour of the 2B EDG Being Inoperable.

The inspectors reviewed PIP 2-C99-03033 and the associated planned correction actions. The licensee identified all procedures that removed an EDG from service. These procedures have been changed to include adding the appropriate EDG to the list of components to be declared inoperable. This completed corrective action should prevent recurrence of similar events. This LER is closed.

O8.2 (Closed) LER 50-414/99-003-(00,01): Unplanned Actuation of Engineered Safety Features Actuation System Due to "A" Steam Generator High Level Caused by Inadequate Procedural Guidance

On June 12, 1999, with Unit 2 in Mode 4 and reactor coolant system (RCS) temperature at 240 degrees Fahrenheit (F), a "P-14" engineered safety feature (ESF) actuation occurred when level in the 2A steam generator exceeded the nominal trip setpoint of 77.1 percent while control room operators were opening the 2A steam generator main steam isolation valve (MSIV). A P-14 actuation automatically trips the main turbine, isolates main feedwater, and trips the main feedwater pumps in order to protect the turbine from possible water intrusion. The automatic actions did not occur because these components were already in their actuated state due to existing plant conditions. The level had increased in the 2A steam generator after operators opened the MSIV, because a vacuum existed on the downstream side of the valve. When the MSIV was opened, the steam generator depressurized, resulting in a swell of steam generator inventory. The P-14 feature is required to be operable in Modes 1 and 2, with an exception in Mode 2 when certain main feedwater system valves are closed and deactivated. With the plant in Mode 4, this feature was not required and the P-14 ESF actuation did not impact plant operation and had no actual safety significance.

The licensee determined that the root cause of this event was that the controlling procedure (OP/2/A/6100/001, Revision 120, Controlling Procedure For Unit Startup) was inadequate to ensure a P-14 ESF actuation would not occur for the given plant conditions. Typically, the MSIVs are opened during this startup procedure before a condenser vacuum is established; however, due to the nature of this shutdown, a condenser vacuum had already been established. To prevent recurrence of this event, the licensee modified procedure OP/2/A/6100/002, Revision 120, Controlling Procedure For Shutdown, Enclosure 4.2, Unit Shutdown from Mode 3 to Mode 5, to require P-14 to be blocked.

The inspectors reviewed the procedures and interviewed operators involved with the event. The inspectors determined that another procedure (OP/2/A/6250/006, Revision 34, Equalizing Pressure Across the Main Steam Isolation Valves, Enclosure 4.5), which was referenced by the startup procedure, controlled the opening of the MSIVs. A note prior to Step 2.2 directed the operator to always use analog computer points [from the operator aid computer (OAC)] when monitoring steam pressures. The procedure instructed operators to monitor steam generator pressure and main steam header pressure and open the MSIVs when the differential pressure (dp) across the valves was less than 10 pounds per square inch differential (psid). Because of fluctuating main steam header pressure indication from the OAC, the operator performing the enclosure relied on the main steam header pressure gauge on the main control board in lieu of stopping to address the apparent problem. This gauge had an indicating range of 0-1300 pounds per square inch gauge (psig) with discreet increments of 20 psi. The operator used this indication and erroneously determined that the dp across the MSIV was less than 10 psid. The actual dp was later determined to be approximately 20 psid. The inspectors concluded that control room operators failed to follow OP/2/A/6250/006 when opening the 2A MSIV. Had this procedure been properly followed, the P-14 actuation could have been prevented. This failure to follow procedures constitutes a violation of minor significance and is not subject to formal enforcement action. After operators reduced the dp to acceptable limits, all main steam isolation valves were successfully opened without further problems. The inspectors reviewed the licensee's corrective actions described in PIP 2-C99-2428. Although these actions were focused more on enhancing the shutdown procedure to disable the P-14 feature during shutdown conditions, and not on the human performance issue, the inspectors concluded that they were adequate to prevent recurrence of this event. This LER is closed.

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/3820/004, Revision 301, Operating Checkout of Limitorque and Rotork Valve Actuators

- IP/0/A/3820/001A, Revision 007, Limitorque Actuator Testing Using The Kalsi Engineering Test Bench
- IP/0/A/3820/001, Revision 050, Limitorque Component Actuator Corrective Maintenance
- IP/1/A/3176/001B, Revision 015, Procedure for Containment Hydrogen Monitor System (VY) 92 Day Channel Calibration
- MP/0/A/7400/001, Rev. 024, Diesel Fuel Oil Injection Pump Removal, Replacement and Adjustment

The inspectors' concerns regarding the licensee's performance of procedure MP/0/A/7400/001 are discussed in detail in Section M2.1 below. For the other procedures, maintenance and surveillance activities were performed using good workmanship, proper procedural adherence, and appropriate controls for using calibrated measuring and test equipment. Appropriate radiological practices were also observed where necessary.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 1B EDG Maintenance and Subsequent Test Failures Requiring a Notice of Enforcement Discretion (NOED 99-2-003)

a. Inspection Scope (62707, 61726, 71707)

The inspectors observed portions of planned preventive maintenance on the 1B EDG and followed the licensee's activities to resolve subsequent test failures that ultimately resulted in a NOED being granted on November 19, 1999. The inspectors reviewed data recorder traces and plant computer trends for the EDG tests, observed portions of the maintenance and surveillance efforts performed on the EDG, and verified compensatory actions used by the licensee to support the NOED. The NOED allowed 48 additional hours (added to the 72 hours allowed by TS 3.8.1 for having one EDG inoperable) to facilitate repairs and testing.

b. Observations and Findings

On November 16, 1999, the licensee performed several maintenance activities associated with the 1B EDG, including the replacement of eight heim joints (ball bearing-in-socket type threaded rod joints) used to connect the two diesel engine fuel racks to fuel pumps associated with each of the 16 fuel cylinders. The fuel racks are connected to the mechanical governor (which receives input from an electronic governor) and connected to the individual cylinders' fuel pumps to regulate the amount of fuel flow to the engine. For ease of lubrication, the licensee replaced these eight older heim joints with newer parts that had grease fittings. The other eight cylinders' joints had been replaced with the newer type over the previous several weeks, along with those for all 16 fuel cylinders in the 1A EDG.

During a subsequent post-maintenance operability test of the 1B EDG, its generator output breaker unexpectedly tripped open on overcurrent while operators were attempting to increase EDG load from approximately 2500 kilowatts (KW) to 4000 KW. Plant computer traces indicated that, just prior to the breaker opening, the EDG load suddenly increased to 7000 KW, after cycling briefly between 4200 KW and 3300 KW (approximate figures) while load demand held constant at 4000 KW. The licensee determined that some of the eight new heim joints had sticking bearings, which caused the associated fuel racks to bind. They postulated that the fuel racks were eventually able to produce enough torque to free the stuck joint bearings. The licensee concluded that the sudden opening of the fuel racks caused the sharp load increase. A second operability test was conducted on November 17, 1999, with no problems. This seemed to support the licensee's supposition that the heim joints were now unrestricted in their required range of motion. The licensee then exercised and inspected all of the heim joints on the engine, replaced three that were thought to be vulnerable to future problems, and tested the EDG a third time.

During this third test on November 18, 1999, the EDG output breaker again tripped open on overcurrent, this time while the operator was reducing load and attempting to maintain the power factor at 0.95 lagging as required by the test procedure. The breaker opened while the operator was manipulating the speed and voltage control switches used to adjust diesel engine load and power factor. Data recorder traces indicated that there was an actual sudden increase in current (as measured for all three phases), and a sudden drop in power factor to below 0.8 lagging before the 50 DGT overcurrent relay actuated. The licensee performed more troubleshooting and found that the voltage control pushbutton, used to decrease the power factor, was sticking slightly such that a demand signal was still present fractions of a second after the pushbutton was released. Additionally, there were some inconsistencies in the measured output resistance for a power-driven potentiometer (PDP) in the voltage control circuitry. This suggested that the wiper in the potentiometer had intermittent dirt or dust buildup and was not producing a continuous signal across its entire range of control. The licensee replaced both the pushbutton and the PDP and performed another functional test of the diesel. During this fourth test, late on November 18, 1999, the output breaker again tripped open on overcurrent; this time without the operator manipulating either pushbutton for load or power factor adjustments. As with the third test, data indicated that there was an actual current transient that preceded the breaker trip. However, unlike the first test failure on November 16, 1999, there were no unexpected load swings that preceded the final two failures. Thus, the licensee was confident that the first failure on November 16, 1999, was likely associated with the heim joints; and that the final two failures were caused by an electronic problem in the voltage control circuitry. Based on their reviews of test data, the inspectors found no discrepancies with this preliminary conclusion.

At approximately 1:45 a.m., on November 19, 1999, the NRC granted NOED 99-2-003, allowing the licensee an additional 48 hours to further troubleshoot and make repairs to the EDG control circuitry without following the actions of TS 3.8.1. The NOED was granted based on several compensatory measures the licensee implemented (which were verified by the inspectors) and the low risk factors associated with operating the unit with the inoperable EDG while repairs were being made.

At the recommendation of the assisting vendor, the licensee replaced and tuned the electronic governor unit located in the generator control panel. The vendor suggested that the last two failures were likely caused by the electronic governor based on his review of the test data. After governor installation and tuning, the licensee performed functional testing. Associated TS surveillance procedures were then performed, including an isolated bus test in which safety-related plant loads were cycled on and off of the essential 4160 volt switchgear with the EDG being its only power source. The EDG was successfully tested and declared operable at 11:09 p.m. on November 20, 1999, at which time the TS LCO and NOED were exited. The inspectors observed portions of this testing and noted no further erratic behavior of the EDG or its output breaker.

At the end of the inspection period, the licensee was planning to ship the electronic governor assembly to a vendor for diagnostic testing to determine its failure mode. The licensee documented all of the above items in its corrective action program under PIP 1-C99-4675. The licensee was planning to submit an LER to document the EDG being inoperable beyond its TS 3.8.1 allowed outage time. Further NRC review of this issue will be conducted under Unresolved Item (URI) 50-413/99-07-02: 1B EDG Inoperability Due to Successive Test Failures Following Maintenance - NOED 99-2-003. This URI will track the NOED that was granted on November 19, 1999.

Other Issues Raised While Addressing the 1B EDG Problems

The inspectors identified several other concerns while inspecting the 1B EDG maintenance, troubleshooting and testing efforts. All of the items below will be inspected under URI 50-413/99-07-02. They included the following:

Maintenance technicians' performance of procedure MP/0/A/7400/001, Revision 24, Diesel Fuel Oil Injection Pump Removal, Replacement, and Adjustment:

During the initial performance of this procedure to replace heim joints (prior to the first EDG failure), the inspectors observed that the only procedure sections documented as being performed were Sections 11.1 and 11.8. A subsequent review by the inspectors found that two other sections (11.5 and 11.6) contained steps that appeared critical in ensuring successful heim joint installation. The associated work order contained no instructions on which specific procedure sections to perform. The inspectors were informed by station management that some of the key parameters discussed in Sections 11.5 and 11.6 were verified by other means. Through URI 50-413/99-07-02, the inspectors will ascertain whether or not inadequate work instructions and/or poor procedural adherence practices allowed the non-documentation or non-performance of key steps in Sections 11.5 and 11.6.

The licensee's compliance with TS LCO 3.8.1 Required Actions B.3.1 and B.3.2:

The licensee initially entered the LCO action when the EDG was removed from service for the planned maintenance. The TSAIL program lists all TS LCO Required Actions and Completion Times when inoperable equipment is entered by operators. TS 3.8.1, Required Action B.3.1 directs the licensee to perform a common-mode failure determination on the (opposite train) operable EDG within 24 hours of one being declared inoperable or perform a surveillance test on the operable EDG in accordance with Required Action B.3.2 (also within 24 hours). Action B.3.1 was cleared from TSAIL within 15 minutes of the 1B EDG initially being declared inoperable because the inoperability was strictly due to planned maintenance. When the conditions changed as a result of the 1B EDG test failures, operators failed to reopen the tracking item for Action B.3.1 in TSAIL for performing the common-mode failure determination. Work control center and control room operators on shift a day after the 1B EDG was restored could not explain to the inspectors how TS Action B.3.1 was complied with in light of the 1B EDG failures. The inspectors were later directed to a statement in PIP 1-C99-4675, which read, "This is not a common mode failure due to the fact that D/G 1A has been successfully passing its Operability PT without any of the problems that are documented in this PIP." This statement was added to the PIP two days after the last diesel failure. The inspectors were informed by licensee personnel that more detailed common-mode failure determinations were verbalized by engineers for the 1A EDG throughout the repair efforts as each potential cause was investigated. Through URI 50-413/99-07-02, the inspectors will review the adequacy of the licensee's common-mode failure determination for the 1A EDG, as well as address the operators' tracking of TS Required Actions B.3.1 and B.3.2 in the TSAIL program.

The licensee's compliance with TS LCO 3.7.8 (Action A) and 3.8.1 (Action B.1):

When EDG 1B was declared inoperable, it rendered the 1B NSWS pump inoperable. The licensee's procedure (OP/0/A/6400/006C, Revision 224, Nuclear Service Water System, Enclosure 4.11) for actions to take when one NSWS pump and/or its associated EDG is inoperable directed operators in Step 2.5 to ensure that both units are logged in TSAIL under LCO 3.7.8, Action A. Action A contained a note directing the operators to enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," for emergency diesel generator made inoperable by NSWS. The inspectors noted that the applicable Conditions and Required Actions of LCO 3.8.1 had not been entered for the 2B EDG. A review of the TS Bases for LCO 3.7.8 stated that an NSWS train is considered operable during Modes 1 through 4 when: (1) both NSWS pumps on the NSWS loop are operable; or (2) one unit's NSWS pump is Operable and one unit's flow path to the non-essential header, auxiliary feedwater pumps, and containment spray (NS) heat exchangers are isolated (or equivalent flow restrictions). For the first three days of the 1B EDG inoperability, it was not apparent to the inspectors that either of the above two conditions was satisfied. Licensee management explained that they had equivalent flow restrictions due to the unavailability (and hence isolation) of the 1B EDG, and the fact that only one unit was required to be assumed affected by the design basis accident, requiring only that unit's NS heat exchanger to be considered a heat load for NSWS. They further explained that the non-essential headers of NSWS are automatically isolated during the postulated accident. Under URI 50-413/99-07-02, the inspectors will review single pump (specifically 2B NSWS pump) flow balance data and system design to verify the assumptions used to support the licensee's conclusions.

c. Conclusions

The 1B EDG experienced successive test failures following maintenance on November 16, 1999. To allow further troubleshooting and repair efforts to continue with Unit 1 operating in Mode 1, the NRC granted a NOED on November 19, 1999, prior to the end of the TS allowed outage time. The inspectors identified several concerns related to procedural adherence during heim joint replacement, the common-mode failure determination process, and TS 3.7.8 compliance related to B train NSWS and the 2B EDG. An unresolved item was opened to track the followup of these items.

M3 Maintenance Procedures and Documentation

M3.1 Inservice Inspection (ISI) - Unit 1 (73753)

The inspectors reviewed procedures and documentation for licensee activities involving ISI and flow accelerated corrosion (FAC). Piping and component ISI documents were inspected against requirements of the American Society of Mechanical Engineers (ASME) Section XI, 1989 Edition, while the containment ISI procedures and documents were inspected against requirements of ASME Section XI, 1992 Edition with 1992 Addenda. The reviewed portion of the FAC program involved repair and replacement activities in ASME class piping and were inspected against the requirements of ASME Section XI, 1989 Edition. Inservice inspection procedures and documentation met the requirements of applicable codes and regulations.

M8 Miscellaneous Maintenance Issues (92700, 92902)

M8.1 (Closed) LER 50-413/99-008-(00,01): Operation Prohibited by Technical Specification 3.5.2 Due to an Inoperable Centrifugal Charging Pump and Operation Prohibited by Technical Specification 3.7.12 Due to Inadequate Control of the Auxiliary Building Filtered Ventilation Exhaust (VA) System Pressure Boundary

(Closed) URI 50-413/99-04-01: VA System Potentially Inoperable due to Premature Opening of ECCS Pump Room Ventilation Boundary Doors During Pump Replacement

(Closed) NOED 99-2-002: Catawba Unit 1 Inoperable Centrifugal Charging (NV) Pump and VA System

LER 50-413/99-08-(00,01) described an event involving the failure of the 1B NV pump while it was in service providing normal charging to the RCS. It also described a subsequent event in which plant personnel unknowingly caused the VA System to be inoperable while preparing to replace the failed NV pump. As discussed in NRC Inspection Report 50-413,414/99-04, the licensee requested and was granted a NOED to allow continued Unit 1 operation with the inoperable NV pump and inoperable VA system for a period not to exceed seven days from the time the pump was initially declared inoperable (11:20 p.m., on June 8, 1999). At 4:00 a.m., on June 14, 1999, the licensee successfully completed testing after replacement of the pump rotating element, restored the associated NV and VA systems to operable status, and exited the LCO prior to the NOED expiring. However, the event was reportable because the unit operated in Mode 1 with the pump inoperable for greater than 72 hours - the maximum TS 3.5.2 allowed outage time. The licensee had not completed its root cause determination for the pump failure, as the failure analysis had not been completed by the vendor at the close of this inspection period. This failure analysis determination is in the licensee's corrective action program under PIP 1-C99-2373. Because this was the first NV pump failure at Catawba in ten years, the inspectors concluded that the licensee's continuing actions to investigate the failure were adequate and that no further inspection was necessary to address this aspect of the LER.

The LER also reported the NRC-identified TS 3.7.12 violation associated with the VA system being inoperable due to workers prematurely blocking the 1B NV pump room door in the open position. To increase worker comfort during the NV pump replacement, licensee personnel had blocked the door open with flexible ventilation ducts provided for room cooling. This was done prior to the licensee requesting or the NRC granting discretion allowing the VA system pressure boundary to be breached. This condition was discovered by the inspectors and communicated to licensee management personnel at a Plant Operations Review Committee (PORC) meeting at approximately 2:40 p.m, on June 10, 1999. The door, identified as Door No. AX220, had been blocked open around 12:00 a.m that day and was closed at 2:55 p.m, approximately 15 hours later. With the door blocked open, particularly with air conditioning units blowing air into the room, neither train of the Unit 1 VA system would have been able to maintain a negative pressure on the room as required by TS 3.7.12. Therefore, the unit operated in Mode 1 with the VA system inoperable and in violation of TS 3.7.12 and TS 3.0.3.

The VA system was designed to maintain a negative pressure in the ECCS pump rooms such that radionuclides potentially leaking from ECCS components following a design basis event could be processed through the filtration system before being released to the environment. The safety significance of the blocked-open 1B NV pump room door was minimized by the fact that the 1B NV pump (the main potential leak source) was isolated from the ECCS to facilitate the pump's replacement. The only other ECCS components of concern located in the room were five valves communicating with the opposite train pump, 1A, which itself was located in a separate room. The valves presented a less significant radiological concern and were verified not to have any packing leaks subsequent to the event (and in support of the ensuing NOED request). The inspectors detected no leaks in those valves during independent walkdowns.

The licensee determined that the individuals who blocked the door open were unaware of the potential safety impact to the VA system and TS implications with the plant operating in Mode 1. The licensee attributed this to unclear management expectations. The inspectors noted that a similar event occurred in 1998, in which the Unit 2 containment annulus ventilation system was rendered inoperable when personnel blocked open a ventilation boundary door while implementing a modification. For the earlier event, documented in LER 50-414/98-01-00, the licensee determined the cause to be an inadequate process for determining what compensatory actions were needed in order to perform work on the door. Because the two events were attributed to different causes, the licensee determined that the more recent event was not a recurring one.

The licensee has developed, as part of a new management focus initiative, a new organization in engineering dedicated to improving the licensee's overall performance in the area of maintaining and operating safety-related ventilation systems. Other corrective actions for the more recent event included issuing site-wide communications and placing placards on each ECCS pump room door clearly indicating that the doors' closure is required for VA system operability.

The failure to place Unit 1 in Mode 3 and subsequently Mode 4 when both trains of the VA system were inoperable for approximately 15 hours on June 10, 1999, was contrary to the requirements of TS 3.7.12 and TS 3.0.3. This Severity Level IV violation is being treated as a NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. The violation is in the licensee's corrective action program as PIP 1-C99-2373. It is identified as NCV 50-413/99-07-03: Operation in Mode 1 with VA System Inoperable for 15 Hours Due to 1B NV Pump Room Door Being Blocked Open.

The inspectors noted some discrepancies in the LER discussion of the event. The event timeline indicated that a walkdown determined that the pump room door was found open at 10:00 a.m. and that it was closed, following discussions between engineering and maintenance personnel, two hours later at 12:00 noon (for a total open time of 12 hours). The door was actually discovered open by the inspectors and communicated to the PORC committee members at approximately 2:40 p.m. The doors were closed at 2:55 p.m, nearly three hours after the time indicated in the LER. The licensee indicated that the LER information was obtained from a root cause determination in which cognizant personnel were not interviewed until several weeks after the event occurred. This pointed to a need for more scrutiny in the root cause and LER development processes by the licensee. LER 50-413/99-08-(00,01), URI 50-413/99-04-01, and NOED 99-2-002 are closed.

M8.2 <u>(Closed) LER 50-413/99-014-00</u>: Missed Surveillances and Operation Prohibited by Technical Specifications Occurred as a Result of Defective Procedures or Programs and Inappropriate Technical Specification Requirements

This LER reported five separate violations of TS SRs that were initially identified in 1996 during the licensee's implementation of NRC Generic Letter (GL) 96-01, Testing of Safety-Related Logic Circuits. The violations, which were not initially classified as TS non-compliances during the licensee's 1996-97 effort, were re-evaluated following an NRC inspection conducted in July 1999 to review their GL 96-01 activities. This inspection effort, and the NRC's enforcement action taken for the first of the five findings, was documented in NRC Inspection Report 50-413,414/99-05. The first violation was acknowledged by the licensee on July 30, 1999, but not reported in this LER until September 1, 1999, two days past the deadline dictated by 10 CFR 50.73. The failure to report the first example within 30 days constituted a violation of minor significance and is not subject to enforcement action. A second example was reported separately in LER 50-413/99-011-00, which will be reviewed in a future inspection report. The remaining three items are discussed in the following paragraphs.

Failure to Perform Adequate Analog Channel Operational Test (ACOT) for the Overpower Delta Temperature (OPDT) Reactor Trip Circuitry

In August 1996, the licensee identified that the Unit 2 procedure used to implement TS SR 4.3.1.1, Table 4.3-1, Functional Unit 7 (now Improved TS SR 3.3.1.7), failed to verify the proper functioning of the circuitry that reduces the OPDT setpoint when a flux imbalance is sensed between upper and lower power range detectors. The procedure was subsequently corrected and the test performed satisfactorily. The procedural error was traced back to a Fall 1995 core reload cycle in which the new core analysis called for a flux imbalance penalty that had not been required for previous fuel cycles. While the OPDT circuitry was properly modified to include this imbalance penalty, the quarterly ACOT test procedures were not revised to include testing of the modified circuit. This testing deficiency was initially included in the licensee's corrective action program under PIP 2-C96-2348.

Failure to Properly Verify the Containment Isolation Phase B Signal Actuation of the Manual Purge and Exhaust Isolation Function

The licensee determined in December 1996 that it was not properly isolating the manual phase B and manual safety injection actuation circuitry such that the phase B signal could be conclusively verified to have actuated the containment purge and exhaust isolation. Procedures were subsequently corrected and the surveillance requirement (then TS SR 4.3.2.1, Table 4.3-2, Functional Unit 3.c.1; now improved TS SR 3.3.6.4) has since been satisfied. The test deficiency, which affected both Units 1 and 2, was initially discussed in PIP 1-C96-3349 and attributed to defective procedures.

The failure to have adequate procedures for the performance of the OPDT and containment isolation (phase B) surveillance requirements described above constituted a violation of TS 5.4.1 (then TS 6.8.1.a). This Severity Level IV violation is being identified as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy, and is identified as NCV 50-413,414/99-07-04: Failure to Have Adequate Procedures for Conducting TS Surveillance Requirements for Manual Containment Purge and Exhaust Isolation and OPDT Functions.

To address deficiencies in the surveillance program overall, the licensee had initiated corrective actions prior to July 1999 including the establishment of a team to perform a comprehensive review of procedures against TS requirements to support the January 1999 conversion to improved TS. A number of findings were generated from this review, which were subsequently corrected and reported to the NRC in earlier LERs.

Failure to Test Manual Initiation of VA System Operation

In November 1996, the licensee determined that it had not been manually actuating the VA system as required by previous TS Table 4.3-2, Functional Unit 16a. However, upon further review, the licensee concluded that the TS requirement was inappropriate in that the system, which is normally in the filtered mode of operation supplying and exhausting air to and from the entire auxiliary building, could not be "manually" actuated to its safety alignment, in which it only serves the ECCS pump rooms. By design, this alignment transfer was and still is accomplished automatically in response to a safety injection signal. In 1996, the licensee failed to recognize the need to request a TS amendment from the NRC to correct the discrepancy. The conflict was ultimately eliminated when Catawba converted to Improved Technical Specifications (ITS) on January 16, 1999. The licensee originally submitted their ITS amendment request in May of 1997. The inspectors concluded that, because the TS requiring manual actuation of the VA system was a known TS discrepancy, the licensee should have requested a TS amendment independent of the improved TS submittal, which was not due for implementation until 20 months later. The inspectors determined that the licensee's actions to correct the above discrepancy were untimely and inadequate. The failure to promptly correct the inadequate TS is considered a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. It is the first of a two-example violation and is identified as NCV 50-413,414/99-07-05: Failure to Take Corrective Actions to Revise Inappropriate TS Requirements - Two Examples. The test discrepancy was originally included in the licensee's corrective action program under PIP 0-C96-2957.

The above issues and the failure to initially recognize them as missed TS surveillances were collectively described in the licensee's corrective action program under PIP 0-C99-3097. This LER is closed.

III. Engineering

E8 **Miscellaneous Engineering Issues** (92903)

E8.1 (Closed) URI 50-413,414/99-04-03: Review of Licensee's Justification for Excluding Safety-Related Sump Pumps from the In-Service Testing (IST) Program

This URI was opened to allow further evaluation of the licensee's justification for not including safety-related sump pumps, particularly the turbine-driven auxiliary feedwater pump (TDAFWP) sump pumps, in its IST program.

Discussions with engineering personnel revealed that the licensee's criteria for including pumps into the IST program were based on NUREG-1482, Guidelines for Inservice Testing at Nuclear Power Plants. Following a review of NUREG-1482, the inspectors determined that inclusion was warranted if the pumps were classified as American Society of Mechanical Engineers (ASME) Code Class 1, 2, or 3, and if the pumps were required to perform a specific safety-related function in shutting down a reactor, maintaining the shutdown condition, or mitigating the consequences of an accident. The TDAFWP sump pumps are currently classified by the licensee as ASME Code Class 3, which the licensee indicated was overly conservative. The inspectors reviewed Regulatory Guide 1.26, Quality Group Classifications and Standards For Water, Steam, And Radioactive-Waste-Containing Components of Nuclear Power Plants, and determined that none of the sump pumps were required to be classified as Quality Class C, or the equivalent of ASME Code Class 3. A less conservative classification would exempt the sump pumps from IST requirements based on the NUREG-1482 guidance. Additionally, the inspectors determined that the sump pumps did not directly perform one of the three specific safety-related functions mentioned above, although the failures of both A and B train TDAFWP sump pumps could render the associated TDAFWP inoperable and incapable of performing its design basis function. Given the importance of the TDAFWP sump pumps, the licensee indicated that some type of performance testing would be considered. The inspectors identified no discrepancies with the licensee's conclusion that formal inclusion of safety-related sump pumps in the IST program was not required. This URI is closed.

E8.2 (Closed) Temporary Instruction (TI) 2515/142: Draindown During Shutdown And Common-Mode Failure (NRC Generic Letter 98-02)

a. Inspection Scope (TI 2515/142)

The inspectors reviewed the plant's susceptibility to a potential RCS drain down event caused either by operator error or equipment failure which could lead to a common-cause failure of all emergency core cooling system (ECCS) pumps. The inspectors reviewed station operating procedures, ECCS system piping design and configuration, administrative controls, licensed operator training, and (for a historical perspective) the circumstances surrounding a significant loss of inventory event that occurred at Catawba on June 11, 1990.

b. Observations and Findings

The inspectors reviewed various ECCS system drawings and determined that the Catawba plant design made it susceptible to a draindown/loss of common (ECCS) pump suction header event. Catawba's Unit 1 and Unit 2 residual heat removal (ND) systems have two trains, A and B, which are normally cross-connected via two normally opened cold leg injection crossover valves. If a single active failure rendered one train's ND pump inoperable, the remaining pump could still provide injection flow to all four RCS cold legs. Between the two cold leg crossover valves, the piping system branches off with a flow path back to the FWST via the FWST supply line to the common ECCS pump suction header. This flow path has one normally locked closed manual valve, ND-33 (ND System Return To FWST). If ND-33 and a cold leg crossover valve were simultaneously opened with that train (the one associated with the crossover valve) of ND in service providing decay heat removal for the RCS, a flow path would exist that would pump RCS inventory via the FWST supply line to the common ECCS pump suction header. Depending on the temperature of the RCS, water in the common ECCS pump suction header could flash to steam creating a steam/water mixture that could fail all ECCS pumps on both trains.

The inspectors focused on the established barriers to prevent such an event from occurring. The inspectors determined the primary barrier to be the administrative controls for operating valve ND-33. The inspectors considered the plant conditions under which this valve was permitted to be opened. From a review of station operating procedures, the inspectors determined that manipulation of valve ND-33 was procedurally restricted to Modes 5, 6, or No-Mode (reactor defueled). Discussions with operations and engineering personnel did not reveal any routine evolutions that conflicted with this conclusion. In these shutdown modes, a draindown event causing loss of RCS inventory is possible based on system design as discussed above; however, the inspectors determined that adequate configuration control was established through approved procedures to prevent such an event. With ND-33 manipulations restricted to Modes 5, 6, or no-mode, the potential for loss of the ECCS pump common suction header due to steam formation is reduced because RCS temperature would be less than 200 degrees F.

The inspectors reviewed a June 11, 1990, event in which Catawba Unit 1 experienced a loss of RCS inventory. This event was reported in LER 50-413/90-013. On June 11, 1990, following performance of PT/1/A/4200/57, Refueling Water and Residual Heat Removal Check Valve Full Stroke Test, operators had performed valve manipulations to restore the B train of ND to a normal decay heat removal alignment. Failure to perform the procedure steps in the correct sequence resulted in operators incorrectly aligning the discharge of the A train ND pump to the FWST, as well as to the RCS cold legs. The A train of ND was in service for decay heat removal when this occurred. Because of the temporary loss of decay heat removal when RCS inventory was being pumped to the FWST, RCS hot leg temperatures increased from 197 to 203 degrees F causing the unit to inadvertently enter Mode 4. Prompt actions from licensed operators terminated this event, restored RCS decay heat removal, and returned the unit to Mode 5 with RCS temperatures below 200 degrees F. The inspectors reviewed the licensee's corrective actions and determined that sufficient emphasis was placed on the human performance aspects of this event. Although more recent events have occurred at Catawba involving the inadvertent addition of water to the RCS from interconnected systems, only one event was noted of any significance since 1990 concerning the transfer of inventory from the RCS (a December 1997 Notice of Unusual Event involving the loss of inventory through two loop drain valves). The inspectors concluded that the licensee's corrective actions following the 1990 event were helpful in preventing the type of inventory transfer event described in the TI from recurring.

c. Conclusions

Catawba Unit 1 and Unit 2 designs make each unit susceptible to a RCS draindown/loss of emergency core cooling system pump common suction header event. However, established administrative controls and corrective actions from a previous draindown event are in place to prevent such an incident from occurring.

E8.3 (Closed) URI 50-413,414/98-15-02: Potentially Non-Conservative TS Surveillance Criteria for Annulus Ventilation System Drawdown

Calculation CNC-1211.00-00-0086 established an acceptance criteria of 16 seconds for performance of the reactor building annulus ventilation drawdown system performance test. Duke Power procedure PT/1(2)/A/4450/003C, Annulus Ventilation System Performance Test, specifies the requirements for testing the annulus ventilation system. The acceptance criteria for the annulus ventilation drawdown test specified in the procedure was 16 seconds. On November 11, 1998, the licensee initiated PIP C-98-4404 to document that the acceptance criteria in TS 4.6.1.8.d.4 was non-conservative with respect to the calculation dose analysis. The TS specified 60 seconds as the acceptance criteria for the drawdown time for the annulus ventilation system performance. TS 4.6.1.8.d.4 was subsequently renumbered to SR 3.6.16.2 by the ITS, which were implemented by the licensee in January 1999.

The inspectors reviewed the results of the annulus ventilation drawdown tests completed for Unit 1 since May 1991 and for Unit 2 since September 1997. The measured drawdown times to approximately minus 1.5 inches water gauge were 14 seconds or less. Therefore, the inspectors concluded that the surveillance tests showed that the annulus ventilation system was performing in accordance with the requirements specified in the design requirements.

The licensee did not submit a Technical Specification (TS) change request when the condition was identified in November 1998. The error in the TS should have been corrected under the corrective action program. The failure of the licensee to request an amendment to TS SR 3.6.16.2 to correct the acceptance criteria for annulus drawdown time in a reasonable time was a violation of 10 CFR 50, Appendix B, Criterion XVI. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy and is identified as the second example of NCV 50-413,414/99-07-05: Failure to Take Corrective Actions to Revise Inappropriate TS Requirements - Two Examples. The licensee initiated PIP C-99-04566 to document and disposition this NCV. The licensee will submit a TS change to correct the non-conservative acceptance criteria in the TS surveillance requirement. Pending revision of the TS, the licensee has established administrative controls for the annulus drawdown system performance acceptance criteria, which meets the design requirements.

E8.4 (Closed) LER 50-413/98-016-00: Missing Interlock Discovered During a Design Review on ECCS Pump Area Sump Pumps Caused Plant to be in Condition Outside the Design Basis

During a design review for a proposed station modification, licensee engineers discovered that an interlock on the containment spray (NS) and ND pump sump pumps, which was described in the Updated Final Safety Analysis Report (UFSAR) Section 6.3.2.5, had not been installed during original plant construction. The purpose of the interlock was to avoid a situation where a certain size leak in the ECCS would go undetected by the control room operators and result in an unknown loss of RCS inventory due to a passive ECCS failure outside containment such as a pump seal failure or pipe break. The licensee committed to install this interlock in response to the NRC staff FSAR question 440.144 during plant licensing. This interlock was required, in part, to comply with the leak detection capability required for ECCS and containment heat removal system described in 10 CFR 50, Appendix A, General Design Criteria (GDC) 35 and 38.

The licensee initiated PIP C-98-4098 on October 20, 1998, to document and disposition this problem. The licensee also notified NRC within one hour of discovery of the problem pursuant to 10 CFR 50.72 that the plant was outside the design basis. A written LER was submitted to NRC in a letter dated November 19, 1998.

The ND and NS sump is located in the auxiliary building. Level switches in the sump control automatic operation of the sump pumps. The level switches are set to start the sump pumps when the water level in the sump reaches the "Hi" level. The pumps will operate until the water level drops to "Low" level. When the water level in the sumps reaches the "Hi-Hi" level setpoint, the pumps continue to operate and an alarm is initiated in the control room. The purpose of the interlock was to stop the pumps on receipt of a safety injection signal. The pumps would not restart until the water level reached the "Hi-Hi" level at which time an alarm would be initiated in the control room to alert the operators that the sump pumps were operating. This would alert the operators during post-loss of coolant accident (LOCA) operation that a passive failure (leak) of the ND or NS systems had occurred.

The sump pumps are provided with a local control panel with three switch settings: manual, auto, or standby. When the switch is in manual, the pumps will operate regardless of the sump level. In the "auto" position, the pumps operate at the "Hi" level switch setpoint. In standby, the pumps will not start until the water level reaches the "Hi-Hi" level switch setpoint. In addition to starting the pumps, the "Hi-Hi" level switch also initiates an alarm in the control room. Immediate corrective actions included placement of the sump pumps in a standby basis. This essentially duplicated the intent of the interlock controls and provides the ND and NS leak detection system required by GDC 35 and 38. The licensee has prepared plant modifications, Nuclear Station Modification (NSM) CN-11405 for Unit 1 and NSM CN-21405 for Unit 2 to install the interlock between the solid state protection system and the sump pumps as described in the UFSAR. This work is scheduled for the next refueling outages.

The safety consequences of the failure to install the interlock were reviewed by the inspectors. The design basis for the interlock was to provide ND/NS system leak detection capability to ensure that no more than the approximately 2400 gallons was lost prior to initiation of an alarm to alert the operators that a leak had occurred, and to ensure a minimum of 30 minutes of operator response time to respond to the potential of excessive loss of recirculation water inventory. Without the interlock installed, the sump pumps would automatically cycle to pump out the sump prior to reaching the alarm setpoint. The operators would not be aware of the loss of inventory due to a passive system failure (leak). However, an increase in level or overflow of the 10,000 gallon capacity liquid rad waste tank and/or radiation monitor alarms in the area of the leak would alert operators and provide an indirect indication of leakage due to a passive failure of the ND or NS systems. This would alert the operators to the need for action and provide sufficient response time to assure adequate recirculation water inventory during the long-term post-LOCA recirculation cooling phase of ECCS. Therefore the inspectors concluded that the safety significance of this design deficiency was low.

Failure to install the interlock as described in the UFSAR was a violation of 10 CFR 50, Appendix B, Criterion III. This Severity Level IV violation is being treat as a NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy and is identified as NCV 50-413,414/99-07-06: Failure to Install ECCS Interlock Caused Plant to be Outside the Design Basis.

E8.5 (Closed) LER 50-413/99-009-(00,01): Inoperability of Containment Valve Injection Water System (CVIWS) in Excess of Technical Specification Limits Due to Inadequate Testing Following a Surveillance Test Failure

On December 23, 1997, CVIWS valve 1NW-237B failed its ESF response time test. The failure was investigated and no problem was identified. The valve was retested using a different test method and was subsequently declared operable. On May 18, 1999, valve 1NW-237B again failed the ESF response time test. Investigation of this failure disclosed that the 1997 valve retest was insufficient to detect the problem which caused the original test failure and that the valve had been inoperable since the December 1997 test. On June 21, 1999, the licensee determined that the inoperability of this valve caused one of two trains of the CVIWS to be inoperable. The Technical Specifications require both trains to be operable and specify actions to be taken in the event one train is inoperable. The licensee initiated PIP C-99-01993 to document and disposition this problem. The licensee reported this problem to NRC and submitted licensee event reports to NRC in letters dated July 19, 1999, and September 15, 1999.

CVIWS valve 1NW-237B injects water between the discs of NI system valve 1NI-178B to seal the valve in the event of a passive upstream failure of the residual heat removal system, such as a pump seal failure. Valve 1NI-178B is normally open and remains open during cold leg injection and recirculation. Following a LOCA, the valve would close for realigning the NI system to hot leg recirculation. A water seal is provided to the valve from 1NW-237B for containment isolation. The control logic for valve 1NW-237B which is a normally closed solenoid valve is to fail open on loss of power to the solenoid following receipt of a containment high-high pressure signal (indication of a LOCA) after valve 1NI-178B closes.

The root cause of the inadequate December 1997, valve retest was attributed to lack of knowledge and experience by the test coordinators. There is an interlock between Valves NW-237B and NI-178B which prevents NW-237B from opening until valve NI-178B is closed. During the 1997 retest, the interlock was defeated by using a jumper across the interlock contact which simulated closure of valve NI-178B. Investigation of the cause of the May 1999 test failure disclosed that the interlock circuitry in the actuator of valve 1NI-178B required adjustment. The interlock was repaired by adjusting a switch striker screw.

The licensee reviewed the potential worst case unfiltered leakage during the time period when the valve 1NW-237B was considered inoperable. This amount of leakage, when added to the actual known ECCS leakage, was less than the allowable unfiltered ECCS leakage permitted in the off site dose calculations. In addition, leakage from a closed

1NW-178B would only be a concern if a passive upstream failure of the system occurred during hot leg recirculation.

Failure to properly retest CVIWS valve 1NW-237B in December 1997 resulted in Train B of the CVIWS being inoperable during power operations (Modes 1, 2, 3, and 4) conducted between December 1997 and May 1999. This was contrary to the requirements of TS 3.6.17, which requires two CVIWS trains (Trains A and B) to be operable during Modes 1, 2, 3, and 4. This Severity Level IV violation is being treat as an NCV consistent with Section VII.B.1 of the NRC Enforcement Policy and is identified as NCV 50-413/99-07-07: Inoperable Train B CVIWS During Fuel Cycle 11.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radiological Effluent Releases (84750)

a. Inspection Scope

Verify that site radiological effluents are monitored and off site dose commitment projections for a member of the public were performed to assure that appropriate radwaste systems are fully utilized to keep off site doses As Low As Reasonable Achievable (ALARA.)

b. Observations and Findings

The inspectors verified that the licensee was calculating projected dose commitments to a member of the public from radioactive materials in the liquid and gaseous effluents released to unrestricted areas for each month in 1999 to assure that appropriate radwaste systems were fully utilized when required. All projected doses were well below the monthly effluent ALARA dose limits.

The inspectors reviewed the operational status of the liquid and gaseous radioactive waste systems with the radioactive waste system engineer to verify the systems were properly maintained. PIPs were also reviewed to identify any adverse trends in radwaste system operations. The inspectors determined that the radioactive waste treatment systems were functioning properly. The assigned engineer worked closely with the radiation protection and chemistry staff on radiological gaseous and liquid effluent systems. As a result, numerous system performance problems in recent years had been resolved and system performance had improved. As an example, the volume of water entering the liquid radioactive waste system has been reduced in recent years by controlling systems leakage. The licensee was making several changes to the UFSAR to better describe current liquid radwaste system processes. The licensee planned to remove accumulated sludge in several radioactive waste tanks. The cleanup of the floor drain tank began during the assessment period.

c. Conclusions

The inspector concluded the licensee was maintaining radioactive waste process systems and monitoring radiological effluents to maintain offsite doses from radioactive waste effluents ALARA.

R1.2 Transportation of Radioactive Materials (86750)

a. Inspection Scope

To review a shipment of radioactive material with licensee personnel to verify personnel were knowledgeable of NRC, Department of Transportation, and licensee radioactive waste shipping requirements.

b. Observations and Findings

There were no shipments of radioactive material during the inspection. A previous shipment of radioactive material was selected by the inspector and the licensee's staff walked the inspector through the shipping preparations, procedures, and documentation maintained in the licensee's transportation records. The inspector found the staff knowledgeable of shipping requirements.

The licensee used a vendor computer program to assist the staff in performing calculations and generating the documentation for the shipment of radioactive materials. The inspectors found that the licensee had performed an analysis of the software and documented a verification and validation of the computer application in Software and Data Quality Assurance Document-70122-COM, approved January 13, 1999. The plant staff also performed reviews of the programs for potential improvements.

c. Conclusions

Licensee personnel were knowledgeable of radioactive material transportation requirements and procedures. Reviewed radioactive material transportation documentation met regulatory requirements. The inspector concluded that the verification and validation of vendor computer software capabilities and established quality controls on the use of the computer program were acceptable.

R1.3 Solid Radioactive Waste (86750)

a. Inspection Scope

Review the licensee's measures to minimize the generation of solid radioactive waste.

b. Observations and Findings

The inspector reviewed the effectiveness of the licensee's low level solid waste sorting program the licensee implemented in February 1999. Containers of solid radioactive waste (trash) collected during outages and routine operations are sorted by HP technicians for materials that can be reused and materials found free of radioactive contamination are removed from the waste and surveyed again with bag monitors for release as clean trash. The licensee reported that the program had recovered reusable tools and equipment and had helped reduce the total quantity of dry active waste for disposal. The quantity of solid radioactive waste continued to decline for the fourth consecutive year.

c. Conclusions

The licensee was effective in reducing the total amount of solid radioactive waste generated. The volume of solid radioactive waste generated at Catawba continued to decline.

R1.4 Turbine Building Sump (TBS) Alarms and Radiological Protection Responses (84750)

a. Inspection Scope

Review the adequacy of Radiation Protection (RP) response to recent TBS effluent radiation monitor alarms.

b. Observations and Findings

During a routine review of the August 20, 1999, control room log, the inspectors noted log entries concerning TBS effluent monitors that indicated the sump had not been sampled and sampling procedures may not have been followed.

The Unit 1 and 2 TBSs were normally pumped to the conventional waste water treatment system (a waste holding pond). System design also permitted the sumps to be pumped to the liquid radioactive waste system with manual valve operations. When the TBS pumps were shutdown, the sumps could overflow onto the turbine building floors without any additional operator actions. The radioactivity of the TBS was usually below radiological effluent lower levels of detection. However, the inspectors found two PIPs (C-99-01631 and C-99-03131) documenting the presence of low level byproduct radioactive material in the sump recently in April and August of 1999. In each event the TBS radiological effluent monitor (1EMF-31) trip setpoints were reached and the effluent transfer pumps were shut down. The trip setpoints were set well below permissible liquid radiological effluent limits to alert operations early of changing radiological conditions in the TBS.

The inspectors determined through interviews with the radiation protection technician (RPT) and the operator referred to in the August 20, 1999, control room log entries, that rain water was collecting in the Unit 1 TBS rapidly and the licensee was anticipating a TBS overflow with the effluent pumps shutdown. The RPT and the operator both reported that in previous periods of heavy rain it was common to see natural radioactivity in the rain water as rain collected natural radioactive nuclides from the atmosphere. The licensee personnel reported they had observed the phenomenon at the site for years. They suspected the 1EMF-31 trip was due to natural radionuclides in the rain water.

The licensee's procedure required the TBS be sampled following a 1EMF-31 trip prior to restart of the of the effluent pumps. There was an exception to the sampling requirement if it was determined that the 1EMF-31 trip was due to a spike. When the operator notified the RPT that the high level alarm had come in on the TBS, approximately six minutes later, he also reported the radioactivity on the 1EMF-31 monitor was trending down. The RPT and operator reported they considered the monitor's response a spike and therefore sampling was not required. Following the conversation, the operator restarted the pumps a couple of minutes later at 12:39 p.m.

The inspectors noted that the procedure did not define a spike. The inspector determined through a review of control room charts provided by the licensee that the EMF-31 monitor did begin to trend back down. However, as that was only after a four to six minute period; it did not appear to be an instrumentation spike.

Title 10 CFR Part 20.1501 requires, in part, licensees make or cause to be made, surveys that: (1) may be necessary for the licensee to comply with the regulation in this part; and (2) are reasonable under the circumstances to evaluate (i) the extent of radiation levels (ii) concentration or quantities of radioactive material; and (iii) the potential radiological hazard that could be present.

Licensee Procedure HP/O/B/1004/004, Radioactive Liquid Waste Release, Revision 31, July 28, 1998, provided actions to be taken by RP in response to EMF-31 high radiation level alarms. Step 4.6.2 of the procedure required that the staff take several actions, including obtaining a liquid sample from applicable TBS.

Failure to make radiation surveys necessary to identify and control TBS sump contents prior to their release was a violation of licensee procedures HP/O/B/1004/004 and 10 CFR Part 20.1501(a). This Severity IV violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP C-99-03486. This item is identified as NCV 50-413/99-07-08: Failure to Comply with 10 CFR Part 20 and Licensee Survey Requirements for Sampling the Release of the TBS.

The inspectors also found the licensee's control room log entries did not accurately capture all of the communication and testing associated with the release of liquid from the sump.

c. <u>Conclusions</u>

Licensee personnel failed to comply with 10 CFR Part 20 and licensee survey requirements for sampling the release of the TBS and an NCV was identified. The licensee's control room logs reviewed during the inspection did not accurately reflect information associated with liquid releases from the TBS.

R7 Quality Assurance in RP&C Activities

R7.1 Documentation and Corrective Actions (83750)

a. Inspection Scope

Recent PIPs for the RP program were reviewed to identify adverse radiological effluent solid waste and transportation of radioactive material trends and specific PIPs were reviewed to verify corrective actions were appropriated and resolved.

b. Observations and Findings

The inspectors reviewed recent RP issues identified in licensee PIPs. The inspectors determined that the licensee's threshold for placing issues into the licensee's corrective action program appeared to be low for regulatory compliance issues and appropriate to make program improvements and meet RP goals. No significant adverse trends in RP performance were identified. The reviewed condition reports included good analysis of problems with appropriate corrective actions to prevent recurrence.

c. Conclusion

The RP personnel were effectively utilizing the corrective action program to make program improvements and correct identified program deficiencies or non-compliance.

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 November 30, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

T. Beadle, Emergency Preparedness Manager
R. Beagles, Safety Review Group Manager
M. Boyle, Radiation Protection 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
D. Sweigart, Safety Assurance Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71714:	Cold Weather Preparations
IP 71750:	Plant Support Activities
IP 73753:	Inservice Inspection
IP 84750:	Radioactive Waste Treatment, Effluent, and Environmental Monitoring
IP 86750:	Solid Radioactive Waste Management and Transportation of Radioactive Material
IP 92700:	Onsite Followup of Written Reports of Non-routine Events at Power Reactor Facilities
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
TI 2515/142:	Draindown During Shutdown and Common-Mode Failure (Generic Letter 98-02)

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-414/99-07-01	NCV	Failure to Perform SR 3.8.1.1 Within One Hour of the 2B EDG Being Inoperable (Section O8.1)
50-413/99-07-02	URI	1B EDG Inoperability Due to Successive Test Failures Following Maintenance - NOED 99-2-003 (Section M2.1)
50-413/99-07-03	NCV	Operation in Mode 1 with VA System Inoperable for 15 Hours Due to 1B NV Pump Room Door Being Blocked Open (Section M8.1)
50-413,414/99-07-04	NCV	Failure to Have Adequate Procedures for Conducting TS Surveillance Requirements for Manual Containment Purge and Exhaust Isolation and OPDT Functions (Section M8.2)
50-413,414/99-07-05	NCV	Failure to Take Corrective Actions to Revise Inappropriate TS Requirements - Two Examples (Sections M8.2, E8.3)
50-413,414/99-07-06	NCV	Failure to Install ECCS Interlock Caused Plant to be Outside the Design Basis (Section E8.4)
50-413/99-07-07	NCV	Inoperable Train B CVIWS During Fuel Cycle 11 (Section E8.5)

50-413/99-07-08	NCV	Failure to Comply with 10 CFR Part 20 and Licensee Survey Requirements for Sampling the Release of the TBS (Section R1.4)

<u>Closed</u>

50-414/99-005-00	LER	Missed Emergency Diesel Generator Technical Specification Surveillance Concerning Verification of Availability of Offsite Power Sources Resulted from Defective Procedure (Section O8.1)
50-414/99-003-(00,01)	LER	Unplanned Actuation of Engineered Safety Features Actuation System Due to "A" Steam Generator High Level Caused by Inadequate Procedural Guidance (Section O8.2)
50-413/99-008-(00,01)	LER	Operation Prohibited by Technical Specification 3.5.2 Due to an Inoperable Centrifugal Charging Pump and Operation Prohibited by Technical Specification 3.7.12 Due to Inadequate Control of the Auxiliary Building Filtered Ventilation Exhaust System Pressure Boundary (Section M8.1)
50-413/99-04-01	URI	VA System Potentially Inoperable Due to Premature Opening of ECCS Pump Room Ventilation Boundary Doors During Pump Replacement [NOED 99-2-002] (Section M8.1)
50-413/99-014-00	LER	Missed Surveillances and Operation Prohibited by Technical Specifications Occurred as a Result of Defective Procedures or Programs and Inappropriate Technical Specification Requirements (Section M8.2)
50-413,414/99-04-03	URI	Review of Licensee's Justification for Excluding Safety-Related Sump Pumps from the IST Program (Section E8.1)
2515/142	TI	Draindown During Shutdown and Common-Mode Failure (NRC Generic Letter 98-02) (Section E8.2)
50-413,414/98-15-02	URI	Potentially Non-Conservative TS Surveillance Criteria for Annulus Ventilation System Drawdown (Section E8.3)

50-413/98-016-00	LER	Missing Interlock Discovered During a Design Review of ECCS Sump Pumps Caused Plant to be in Condition Outside the Design Basis (Section E8.4)
50-413/99-009 (00,01)	LER	Inoperability of Containment Valve Injection Water System in Excess of Technical Specification Limits Due to Inadequate Testing Following a Surveillance Test Failure (Section E8.5)

LIST OF ACRONYMS USED

AC	-	Alternating Current
ACOT	-	Analog Channel Operational Test
AFW	-	Auxiliary Feedwater
ALARA	-	As Low As Reasonably Achievable
ASME	-	American society of Mechanical Engineers
CFR	-	Code of Federal Regulations
CVIWS	-	Containment Valve Injection Water system
DBD	-	Design Basis Documents
DP	-	Different Pressure
EA	-	Enforcement Action
ECCS	-	Emergency Core Cooling System
EDG	-	Emergency Diesel Generator
ESF	-	Engineered Safety Feature
F	-	Fahrenheit
FAC	-	Flow Accelerated Corrosion
FWST	-	Refueling Water Storage Tank
GDC	-	General Design Criteria
GL	-	Generic Letter
IP	-	Inspection Procedure
IST	-	Inservice Testing
ITS	-	Improved Technical Specifications
KW	-	Kilowatts
LCO	-	Limiting Conditions for Operation
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
MSIV	-	Main Steam Isolation Valve
NCV	-	Non-Cited Violation
ND	-	Residual Heat Removal
NI	-	Safety Injection
NOED	-	Notice of Enforcement Discretion
NRC	-	Nuclear Regulatory Commission
NS	-	Containment Spray
NSM	-	Nuclear Station Modification
NSWS	-	Nuclear Service Water System

NV	-	Chemical and Volume Control (Charging) System
OAC	-	Operator Aid Computer
OPDT	-	Overpower Delta Temperature
PDP	-	Power-Driven Potentiometer
PIP	-	Problem Identification Process
PORC	-	Plant Operations Review Committee
psid	-	Pounds Per Square Inch Differential
psig	-	Pounds Per Square Inch Gauge
RCS	-	Reactor Coolant System
RP	-	Radiation Protection
RP&C	-	Radiological Protection and Chemistry
RPT	-	Radiation Protection Technician
SNSWP	-	Standby Nuclear Service Water Pond
SR	-	Surveillance Requirements
TBS	-	Turbine Building Sump
TDAFWP	-	Turbine Driven Auxiliary Feedwater Pump
TI	-	Temporary Instruction
TSAIL	-	Technical Specification Action Item Log
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VA	-	Auxiliary Building Filtered Ventilation Exhaust System
VC/YC	-	Control Room Area Ventilation/Chilled Water