withholding of such material, you <u>must</u> specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated at Atlanta, Georgia
this 18th day of August, 1997

U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-413, 50-414
License Nos:	NPF-35, NPF-52
Report Nos.:	50-413/97-09, 50-414/97-09
Licensee:	Duke Power Company
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	422 South Church Street Charlotte, NC 28242
Dates:	June 8 - July 19, 1997
Inspectors:	J. Zeiler, Acting Senior Resident Inspector R. L. Franovich, Resident Inspector M. Giles, Resident Inspector (In Training) N. Economos, Region II Inspector (Sections M8.1, 2, 3, 4) R. M. Moore, Region II Inspector (Sections O8.1, E2.1)
Approved by:	S. M. Shaeffer, Acting Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 & 2
NRC Inspection Report 50-413/97-09, 50-414/97-09

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by Regional reactor safety inspectors.

<u>Operations</u>

- A Non-Cited Violation (NCV) was identified for failure to declare three ice condenser intermediate deck doors inoperable and log an associated Technical Specification Action Item Log entry after identifying ice buildup on the doors. This item, along with several other minor human performance weaknesses, indicated a need for greater attention to detail and questioning attitude by operations personnel during the performance of routine activities (Section O1.1).

- The root cause evaluations of a reactor coolant pump trip and subsequent reactor trip were adequately performed. The cause of the trip did not involve human error or non-conservative decision making. The protective relaying associated with the short bus of 2TB functioned as designed. However, a delay in troubleshooting activities to locate the source of the associated ground indicated that the ground received a low priority status in the work schedule and that trained personnel were not readily available to troubleshoot ground indications in a timely manner (Section O1.2).

- Control room operators were effective in precluding a turbine runback by reducing reactor power to 50% before the 2B Main Generator Power Circuit Breaker opened on low air pressure. The licensee's root cause evaluation was detailed, and actions to prevent recurrence were considered adequate (Section O1.3).

- The decision to deviate from the preferred normal alignment of Lower Containment Ventilation Unit (LCVU) operation to support planned maintenance exhibited non-conservative work scheduling and operator judgement. This resulted in lower containment air temperature increasing slightly above the adjusted Technical Specification limit for a brief period of time. The LCVU operating procedures did not address the adverse impact of removing two LCVUs from service simultaneously, nor did the procedure address the interaction between LCVU operation and integrated containment ventilation systems. These procedural inadequacies were identified as a NCV (Section O1.4).

- A violation (first example) for failure to follow procedure was identified related to Operations failure to adequately document 10 CFR 50.59 screening evaluations (Section O8.1).

Maintenance

- A Failure Investigation Process (FIP) team was thorough in investigating the cause of an electrical flash in a 600 Volt breaker cubicle associated with Motor Control Center 2MXM. The root cause indicated configuration and procedure weaknesses in the method of locking out 600 Volt breaker cubicles to the maintenance position. Adequate corrective actions to prevent recurrence of this incident were implemented (Section M1.1).

- The licensee's identification of a technician's failure to follow a leak rate test procedure that resulted in an invalid test of valve 2NV-874 during the previous refueling outage was an example of good questioning attitude; however, the procedure completion review was untimely. The Plant Operations Review Committee performed a thorough review of subsequent activities to properly retest the valve. Good engineering support was provided, both in developing a leak rate test procedure and briefing package for the evolution. The failure to follow the leak rate test procedure was identified as a Violation (Section M1.2).

Engineering

- The licensee's identification of a discrepancy between primary and secondary thermal power indication exhibited attention to detail in the review of plant data. Actions to initiate a FIP team to investigate the root cause were appropriate and steps to reduce reactor power until the discrepancy was understood were conservative. Replacement of a faulty T_{ref} card was well-planned, coordinated and controlled, and executed in an expeditious manner (Section E1.1).

- Resolution of Design Base Document (DBD) open items was generally adequate. However, a violation (second example) for failure to follow procedure was identified related to Engineering's failure to enter DBD open items into the Problem Identification Process as required by procedure and stated in the licensee's response to the Design Basis 50.54f letter (Section E2.1).

- The licensee's corrective action audit that assessed the resolution of Self-Initiated Technical Audit findings was identified as a strength in corrective action performance (Section E2.1).

- The licensee adequately addressed the Emergency Diesel Generator 10 CFR Part 21 issue related to potentially defective intake/exhaust springs (Section E2.1).

- Based on in-office review of the licensee's March 31, 1997, annual summary on 10 CFR 50.59 changes, onsite review of the licensee's 10 CFR 50.59 evaluations, and audit of the licensee's procedures, the inspector concluded that the licensee had complied with the provisions of the regulation for the changes listed in the annual summary (Section E3.1).

Plant Support

- Radiological control practices observed during the inspection period were considered to be proper (Section R1.1).

Report Details

Summary of Plant Status

Unit 1 operated at or near 100% power during the inspection period.

On June 26, a Unit 2 reactor trip occurred on low Reactor Coolant System loop flow as a result of an electrical ground fault which de-energized the electrical bus that powers the "2B" Reactor Coolant Pump (RCP). The unit was returned to 100% power operation on June 29. Power was reduced to 50% on July 2, to preclude a turbine trip/reactor trip upon the anticipated failure of Main Generator Power Circuit Breaker (PCB) 2B. A solenoid (or pilot) valve associated with the air supply to all three main generator PCB poles had failed, rendering the air system unable to deliver air to the breaker. The solenoid valve was replaced, and the unit was returned to 100% power the following day. Reactor power was reduced to 99.3% on July 15 in response to a discrepancy between primary and secondary thermal power indications. The discrepancy was attributed to feedwater venturi defouling and hot leg streaming, and did not reflect an actual temperature difference. The unit returned to 100% power on July 17 and operated at or near 100% power for the remainder of the inspection period.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspector reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspector conducted frequent control room tours to verify proper staffing, operator attentiveness and communications, and adherence to approved procedures. The inspector attended daily operations turnover and Site Direction meetings to maintain awareness of overall plant 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 from the Control Room to assess operability. Plant tours were conducted to observe equipment status and housekeeping. Problem Identification Process (PIP) reports were routinely reviewed to assure that potential safety concerns and equipment problems were reported and resolved.

In general, the conduct of operations was professional and safety-conscious. Good plant equipment material conditions and housekeeping were noted throughout the report period. However, as addressed below, several minor operator human performance deficiencies were identified involving a failure to enter a TS Action Statement, failure to identify equipment status anomalies, and failure to properly document a Technical Specification Action Item Log (TSAIL) entry.

Failure to Declare Unit 2 Ice Condenser Intermediate Deck Doors Inoperable and Enter Applicable TS Action Statement

On June 17 at 2:38 p.m., while performing the weekly TS surveillance on the intermediate deck doors, the licensee identified that three doors had ice buildup (reported to be less than one-half inch thick). The function of these doors is to open during a design basis accident to ensure that the containment Loss Of Coolant Accident (LOCA) atmosphere would be diverted through the ice condenser. Upon discovery of the ice, a test procedure discrepancy was entered and a work request was initiated to remove the ice. However, work to remove the ice or investigate the extent of the impact on the door opening function was not initiated due to problems with personnel accessing containment through the containment airlock door. Later that night, the oncoming Shift Work Manager became aware of the previous day's problem and contacted engineering personnel to perform an operability evaluation of the condition. The following morning, the inspector reviewed the results of this evaluation. The evaluation concluded that the "ice condenser" was operable. This was based primarily on a previous McGuire Nuclear Station analysis that showed up to one-third of the intermediate deck doors could fail to open and there would still be enough ice condenser flow area for LOCA heat removal. The inspector determined the evaluation focused to narrowly on the ice condenser system operability and failed to adequately evaluate the operability of the intermediate deck doors, especially with regard to consideration of information in the applicable TS and Bases.

TS 3.6.5.3 requires the intermediate deck doors be operable in Modes 1-4. TS Surveillance Requirement 4.6.5.3.2 requires a 7-day verification that the intermediate deck doors be closed and free of frost accumulation. The TS Bases also states that impairment by ice, frost, or debris is considered to render the doors inoperable, but capable of opening. Based on this, the inspector concluded that operations personnel had failed to declare the three doors inoperable and follow the Action Statement of TS 3.6.5.3.a when the problem was initially identified. This action statement allowed power operation to continue for up to 14 days provided ice bed temperature was monitored at least once per four hours and the maximum ice bed temperature was maintained less than or equal to 27°F. The licensee initiated PIP 2-C97-2014 to investigate this incident.

On June 18, after repairing the containment airlock, ice was removed from the three intermediate deck doors. The cause of the ice buildup was found to be the failure of heat tracing on an ice condenser air handling fan drain line, which prevented adequate draining of defrost condensate. The heat tracing was subsequently repaired. The licensee determined during activities to remove the ice that all three doors were not blocked to the extent that would have prevented their opening during a LOCA. The inspector also noted that the ice bed monitoring system was operational during the period that ice was on the doors and control room annunciator alarms would have alerted the operators of anomalous ice bed temperatures. Therefore, the inspector considered the safety consequences of this incident to be minimal.

The inspector reviewed Operations Management Procedure (OMP) 2-29, Technical Specifications Action Item Log. Step 3.4 requires that non-compliance with a Limiting Condition For Operation requiring operation in a TS Action Statement, be logged in TSAIL. The inspector determined that a TSAIL entry was not logged for this condition when ice was identified on the doors rendering them inoperable. The failure to declare the doors inoperable and enter a TSAIL entry for the applicable TS Action Statement in accordance with OMP 2-29 was identified as a Violation of TS 6.8.1, Procedures and Programs. This failure to follow procedures constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy. This item is identified as NCV 50-414/97-09-01: Failure to Declare Ice Condenser Intermediate Deck Doors Inoperable and Log Appropriate TSAIL Entry.

Auxiliary Shutdown Panel Volume Control Tank (VCT) Instrumentation Drift

During a walkdown of the four Motor Driven Auxiliary Feedwater Shutdown Panels, the inspector identified that three of the four VCT level indications were not reading accurately. There is one VCT gauge on each Shutdown Panel. Gauge indications differed from control room indications by as much as 20 percent level. The inspector alerted operations personnel to the problem and noted that they were very responsive in initiating corrective actions. Due to subsequent problems in calibrating the gauges and unavailability of like parts, engineering modifications were developed and implemented to replace the gauges with more accurate models. Based on discussions with Instrumentation and Electrical (IAE) personnel, it was indicated that most likely, the gauges had drifted out of accuracy over a long period of time.

The inspector reviewed periodic surveillance test procedures associated with verifying Shutdown Panel instrumentation indications. VCT level was not among the indications checked periodically. The inspector noted, however, that VCT level was not required by TS to be operable from the Shutdown Panels. However, the VCT indication could be potentially used during operation from the Shutdown Panels. It was also apparent that there had been opportunities to have identified the gauge output drift during the periodic surveillances of other Shutdown Panel instrumentation.

Unit 2 Power Range Channel NI-42 Spare Window Illuminated

On June 27, 1997, the day after Unit 2 tripped on low Reactor Coolant System flow, the inspector noticed an annunciator window on the Nuclear Instrument (NI)-42 Power Range drawer that was illuminated. The annunciator window was labeled "spare" and appeared to serve no function. The inspector questioned the control room operators about the illuminated window. The window apparently first illuminated following the trip; however, the operators were not aware that the window was illuminated, nor the reason for the condition. Based on subsequent discussions with reactor engineering personnel, the inspector learned that this spare annunciator window was previously used as the negative rate trip indication light. During the previous refueling outage, this trip function was isolated from the reactor protection logic. The modification that implemented the rate trip change was supposed to have removed the bulb from these windows on all of the NI drawers. It was believed that the bulb in the NI-42 drawer was removed, but may have been reinstalled by IAE personnel by mistake during subsequent NI maintenance activities following the refueling outage. The light was extinguished once the rate trip function was reset and the bulb removed. The licensee initiated a PIP to address this problem.

TS Logging Error for Tracking Containment Airlock Door Seal Surveillance Test

On July 11, 1997, during review of the Unit 2 TSAIL, the inspector noticed an incorrect entry that was made on July 9. The entry was for tracking a TS required 72-hour airlock door seal test following opening of the airlock door on July 9. The time required for the test to be performed was listed in TSAIL as July 16 instead of July 12. The inspector discussed the error with operations personnel who corrected the entry. It was also indicated that the seal test was scheduled to be performed that same day. Based on this, the inspector determined the test would not have been missed even though the TSAIL was incorrect. The inspector was concerned that the TSAIL error had not been identified over the two previous two days that the problem existed.

Individually, the above problems had little actual safety consequences, however, in the aggregate represented the need for greater attention to detail and questioning attitude by operations personnel during the performance of routine activities.

O1.2 Unit 2 Reactor Trip on Low Reactor Coolant System Flow

a. Inspection Scope (71707, 93702)

On June 26, a Unit 2 reactor trip from 100% power occurred when the 2B Reactor Coolant Pump (RCP) tripped and caused a loss of flow signal in the associated loop. The inspector discussed the unit trip with engineering, operations and maintenance personnel, as well as reviewed the associated electrical diagrams, Unit Trip Report and PI? 2-C97-2221.

b. Observations and Findings

On June 21, a negative leg ground was detected on non-vital distribution bus 2CDB. The ground subsequently was traced to the 125 VDC control power circuit of breaker 2TB-6. On June 26, the breaker was opened to facilitate troubleshooting the cause of the ground. The Instrument and Electrical (IAE) technicians noticed that the breaker failure initiation relay in 2TB-6 control cubicle was chattering, but continued with their troubleshooting activities. Shortly thereafter, a reactor trip occurred.

The licensee determined that the source of the ground fault was the breaker pushbutton, a Cutler-Hammer E30 model. The pushbutton had failed and created a negative leg-to-ground fault on 2CDB. The pushbutton internals had changed state when 2TB-6 was tripped open during troubleshooting, introducing a fault path to the positive leg. Noise from the cabinet ground was induced through the switch and the breaker failure initiation relay (94B) coil, causing it to chatter and eventually actuate to trip the incoming breaker on the short bus of 2TB. The auto-close function of the 2TB tie breaker was blocked by a lockout relay, and the bus de-energized. The 2B RCP, which is supplied from the bus, tripped, and the subsequent low flow in the B loop caused a reactor trip.

The inspector discussed the reactor trip with operations and engineering personnel to determine if the root cause involved a human error. The chattering of the relay, generated when 2TB-6 was opened, could have been stopped if the IAE technicians had reclosed the breaker when they noticed that relay chattering. However, they did not understand what was causing the chattering at the time. The inspector concluded that the IAE technicians responded appropriately by leaving the breaker in the opened position since the cause and impact of the relay chattering were not understood.

The inspector inquired about the time delay between ground detection (identified on a Saturday) and troubleshooting activities (initiated the following Wednesday). Licensee personnel indicated that Single Point Of Contact (SPOC) technicians were not trained and qualified to use the ground-chasing equipment. As a result, attempts to locate the ground could not be made until the following Monday when a trained IAE technician would be available. Also, priority status was not associated with troubleshooting the ground indication early in the week. In addition, the inspector determined that only two technicians on site were fully qualified to use the ground-chasing equipment to locate the source of a ground, and that one of those technicians had been offsite since February and was not scheduled to return until October of this year. A shortage of trained personnel available to perform the troubleshooting contributed to the delay. At the end of the inspection period, the delay in investigating the ground, associated contributing factors, and appropriate corrective actions were not addressed within the licensee's corrective action program.

The unit was restarted on June 28 after trip list activities were performed and minor equipment problems were corrected. The licensee is planning to document the reactor trip in a Licensee Event Report.

c. Conclusions

The inspector concluded that root cause evaluations of the reactor trip were adequately performed. The cause of the trip did not involve human error or non-conservative decision making. The protective relaying associated with the short bus of 2TB functioned as designed. The inspector determined that, although the delay in troubleshooting activities to locate the source of the ground did not affect the outcome (reactor trip), challenges existed in the following areas: (1) associating appropriate priority to locating ground indications in a timely manner, and (2) ensuring that trained personnel are available to troubleshoot ground indications. At the end of the inspection period, efforts to address the delay, understand its causes, and identify corrective actions were not evident in the licensee's corrective action program.

O1.3 Unit 2 Downpower in Response to Generator Output Breaker Trouble

a. Inspection Scope (71707)

On July 2, Unit 2 control room operators received a generator breaker trouble alarm and identified a continuous decrease in minimum close air pressure on 2B Main Generator Power Circuit Breaker (PCB). Operators began a rapid load reduction, and the PCB automatically tripped after reactor power reached 50%. The inspector reviewed PIP 2-C97-2177 and discussed the downpower and associated equipment failure with licensee personnel.

b. Observations and Findings

On July 2, the Main Generator PCB 2B Trouble annunciator alarmed in the control room. Control room operators determined that there was a continuous decrease in air pressure on the 2B Main Generator PCB, indicating an approach to the minimum air pressure is required to open the breaker. Air pressure is required to open the breaker and dissipate the resulting arc. Since the safety function of the PCB was to open, it was designed to automatically open before the minimum pressure required for this function is reached. The minimum trip pressure on Main Generator PCB 2B is between 446 and 452 psig.

To preclude an automatic turbine runback on the potential automatic opening of the PCB, operators began a rapid load reduction. The PCB automatically tripped after reactor power reached 50%. No overcurrent alarms were received on Main Transformer 2A.

The license determined that a solenoid (or pilot) valve associated with the air supply to all three main generator PCB poles had failed, rendering the air system unable to deliver air to the breaker. Normally, the solenoid valve receives signals from the breaker poles to supply air to them. When the air pressure on any pole reaches approximately 485 psi, a pressure switch actuates and the solenoid valve shuttles to pneumatically control a regulator that delivers air to the breaker poles. When air pressure is restored to 500 psi, the signal from the pole to the solenoid is terminated.

Station PIP 2-C97-2177 documented the root cause of the solenoid failure. The failed solenoid was new and had been installed during the April 1997 refueling outage. The component failure was attributed to a deformed nylon bushing. The valve had been assembled to compensate for the defect, which initially allowed the valve to operate as designed. However, the valve's internal components drifted from their assembled positions over time and eventually were unable to engage with the valve's lower assembly, thereby preventing air flow to the poles.

To address the potential that newly purchased solenoid valves could be installed with problems, the licensee had revised procedure IP/0/B/4974/01, Main Generator PCB Maintenance. Revision 5 of the procedure included a Note between Steps 10.3.7 and 10.3.8. The Note read: "If pilot valve is replaced, ensure pilot valve has been disassembled and inspected for proper assembly and components, or rebuilt prior to installation." The inspector verified that this procedure change had been made.

c. Conclusions

The inspector concluded that control room operators were effective in precluding a turbine runback by reducing reactor power to 50% before the PCB opened. The licensee's root cause evaluation was detailed, and actions to prevent recurrence were adequate.

O1.4 Lower Containment Air Temperature Exceeded for Short Duration

a. Inspection Scope (71707)

On June 30, the licensee was performing maintenance on the Unit 2 Lower Containment Ventilation Units (LCVUs). While the 2A and 2D LCVUs were out of service, the lower containment temperature increased to 117.4°F. The inspector reviewed applicable operating procedures, TS, the FSAR, tagout requirements, the innage work schedule, and PIP 2-C97-2127. The inspector also discussed the issue with operations, engineering and work control personnel.

b. Observations and Findings

During normal operation, the Containment Chilled Water (YV) chillers service various containment loads including the LCVUs and the Reactor Coolant Pump (RCP) Motor Air Coolers. On June 30, preventive maintenance (PM) and electrical motor testing were scheduled for the 2A and 2D LCVUs. The 2A LCVU was removed from service first. After the PM for the 2A LCVU was completed, but before motor testing was completed, operations personnel decided to remove the 2D LCVU for PM. The 2D LCVU was removed from service at 10:55 a.m. While both LCVUs were out of service, lower containment temperature increased. To compensate for the temperature increase, control room operators adjusted the operation of the remaining inservice LCVUs (2B and 2C) from "Normal" to "High Speed," and then to "Max Cool." However, for a brief period of time lower containment temperature had exceeded the high-high temperature Operator Aid Computer (OAC) alarm setpoint of 115.6°F and the adjusted TS limit of 117.2°F, ultimately reaching 117.4°F. Lower containment temperature was above 117°F for approximately 3 minutes before it was restored to within TS limits. The Action required by TS 3.6.1.5 was to restore the air temperature to within the limits within 8 hours or be in at least hot standby within the next 6 hours. Since the high lower containment temperature existed for only a few minutes, the licensee was in compliance with the TS action.

At approximately 11:10 a.m., operations personnel decided to postpone the PM on the 2D LCVU, recall the associated tags and return the LCVU to service until the 2A LCVU was restored to operation. While operators were returning the 2D LCVU to service and all three LCVUs to normal alignment, the YV chillers in service (A and C) tripped on low flow. Based on a review of the circumstances surrounding the trip of the A and C YV chillers, the inspector discerned that the following took place. When the B and C LCVUs were taken to "Max Cool" in an effort to reduce lower containment temperature, the flow control valves in the chiller loop fully opened as designed, and thermostatic control of the chilled water supply was lost. When operations subsequently restored the D LCVU to service and returned the LCVUs to normal operation, thermostatic control of the flow control valves was reinstated. The existing temperature caused the flow control valves to throttle closed, and the chillers tripped on low load. Normal alignment with the A and B YV chillers was established within 30 minutes of the chiller trips. The C YV chiller had also been restarted, but tripped after running for 10 minutes. Shortly thereafter, containment temperatures were restored to normal levels.

Operations surveillance procedure PT/1/A/4600/02A, Mode 1 Periodic Surveillance Items, Enclosure 13.1, Periodic Surveillance Items Data, approved January 23, 1997, provides surveillance acceptance criteria in accordance with the lower containment temperature limits imposed by TS 3.6.1.5. Lower containment minimum and maximum air temperature limits are based on the average inlet temperatures of the operating LCVUs. Temperature readings associated with non-running LCVUs provide indication of static air temperature and, therefore, are not used to determine average containment air temperature. Therefore, temperature limits are adjusted conservatively as a function of uncertainty (because of the reduced sample size) in generalizing local indications to average containment air temperature. As the number of LCVUs in service decreases, the temperature limit decreases (becomes more conservative). With two LCVUs running, the lower containment TS limit of 120°F was adjusted to 117.2°F.

The Containment Lower Compartment Ventilation Subsystem as described in the FSAR is designed to maintain a maximum temperature of 120°F in the lower compartment during normal plant operation. During normal operation, three units (each providing 33.3% capacity) are in service, and one unit is on standby. Technical Specification Interpretation 3.6.1.5 states that containment air temperature can be maintained with one active component out-of-service (i.e., three LCVUs in service).

Based upon a review of the FSAR and TS, as well as discussions with on-shift operators, the inspector determined that the decision to remove the D LCVU from service while preventive maintenance (PM)s on the A LCVU were ongoing was non-conservative and caused lower containment temperature to exceed the adjusted TS limit.

The inspector also determined that problems existed with procedure OP/2/A/6450/01, Containment Ventilation Systems, dated June 15, 1994, which controls the configuration of the LCVUs. The procedure did not provide adequate guidance to address the impact of removing two LVCUs from service on lower containment temperature. Operations Management Procedure 2-18, Tagout Removal and Restoration Procedure, Revision 46, Responsibility 4.8, states that the person placing or removing tag(s) shall check procedures affected and any outstanding tagouts associated with that procedure/system for any adverse effects. Because the adverse impact of removing 2 LCVUs from service was not addressed in the procedure, this responsibility could not be effectively realized.

In addition, procedure OP/2/A/6450/01 did not address the interaction between LCVU operation and integrated Containment Ventilation (VV) Systems. Step 2.7.3 of OP/2/A/6450/01, Enclosure 4.12, LCVU Additional Cooling and YV Chiller Trip Prevention, directs the operator to ensure that three LCVUs are in the "NORM" position. The performance of this step caused the A and C YV chillers to trip. Procedure guidance to slowly reduce the demand on the system was not provided, nor was a precaution or note provided to warn of the potential to induce a chiller trip as a function of load demand changes.

The inspector also noted that no procedure guidance was available for swapping between running and non-running LCVU units. OP/2/A/6450/01, Enclosure 4.2, Lower Containment Ventilation Unit Startup and Normal Operation, provided procedural guidance for starting up the system by placing three LCVUs in operation. Enclosure 4.7, Lower Containment Ventilation Unit Shutdown, provides procedural guidance for shutdown of the system by placing all four LCVU switches in the OFF position.

However, no procedural guidance existed for stopping an individual LCVU and subsequently restarting it or making other required alignment changes needed to facilitate the performance of the PM. The inspector recognized that this lack of procedural guidance was unrelated to the lower containment temperature increase and the YV chiller trips.

The inspector also identified a minor discrepancy in the planned innage work schedule. The 2A LCVU had two work items planned to be worked which included a PM and electrical motor testing. The PM on the 2A LCVU was scheduled to be completed at 12:00 p.m. on June 30, 1997. The motor electrical testing on the 2A LCVU was scheduled to be completed at 1:00 p.m. on June 30. The PM on the 2D LCVU was scheduled to commence at 12:00 p.m. on June 30, immediately following the scheduled completion of the PM on the 2A LCVU. This schedule allowed both the A and D LCVUs to be out of service for 1 hour, which was non-conservative and not in accordance with the alignment described in the FSAR.

c. <u>Conclusions</u>

The inspector concluded that the decision to deviate from the preferred normal alignment of LCVU operation to support planned maintenance exhibited non-conservative work scheduling and operator judgement. As a result, lower containment temperature increased slightly above the adjusted TS limit for a brief period of time. However, temperatures were reduced below the adjusted TS limit within 8 hours as required by the TS action requirement. Therefore, exceeding the lower containment air temperature on plant equipment had minor safety significance and did not pose a threat to safety-related equipment. The LCVU operating procedures did not address the adverse impact of removing two LCVUs from service simultaneously, nor did the procedure address the interaction between LCVU operation and integrated containment ventilation systems. These procedural inadequacies constitute a violation of TS 6.8.1, Procedures and Programs. This failure constitutes a violation of minor significance and is being treated as a NCV, consistent with Section IV of the NRC Enforcement Policy. This item is identified as NCV 50-414/97-09-02: Inadequate LCVU Operating Procedure.

O8 Miscellaneous Operations Issues (92901)

O8.1 <u>(Closed) Unresolved Item (URI) 50-413,414/94-13-02:</u> Emergency Operating Procedure (EOP) 50.59 Evaluations Not Reviewed by Nuclear Safety Review Board (NSRB) as Required by TS

This item was related to an apparent failure to meet the TS requirement for the NSRB to review 50.59 evaluations for EOP changes. The inspector's review determined that the required 50.59 evaluations were being appropriately reviewed by the NSRB. The licensee's procedures had been inconsistent in defining the 10 CFR 50.59 screening evaluation and the 10 CFR 50.59 Unreviewed Safety Question (USQ) evaluation. The TS requirement was intended for the NSRB to review the 10 CFR 50.59 USQ evaluations. Nuclear Site Procedure NSD-209, 10 CFR 50.59 Evaluations, Revision 5, was revised after 1994 to clearly define the two evaluations. The licensee initiated a change to NSD-703, Administrative Instruction for Station Procedures, to clearly distinguish on the procedure change process documentation whether the evaluation performed was a screening evaluation or an USQ evaluation. The inspector reviewed three USQ evaluations for EOP changes and verified the USQ evaluation had been sent to the NSRB for review. A 1995 evaluation had been reviewed and two 1997 evaluations were scheduled for review at the next NSRB meeting. The inspector concluded that this issue was adequately resolved and the TS requirements had been met by the licensee.

During the investigation of the above issue, the inspector reviewed approximately 20 examples of 10 CFR 50.59 screening evaluations for EOP changes and identified a deficiency in the licensee's procedure implementation of this activity. Specifically, the justifications for the screening questions were inadequate in many changes. The justifications were inadequate in that they only repeated the screening question as a negative statement. NSD-209, 10 CFR 50.59 Evaluations, Revision 5, required the documentation of justification for responses to 50.59 screening questions. It further stated that justifications should be complete enough so that an independent reviewer could come to the same conclusion. The following EOP change 50.59 screening evaluations were inadequate and did not meet the applicable procedure requirements:

- EP/2/A/5000/FR-I.2 dated November 17, 1995
- EP/1/A/5000/FR-I.1 dated September 19, 1996
- OP/1/A/6350/08 dated February 28, 1996
- EP/2/A/5000/F-0 dated March 26, 1997
- EP/1/A/5000/FR-H.1 dated August 16, 1996
- EP/1/A/5000/FR-H.1 dated January 30, 1995

This failure to follow NSD-209 for 10 CFR 50.59 screening evaluations, is identified as the first example of Violation (VIO) 50-413,414/97-09-04: Failure to Follow Procedure. The inspector did not identify any USQ condition related to the inadequate 50.59 screening evaluations.

The inspector noted that the 50.59 screening evaluations for EOP changes were performed by the Operations organization. Previous inspections of 50.59 evaluation performance have concluded that the Engineering organization performed to a high standard in this area for 50.59 evaluations related to modifications. Although both organizations receive the same training and use the same procedures. Operation's performance in this activity was deficient as previously noted. The inspector reviewed a 1997 50.59 USQ evaluation for an EOP change. This evaluation was good in that it included a well detailed justification for responses to the USQ evaluation questions. This indicated that the Operations deficient performance was related only to the 50.59 screening evaluations.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Electrical Flash During Breaker Preventive Maintenance

a. Inspection Scope (62707)

The inspector reviewed the circumstances and the licensee's corrective actions associated with an electrical flash that occurred inside a 600 Volt non-safety-related breaker cubicle while periodic breaker PM was being performed. The electrical flash resulted in a minor personnel injury and extensive damage to the breaker cubicle.

b. Observations and Findings

On June 3, 1997, an Instrumentation and Electrical (IAE) technician was performing PM on 600 Volt breakers 2MXM-F09C and 2MXM-F09D. These breakers supplied power to two Unit 2 ice condenser refrigeration air handling fans. The PM activity involved testing the overcurrent protective devices associated with the breakers. The technician had removed breaker F09C from its cubicle and was in the process of removing breaker F09D from its cubicle. While removing F09D, an electrical flash occurred in the F09C cubicle, which was located directly above F09D. The technician received minor facial burns, but was not seriously injured. Breaker F09C was electrically welded in its cubicle as a result of the electrical fault. The inspector responded to the breaker work location and noted good licensee immediate actions in response to the incident. These actions included terminati[illegible] ll PM work, roping off the area for personnel safety consideratio[illegible] and initiating a Failure Investigative Process (FIP) to determine the root cause of the electrical fault.

On June 6, 1997, Motor Control Center 2MXM was de-energized, and the breaker cubicle for F09C inspected. The damage to the bus was minimal; however, the stabs for F09C were badly damaged and required replacement. Both breakers F09C and F09D were repaired, tested, and returned to service. The inspector attended the PORC meeting conducted to discuss the repair plans and noted that management performed a thorough review of the plans with good discussions on the impact of the work planned on the plant. The repairs were completed without incident.

The FIP team was thorough in their investigations and determined that the stabs behind breaker F09C had come in contact with the energized bus. Since the breaker power connecting cables had been determed and left untaped in the bottom of the breaker cubicle, an electrical ground path was created when the cables were re-energized. The FIP determined the method for racking the breaker out in the maintenance position was inadequate. In the maintenance position, a lock tab on the front of the breaker cubicle had been used to position the breaker away from the bus; however, this method did not provide sufficient distance between the bus and stabs. While this method had not resulted in any problems in the past, the result of having two breakers in the maintenance position, located one above the other, created an even smaller bus/stab distance that resulted in electrical flash over.

As a result of the FIP investigations, instrumentation procedures governing work on 600 Volt breakers were revised to change the method of racking out these breakers for maintenance. Instead of using the lock tab, procedures directed that a padlock be placed on the breaker or the breaker be removed completely to ensure adequate stab/bus distance is maintained. In addition, IAE personnel involved with breaker work were to be provided training on this new method of racking 600 Volt breakers out to the maintenance position.

c. Conclusions

The inspector concluded that the FIP team was thorough in investigating the cause of the electrical flash. The root cause evaluation revealed configuration weaknesses in the method of locking out 600 Volt breaker cubicles to the maintenance position. The inspector determined that the licensee adequately implemented corrective actions to prevent recurrence of this incident.

M1.2 Inadequate Leak Rate Test of Unit 2 Containment Isolation Valve

a. Inspection Scope (40500, 61726, 62707)

On June 4, 1997, the licensee identified that Unit 2 containment isolation valve 2NV-874 had not been properly Type C leak rate tested in accordance with 10 CFR 50, Appendix J, during the previous refueling outage. On June 6, the valve was properly tested and failed the Type C leak rate test. The valve disc was replaced, and the valve was successfully tested on June 7. The licensee submitted LER 50-414/97-004 to document the inadequate leak rate test conducted during the outage. The inspector reviewed the circumstances associated with the inadequate testing, attended PORC meetings to discuss retesting valve 2NV-874 online, witnessed aspects of the June 6 retest, reviewed leak rate test results, and discussed the incident with engineering and Operations Test Group (OTG) personnel.

b. Observations and Findings

On June 4, 1997, the OTG Supervisor was conducting a procedure completion verification of Unit 2 Periodic Test (PT) procedure PT/2/A/4200/01C, Containment Isolation Valve Leak Rate Test. This procedure had been performed during the previous refueling outage in April 1997. During the review, the supervisor identified that Step 2.2.3 of Enclosure 13.7, Penetration No. M228 Type C Leak Rate Test, had been marked "Not Applicable" by the OTG technician performing the test, resulting in the step not being performed. This step required test vent flow path valve 2NV-873 to be opened while testing inside containment isolation check valve 2NV-874 (associated with the Standby Makeup System flowpath to the reactor coolant pump seals). Without an open test vent flowpath, the leak rate test on 2NV-874 had been invalid.

The inspector verified that appropriate actions were implemented upon identification of the invalid leak rate test. These actions included 2NV-874 being declared inoperable and, in accordance with TS 3.6.3, the outboard containment isolation valve (2NV-872A) in the penetration was closed and power was removed from the valve operator within four hours. The inspector attended the June 5 and 6 PORC meetings conducted to discuss activities to retest 2NV-874. Management thoroughly discussed the impact on the plant with testing the valve while online. In addition, engineering developed a special leak rate test procedure and a detailed briefing package explaining the necessary actions for controlling the retest activities.

On June 6, the inspector witnessed aspects of the leak rate test on 2NV-874. The inspector noted that testing was well controlled and performed in accordance with the test procedure. The valve was not able to be pressurized and resulted in a failed leak rate test. Valve maintenance was performed resulting in replacement of the valve disc and disc spring. A subsequent leak rate test was performed following the maintenance activity. The inspector reviewed the results of this testing which verified that leakage was within acceptable limits. Following successful testing, 2NV-874 was declared operable and the penetration was returned to its normal configuration.

c. Conclusions

The inspector concluded the identification by the OTG Supervisor of a procedure discrepancy that resulted in an invalid leak rate test of nD-874 was an example of good questioning attitude. The PORN performed a thorough review of subsequent activities to properly perform the leak rate test. Good engineering support was provided, both in developing a leak rate test procedure and briefing package for the evolution.

The inspector noted that the procedure completion review was not performed by the OTG Supervisor following actual completion of all testing or prior to plant startup from the refueling outage. Since this was the only review that was required following test procedure completion, the inspector considered the review untimely. Had this review been completed prior to plant startup, this problem may have been identified and corrected prior to the unit entering a mode requiring containment integrity. The failure to open test vent valve 2NV-873 during leak rate testing of valve 2NV-874 in accordance with PT/2/A/4200/01C was identified as a violation of TS 6.8.1. This issue is identified as Violation 50-414/97-09-03: Failure to Follow Procedure Results in Invalid Local Leak Rate Test of Valve 2NV-874.

M8 **Miscellaneous Maintenance Issues** (92902.

M8.1 (Closed) VIO 50-413, 414/97-01-01: Failure to Include all Structures, Systems and Components in the Scope of the Maintenance Rule as Required by 10 CFR 50.65

This violation was identified when the inspectors determined that the licensee had incorrectly excluded a number of structures, systems and components from the scope of the Maintenance Rule. The licensee acknowledged the violation and issued a Problem Investigation Process (PIP) report PIP No. 0-C97-0419, to document corrective actions taken and, track the progress made in addressing the issues. The systems affected included Nuclear Sampling (NM), Main Steam to Auxiliary Equipment (SA), Auxiliary Building Chilled Water (YN) and Ice Condenser Hitch Pins (NF). Following a review by the site Expert Panel these systems or components were added to the scope of the Maintenance Rule.

Corrective actions taken or planned included a review of the 239 functions that had been excluded from the Maintenance Rule scope. This review was scheduled for completion in December 1997, and will be documented in PIP No. 0-C97-0419. In addition, structures and functions excluded from the Maintenance Rule will be reviewed for Generic Scoping applicability. The due date for this review is also December 1997. The inspectors concluded the licensee's corrective actions were appropriate.

M8.2 (Closed VIO 50-413,414/97-01-04: Failure to Implement the Requirements of (a)(1) and (a)(2) of the Maintenance Rule

This violation was identified when the inspectors determined that the licensee was using Forced Outage Rate (FOR) instead of Unplanned Capability Loss Factor (UCLF) as a Plant Level Performance Criteria for monitoring A2 systems per 10 CFR 50.65. The concern was that FOR was not as sensitive as UCLF in detecting declining performance in some systems.

The licensee acknowledged the violation and took appropriate action to correct the problem. The licensee incorporated the Plant Transient Criteria as part of the Forced Outage Criteria. This combination of criteria was intended to provide appropriate equivalent defense in depth monitoring as the Unplanned Capability Loss Factor. A Plant Level

Performance Criteria called Plant Transients, which defined unacceptable performance was added to Engineering Directives Manual (EDM)-210 as Rev. 4. The inspectors concluded the licensee's corrective actions were appropriate.

M8.3 (Closed) Inspector Followup Item (IFI) 50-413,414/97-01-02: Followup and Review of Licensee Procedure to Implement the Requirements of (a)(1) and (a)(2) of the Maintenance Rule after Issuance of Regulatory Guide 1.160, Rev.2

EDM-210," Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants or the Maintenance Rule," Rev. 5, revised the definition of Maintenance such that it was now in agreement with Regulatory Guide 1.160, Rev. 2, dated March 1997. Revision 5 of the EDM now considers any operator action performed in support of Maintenance as a Maintenance Preventable Function Failure (MPFF) candidate. In addition, the flow graph of Appendix A to the subject EDM, were revised for clarity. One of the two was revised from Vendor Error to Off-site Vendor Services while the other from Operations or Plant configuration control to Operation or Plant Configuration Control not associated with a maintenance activity. The inspectors concluded the licensee's corrective actions were appropriate.

M8.4 (Closed) IFI 50-413,414/97-01-03: Followup on Licensee Actions to Provide Performance Criteria for Structures After Resolution of this Issue

EDM-210, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants or the Maintenance Rule," Rev. 5, changed the performance criteria for all Maintenance Rule structures to comply with Regulatory Guide 1.160, Rev. 2. This criteria applies to both risk and non-risk significant Maintenance Rule structures.

EDM-410, "Inspection Program for Civil Engineering Structures and Components," Rev. 1, dated June 16, 1997, is the controlling document for monitoring and assessing civil engineering structures and components to the requirements of 10 CFR 50.65 and Regulatory Guide 1.160, Rev. 2, dated March 1997. It provides examination guidelines, acceptance criteria and documentation requirements. As such, Catawba civil engineering was responsible for implementing the inspection program for structures and components. The inspectors reviewed EDM-410, Rev. 1 for content and adequacy. The inspectors noted that the procedure provided adequate guidelines and the acceptance criteria contained within, followed Regulatory Guide 1.160, Rev. 2 guidelines for acceptable and unacceptable performance criteria.

Through discussions and document review, the inspectors ascertained that the inspection program for structures was adequately administered and implemented. Responsible engineers had received training and were familiar with Maintenance Rule requirements as they applied to their area of responsibility.

At the close of this inspection, 39 structures had been inspected and an additional 120 were scheduled for inspection by year's end. Inspection per the revised EDMs -210 and -410 commenced on July 1, 1997. The inspectors reviewed the licensee's classroom training material, ES-CN-97-21, used to communicate Regulatory Guide 1.160, Rev. 2 guidelines. Training of personnel was held between June 9 and 18, 1997. The inspectors concluded the licensee's corrective actions were appropriate.

III. Engineering

E1 Conduct of Engineering

E1.1 Primary and Secondary Thermal Power Discrepancy

a. Inspection Scope (37551)

On July 15, the licensee discovered a discrepancy of approximately 0.6% between the Unit 2 primary and secondary thermal power indications. Secondary thermal power was immediately reduced to 99.3% (reactor power was reduced to 99.7%) and a FIP team was initiated to determine the cause of the discrepancy. The inspector attended management briefings by the FIP team members on the progress of their investigation; reviewed associated TS and TS Interpretations; and discussed the issue with Operations, Engineering and Maintenance personnel.

b. Observations and Findings

On July 15, Operations personnel were notified by the reactor engineering group that there was a 0.6% discrepancy between primary and secondary thermal power indications, and that actual thermal power might be greater than the secondary thermal power (the designated thermal power best estimate) indication. The reactor engineering group discovered, during a routine review of secondary plant parameters, that primary thermal power had slowly increased over time since the Unit 2 restart from the April 1997 refueling outage. A FIP team was initiated to determine the cause of the discrepancy, and control room operators decreased reactor power to 99.3%. The reactor was operated at 99.3% power until the FIP team could determine the cause of the discrepancy.

The FIP team determined, during the course of their investigation, that the T_{ref} indication had been drifting downward since May 11, 1997, from 587.3°F to 586.9°F. Operations responded by decreasing T_{ave} to minimize the T_{ref}/T_{ave} error. Lowering T_{ave} caused the reactor to increase ΔT to maintain reactor power equal to secondary power. The drift in the T_{ref} indication resulted in changes in T_{cold}, T_{hot}, T_{ave} and ΔT, but did not cause a change in indicated or actual primary and secondary thermal power. Although the FIP team could not attribute this indication drift to the primary/secondary thermal power indication discrepancy, they determined that a degraded 7300 process card was responsible for the drift and initiated plans to have the card replaced after the root cause of the power indication discrepancy was identified.

The FIP team also determined that indicated feedwater flow had decreased while steam flow had remained constant. This was attributed to feedwater venturi defouling as a function of the new cycle (restart from the April refueling outage was in early May), the recent reactor trip (June 26), and was the recent rapid downpower (July 2). The result of defouling was a decrease in indicated feedwater flow with a consequential decrease in indicated secondary thermal power. Operations maintains secondary Thermal Power Best Estimate (TPBE) near 100% by periodically opening flow control valves, which in turn causes primary power to increase to maintain T_{ave} for 100% power level. The gradual defouling caused an increase in actual and indicated primary thermal power, as well as actual secondary thermal power. However, the resultant discrepancy between indicated and actual secondary thermal power accounted for approximately 0.10% to 0.15% of the 0.6% discrepancy between primary and secondary indicated thermal power.

The major contributor (0.3% to 0.4%) to the discrepancy between primary and secondary thermal power was determined by the FIP team on July 16 as hot leg streaming. According to Westinghouse, hot leg streaming refers to the inability to accurately characterize bulk hot leg temperature. The licensee examined data from the Unit 2 Beginning of Cycle and identified changes in the behavior of this phenomenon from previous cycles. Specifically, calculations revealed that indicated T_{hot} had increased by 0.2°F and caused indicated primary thermal power to increase. As discussed above, these changes were originally masked by the decrease in primary temperatures accompanying the decrease in T_{ref}/T_{ave} as a function of T_{ref} indication drift.

Hot leg streaming has occurred in previous cycles on both units and has resulted in as high as a 1.0% difference between primary and secondary thermal power. To account for this, an adjustment factor in the OAC calculation corrects the discrepancy.

The FIP team concluded that secondary thermal power had always been accurately and correctly indicated, and that primary thermal power indication did not reflect an actual increase in power level above TS limits. The inspector discussed the impact of the primary thermal power indication on Reactor Protection System setpoints and functions. According to the reactor engineering group, the venturi defouling and hot leg streaming factors did not constitute a sufficient temperature error to warrant adjustment via the Reactor Coolant System (RCS) Temperature Calibration Procedure, which is run quarterly. The OPΔT and OTΔT trip strings remained within their TS limits. In addition, the nuclear instrumentation system is calibrated to secondary thermal power, so the associated overpower trip setpoints were unaffected.

Reactor Power was increased to 99.5% on July 16 and the degraded T_{ref} card was replaced on July 17. The inspector attended the prejob brief for the card replacement and observed the work activity in the control room. The replacement was successfully completed within less than 1 hour and without incidence. At the end of the inspection period, the license was considering either performing periodic manual calculations to the correct the thermal power discrepancy, or conducting a full calorimetric to account for the deviation.

c. Conclusions

The inspector concluded that the licensee's identification of the thermal power discrepancy exhibited attention to detail and a thor[illegible] review of plant data. Actions to initiate a PIP team to inv[illegible] root cause were appropriate, and steps to reduce reactor po[illegible] discrepancy was understood were conservative and indicative [illegible] positive nuclear safety ethic. Replacement of the faulty $T_{[illegible]}$ [illegible]d was well-planned, coordinated and controlled, and executed in an expeditious manner.

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Corrective Actions

a. Inspection Scope (37550, 92903)

The inspector reviewed Engineering corrective actions to resolve open items identified during the development of the station Design Base Documents (DBDs) and findings from Self-initiated Technical Audits (SITAs). Also reviewed were the licensee's actions to address a 10 CFR Part 21 issue related to a defective Emergency Diesel Generator (EDG) intake/exhaust valve spring. Applicable regulatory requirements included 10 CFR 50 Appendix B, FSAR, Technical Specifications, and implementing licensee procedures.

b. Observations and Findings

DBDs

Developed between 1990 and 1994, DBDs consolidated design and licensing documentation for selected station systems and programs. The procedure guidance for development and maintenance of DBDs was provided by Engineering Directives Manual, EDM-170, Design Specifications, revision 5. Open items were evaluated for operability during the DBD development and Licensee Event Reports (LERs) initiated as required. EDM-170 required the remaining items to be entered into the Problem Investigation Process (PIP) for tracking and resolution. Additionally, the licensee's February 10, 1997, response to the 10 CFR 50.54f letter related to the Adequacy and Availability of Design Basis Information, stated that DBD open items would be entered into the PIP for tracking and resolution.

The inspector reviewed the resolution of open items in the Reactor coolant System DBD to sample the adequacy of item resolution activity. Approximately 20 items were evaluated to verify that the PIP and interfacing station programs evaluated and resolved the open item issues. The items were adequately resolved.

An independent industry audit of Catawba in late 1996, identified as a finding the numerous long-term unresolved DBD open items. The response to the finding was to initiate a blanket PIP (PIP 0-C97-0595 dated March 5, 1997) to cover the systems with the identified open items. Many of these open items were not previously in the PIP process. The PIP corrective actions established a schedule to resolve and close the referenced DBD open items by September 1, 1997.

During this inspection, the inspector identified additional DBD open items which were not entered into the PIP process nor included in the blanket PIP. The open items were included in DBD CNS-1435.00-0002, Post Fire Safe Shutdown, revision 4, and DBD CNS-1465.00-00-0018, Station Blackout (SBO) Rule, revision 2. Although not entered into the PIP process, the licensee provided meeting documentation indicating the Post Fire Safe Shutdown open items were being evaluated. These items were identified by a November 1995 electrical post fire shutdown review performed after the initial DBD development and entered into the DBD by revision 4 at that time. There was no documented evaluation of operability or Appendix R commitments which would have been addressed by the PIP process. Following the inspector's identification of this issue the licensee initiated PIP 0-C97-1918 to track resolution of these open items. The inspector identified no significant safety concerns related to the open items reviewed. This failure to follow procedure for resolution of DBD open items is identified as the second example of Violation 50-413,414/97-09-04: Failure to Follow Procedure.

SITAs

The inspector reviewed a recently completed SITA report dated June 11, 1997, which reviewed the adequacy of resolution of SITA findings. The scope of the audit was good in that it reviewed the resolution of 80 findings from four previous SITAs. The depth of the audit was good in that corrective actions were verified through the extent of station programs (e.g., PIP, work requests, modification, etc.) involved in the resolution. The findings were well defined and demonstrated an independent and objective audit. Corrective actions for the findings had not yet been developed.

EDG 10 CFR Part 21 Notice

The inspector reviewed the licensee's actions to address a Cooper Industries 10 CFR Part 21 notice regarding potentially defective EDG intake/exhaust valve springs which was applicable to Catawba. The notice was initiated in 1991 and revised on May 1, 1997. The licensee had included an inspection for the spring defect into the EDG maintenance procedure. A defective spring was identified at Catawba in 1996. The spring was replaced, analyzed, and sent to the vendor for further analysis. The licensee's response to the notice on this issue was appropriate.

c. Conclusions

Resolution of DBD open items was generally adequate in that no safety significant issues were identified in the open items. A violation was identified for failure to follow licensee procedure requirements to enter open DBD open items into the station PIP process for tracking and resolution. The audit of SITA corrective actions demonstrated that the licensee was aggressively following SITA findings and is identified as a strength in corrective action performance. Additionally, the licensee adequately addressed the EDG 10 CFR Part 21 issue related to potentially defective intake/exhaust springs.

E3 Engineering Procedures and Documentation

E3.1 Changes, Tests, and Experiments Performed In Accordance With 10 CFR 50.59 (thru December 31, 1996)

a. Inspection Scope (37551)

By letter dated March 31, 1997, Duke Power Company (the licensee) submitted its annual summary of all changes, tests, and experiments, which were completed under the provisions of 10 CFR 50.59 for the period through December 31, 1996. The licensee's March 31, 1997, summary included approximately 380 changes made during the subject period. The inspector evaluated these changes against the provisions of the regulation.

b. Observations and Findings

In accordance with 10 CFR 50.59, a licensee may: (1) make changes in the facility as described in the safety analysis report, (2) make changes in the procedures as described in the safety analysis report, and (3) conduct tests or experiments not described in the safety analysis report, without prior Commission approval, unless the change involves a change in the Technical Specifications or an Unreviewed Safety Question (USQ). The regulation defines an USQ as a proposed action that: (a) may increase the probability of occurrence or consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report, or (b) may create a possibility for an accident or malfunction of a different type than any previously evaluated in the safety analysis report, or (c) may reduce the margin of safety as defined in the basis for any Technical Specification.

The inspector reviewed the licensee's current (dated March 10, 1997) version of Nuclear System Directive 209, "10 CFR 50.59 Evaluations," which is patterned after NSAC-125, "Guidelines for 10 CFR 50.59 Safety

Evaluations," June 1989. This document requires that changes be evaluated against the appropriate Final Safety Analysis Report (FSAR), Technical Specifications, and NRC Safety Evaluation Report sections to determine if there is need for revision. Specifically, the criteria specified by 10 CFR 50.59 are broken down into seven (7) questions. For a change to be qualified for 10 CFR 50.59, the answers to all seven questions must be "no". Based on review of this document, and the review of the licensee's 10 CFR 50.59 evaluations, the inspector concluded that the licensee's directive appropriately reflects the criteria of this regulation and that, if followed accordingly, should ensure that a change would be correctly performed under this regulation.

The inspector performed an in-office review of the licensee's summary to determine the nature and safety significance of each change. Through this review, the inspector selected the following changes for more detailed review onsite:

- Exempt Changes:

  Exempt Change CE-3176
  Exempt Change CE-3705
  Exempt Change CE-3759
  Exempt Change CE-4745
  Exempt Change CE-4746
  Exempt Change CE-4821
  Exempt Change CE-4822
  Exempt Change CE-7416
  Exempt Change CE-7977
  Exempt Change CE-8126
  Exempt Change CE-8182
  Exempt Change CE-8245
  Exempt Change CE-8410
  Exempt Change CE-61008
  Exempt Change CE-61162

- Miscellaneous Changes:

  SIMULATE (a computer code) Version 4

- Modifications:

  NSM CN-11371
  NSM CN-20396

- Operable But Degraded Evaluations:

  PIP 2-C97-0157
  PIP 2-096-3250

- Operability Evaluations:

Operability Evaluation dated 2/15/94
Operability Evaluation dated 2/18/94
Operability Evaluation dated 6/28/94

- Procedure Changes:

  OP/1/A/6200/11
  AM/2/A/5100/07
  OP/2/B/6200/33, Change 4 Rev. 4
  OP/1/A/6550/14
  PT/1/B/4700/82

The inspector determined that these changes were correctly evaluated under the provisions of 10 CFR 50.59.

During the in-office and onsite reviews, the inspector made a number of observations and has communicated them to licensee personnel:

- The use of Duke-specific system identifiers in the annual summary (which is submitted to the NRC and is thus available to the public) is discouraged unless the licensee provides a key in the summary. These identifiers do not bear any apparent correlation to the actual systems (e.g., NC = reactor coolant system, KC = component cooling system, etc.). The inspector made a similar observation on the summary submitted on March 2?, 1996 (see Inspection Report 50-413,414/96-10).

- The licensee's corresponding revision of the UFSAR, per 10 CFR 50.71, lags behind 10 CFR 50.59 evaluations. The next update of the UFSAR, scheduled for late 1997, should capture all the changes that are within the scope of the UFSAR.

- While the licensee had acceptably evaluated all the changes audited by the inspector, a number of them appeared in the summary with insufficient information for a reader to even determine what system was involved, or what change was made. The inspector recommended a several-sentence description, identifying the system, the component, and the nature of the change, and accompanied by a several-sentence evaluation. Despite this problem with the summary, the evaluations were found to be thorough and in compliance with 10 CFR 50.59. The licensee was aware of this problem with the summary and has initiated actions to correct such weakness by revising its guidance document, NSD 209 (see Problem Investigation Process Form 0-C97-2027, dated June 19, 1997).

- The term "Exempt Changes" may cause confusion in the context of 10 CFR 50.59. It is a term internal to the licensee's documentation. It pertains to changes that "do not require the Modification

Program controls for configuration management and therefore are specifically exempted from the requirements to process an editorial NM or NSM." According to licensee personnel, an "exempt change" is essentially a minor change.

- The summary contained a significant number of errors, which stated the opposite of the actual facts. For example, test procedure TT/1/A/9200/88 states "there are Unreviewed Safety Questions associated with this test procedure" when the onsite evaluation shows that there was no unreviewed safety question. The licensee submitted a letter on July 9, 1997, correcting such errors.

c. Conclusions

Based on in-office review of the licensee's March 31, 1997, annual summary on 10 CFR 50.59 changes, onsite review of the licensee's 10 CFR 50.59 evaluations, and audit of the licensee's procedures, the inspector concluded that the licensee had complied with the provisions of the regulation for the changes listed in the annual summary.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Tours of the Radiological Control Area (RCA) (71750)

The inspectors periodically toured the RCA during the inspection period. Radiological control practices were observed and discussed with radiological control personnel, including RCA entry and exit, survey postings, locked high radiation areas, and radiological area material conditions. The inspector concluded that radiological control practices were proper.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on July 11 and July 23, 1997. The licensee acknowledged the findings presented. No proprietary information was identified. Dissenting comments were not received from the licensee.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Bhatnager, A., Operations Superintendent
Birch, M., Safety Assurance Manager
Coy, S., Radiation Protection Manager
Forbes, J., Engineering Manager
Jones, R., Station Manager
Harrall, T., Instrument and Electrical Maintenance Superintendent
Kelly, C., Maintenance Manager
Kimball, D., Safety Review Group Manager
Kitlan, M., Regulatory Compliance Manager
Nicholson, K., Compliance Specialist
Peterson, G., Catawba Site Vice-President
Tower, D., Regulatory Compliance

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726: Surveillance Observation
IP 37550: Engineering
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 93702: Prompt Onsite Response to Events

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-414/97-09-01	NCV	Failure to Declare Ice Condenser Intermediate Deck Doors Inoperable and Log Appropriate TSAIL Entry (Section O1.1)
50-414/97-09-02	NCV	Inadequate Lower Containment Ventilation Unit Operating Procedure (Section O1.4)
50-414/97-09-03	VIO	Failure to Follow Procedure Results in Invalid Local Leak Rate Test of Valve 2NV-874 (Section M1.2)
50-413,414/97-09-04	VIO	Failure to Follow Procedure - Two Examples (Sections O8.1, E2.1)

<u>Closed</u>

50-413,414/97-01-01	VIO	Failure to Include All Structures, Systems and Components in the Scope of the Maintenance Rule as Required by 10 CFR 50.65(b) (Section M8.1)
50-414,414/97-01-02	IFI	Followup and review of licensee procedure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule after issuance of Revision 2 of Regulatory Guide 1.160 (Section M8.3)
50-413,414/97-01-03	IFI	Followup on Licensee Actions to Provide Performance Criteria for Structures After Resolution of this Issue (Section M8.4)

50-413,414/97-01-04	VIO	Failure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule (Section M8.2)
50-413,414/94-13-02	URI	Emergency Operating Procedure 50.59 Evaluations Not Reviewed by Nuclear Safety Review Board as Required by TS (Section O8.1)

List of Acronyms

CFR - Code of Federal Regulations
DBD - Design Basis Documents
EDG - Emergency Diesel Generator
EDM - Engineering Directives Manual
EOP - Emergency Operating Procedure
FIP - Failure Investigative Process
FSAR - Final Safety Analysis Report
IAE - Instrument and Electrical
IFI - Inspector Followup Item
IST - Inservice Testing
LCVU - Lower Containment Ventilation Unit
LER - Licensee Event Report
LLRT - Local Leak Rate Test
MPFF - Maintenance Preventable Function Failure
NCV - Non Cited Violation
NM - Nuclear Sampling
NRC - Nuclear Regulatory Commission
NSD - Nuclear Site Directive
NSRB - Nuclear Safety Review Board
OAC - Operator Aid Computer
PDR - Public Document Room
PIP - Problem Investigation Process
PM - Preventive Maintenance
psig - Pounds Per Square Inch Gauge
RCA - Radiologically Controlled Area
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
RG - Regulatory Guide
SA - Main Steam to Auxiliary Equipment
SBO - Station Blackout Rule
SITA - Self Initiated Technical Audit
SPOC - Single Point of Contact
TPBE - Thermal Power Best Estimate
TS - Technical Specifications
TSAIL - Tech Spec Action Item Log
UCLF - Unplanned Capability Loss Factor
UFSAR - Updated Final Safety Analysis Report

URI	-	Unresolved Item
USQ	-	Unreviewed Safety Question
VDC	-	Volts, direct current
VIO	-	Violation
VV	-	Containment Ventilation
WO	-	Work Order
YN	-	Auxiliary Building Chilled Water