U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	422 South Church Street Charlotte, NC 28242
Dates:	July 5 - August 15, 1998
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Enclosure 2

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/98-08, 50-414/98-08

This integrated inspection included a [illegible] of licensee operations, maintenance, engineering, and plant su[illegible]. The report covers a 6-week period of resident inspection; in addit[illegible] it includes the results of announced inspections by regional based inspectors. [Applicable template codes and the assessments for items inspected are provided.]

Operations

- The licensee reported Technical Specification violations involving missed surveillances or inoperable equipment in accordance with NRC requirements. While some are older issues that are being identified now due to the licensee's increased sensitivity to Technical Specification compliance, others are the result of long-standing plant or program deficiencies that are just now being identified during routine operational or surveillance activities. (Section O1.2; [NEG-1A,1C,5A])

- Although the licensee's focus on safety was appropriate during the Plant Operations Review Committee meetings attended by the inspectors, it was noted that one recommendation regarding an interpretation of TS 4.6.5.1.b.2 was determined by the NRC to be incorrect. (Section O7.1; [NEG-5A])

- The integration of information into an automated control room log application was considered an improvement. (Section O8.1; [POS-1A])

- The detail provided in control room logs was not consistently sufficient to understand the basis for operational decisions or actions. (Section O8.1; [NEG-1A])

- The licensee's immediate response to an issue involving an inoperable component cooling water pump was appropriate. (Section O8.2; [POS-5C])

- The licensee's analysis of an issue involving an inoperable component cooling water pump failed to identify several opportunities for earlier identification of the inoperability. (Section O8.2; [NEG-5B]

Maintenance

- A licensee event report was submitted involving the licensee's failure to recognize an inoperable Unit 2 Channel 3 overtemperature delta temperature reactor trip setpoint and take action required by Technical Specification 3.3-1, Action 6, to trip the associated bistable within 6 hours. Further N[illegible] review of this matter will be conducted under the licensee event report followup. (Section M3.1; [LER-2B])

- An unresolved item was identified pending additional NRC review of the licensee's methodology of setting Reactor Protection System and Engineered Safety Features Actuation System trip setpoints outside

limits specified in the facility's Technical Specifications. (Section M3.2; [URI-2B, 4C])

- Inspectors identified a violation associated with an inadequate procedure governing a flush of piping from the nuclear service water system to the auxiliary feedwater system. The procedure did not direct personnel to declare affected auxiliary feedwater system pumps inoperable during the pipe flush, which potentially diverted a sufficient amount of flow from the pumps to render them inoperable. (Section M3.3; [VIO-2B,4A,4B])

- Actions to correct the procedural inadequacy associated with the nuclear service water system to auxiliary feedwater system pipe flush were completed in a timely manner. (Section M3.3; [POS-5C])

- The Second Ten-Year Interval Program Manual for the second ten-year inservice test interval contained the proper elements of the American Society of Mechanical Engineers/American National Standards Institute Operations and Maintenance Code Standards. (Section M3.4; [POS-2B])

Engineering

- An unresolved item was opened pending additional NRC review of the basis for installing portable air sampling equipment with tygon tubing. (Section E3.1; [URI-4A,4B,5C])

- A non-cited violation was identified concerning a 1996 non-compliance with Technical Specification 3.4.6.1 due to the omission of Regulatory Guide 1.45 related computer points for EMF-38 and EMF-39 during the design of the operator aid computer replacement modification. (Section E8.2; [NCV-4C; POS-5A])

- A non-cited violation was identified concerning a 1996 non-compliance with Technical Specification 3.4.6.1 due to a nonconservative calculation of the rate of change for the containment floor and equipment sump level monitoring subsystem. (Section E8.3; [NCV-4A,4B; POS-5A])

- Deficiencies have been identified with previous licensee event reports over the last two years for which licensee personnel have initiated corrective actions to improve the quality of reports submitted to the NRC. (Section E8.3; [NEG-4C])

Plant Support

- The licensee's radiological protection performance was adequate. (Section R1.1; [POS-1A])

Report Details

Summary of Plant Status

Unit 1 began the period operating at 100 percent power. On August 7, 1998, a Technical Specification-required shutdown to Mode 3 (and subsequently to Mode 5 on August 8) was completed due to blocked flow passages in the ice condenser, which had been declared inoperable on August 5. The unit remained shut down in Mode 5 through the end of the inspection period in order to complete ice condenser inspection and repair efforts.

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 and communications, and adherence to approved procedures. The inspectors attended operations shift turnovers and site direction meetings to maintain awareness of overall plant status and operations. Operator logs were reviewed to verify operational safety and compliance with Technical Specifications (TS). Instrumentation, computer indications, and safety system lineups were periodically reviewed, along with equipment removal and restoration tagouts, to assess system availability. The TS Action Item Log (TSAIL) books for both units were reviewed daily for potential entries into limiting conditions for operation (LCO) action statements. The inspectors conducted plant tours to observe material condition and housekeeping. Problem Identification Process (PIP) reports were routinely reviewed to ensure that potential safety concerns and equipment problems were resolved. The inspectors identified some examples of insufficient detail provided in control room logs which are described in Section O8.1. Otherwise, no problems were identified by the inspectors.

O1.2 Onsite Followup of Events

a. Inspection Scope (93702, 71707)

The licensee made several 24-hour notifications to the NRC in accordance with 10 CFR 50.72 during the inspection period. The reportable items were reviewed for safety significance, root causes, corrective actions, common themes, and to determine whether the items were reported in accordance with NRC requirements.

b. Observations and Findings

The licensee requested and received enforcement discretion from the NRC for requirements associated with two of the four reportable events discussed in this section. Additionally, a Notice of Enforcement

Discretion (NOED) was granted for a third item discussed in Section M1.2 of this report. The following reportable items were reviewed:

Inoperable Control Room Ventilation System

On July 6, 1998, an improperly secured damper used to isolate redundant trains of the control room ventilation system inadvertently opened when pressurized by the B train while the A train pressure boundary was inoperable and breached for modification implementation. This resulted in the control room pressure boundary being degraded and incapable of being pressurized by either train of the control room ventilation system, placing both units in TS 3.0.3. The event was reported to the NRC within 1 hour in accordance with 10 CFR 50.72 (b)(2)(iii)(D) and documented in licensee event report (LER) 50-413/98-12. This represented the sixth reportable event in 1998 involving ventilation systems caused by missed surveillance tests, improper configuration control, or human performance errors that led to TS 3.0.3 entries. As a result of the multiple reportable events, the licensee initiated an internal Event Investigation Team (EIT) to address potential common themes and/or failure mechanisms. The licensee had not documented its EIT findings by the close of this inspection period. The inspectors will conduct a further review of this event along with the recent negative trend in ventilation system configuration control and surveillance testing practices. The inspectors' review, which will also address the regulatory significance of the recurring issues, will be tracked under LER 50-413/98-12.

Inoperable Refueling Water Storage Tank (RWST) Level Detection Channels

On July 23, 1998, the licensee made a 4-hour report per 10 CFR 50.72 (b)(1)(ii)(B) when two of four RWST level channels in each unit failed due to lightning strikes. The licensee declared the channels inoperable and entered TS 3.0.3 for both units, eventually exiting TS 3.0.3 for Unit 1 when one of the two channels was restored to normal indication before the action statement requirement to be in Hot Standby (Mode 3) expired. The licensee ultimately requested and received a NOED (98-2-001) for Unit 2 to allow repairs to continue prior to the expiration of TS 3.0.3. More details of this reportable item are discussed in Section 08.6 of this report.

Inoperable Auxiliary Building Ventilation System due to Inadequate Surveillance Testing of Emergency Core Cooling System (ECCS) Pump Rooms

The licensee determined on July 22, 1998, that previous test procedures had not properly verified that the ECCS pump rooms were maintained by the auxiliary building ventilation system at a negative pressure with respect to all adjacent areas. Specifically, the licensee's procedures previously tested adjacent areas by performing smoke tests on doors separating the rooms from various hallways. They did not verify a negative pressure relative to adjacent duct shafts, pipe trenches, and the mechanical penetration room. The licensee declared both trains of auxiliary building ventilation systems for both units inoperable and

invoked TS 3.0.3 and TS 4.0.3, which allowed 24 hours to successfully complete the testing on either train for both units or initiate shutdown to Mode 3 and subsequently Mode 5. The licensee reported this issue per 10 CFR 50.72(b)(1)(ii)(B) as a potential condition outside design basis and subsequently submitted LER 50-413/98-09.

On July 22 and 23, 1998, the inspectors observed testing of the pump rooms under newly revised procedures (PT/0/A/4450/004A, Auxiliary Building Filtered Exhaust System Performance Test, Rev. 41) which measured the differential pressure with respect to all adjacent areas for each pump room. The inspectors verified that the revised testing satisfied TS requirements.

The inspectors will address the regulatory significance of the past testing deficiencies in conjunction with the LER review.

Unit 1 Ice Condenser Flow Channel Blockage

On August 5, 1998, the licensee identified several blocked flow channels in bays 13, 20, and 23 of the Unit 1 ice condenser while performing TS surveillance requirement 4.6.5.1.b.2). The licensee declared the ice condenser inoperable and, on August 8, completed a unit shutdown to Mode 5 as required by TS. A report was submitted in accordance with 10 CFR 50.72 (b)(1)(I)(A) formally notifying the NRC of the operability issue and TS-required shutdown.

The licensee later identified more significant ice blockage in the bay 5 flow channels and preliminarily determined that the Unit 1 ice condenser had been inoperable since June 1996 when a block ice press leaked water in the ice bed during the steam generator replacement outage. The licensee and the inspectors later identified several other degraded conditions associated with the Unit 1 ice condenser, including: foreign material; dented baskets; loose intermediate deck door bolts; missing basket top ring screws; loose tape on top deck doors; and unapproved modifications (i.e., wire mesh in the intermediate deck area behind ventilation ductwork and flexible material used as a thermal insulation barrier on the top deck of the ice condenser). The unit remained in a forced outage for the remainder of the inspection period pending resolution of these degraded conditions.

Additionally, the NRC determined on August 12, 1998, that the licensee had previously been in noncompliance with specific wording in TS surveillance requirement 4.6.5.1.b.2) to perform every nine months an inspection of the lower inlet plenum structures and turning vanes for ice or frost accumulation. The NRC granted enforcement discretion (NOED 98-6-015) for this requirement pending the receipt and approval of a TS amendment request to modify the frequency of the requirement, which could only be performed with the reactor shutdown. The licensee submitted a TS amendment request on August 14, 1998. Additional detail concerning these issues will be provided in special NRC Inspection Report 50-413,414/98-13. The licensee will document the TS-required shutdown in LER 50-413/98-15, along with the licensee's root cause

determination, discussion of safety significance, and corrective actions. The inspectors will address the regulatory significance of the past surveillance practice in conjunction with the LER review. The NOED will remain open pending this review.

c. Conclusions

The licensee reported Technical Specification violations involving missed surveillances or inoperable equipment in accordance with NRC requirements. While some are older issues that are being identified now due to the licensee's increased sensitivity to Technical Specification compliance, others are the result of long-standing plant or program deficiencies that are just now being identified during routine operational or surveillance activities.

01.3 Operations Clearances (71707)

The inspectors reviewed the following clearances during the inspection period:

- Tagout 18-914 Fuel Pool Ventilation System
- Tagout 28-665 Component Cooling (KC) Water System - Maintain Pump 2A1 Operable for Train Availability
- Tagout 28-663 Component Cooling Water System - PM on 2KC Pump 2A1
- Tagout 28-668 Component Cooling Water System - To Support KC HX 2A Cleaning
- Tagout 28-688 Component Cooling Water System - Change 2KC-31 From Reverse Acting to Clockwise to Close
- Tagout 28-710 Residual Heat Removal (ND) System - Calibrate ND Pump 2A Miniflow Controller

The inspectors observed that the clearances were properly prepared and authorized and that the tagged components were in the required positions with the appropriate tags in place. The inspectors identified a discrepant valve position associated with 2KC-001A, Component Cooling Water System Auxiliary Building Non-essential Return Header Isolation Valve, controlled closed under Red Tag 4840, Tagout 28-685. The inspectors notified the Shift Work Manager, who later determined that the valve was positioned in accordance with the governing tagout, but that the valve position had been incorrectly labeled (in black marker) such that the open and closed indications on the valve actuator were reversed. The licensee took actions to remove this operator aid in a timely manner, however, no permanent indication of valve position was subsequently provided on the valve. The inspectors noted that uncontrolled operator aids had been previously identified by NRC inspectors and documented in NRC Inspection Report 50-413,414/96-20.

The inspectors noted that the licensee does not have a procedure to control operator aids with respect to valve position indication. Hence, this occurrence was considered as an example of poor performance.

O7 Quality Assurance in Operations

O7.1 General Comments (40500)

The inspectors attended several Plant Operations Review Committee (PORC) meetings during the period that addressed various TS compliance issues, missed surveillances, NOED requests, and operational issues (discussed throughout this inspection report). Although the licensee's focus on safety was appropriate during the PORC meetings attended by the inspectors, it was noted that one recommendation regarding an interpretation of TS 4.6.5.1.b.2. was determined by the NRC to be incorrect.

O8 Miscellaneous Operations Issues (92901, 92700)

O8.1 (Closed) Inspector Followup Item (IFI) 50-413,414/96-20-03: Log Keeping Practices

This item was opened pending the licensee's assessment of logkeeping practices. During previous NRC inspections (documented in NRC Inspection Reports 50-413,414/96-02 and 96-16), numerous problems with control room logs were identified. Specifically, control room logs lacked detail; little information regarding equipment operability status was documented in the control room logs; it was difficult to determine the chronology of events because numerous different "satellite" logs contained information pertinent to plant operations and equipment status; and minimal entries in operations logs precluded their use as a diagnostic tool for identifying and correcting equipment problems in a timely manner.

To address the NRC's concerns regarding the quality of control room logs, the licensee initiated PIP 0-C97-0763, which assigned corrective actions to the operations organization. The licensee subsequently adopted an electronic log-keeping program (Autolog) that integrated all "satellite" log books into a single log. The objective of this change was to ensure that logs were sufficiently complete to facilitate detailed event reconstruction.

The inspectors reviewed log entries associated with various events that occurred between December 1997 and the present to assess the quality of log entries. The integration of the logs into an automated, computer-based tool was effective in providing a centralized source of information for event reconstruction; however, the level of detail provided in the logs was not consistently sufficient to understand the basis for operational decisions. The inspector noted that entries associated with the Technical Specification Action Item Log (TSAIL) often did not provide information regarding why a system or component was inoperable (e.g., for scheduled maintenance, surveillance testing,

equipment problems, etc.). Specifically, the inspector reviewed logs associated with the May 7, 1998, Unit 1 upper surge tank heat-up event (discussed in NRC Inspection Reports 50-413,414/98-06 and 98-07). The inspector was unable to infer a relationship between auxiliary feedwater (AFW) system inoperability and the status of valves 1CM-127, 1CA-291, and 1CA-292. As such, a review of other documentation (e.g., Shift Work Manager's logs, PIPs, etc.) or corporate memory would be necessary to understand the basis for AFW system inoperability and associated corrective action. The inspectors identified an additional example of insufficient detail when reviewing logs associated with the June 27, 1998, Unit 1 shutdown. The reason for the unit shutdown (to repair a leak in the AFW tempering flow line to the C steam generator) was not provided in the logs.

The inspectors also reviewed Operations Management Procedure (OMP) 2-17, Unit Unified Logbook Maintenance, Revision 29, and Nuclear Policy Manual Chapter 3, Nuclear Site, Section 3.1.3.6, Operations Records. General Instruction 6.3 of the Nuclear Policy Manual stated that sufficient entries shall be made to permit the reconstruction, at a later date, of the sequence of events during a shift. The inspectors concluded that, although the sequence of events could be reconstructed, the reasons for some operational decisions or actions were not provided in the logs.

The inspectors also noted that unit designations for equipment were occasionally incorrect, and equipment was characterized as "cleared from TSAIL" or "operable" when a TSAIL item number was removed from the log, even though another TSAIL item was outstanding and the equipment was, therefore, still inoperable.

The inspectors discussed these observations with operations shift management, who indicated that similar observations had been previously noted and documented in PIP 0-C98-1987.

In conclusion, the integration of information into Autolog constituted an improvement; the detail provided in control room logs was not consistently sufficient to understand the basis of operational decisions or actions; and the licensee has initiated corrective actions to improve the quality of control room logs.

08.2 (Open) LER 50-414/97-003: Component Cooling System Unavailability

This LER documented an event in which engineering determined that between January 25, 1997, and February 17, 1997, the 2A1 KC pump would not have restarted automatically during an event following a load shed. The documentation reviewed indicated that the pump motor breaker would not close on demand because the closing springs were not fully charged. The licensee determined that the root cause of the springs not fully charging was a failure of the breaker charging spring motor coils on January 25, 1997.

The inspectors evaluated the licensee's immediate response to the issue and concluded that the licensee responded appropriately. The licensee adequately identified the root cause.

However, the inspector also concluded that the licensee failed to document in the LER other concerns associated with the event. Specifically, the licensee failed to evaluate if there were missed opportunities to determine that the springs were not fully charged during the three-week period of inoperability.

Documentation reviewed by the inspectors indicated that operators performed weekly electrical power source alignment checks per procedure PT/2/4350/03, Electrical Power Source Alignment Verification. During these checks, the operators were required to verify that the 2ETA-6 breaker springs were charged. Documentation indicated that the operators performed PT/2/4350/03 to verify that the breaker springs were charged on January 27, 1997, February 3, 1997, and February 10, 1997. The documentation indicated that on each of these occasions, operators checked that the springs were fully charged. This would suggest that operators missed three opportunities to identify the inoperable pump, one of which (January 27) could have prevented the TS LCO action statement from being exceeded. Based on the above, the inspectors concluded that the operators failed to determine that the spring was not properly or completely charged. Pending additional NRC review of the availability of the other KC pumps and other ECCS equipment during the period KC pump 2A1 was unavailable, this LER will remain open.

08.3 (Closed) LER 50-413/96-005: Automatic Reactor Trip With The Unit Subcritical Due to an Equipment Failure

This LER described a Unit 1 event in which an automatic reactor trip occurred due to an inverter failure while the reactor was subcritical in preparation for a scheduled refueling outage. This event was described in Inspection Report 50-413,414/96-08, Section 01.3. In that report, the inspectors concluded that the operators' response to the event was adequate, the plant functioned as designed, and the followup investigation to identify the cause of the component failure was also adequate. The inspector also verified that the subsequent corrective actions identified in the LER had been complete. No violations or deviations were identified. This LER is closed.

08.4 (Closed) LER 50-413/96-014: Technical Specification Required Unit Shutdown Due to Equipment Failure

This LER described an event in which Unit 1 was shutdown following the failure of a solid state protection system train B relay. The shutdown was required by TS because the failure analysis, planning, and replacement of the relay could not be performed within the time frame permitted by TS. The inspectors concluded that the licensee's actions to shutdown the plant in response to the failed component were adequate and performed as required. The inspectors also verified that subsequent

corrective actions identified in the LER were completed. This LER is closed.

08.5 (Closed) LER 50-413/96-003: Forced Shutdown Due to a Rod Control Malfunction

This LER documented an event in which the licensee was required to perform a TS required shutdown of Unit 1 due to rod control failure. This event was documented in NRC Inspection Report 50-413,414/96-08, Section 01.2. The cause of the rod control failure was attributed to a failed logic firing card. As concluded in Inspection Report 50-413,414/96-08, the actions taken by the licensee to identify the root cause of the rod control malfunction were adequate. This LER is closed.

08.6 (Closed) LER 50-413/98-11: Condition Prohibited by Technical Specifications - Two Refueling Water Storage Tank Level Channels on Each Unit Inoperable Due to Lightning Activity

On July 23, 1998, Units 1 and 2 entered TS 3.0.3 when two of the four channels of refueling water storage tank (RWST) water level instrumentation (two per unit) failed during an electrical storm. Technical Specification 3.0.3 required that the units be in Hot Standby by 12:31 a.m., on July 24, 1998, if at least one of the inoperable channels per unit could not be restored to operable status.

One of the inoperable Unit 1 channels was returned to an operable status within the allowed outage time, and Unit 1 exited TS 3.0.3. The remaining inoperable Unit 1 channel was bypassed in accordance with TS 3.3.2, Action 16a.

The licensee determined that the two inoperable Unit 2 RWST level channels required transmitter replacements, which could not be performed within the time period allowed by TS 3.0.3. The licensee requested enforcement discretion to allow them an additional 48 hours to restore at least one of the inoperable Unit 2 RWST level channels to an operable status or be in Hot Standby.

The NRC verbally granted enforcement discretion on July 23, 1998, and provided a written NOED (98-2-001) on July 24, 1998. The NOED was granted contingent on the licensee's compensatory measure of a dedicated operator to monitor level indications provided by the two remaining operable RWST level transmitters. This operator would be responsible for directing manual swapover to the containment sump in the event that the automatic swapover did not occur during a potential loss of coolant accident.

The inspectors verified that one of the Unit 2 inoperable RWST level channels was restored to operable status at 10:27 a.m., on July 24, 1998. Unit 2 exited TS 3.0.3 within the time period allowed in the NOED. The remaining inoperable channels in Units 1 and 2 were returned to service when the transmitters were replaced and recalibrated on July 25, 1998.

The safety significance of the inoperable RWST level channels was minimized by the fact that the two other channels in each unit remained operable and thereby would have satisfied the required logic to

automatically initiate a containment sump swapover on low RWST level following a safety injection. Additionally, the inspectors verified that the compensatory actions established in the control room were adequate to ensure continuous attention to Unit 2 RWST level status. The licensee established a multi-discipline team to review the root cause of the transmitter failures and to identify potential long-term corrective actions. Evaluation of additional lightning protection measures was identified as a corrective action in PIP 1-C98-2630. No violations were identified. This LER and associated NOED 98-2-001 are closed.

O8.7 (Closed) Unresolved Item (URI) 50-413,414/97-300-02: Catawba Updated Final Safety Analysis (UFSAR) Discrepancies

This URI concerned two issues. The first involved a failure to perform a safety evaluation with an unreviewed safety question determination for compensatory actions associated with the realignment of the auxiliary feedwater system pumps' normal suction sources. This issue was subsequently dispositioned as Violation 50-413,414/98-01-05.

The second issue involved Emergency Procedure EP/1(2)/A/5000/ECA-1.1, Loss of Emergency Coolant Recirculation, which directs manual operator action to defeat the automatic swap of ECCS pump suctions from the refueling water storage tank (RWST) to the containment sump on RWST low-low level when an inter-system loss of coolant accident (ISLOCA) results in inadequate emergency sump levels to support ECCS pump operation. As ISLOCAs and related manual operator actions were not addressed in the UFSAR, the potential of an unreviewed safety question was identified. Subsequent review by the inspectors of the 10 CFR 50.59 evaluation for EP/1(2)/A/5000/ECA-1.1, which was based on the Westinghouse Owners Group (WOG) Emergency Response Guideline (ERG) ECA-1.1, indicated compliance with Technical Specifications and that the assumptions used in UFSAR Chapter 15 accident analysis were not affected. Problem Identification Process report 0-C97-4239, written to address related NRC concerns, reiterated that ISLOCA events resulting in inadequate sump levels were non-bounding and confirmed that the auto swap defeat feature was not added after the original UFSAR, but contained in the original plant design. Accordingly, having verified that UFSAR Sections 1.8.1.8 and 13.5.2.1.2 recognize the WOG ERGs and associated deviation documents as the Catawba Emergency Procedures, this URI 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 portions of the following maintenance and surveillance activities:

- IP/2/A/3222/001C, Revision 16, Refueling Water Storage Tank Level Channel 3
- T/1/A/4350/002B, Revision 87, Diesel Generator 1B Operability Test
- OP/A/6450/011, Revision 99, Control Room Area Ventilation/Chilled Water System
- IP/0/A/3162/005, Revision 26, Control Room Ventilation System Chlorine Detectors
- PT/0/A/4200/017, Revision 22, Standby Shutdown Facility Diesel Test
- MP/0/A/7450/080, Revision 1, Troubleshooting And Corrective Maintenance of HVAC Dampers (Including Fire Dampers)
- PT/0/A/4450/001C, Revision 12, Auxiliary Building Filtered Exhaust Filter Train Performance Test
- IP/0/A/3710/002, Revision 30, Battery Removal, Replacement, Storage and Handling, (used to replace cell 94 in the 2B DG battery bank)
- PT/2/A/4200/001E, Revision 27, Upper Containment Personnel Air Lock Leak Rate Test
- PT/0/A/4450/004A, Revision 41, Auxiliary Building Filtered Exhaust System Performance Test

In general, the referenced maintenance and surveillance activities were performed well, with proper adherence to procedural compliance, equipment calibration, and radiation protection requirements.

M1.2 Missed Diesel Fuel Oil System Surveillance Test

a. Inspection Scope (61726)

On August 5, 1998, the licensee identified a missed TS surveillance requirement involving the emergency diesel generator (EDG) fuel oil system. The inspectors reviewed the circumstances of the missed surveillance and evaluated the licensee's actions to resolve the issue.

b. Observations and Findings

TS surveillance requirement 4.8.1.1.2.i.2 required the licensee to perform pressure testing of the EDG fuel oil system every ten years (with a two and one half year grace period). The TS specifically required that those portions of the diesel fuel oil system designed to Section III of the ASME Code be subjected to a test pressure equal to 110 percent of system design pressure. The licensee had previously been performing the test at nominal system pressure. All four EDGs were

declared inoperable at 5:55 p.m. on August 5, 1998, and the licensee entered TS 3.8.1.1 Action f for both units. The licensee had been conducting the alternative test in accordance with ASME Section XI Code Case N-498-1, which had been previously approved for use by the NRC on February 13, 1995. However, the licensee failed to request an amendment to TS 4.8.1.1.2.i.2 at that time to incorporate the Code Case exemption.

The licensee later determined that only the Unit 1 diesels were technically inoperable since their testing interval had expired. For Unit 2, which was licensed in 1986, the licensee had until November 1998 to properly conduct the TS surveillance. The licensee determined that testing the system at the TS-specified pressure for either unit was not reasonable and requested enforcement discretion on August 6, 1998. The request was to allow the EDGs to be considered operable as demonstrated by the alternative testing method, thereby precluding the need to perform the test at the TS-specified pressure. The NRC verbally granted enforcement discretion on August 6, 1998, and provided a NOED (98-6-013) to the licensee on August 7, 1998. The previously missed surveillance for Unit 1, due to a failure to request a TS amendment, constituted a violation of minor significance and is not subjected to formal enforcement action. Associated NOED 98-6-013 will remain open pending issuance of the related TS and review of LER 50-413/98-14.

c. Conclusions

The inspectors concluded that the missed surveillance for Unit 1 was due to an oversight on the licensee's behalf when, upon receiving NRC approval to invoke ASME Section XI Code Case N498-1 in 1995, they failed to request a TS amendment removing the specific requirement for testing the emergency diesel generator fuel oil system at 110 percent of design pressure. This was considered a minor violation.

M3 Maintenance Procedures and Documentation

M3.1 Inoperability of a Unit 2 Reactor Protection System (RPS) Channel 3 Function

a. Inspection Scope (61726)

On July 17, 1998, the licensee identified an error in procedure IP/2/A/3222/000C, Analog Channel Operational Test (ACOT) III 7300, Revision 49. As a result of the error, an out-of-calibration channel of the Over Temperature Differential Temperature (OTΔT) trip setpoint was undetected during quarterly testing on April 14, 1998, and remained inoperable for three months. The inspectors reviewed TS requirements and bases, associated procedures, and PIP 2-C98-2463. The inspectors also discussed the issue with engineering and regulatory compliance personnel.

b. Observations and Findings

On April 14, 1998, IP/2/A/3222/000C, which implements a TS surveillance requirement to verify that the Unit 2 Channel 3 Engineered Safety Features Actuation System (ESFAS) and RPS setpoints are properly calibrated on a quarterly basis, was performed. Because of a procedural error, licensee personnel failed to recognize that the "as found" and "as left" voltage readings for the OTΔT reactor trip setpoint bistable were outside TS setpoint allowable values. The procedural error involved a referenced allowable value of ≥ 3.105 volts. The correct allowable value was ≤ 3.389 volts. The "as left" value was 3.635 volts, which exceeded the correct allowable value. Calibration technicians determined (based upon the incorrect values in the procedure) that Channel 3 of the OTΔT trip function was out-of-calibration, but operable. Work order 98037244 was written to recalibrate a lead-lag circuit card that the technicians suspected had caused the out-of-calibration values. Work was initiated nearly three months later on July 8, 1998, but technicians could not identify a problem with the lead-lag card.

Engineering was contacted for assistance, and engineering personnel identified the procedure error during their review of the procedure on July 13, 1998. At 8:24 p.m., on July 13, the licensee declared the Unit 2 Channel 3 OTΔT reactor trip function inoperable. The associated bistable was tripped in accordance with TS 3.3.1, Table 3.3-1, Action 6. The calibration procedure was revised to correct the errors, the channel was calibrated to within limits on July 14, 1998, at approximately 3:00 a.m., and the channel was taken out of the tripped condition. The licensee reviewed procedures associated with calibration of the other channels of the RPS for both units and determined that, although the same error was made in all eight (four per unit) ACOT procedures, all other channels were calibrated within allowable limits.

The licensee initiated PIP 2-C98-2463 to document the issue. Because the channel 3 out-of-calibration condition was undetected on April 14, 1998, the applicable TS action (to trip the bistable associated with the inoperable channel within 6 hours) was not taken. The licensee notified the NRC of this TS non-compliance in LER 50-414/98-03. Additional NRC review of the non-compliance, including an assessment of regulatory significance, will be tracked with the LER.

c. Conclusions

An inadequate procedure resulted in an inoperable Overtemperature Delta Temperature channel. Although unaware of the inoperability, the licensee delayed the recalibration of the TS instrument, resulting in it being inoperable for nearly three months.

M3.2 Reactor Protection System Trip Setpoint Values

a. Inspection Scope (61726)

The inspectors reviewed analog channel operational test procedures and PIPs 0-M98-0966 and 0-C98-1186 to address a generic issue related to the setting of reactor protection system trip setpoints as a result of the issue discussed in Section M3.1 above, and a recent Catawba PIP on the subject. The inspectors conducted this review to determine whether as-left trip setpoints were within TS-specified limits.

b. Observations and Findings

The inspectors noted that procedure IP/2/A/3222/000C provided data sheets for the setpoint values that allowed the "as left" values to fall within a range around the setpoint values, although the TS Tables 2.2-1 and 3.3-4 provided setpoint values for reactor trip functions (e.g., Power Range Neutron Flux, Pressurizer Pressure - Low, Steam Generator Water Level Low-Low) that were equal to or more conservative than the setpoints listed in the data sheets. The TS tables did not provide for a range around the TS setpoints, although the licensee's calibration procedures did. As a result, the inspectors identified multiple examples whereby the "as left" setpoint values were outside the TS trip setpoint limits specified in the TS setpoint tables, but within the allowable limits.

The inspectors questioned the appropriateness of specifying a desired voltage range that exceeded the value specified in the TS setpoint tables. The licensee had initiated PIP 0-C98-1186 to document a concern that had been identified by the Nuclear Safety Review Board in May 1998. The PIP indicated that the TS bases characterized the reactor trip and ESFAS setpoints in Table 2.2-1 and 3.3-4 as "nominal," or approximate, values. The licensee indicated that calibrating the setpoints within a range that represented the accuracy band of their measuring and testing equipment was in compliance with the TS Bases.

The inspectors also reviewed Task Interface Agreement (TIA) 97-007 to understand the NRC's position on the issue with respect to a different Westinghouse plant. According to the TIA, the applicable Westinghouse Setpoint Methodology for Protection Systems also characterized the TS setpoints as nominal, or approximate, values. However, while the setpoint methodology and the TS Bases both agreed that the TS setpoints were nominal values, the reactor trip and ESFAS TS limits were presented in the accompanying LCOs as "Trip Setpoint" and "Allowable Value" table entries. As such, minimum or maximum values (with associated inequality symbols) for each function, rather than trip setpoint *nominal* values, were specified. The NRC further argued that 10 CFR 50.36(a) states that a summary statement of the bases or reasons for specifications shall be included in a license application, but that the bases shall not become part of the TS. The NRC's position was that the licensee was required to comply with the TS, and that the TS Bases did not provide requirements or relief.

Pending additional NRC review of this issue, this is characterized as URI 50-413,414/98-08-01: Failure to Establish RPS and ESFAS Trip Setpoints in Accordance With TS Limits.

c. Conclusions

An unresolved item was opened pending further NRC review of a potential non-compliance with TS requirements governing RPS and ESFAS trip setpoints.

M3.3 Nuclear Service Water System Flow to the Auxiliary Feedwater System

a. Inspection Scope (61726)

The inspectors observed a periodic clam flush of the nuclear service water (RN) system piping that supplies the Unit 1 CA system. The inspector questioned the operability of the CA system during the pipe flush, discussed the evolution with test technicians and engineering personnel, and reviewed governing procedures.

b Observations and Findings

In 1987 and 1988, the licensee identified a clam infestation in the RN system that threatened the operability of the RN system, as well as the CA system, since RN is the assured suction source for CA. This issue was documented in PIP 0-C87-0003. To ensure that the RN system was not degraded by future clam infestations, the licensee initiated a routine pipe flush to monitor for the presence of clams. The pipe flush has been performed monthly in accordance with PT/1(2)/A/4200/059, RN to CA Suction Pipe Flush.

On March 4, 1998, the inspectors observed a monthly flush of the RN system piping that supplies the Unit 1 B-train motor-driven CA pump and the turbine-driven CA pump. The CA system was not declared inoperable and logged in the TSAIL during the conduct of the test. The inspectors asked the licensee how much flow was diverted from the CA system during the pipe flush, and if sufficient flow was available to the CA system to ensure that the system was capable of performing its safety function upon demand.

The 10 CFR 50.59 evaluations performed in April 1988 to support RN to CA pipe flushing for Units 1 and 2, considered a loss of coolant accident (LOCA) to evaluate the impact of the pipe flush on the CA system's operability. However, in the process of formulating a response to the inspectors' question, the licensee determined that a main steam line break (MSLB) or feedwater line break (FWLB) event would yield the greatest RN to CA demand. Analysis assuming RN to CA flow demand during a MSLB or FWLB event, concurrent with a failure of the opposite (non-flushed) train of RN, indicated that flow assumptions for the turbine-driven CA pump and the motor-driven CA pump associated with the flushed train could not be met with the flush in progress. Therefore, the

associated train's motor-driven CA pump and the turbine-driven pump (for each unit) during the pipe flush were inoperable.

The inspectors reviewed procedures PT/1/A/4200/059, RN to CA Suction Pipe Flush, Revision 31 and PT/2/A/4200/059, RN to CA Suction Pipe Flush, Revision 32, and determined that the procedures were inadequate in that they did not indicate that two CA pumps would be inoperable during the conduct of the test and direct personnel to log the items in TSAIL. This constitutes a violation of TS 6.8.1.a, and is characterized as Violation (VIO) 50-413,414/98-08-02: Failure to Declare Two CA System Pumps Inoperable During RN to CA Pipe Flu

The licensee determined that the flushes were not of sufficient duration to have exceeded the outage time allowed by the TS 3.7.1.2 action requirement. Therefore, no NRC notification was required. The inspectors reviewed procedures completed since July 1997 and verified that the times the flushes were in progress did not exceed the 6-hour inoperability time allowed by TS; no reportability requirements were violated.

After determining the impact of a MSLB or FWLB upon CA system operability, the licensee took immediate action to place the procedures governing the RN to CA system pipe flushes on administrative hold until revisions could be completed to instruct test personnel to have the associated CA system declared inoperable during the performance of the pipe flush. The procedures were also enhanced to include additional controls for assuring control room communication to test personnel of an automatic start of the CA system so that it could be restored to proper operational alignment. The inspectors reviewed PT/1/A/4200/059, RN to CA Suction Pipe Flush, Revision 32, and PT/2/A/4200/059, RN to CA Suction Pipe Flush, Revision 33, to verify that the procedure changes were incorporated and approved on April 15, 1998.

c. Conclusions

In response to questions from the inspectors, the licensee determined that the CA system was inoperable during the periodic performance of RN to CA pipe flushing. A violation was identified because the procedure did not direct personnel to declare the CA system inoperable during the pipe flushing. Actions to correct the procedural inadequacy were completed in a timely manner.

M3.4 Inservice Testing Program

a. Inspection Scope (73756)

The inspectors performed an overview inspection of portions of the Inservice Testing (IST) Program and reviewed portions of the Second Ten Year Interval Program Manual to verify that components in the program were identified and that the required testing, frequency of testing, test parameters and justification for deferrals were specified. As part

of this overview, a limited scope review was performed of the containment penetration valve injection seal water (NW) system.

b. Observations and Findings

The inspectors determined that the licensee has implemented the ASME/ANSI Operations and Maintenance (OM) Standards endorsed by 10 CFR 50.55a and the 1989 edition of ASME Section XI Boiler and Pressure Vessel Code, Subsections IWP and IWV with the 1988 addenda. 10 CFR 50.55a(b) references the ASME/ANSI OM standards 1987 edition and OMa 1988 addenda as the applicable standards for programs initiated subsequent to 1992. The licensee's second ten year program interval began on August 19, 1995. Elements of the Code OM standards are incorporated into the Program Manual and in plant procedures. The systems included in the program were identified and pump and valve tables identified the components, type of tests, test frequencies, procedures and test deferrals.

The inspectors reviewed the NW system program and plant drawings to verify that all valves affecting the flow path of this system were tested in the IST program. All of these valves were in the program. Additionally, the inspectors verified performance of the required quarterly stroke time tests. Valve exercise testing to the full open position for a large number of the NW system check valves was deferred to refueling outages on the basis that the containment isolation valves they affect see operating system pressure and/or flow during normal operation. The licensee developed and issued Justification CN-NW-02 for this condition as a matter of record. The inspector concurred in the adequacy of this justification. Also, the licensee had developed a procedure for full flow exercising and for backflow testing of the check valves.

Procedures reviewed, in part or totally, included:

- PT/1/A/4200/001T, Containment Penetration Valve Injection Water System Performance Test, Revision 045
- PT/2/A/4200/09A, Auxiliary Safeguards Test Cabinet Periodic Test, Incorporating Changes 118 to 137
- PT/1/A/4200/001V, Containment Penetration Check Valve Backflow Test, Revision 014
- PT/2/A/4200/027, NW Valve Inservice Test, Revision 29
- SM/0/A/8030/001, Relief Valve Set Pressure Testing and Adjustment, Revision 003.

Portions of SM/0/A/8030/001, Revision 003, were reviewed by the inspectors and found generally adequate. Adequate instructions, acceptance criteria as specified on valve data sheets, leak testing and backpressure testing, where appropriate, were specified. However, in

review of this procedure, the inspectors noted that although a minimum hold time was specified to allow any leakage to fill the discharge cavity, a minimum hold time between tests was not clearly specified. Also a statement in Section 1 of the procedure appeared to state that if a valve failed the as-found test a second valve was not selected for testing. Discussion with the test engineers indicated that this was not intended. On an as-found failure, an additional valve is selected for testing. If the initial valve tested failed due to excessive leakage such that the test bench cannot compensate, the valve is repaired and then the as-found set pressure test is performed. The licensee does not consider that a valid IST as-found test failure has occurred until the set pressure test can be performed. However, when maintenance or repair is required to perform the set pressure test, a second valve is tested. The licensee indicated that the statement in the procedure would be reworded to clearly indicate the testing of the second valve. The licensee generated PIP C98-2885 to track and resolve the issue of minimum hold time and testing of a second valve on the failure of an as-found set pressure test.

c. Conclusions

The Program Manual for the second ten year IST interval contained the elements of the ASME/ANSI Operations and Maintenance Code Standards. The inspectors concluded that the procedures reviewed contained adequate instructions and acceptance criteria.

M8 **Miscellaneous Maintenance Issues** (92902, 92700)

M8.1 (Closed) LER 50-414/96-03: Technical Specification 3.0.3 Required Shutdown due to Ventilation System Motor Failures

This report documented the Unit 2 entry into TS 3.0.3 for inoperability of both trains of the control room ventilation (VC/YC) system and, while in Mode 4 following initiation of a unit shutdown as required by TS 3.0.3, a second entry into 3.0.3 for inoperability of both trains of the auxiliary building (VA) system. Fan motor failures were involved in both TS 3.0.3 entries. The licensee's corrective action included: (1) replacement of the VC/YC train A pressurizing fan motor; (2) vibration analysis of the VC/YC train B pressurizing fan motor in August 1996; (3) replacement of the VC/YC train B pressurizing fan motor in March 1997; and (4) replacement of the VA train A filtered exhaust fan motor. The inspector verified that these corrective actions were completed.

The licensee had determined that the root causes of the fan motor failures were not related; the NRC inspectors agreed with this conclusion (refer to NRC Inspection Report 50-413,414/96-13). Nonetheless, the licensee recognized that the number of motor failures had increased significantly in recent years and initiated a root cause analysis of the trend. A subsequent NRC inspection, documented in NRC Inspection Report 50-413,414/97-08, indicated that the licensee had taken appropriate measures to improve the general condition of motors.

The licensee currently is identifying areas for improvement in the motor testing program to improve their ability to detect and correct problems before motor failures occur. The licensee is also incorporating changes to their motor preventive maintenance program to provide guidance for periodic replacement of motor lubricating oil independent of vendor manual recommendations, which did not necessarily address oil replacement to prevent oil aging and degradation. The inspectors considered this an enhancement. This item is closed.

M8.2 (Closed) VIO 50-413/96-08-02: Failure to Follow Procedure When Adjusting MFIV Nitrogen Accumulator Pressure to Backseat Leaking MFIV

This item addressed the licensee's failure to follow procedure IP/0/A/3010/09B, Nitrogen Charging for Main Feedwater Isolation Valve Actuators, Step 10.2.24, which directed technicians to check the accumulator nitrogen pressure and, if appropriate, adjust the nitrogen pressure as closely as possible to desired pressure. The licensee reduced the pressure significantly below the desired pressure for approximately two minutes. At the reduced nitrogen accumulator pressure, the valve was potentially incapable of performing its safety function.

The licensee's response to the violation, dated August 1, 1996, listed the corrective actions to resolve this issue. These included review of management expectations with respect to deviating from procedure steps due to changing plant conditions, updating work order 95024430-01 package for 1CF-42 nitrogen check to document the procedure deviation and the reason for the deviation, communicating with all maintenance personnel the need to perform a thorough evaluation of working conditions prior to and during work activity execution, and developing a training package for all site personnel to reinforce the requirements of NSD 704, Technical Procedure Use and Adherence, with emphasis on procedure adherence and when it is acceptable to deviate from approved procedures. The inspector verified performance of the corrective actions which were documented in PIP 1-C96-1341. This item is closed.

M8.3 (Open) LER 50-414/96-005: Unit 2 Standby Shutdown System Potentially Outside Design Basis

LER 50-414/96-005 documented an event in which the licensee determined that Unit 2 operated outside its design basis due to the standby shutdown system (SSS) not being operable. The licensee determined that the SSS was inoperable due to system vent valve 2RC116 being inoperable. The vent valve, which was a self-contained automatic, float type vent valve, was installed to ensure that the condenser circulating water (RC) to CA piping was kept completely full. Documentation indicated that on July 10, 1996, the valve was found to be stuck in the closed position. With the valve stuck in the closed position, the removal of air at the systems high point was not possible. The inability to remove the trapped air prevented the RC to CA piping from being completely full. Valve 2RC116 was stuck in the closed position due to impacted mud and corrosion internal to the valve.

The inspectors reviewed documentation which indicated that the valve was required to assure system operability. Duke Power Company Catawba Nuclear Station Design Basis Specifications Volume 7, Specification CNS-1592.CA-00-0001, Revision 10, dated February 8, 1990, Section 31.2.5, RC Manway to CA Pump Suction Vent Valves, stated:

> "This automatic float valve removes air from the RC to CA manway to provide an air free suction source for CA when the RC supply is required. The valve also serves as a check valve if the RC to CA manway pressure goes negative. This valve is important because if it does not function properly and the RC water source is required, the turbine driven pump may become air bound causing the pump to fail."

Based on the information reviewed, the inspector agreed that, with the valve stuck in the closed position, the valve could not perform its intended design function. Therefore, the inability to remove air from the system as required by design resulted in the SSS being inoperable. Documentation reviewed also indicated that no valve maintenance had been performed on this valve since original installation.

The inspectors reviewed the corrective actions and verified that each corrective action had been implemented. However, questions were raised regarding the operability of the Unit 2 turbine drive CA pump as it related to TS surveillance requirement 4.7.13.5. Accordingly, pending further NRC review, this LER will remain open.

M8.4 (Closed) LER 50-413/96-07: Main Steam Safety Valves (MSSV) Outside Setpoint Acceptance Criteria

On June 11, 1996, during TS 3.7.1.1 related in-situ surveillance lift testing of Unit 1 Dresser MSSVs, 9 of the 20 valves exceeded the "as found" lift setpoint tolerance of $\pm$ 1 percent. Based on industry experience, the licensee attributed this setpoint drift to adhesion of the valves' disc and nozzle seating surfaces, primarily due to the surface finish between the two seating faces and the metallurgical properties of each material in combination with thermal transients. The affected valves usually trend downward after the first lift. Data indicates that this phenomena occurs with greater magnitude and with a high degree of repeatability following maintenance that includes lapping the seating faces.

A TS change reflecting a $\pm$ 3 percent "as found" lift setpoint tolerance was subsequently implemented on June 25, 1996. Through a review of MSSV test data for Units 1 and 2 since that time, the inspectors confirmed that "as found" lift setpoints have been within the required $\pm$ 3 percent. However, none of the 20 MSSVs in either unit have undergone recent seating surface lapping. As such, Catawba is currently involved with other utilities in assessing the use of different valve disc material as a possible solution to the sticking phenomena. The licensee determined that the 9 MSSV "as found" lift setpoints addressed in this LER were bounded by a previous safety analysis. The inspectors reviewed

all available MSSV lift test data back to 1988 for both units, verifying it was bounded by the screening/acceptance criteria of the safety analysis. Based on the above, and the fact that the licensee tests all 20 MSSVs per unit during surveillance testing (in lieu of the 20 percent prescribed by the governing ASME Section XI Boiler and Pressure Code), this LER is considered to be closed. No violations or deviations were identified.

M8.5 (Closed) URI 50-413/97-15-03: Anti-Reverse Rotation Devices Not Installed in the 1D Reactor Coolant Pump

The inspectors reviewed the licensee's corrective actions for problems leading to the December 1997 installation of the 1D reactor coolant pump motor without anti-reverse rotation devices. The pump, which was not operating, was found spinning backwards on December 28, 1997, with Unit 1 shutdown in Mode 5. Licensee personnel determined that the pump motor had been a spare that was refurbished prior to being installed in the plant during the 1EOC10 refueling outage earlier that month. The five anti-reverse ratchet pawls had been removed from the motor via a 1983 work order. However, there was no work order generated for the spare motor to have pawls installed. Prior to the October 1997 reassembly activities, the pump motor had been in warehouse storage.

The licensee determined there were no instructions for pawl installation provided in the maintenance procedure used to reassemble the motor. Upon discovery of the problem, licensee personnel installed the anti-reverse devices, and the pump has operated successfully since. A subsequent motor current signature analysis and a breakaway torque measurement confirmed that the pump motor was not damaged during one start attempt that had occurred during the refueling outage before the problem was identified. For long-term corrective actions, the licensee revised procedure SM/0/A/8400/005, Reactor Coolant Pump Major Corrective Maintenance, Revision 5, to include instructions for installing or verifying the installation of the anti-reverse rotation pawls.

The inspectors verified that the anti-reverse pawls were not discussed in the UFSAR for any accident mitigation or safety-related function. They were described in Chapter 5 of the UFSAR for equipment protection purposes. The inspectors also noted that the pump motor was only installed without pawls for a short period of time while the plant was already shutdown for a refueling outage. The error was identified by the licensee while performing inspection activities. The inspectors determined that the licensee's previously inadequate maintenance procedures have been corrected to prevent this type of error from occurring again. No regulatory violation was identified since the reactor coolant pump motor is not safety related.

M8.6 (Closed) URI 50-414/98-01-07: Operability of Valve 2NW-190A

This URI concerned the failure of NW Valve 2NW-190A to open on demand. On January 28, 1998, the licensee encountered difficulty in opening 2NW-190A. The valve was removed from the system and tested satisfactorily.

The valve was reinstalled and subsequently failed to stroke. The maintenance technicians determined that reactor coolant system (RCS) pressure differential of 2250 psig was across the valve. The valve was designed to open against a 150 psig differential. The licensee postulated that check valves in the hot leg injection line and the NW line had leaked allowing RCS to pressurize the valve to 2250 psig. To demonstrate that the valve would function when RCS pressure was removed, the licensee vented the line and the valve performed properly. Subsequently, the valve has performed properly on five stroke tests. Additionally, after venting the line, RCS pressure has not developed across the valve. The inspector determined that most probably the venting of the line at 2250 psig cleared some obstruction which had prevented the check valves from seating tightly.

The inspectors considered the following factors in assessing the valve's operability after the failure to stroke under RCS differential pressure in January. The valve's design function was to provide containment isolation valve injection water to safety injection valve 2NI-121A (hot leg injection valve) to prevent containment accident pressure from escaping through the associated penetration. The valve's initial failure to open was due to a differential pressure exceeding containment accident pressure. Therefore, the valve's function was being satisfied in that the pressure buildup in the line would have prevented containment accident pressure from escaping through the associated penetration. Finally, the inspectors verified that the containment high or high-high pressure signals would still be present throughout the accident, such that when pressure bled down to normal NW system pressure, the valve would have opened. The inspectors concluded that, once the appropriate test conditions were achieved after the venting in January, the valve passed TS acceptance criteria and was therefore operable. On the basis of the fact that the leak integrity of the penetration would have been maintained, and that the valve would have stroked under design conditions, this unresolved item is closed.

III. Engineering

E3 Engineering Procedures and Documentation

E3.1 Inadequate Design Documentation For Portable Radiation Monitors

a. Inspection Scope (37551)

On June 28, 1998, while performing a tour of the auxiliary building, inspectors identified several examples where portable air sampling equipment was staged for use, or connected to permanently installed plant radiation monitoring equipment with tygon tubing. The inspectors were concerned that the observed configuration was not in accordance with plant design drawings and discussed the installation history and documentation with licensee personnel. The licensee initiated PIP 0-C98-2126, which was reviewed by the inspectors along with design drawings of the affected radiation monitoring equipment skids.

b. Observations and Findings

Sample carts were used for the containment radiation monitors (1,2 EMF 38, 39, 40), the unit vent stack monitors (1,2 EMF 35, 36, 37), and the condensate steam air ejector exhaust monitors (1,2 EMF 33).

The inspectors noted that the portable air sampling equipment at Unit 1 and 2 EMFs 35, 36, 37, located on the 594' elevation in the auxiliary building, was connected to the radiation monitoring skid inlet and outlet sample connections and was valved in service. The inlet and outlet sample valves were ball valves which were locked open. Tygon tubing was used to pull a representative sample from the skid inlet piping and to connect the sample pump effluent discharge to the skid outlet piping. Unit 1 and 2 EMFs 35, 36, 37 are listed in UFSAR Section 16.11-7, Radioactive Gaseous Effluent Monitoring Instrumentation - Selected Licensee Commitments, Table 16.11-5, Item #3.

The inspectors requested design documentation supporting the installation and continuous use of the portable air sampling equipment, and whether a 10CFR 50.59 evaluation had been performed to evaluate the consequences to radiation monitoring capability if the tygon tubing ruptured. The inspectors also requested copies of the sampling procedures in order to assess their adequacy in controlling sampling evolutions involving permanently installed plant equipment.

The inspectors were provided with drawing CN-1499-MI-38, Instrument Detail, Unit Vent Radiation Monitor, Unit 1. The instrument detail identified the inlet and outlet sample valves with their associated 3/4-inch stainless tubing as capped with no mention of portable sampling equipment or the connection of tygon tubing. The drawing also specified in Note 8 that the sample valves were to be locked open to prevent inadvertent repositioning. The licensee was unable to provide any design documentation which would have provided administrative controls for installing the portable air sampling equipment. According to licensee personnel, the portable air sampling equipment was installed prior to Units 1 & 2 startups and has been used ever since that time.

The inspectors reviewed HP/0/B/1001/018, Revision 015, EMF Sampling, Section 4.4.4, Unit Vent Sampling, and concluded that the procedure, as written, did not adequately reconfigure the portable equipment to ensure that the permanent system integrity was maintained following sampling activities. The inspectors discussed this concern with a chemistry department scientist and was told that the EMF sampling procedure was being rewritten so it will conform to the standard of Nuclear System Directive 700, Independent Verification, Revision 3. The current procedure was classified as "Information Only" which meant it was not required to be present when the evolution is performed and did not contain signoffs and independent verification. This procedure rewrite will make the EMF sampling procedure more consistent with operational procedures that require signoffs for completed actions which could affect the configuration of operational plant equipment.

The inspectors concluded that the installed portable air sampling equipment was not consistent with the original design documentation and that the licensee had not determined the impact of this equipment, while in service, on the operability of permanent plant equipment. Pending additional NRC review, this issue is characterized as URI 50-413,414/98-08-03: Inadequate Design Documentation For Portable Radiation Monitors.

c. Conclusions

An unresolved item was opened pending additional NRC review of the basis for installing portable air sampling equipment with tygon tubing.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) VIO 50-413,414/96-13-02: Inadequate Procedures, Two Examples

Example one addressed a procedure change that directed operators to close valve 2ND-53, 2B Residual Heat Removal (RHR) heat exchanger inlet manual isolation valve, while warming up the 2B RHR pump and associated suction and discharge piping to within 50 degrees F of the reactor coolant system temperature for startup of the RHR system during normal plant cooldown. This procedure change was designed to prevent thermal deformation of the pump casing and subsequent casing leakage. The procedure caused thermally induced pressure locking of valve 2ND-53. The valve could not be opened manually by hand. A valve wrench was used in an attempt to open the valve, which resulted in a stem-to-disc failure that rendered the B train of RHR inoperable. Corrective actions consisted of drilling a hole in the upstream disc of valve 2ND-53, developing a management procedure for use by system engineers in their review of operations procedure revisions that will include manual valves susceptible to thermally induced pressure locking in addition to those valve types already identified in Generic Letter 95-02, and sending a notification to Westinghouse and INPO to alert other utilities to the possible effects of warming the residual heat removal pump as recommended in Westinghouse Technical Bulletin ESBU-TB-96-03-R0. These corrective actions were documented in PIP 2C96-2003, and were verified complete by the inspectors.

Example two addressed PT/1/A/4700/14, Retype number 0, Auxiliary Shutdown Panel 1B Functional Test, Enclosure 13.9, Control Room/Auto Closure of 1NI-65B and 1NI-88B. This enclosure listed eight effects of the manipulation of three transfer relays used to simulate control transfer from the control room to auxiliary shutdown panel (ASP) 1B. The enclosure was inadequate in that valve 1RN-58B, Nuclear Service Water Loop B Return to Standby Nuclear Service Water Pond Isolation Valve, and valve 1RN-843B, Nuclear Service Water to Conventional Low Pressure Service Water Isolation Valve, were inadvertently realigned during performance of the testing. As a result, the valves repositioned during the test, isolating flow to a portion of the nuclear service water system that was in service to support a liquid radioactive release.

Corrective actions included restoring the nuclear service water system to its proper alignment and implementing procedure corrections to preclude any repeat occurrences. These corrective actions were documented in PIP 0-C96-2123 which was closed on November 24, 1997, and were verified complete by the inspectors. This item is closed.

E8.2 (Closed) LER 50-413/96-13: TS 3.4.6.1 Violation Due To Error In Replacement Operator Aid Computer (OAC) Programming

This LER involved inadequate controls over software changes to the original OAC that led to the omission of NRC Regulatory Guide (RG) 1.45 related computer points associated with radiation monitors EMF-38 and EMF-39 in the new/replacement OAC. This resulted in a non-compliance with TS 3.4.6.1 for approximately two months. Specifically, on December 11, 1996, the licensee discovered that two computer points associated with EMF-38 and EMF-39, which are used by the OAC to generate RG 1.45 related leak detection calculations/alarms, had not been included during the Unit 1 end-of-cycle 9 (1EOC9) refueling/OAC replacement outage completed approximately two months earlier.

NRC RG 1.45 (concerning reactor coolant pressure boundary leakage detection systems) requires three leakage detection systems with the ability to detect a leak inside containment of one gallon per minute (gpm) in less than one hour. Accordingly, TS 3.4.6.1 requires the following reactor coolant leakage detection systems, which are addressed in UFSAR section 5.2.5, to be operable in Modes 1-4: (a) containment atmosphere gaseous radioactivity monitoring system (EMF-39); (b) containment floor and equipment sump (CF&ES) level and flow monitoring subsystem; and (c) either the containment ventilation unit condensate drain tank (VUCDT) level monitoring subsystem or the containment atmosphere particulate radioactivity monitoring system (EMF-38). With only two of the above required leakage detection systems operable, TS 3.4.6.1 allows operation for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours when the required gaseous or particulate radioactivity monitoring system is inoperable.

In this particular case, even though EMF-38 and EMF-39 would have still functioned as radiation monitors by providing alarms if radiation levels had exceeded their respective setpoints, the lack of RG 1.45 related leakage detection made them inoperable with respect to TS 3.4.6.1. However, the CF&ES and VUCDT monitoring systems were still available; therefore, only leak detection system (a) of TS 3.4.6.1 had not been met from the time the Unit entered Mode 4 towards the completion of the 1EOC9 outage on September 24, 1996, until discovered on December 11, 1996. During this period of inoperability (specifically on November 28, 1996), a 0.5 gpm reactor coolant leak was, in fact, detected by the VUCDT monitoring system. This led to the subsequent Unit 1 shutdown to Mode 4 in order to effect repairs to a cracked spool piece weld in the 1D reactor coolant pump leakoff line.

The EMF-38 and EMF-39 RG 1.45 related computer points were added to the original OAC in 1994 as part of the corrective action associated with LER 50-413/94-04. However, due to the uncontrolled manner in which they were added, they were not captured during the design process of the new/replacement OAC that began in 1993. Accordingly, the licensee has since considered changes to the OAC software as a modification and the inspectors verified that NSD 301, Nuclear Station Modifications, reflected as such. Aside from programming the subject computer points and assuring that there were no other missing computer points in the Unit 1 new/replacement OAC, the licensee also made comparison reviews of the Unit 2 OAC database that was being developed for the subsequent Unit 2 OAC replacement outage (completed in 1997). The inspectors verified that the subject computer points were currently included on both units' OACs and appropriately addressed in pre-Mode surveillance and loss of OAC procedures (PT/1(2)/A/4600/002 and PT/1(2)/A/4600/009, respectively).

The subject non-compliance with TS 3.4.6.1 is a non-repetitive, licensee-identified and corrected violation that is being considered as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. It will be identified as NCV 50-413/98-08-04: TS 3.4.6.1 Non-compliance Due To Omission of EMF-38 and EMF-39 OAC Points. The LER is closed.

E8.3 (Closed) LER 50-413/96-006: Containment Floor and Equipment Sump (CF&ES) Level Monitoring Inaccuracy

This LER addressed long-standing inaccuracies in the CF&ES data used to calculate reactor coolant system leakage for both Unit 1 and Unit 2. Specifically, for CF&ES levels less than seven inches, the calculated leakage rate would be non-conservative by as much as 36.8 percent. The nonconservatism was created when licensee personnel failed to consider piping in the sump which rendered the use of a linear slope constant for level versus volume curves inaccurate. This was identified by the licensee on May 9, 1996, during a review of the Catawba Nuclear Station unit data book and the Loss of OAC procedure.

TS 3.4.6.1, item b, required the CF&ES level and flow monitoring subsystem to be operable as one of the three methods of detecting RCS leakage (further requirements and related actions are described in Section E8.3 above). The CF&ES level and flow monitoring system was declared inoperable due to the level calculation discrepancies. The licensee identified that during periods when the CF&ES level and flow monitoring system was inoperable, one of the two remaining leak detection methods as described in TS 3.4.6.1 was also inoperable. Further investigation revealed that Unit 1 had 16 occurrences between September 29, 1994, and May 8, 1996, which totaled 555 hours with two RCS leak detection systems inoperable. Unit 2 had 23 occurrences between March 19, 1994, and March 22, 1996, which totaled 1145 hours. The longest duration of T.S. noncompliance for Unit 1 occurred between June 7 and June 15, 1995, for 186 hours; and for Unit 2 from September 26 through October 5, 1994, for 211 hours. Although the above data was

obtained from a search that only spanned the previous two years, this condition existed since initial plant startup.

Additionally, a review of LER 50-413/94-04 and associated corrective actions revealed that there were occasions prior to 1994 where containment particulate and gaseous radiation monitors EMF 38 and 39 (also required as a leak detection source by TS 3.4.6.1) for both units did not meet criteria established in RG 1.45 to alarm at a RCS leakrate of 1 gpm in 1 hour. As a result, for periods of time prior to 1994, the two radiation monitors were incapable of satisfying the intent of TS 3.4.6.1, items a and c. That issue, combined with the sump level discrepancy discussed above, placed the licensee in noncompliance with TS 3.4.6.1 for periods of time between initial plant startup and 1994 when sump levels were below the minimum level for operability. The older LER was dispositioned in Inspection Report 50-413,414/95-03.

With respect to LER 50-413/96-06, the licensee initially attempted to correct the sump level monitoring discrepancies by increasing the sump levels to seven inches on May 15, 1996. However, further evaluation revealed on May 29, 1996, that at levels below nine inches, the containment floor and equipment drain sumps were still inoperable. Considering the revised minimum sump level limit, three additional noncompliances occurred between May 20 and May 23, 1996, before final corrective actions could be implemented for the OAC.

The required action to be taken when two of the RCS leak detection systems are inoperable is to be in at least Hot Standby within the next six hours and in Cold Shutdown within the following 30 hours. These requirements were not met. The failure to perform actions of Technical Specifications is a violation of regulatory requirements. This non-repetitive, licensee-identified and corrected violation is characterized as an NCV consistent with Section VII.B.I of the NRC Enforcement Policy, and is identified as NCV 50-413/98-08-05: Inoperable Containment Floor and Equipment Sump Level Monitoring Subsystem.

The licensee's corrective actions consisted of the following: (1) implementing an Operator Aid Computer (OAC) change for the computer point which calculates the leakage to each units' containment floor and equipment sumps resulting in an accurate calculation of the rate of change of the volume of water in the sump; (2) plotting and submitting for inclusion in OP/1/A/6700/01 and OP/2/A/6700/01 new curves of level versus volume for all four containment floor and equipment sumps; and (3) the operations procedure group updated the Loss-of-OAC procedures for calculation of leakage to the containment floor and equipment sumps to reflect the new volume versus level curves in the data books. These actions were verified by the inspectors.

The inspectors also identified that the LER was deficient in that pertinent information concerning dates and times when two RCS leak detection systems were inoperable requiring a unit shutdown were not provided. The occurrences, dates, and duration of the noncompliances, were informally tabulated by licensee personnel to support the LER

preparation, but this information was not provided as required by 10 CFR 50.73 section (b)(2)(ii)(C). The inspectors determined that the failure to provide specific information in the LER regarding dates and approximate times of the noncompliances was contrary to NRC requirements. This failure constituted a violation of minor significance and is not subject to formal enforcement action.

It was also noted that the LER had two different report dates: July 10, 1996, as shown on the cover letter and July 17, 1996, on the LER. Neither date was within the 30-day reporting requirement of 10 CFR 50.73, section (a)(1), with the discovery of this event referenced as May 9, 1996. The inspectors raised this issue with the licensee, who indicated that although the sump level curve discrepancy was identified on May 9, it was not determined until June 17, 1996, that there had been reportable TS noncompliances due to the other leak detection systems having been concurrently inoperable. Therefore, although not thoroughly described in the LER, this event was determined to be reportable on the later date.

As discussed in previous NRC inspection reports, the above findings related to poor LER quality have been identified by the inspectors for other LERs in the last two years. This has been discussed with licensee management who issued an internal memorandum during this period, addressing steps that would be taken in the future to improve LER quality.

E8.4 (Closed) IFI 50-413,414/97-03-04: Actions to Address Weaknesses in Generic Letter (GL) 89-10 Implementation

This followup item was opened pending the licensee's completion of actions described in PIP 0-C97-0421, initiated February 14, 1997. The actions were developed to resolve weaknesses which NRC inspectors identified while inspecting the licensee's implementation of Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance. In the current inspection, NRC inspectors reviewed related documentation and verified that the actions had been completed. The issues involved resolution actions specified by PIP 0-C97-0421. The results of the inspectors' review are discussed below:

Issue 1

The licensee justified the minimum thrust requirements specified for Group AD-02 Anchor/Darling double-disk gate valves by demonstrating that they exceeded the "flow isolation" thrust values determined through the Electric Power Research Institute Performance Prediction Methodology (EPRI PPM) hand-calculations. NRC inspectors were concerned that this justification was weak, as the NRC safety evaluation (March 5, 1996) of the EPRI PPM found that "flow isolation" thrusts might not be sufficient to produce the valve disk wedging required to prevent excessive leakage. The safety evaluation stated that users of the PPM hand-calculations for Anchor/Darling double-disk gate valves would need to ensure sufficient disk wedging was achieved to meet design leak tightness requirements.

PIP 0-C97-0421 indicated that the licensee would resolve this issue by responding to the NRC safety evaluation. The inspectors found that the licensee had responded to the NRC safety evaluation in Revision 1 to calculation CNC-1205.19-00-00145, "Anchor/Darling Steam Generator PORV Block Valve Generic Letter 89-10 Calculation." This calculation documented that no design leakage requirements were specified for the Group AD-02 valves. Further, the calculation added margin to the thrust requirements to further assure adequate isolation of flow. This issue is closed.

Issue 2

NRC inspectors were concerned that two valves (1NC31 and 2NC33) in Group AD-04 had only marginal capabilities to complete their closing safety function under design basis conditions.

PIP 0-C97-0421 indicated that the licensee would resolve this issue by modifying the valves to provide additional margin. The inspectors reviewed applicable portions of Modifications CE-8303 and CE-8726 and their post-implementation letters and verified that the licensee had completed the specified modifications to increase the capabilities of these valves. Data provided by the licensee indicated that the valves had closing margins of about 30 and 40 percent at their current settings. This issue is closed.

Issue 3

The valve factor assumed for gate valve Group BW-01 was based on a single test and was unexpectedly high (1.3). As a result, the valve's reliability was questioned.

PIP 0-C97-0421 indicated that the licensee would resolve this issue by testing additional valves from this group. The inspectors found that the licensee had tested additional valves as planned. However, PIP 0-C97-0421 documented that sufficient differential pressures could not be achieved to obtain valid test results. Based on general industry data, the valve factor being applied to these valves by the licensee was very conservative. As the licensee's valves could accommodate this conservative valve factor, there was no safety concern. This issue is closed.

Issue 4

The gate valves in Group WL-01 had only marginal capabilities to complete their opening safety function under design basis conditions. PIP 0-C97-0421 indicated that the licensee would resolve this issue by installing replacement valves with greater capabilities. The inspectors reviewed applicable portions of Modification CN-21370 and its Post Implementation Letter and verified that the licensee had completed the valve replacements. The replacements had capabilities that exceeded design requirements by greater than 40 percent. These valves were redesignated Group AD-05. This issue is closed.

Issue 5

The thrust requirements for the following gate valve groups were calculated using valve factors determined from the results of a single dynamic test each: BW-11, BW-13, PC-01, WH-01, and WH-02. Such limited data provided weak support for the valve factors and the thrust requirements calculated using these valve factors.

PIP 0-C97-0421 indicated that the licensee would resolve this issue by putting in place a plan to document this shortcoming and monitor and evaluate the future performance of these valves. The inspectors found that PIP 0-C97-0421 recorded that the resolution actions had been completed. The PIP indicated that notes had been added to the valve calculations concerning the need to maintain setup margin as high as possible because of the limited data supporting the thrust requirement determinations. Further, the PIP noted that periodic testing and followup trending already part of the MOV program would provide future monitoring for the valves. The inspectors selected valve groups PC-01, WH-01, and WH-02 as a sample for review and verified that the stated notes had been added to their calculations:

CNC 1205.19-00-0011, "GL 89-10 Setup Calculation for Valve 1(2)NV252A, 253B," Revision 3; CNC 1205.19-00-0045, "GL 89-10 Setup Calculation for Valve 1(2)NS003B, NS020A," Revision 2; and CNC 1205.19-00-0038,

"GL 89-10 MOV Calculations, VY System: 1(2)VY015B, VY017A, VY018B," Revision 1. During previous Generic Letter 89-10 inspections, the inspectors had confirmed that the licensee specified periodic testing and followup trending as part of the MOV program. This issue is closed.

Issue 6

The thrust requirements determined for the following globe valve groups were considered weak as they were supported by limited dynamic test data: BW-13, BW-14, and BW-15.

PIP 0-C97-0421 indicated the licensee would strengthen the validation data supporting the thrust requirements for these groups. The inspectors found that PIP 0-C97-0421 described the resolution actions for each group and reported that these resolution actions had been completed. The inspectors selected Group BW-15 (redesignated WL-04) as an example and reviewed its thrust calculation, CNC 1205.19-00-0022, "Generic Letter 89-10 Calculation, NV System: 1(2)NV015B," Revision 1. The inspectors found that the licensee had revised CNC 1205.19-00-0022 to include the results of an EPRI PPM calculation for the group. The licensee noted that the PPM was not fully applicable to these valves because their design basis temperature exceeded that validated for the PPM; however, it was used as the best available source of data. The calculation showed that the required thrust specified by the licensee was conservative as compared to the PPM results. The inspectors found this an acceptable approach for strengthening the thrust requirements for these valves. This issue is closed.

Issue 7

An NRC inspection of the licensee's McGuire facility identified weaknesses that might be applicable to Catawba. These weaknesses involved information and requirements provided in corporate documents and potentially impacted Catawba's MOV calculations.

PIP 0-C97-0421 specified that the corporate changes that resulted from the McGuire findings would be monitored and evaluated for applicability to Catawba. The relevant changes were addressed by corporate PIPS 0-G97-0058, 0-G96-347, and 0-G96-348. Based on a review of the changes that resulted from the corporate PIPs, and based on the results of the inspection that identified this issue, the inspectors identified only two changes that might impact the licensee's calculations. The first was a change to corporate calculation DPC 1205.01-00-0001, "Evaluation of Flow Loop Tests of Kerotest Valves," to Revision 2, requiring addition of margin to the thrust requirements calculated for Kerotest globe valves. The inspectors reviewed the following Kerotest globe valve set-up sheets (calculations) and verified that margin had been added in accordance with DPC 1205.01-00-0001: "Valve 1KC429B Set-Up Sheet," dated January 9, 1997; "Valve 2KC429B Set-Up Sheet," dated January 9, 1997; and "Valve 2KC430A Set-Up Sheet," dated July 23, 1997. The second change potentially impacting the licensee's calculations was updated values for rate of loading established in calculation DPC-1205.19-00-0057, "Evaluation of Rate of Loading Effects," to Revision 2. Even though the values previously employed were more conservative, the inspectors found that the updated values would have minimal safety impact on the licensee's calculations. This issue is closed.

IV. Plant Support

R1 Radiological Protection

R1.1 General Comments (71750)

The licensee's radiological protection performance was adequate.

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 August 24, 1998 and September 10, 1998. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Bradshaw, Safety Assurance Manager
M. Boyle, Radiation Protection Manager

R. Glover, Operations Superintendent
P. Herran, Engineering Manager
R. Jones, Station Manager
M. Kitlan, Regulatory Compliance Manager
G. Peterson, Site Vice-President
R. Propst, Chemistry Manager
D. Rogers, Maintenance Manager
M. Standridge, Acting Safety Review Group Manager

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
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 92700:	Onsite Followup of Event Reports

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-413,414/98-08-01	URI	Failure to Establish RPS and ESFAS Trip Setpoints in Accordance With T.S. Limits (Section M3.2)
50-413,414/98-08-02	VIO	Failure to Declare Two CA System Pumps Inoperable During RN to CA Pipe Flush (Section M3.3)
50-413,414/98-08-03	URI	Inadequate Design Documentation For Portable Radiation Monitors (Section E3.1)
50-413/98-08-04	NCV	T.S. 3.4.6.1 Non-Compliance Due To Omission of EMF-38 and EMF-39 OAC Points (Section E8.2)
50-413/98-08-05	NCV	Inoperable Containment Floor and Equipment Sump Level Monitoring Subsystem (Section E8.3)

Closed

50-413,414/96-20-03	IFI	Log Keeping Practices (Section O8.1)
50-413/96-005	LER	Automatic Reactor Trip With The Unit Subcritical Due to an Equipment Failure (Section O8.3)
50-413/96-014	LER	Technical Specification Required Unit Shutdown Due to Equipment Failure (Section O8.4)
50-413/96-003	LER	Forced Shutdown Due to Rod Control Malfunction (Section O8.5)
50-413/98-011	LER	Condition Prohibited by Technical Specifications - Two Refueling Water Storage Tank Level Channels on Each Unit Inoperable Due to Lightning Activity (Section O8.6)
50-413,414/97-300-02	URI	Catawba Updated Final Safety Analysis Discrepancies (Section O8.7)
50-414/96-03	LER	TS 3.0.3 Required Shutdown due to Ventilation System Motor Failures (Section M8.1)
50-413/96-08-02	VIO	Failure to Follow Procedure When Adjusting MFIV Nitrogen Accumulator Pressure to Backseat Leaking MFIV (Section M8.2)
50-413/96-007	LER	Main Steam Safety Valves (MSSV) Outside Setpoint Acceptance Criteria (Section M8.4)
50-413/97-15-03	URI	Anti-Reverse Rotation Devices Not Installed in the 1D Reactor Coolant Pump (Section M8.5)
50-414/98-01-07	URI	Operability of Valve 2NW-190A (Section M8.6)
50-413,414/96-13-02	VIO	Inadequate Procedures, Two Examples (Section E8.1)
50-413/96-013	LER	TS 3.4.6.1 Violation Due to Error in Replacement OAC Programming (Section E8.2)
50-413/96-006	LER	Containment Floor and Equipment Sump Level Monitoring Inaccuracy (Section E8.3)

50-413,414/97-03-04	IFI	Actions to Address Weaknesses in GL 89-10 Implementation (Section E8.4)

Discussed

50-414/96-005	LER	Unit 2 Standby Shutdown System Potentially Outside Design Basis (Section M8.3)
50-414/97-003	LER	Component Cooling System Unavailability (Section O8.2)
50-414/98-003	LER	Inoperability of a Unit 2 Reactor Protection System (RPS) Channel 3 Function (Section M3.1)
50-413/98-12	LER	TS 3.0.3 Entry Due to Inoperability of Both Trains of VC/YC (Section 01.2)
50-413/98-09	LER	Both Units Entered TS 3.0.3 Due to Inadequate VA System Testing (Section 01.2)
50-413/98-15	LER	TS Required Shut Down and Operation Prohibited by TS Associated with Ice Condenser (Section 01.2)

LIST OF ACRONYMS USED

ACOT - Analog Channel Operational Test
AFW - Auxiliary Feedwater System
ANSI - American National Standards Institute
ASME - American Society of Mechanical Engineers
ASP - Auxiliary Shutdown Panel
CA - Auxiliary Feedwater
CF&ES - Containment Floor and Equipment Sump
CFR - Code of Federal Regulations
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EIT - Event Investigation Team
EPRIPPM - Electric Power Research Institute Performance Prediction Methodology
ESFAS - Engineered Safety Features Actuation System
FWLB - Feedwater Line Break
GL - Generic Letter
GPM - Gallons Per Minute
IFI - Inspector Followup Item
ISLOCA - Inter-System Loss of Coolant Accident
IST - Inservice Testing
KC - Component Cooling Water
KW - Kilowatt
LCO - Limiting Condition for Operation
LER - Licensee Event Report

LOCA - Loss of Coolant Accident
LOOP - Loss Of Offsite Power
MFIV - Main Feedwater Isolation Valve
MSLB - Main Steam Line Break
MSSV - Main Steam Safety Valves
NCV - Non-Cited Violation
ND - Residual Heat Removal
NOED - Notice of Enforcement Discretion
NSD - Nuclear System Directive
NW - Containment Penetration Valve Injection Seal Water
OAC - Operator Aid Computer
OM - Operations and Maintenance
OMP - Operations Management Procedure
PIP - Problem Investigation Process
PORC - Plant Operations Review Committee
PDR - Public Document Room
RCS - Reactor Coolant System
RG - Regulatory Guide
RHR - Residual Heat Removal
RN - Nuclear Service Water
RPS - Reactor Protection System
RWST - Refueling Water Storage Tank
SSF - Standby Shutdown Facility
SSS - Standby Shutdown System
TIA - Task Interface Agreement
TS - Technical Specification
TSAIL - TS Action Item Log
UFSAR - Updated Final Safety Analysis Report
URI - Unresolved Item
VC/YC - Control Room Ventilation System
VIO - Violation
VUCDT - Ventilation Unit Condensate Drain Tank
WO - Work Order