U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report Nos.:	50-413/97-14, 50-414/97-14
Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	422 South Church Street Charlotte, NC 28242
Dates:	October 12 - November 22, 1997
Inspectors:	D. Roberts, Senior Resident Inspector R. Franovich, Resident Inspector M. Giles, Resident Inspector (In Training) D. Forbes, Radiation Specialist, Region II (Sections R1.2, R1.3, R1.4, R3.1, R7.1, and R8.1)
Approved by:	C. Ogle, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure 3

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/97-14, 50-414/97-14

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection. It also includes the results of an announced inspection by a regional radiation specialist.

Operations

- In general, the conduct of operations was professional and safety conscious. (Section O1.1)

- A minor overpower excursion resulted in the 15-minute running average for reactor thermal power slightly exceeding licensed power limits for an extended period. The power excursion was contained within criteria established by previous NRC guidance. (Section O1.2)

- Control room operators failed to detect an extinguished "DC Power On" light for the Unit 1 turbine-driven auxiliary feedwater pump for almost three days. The impact on pump operability of the blown fuse which caused the extinguished light, will be reviewed during closeout of the URI. (Section O1.3)

- Operations personnel inappropriately entered the Technical Specification action statement more than an hour after a reactor trip system logic function failed to meet surveillance test acceptance criteria. However, the failed function was repaired, successfully retested, and returned to service before Technical Specification actions were required. (Section O1.4)

- Nuclear System Directive 317 provided structure and delineated responsibilities for freeze protection. Proceduralized activities were initiated and completed in a timely manner, and work requests were initiated to resolve identified discrepancies. The licensee's efforts to effectively protect plant equipment and systems from freezing conditions improved since the previous cold weather season. (Section O2.1)

- Four unrelated non-emergency events were reported to the NRC in accordance with Title 10 Code of Federal Regulations, Part 50.72 during the period. All of the events were properly reported with sufficient information provided. (Section O2.2)

- Examples of poor performance were noted concerning activities surrounding the inappropriate tagout of a residual heat removal system miniflow valve during planned maintenance. (Section O4.1)

- A deviation, with two examples, from NRC commitments was identified. Both examples involved administrative errors resulting in commitments

being changed internally without proper notification of the NRC. (Sections O8.1 and O8.2)

Maintenance

- Surveillance activities observed by the inspectors involved good workmanship, proper use of procedures, good radiological practices, and proper management of Technical Specification action statements. (Section M1.1)

- New fuel movement activities to support the upcoming Unit 1 refueling outage were performed well. (Section M1.2)

Engineering

- An unresolved item was identified concerning containment penetrations associated with steam supply lines to both units' turbine-driven auxiliary feedwater pumps, which were not in compliance with Title 10 Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 57. The licensee had submitted an exemption request concerning this issue to the NRC during the previous inspection report period. (Section E1.1)

- Remote manual closure capability existed for dual function containment isolation valves; however, the action involved resetting the emergency diesel generator load sequencer, an action requiring further evaluation to be conducted under the above unresolved item. (Section E1.1)

- A non-cited violation was identified concerning the use of aluminum separators in high efficiency particulate air filters located inside containment. (Section E8.2)

Plant Support

- An example of poor performance was identified related to a radiological control area boundary being compromised. This minor discrepancy was immediately corrected by plant personnel and properly addressed by licensee management. (Section R1.1)

- The licensee effectively implemented a program for shipping radioactive materials required by the NRC and Department of Transportation regulations. (Section R1.2)

- The licensee was meeting established goals for radioactive waste generated. Radiological facility conditions and housekeeping in radioactive waste storage areas were observed to be good. (Section R1.3)

- One violation was identified for failure to provide current dose rate information on a radioactive material label as required by Title 10 Code of Federal Regulations, Part 20.1904(a). (Section R1.3)

- The licensee's water chemistry control program for monitoring primary and secondary water quality had been implemented, for those parameters reviewed, in accordance with the Technical Specification requirements and the Station Chemistry Manual for pressurized water reactor water chemistry. (Section R1.4)

- The licensee had properly implemented procedures to maintain an effective program to monitor and control liquid and gaseous radioactive effluents to limit doses to members of the public. The projected offsite doses resulting from those effluents were well within the limits specified in the Technical Specifications, the Offsite Dose Calculation Manual, and Title 40 Code of Federal Regulations, Part 190. (Section R3.1)

- The licensee was effectively conducting formal radiation protection and chemistry audits as required by Technical Specifications and was completing corrective actions in a timely manner. (Section R7.1)

- The Emergency Operations Facility located in downtown Charlotte, North Carolina and its associated equipment were in good repair and condition. Emergency communication and plant computer equipment in the Technical Support Center was in good working order. (Section P2.1)

Report Details

Summary of Plant Status

Unit 1 operated at or near 100% power until November 21, when it began its end-of-cycle 10 coast down for the upcoming refueling outage. The unit ended the inspection period at 98 percent power.

Unit 2 operated at or near 100 percent power until October 20, when a power reduction was initiated to comply with Technical Specification (TS) 3.6.3 following a nitrogen leak associated with the accumulator for main feedwater isolation valve 2CF-33. Power was reduced to approximately 15 percent power, at which the time the valve was gagged shut and repairs commenced. Upon completion of the leak repair and valve post-maintenance testing activities, the unit was returned to 100 percent power on October 21. On November 21, a power reduction to 50 percent was initiated to allow a control circuit card associated with main turbine control valve CV-1 to be replaced. Licensee personnel also replaced a solenoid valve and cleaned instrument air lines associated with main generator power circuit breaker (PCB) 2B. These activities were completed on November 22 and power was increased to 97 percent by the end of the inspection period.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

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

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 turnovers and site direction meetings to maintain awareness of overall plant operations. Operator logs were reviewed to verify operational safety and compliance with 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 ensure that potential safety concerns and equipment problems were reported and resolved.

In general, the conduct of operations was professional and safety-conscious. The Unit 2 power reduction associated with feedwater isolation valve 2CF-33 was conducted safely. Good plant equipment material conditions and housekeeping were noted throughout the report

period. However, as addressed below, several human performance related deficiencies were identified.

01.2 Minor Excursion Over Licensed Power Limits for Unit 1

a. Inspection Scope (71707)

The inspectors reviewed the circumstances associated with a minor power excursion on Unit 1.

b. Observations and Findings

On October 21, 1997, the inspector noted during a review of control room logs that the Unit 1, 15-minute running average for reactor power, as indicated by the Operator Aid Computer (OAC), had exceeded 100 percent. The Unit 1 operator noticed this at 3:39 a.m. and reduced turbine load by 5 megawatts and inserted control rods two steps to bring power below 100 percent. Operations personnel later generated station PIP 1-C97-3382 to document and investigate the power excursion.

The inspectors reviewed the PIP and noted that the Unit 1 OAC 15-minute average was stated as having been in alarm for 15 minutes. The inspectors reviewed OAC trend reports for reactor power and noted that the maximum instantaneous reactor power level, according to secondary heat balance best estimates (computer point C1P1445), was approximately 100.6 percent recorded just before 3:15 a.m. According to the trend report, power continually spiked between 99.7 and 100.3 percent power for the next 20 - 25 minutes before operators noticed the 15-minute average and reduced power. Computer trends indicated that the 15-minute average peaked at 100.05 percent and was in for about 20 minutes. However, it never reached the alarm set point (100.1 percent). Further discussions with plant personnel and review of alarm history data indicated that the statement in the PIP concerning the alarm being in for 15 minutes was in error. Later, this statement was corrected in the PIP documentation.

Further investigation by the inspectors determined that routine reactor coolant system boron dilutions were performed earlier in the shift. However, this was last done 2 hours before the noted power excursion. The inspector interviewed control room personnel who indicated that several activities were occurring at the time of the minor over power, including those associated with a Unit 2 down power (see Section 08.2 of this report). The operator indicated that these activities may have been a distraction and possibly prevented him from noticing the 15-minute average earlier.

Discussions with operators and plant management indicated that operators were expected to maintain reactor power at licensed power levels. Operators were expected to continuously monitor power and immediately take actions to keep it within limit. Plant management discussed this

excursion with those personnel involved in the event and emphasized the need for increased diligence when monitoring power levels.

The inspectors reviewed NRC guidance on minor power excursions and noted that the power level did not exceed previously established criteria.

c. Conclusion

The inspectors concluded from their review that the power excursion was minor and was contained within criteria established by previous NRC guidance.

01.3 Control Power Unavailable to the Unit 1 Turbine-Driven Auxiliary Feedwater (AFW) Pump Trip And Throttle Valve

a. Inspection Scope (71707)

The inspectors reviewed the circumstances associated with a loss of control power to the Unit 1 turbine-driven AFW pump trip and throttle valve.

b. Observations and Findings

During a control room tour on November 17, the inspectors noted that the "DC (Direct Current) Power On" light associated with the Unit 1 turbine-driven AFW pump was extinguished. The inspectors informed the operator at the controls of this observation. The operator replaced the bulb and the light was still not lit. The inspectors mentioned that they had previously observed the light to be out 3 days earlier on November 14, but had assumed then that the extinguished light was related to ongoing maintenance involving a 72-hour LCO on the system. The operator stated that this bulb was in the control circuit for the AFW pump turbine trip and throttle valve. Subsequent licensee troubleshooting determined that fuse FU-2 in control panel 1ELCP0245 was blown. A review of several electrical drawings indicated that control power and electrical overspeed trip functions for the trip and throttle valve were powered through this fuse. The trip and throttle valve and the turbine-driven AFW pump were declared inoperable shortly after 10:00 a.m. and the fuse was subsequently replaced.

The inspectors discussed aspects of this incident with plant personnel to determine whether operators may have missed opportunities to identify the deficiency earlier, and to determine the true impact of the blown fuse on the system's capability to perform its safety functions. The inspectors noted that the blown fuse also caused control power indication to be extinguished at a local control panel, and that if the fuse was indeed blown for more than 3 days, plant personnel may have missed additional opportunities to identify a problem while on field tours. The inspector noted that there were no formal checks in licensee procedures of the "DC Power On" light in the control room. There were

also no control room alarms indicating control power unavailability for the trip and throttle valve.

Engineering personnel were still evaluating whether or not losing control power or the electrical overspeed trip function rendered the system inoperable. According to Section 20.4.1.1, "Auxiliary Feedwater Pump Turbine," of specification CNS-1593.SA-00-0001, Design Basis Specification for the Main Steam to Auxiliary Equipment System (SA) and Feedwater Pump Turbine Exhaust System (TE), Revision 11; at least one of the overspeed trip devices (mechanical or electrical) must be operable for the turbine-driven auxiliary feedwater pump to be operable. The mechanical overspeed trip function was not affected by the blown fuse. The inspectors concluded that further review of this incident and its impact on the turbine-driven AFW pump was necessary. Pending further NRC review, this item is characterized as Unresolved Item (URI) 50-413/97-14-01: Control Power Unavailable to the Unit 1 Turbine-Driven AFW Pump's Trip and Throttle Valve.

c. Conclusion

Control room operators failed to detect an extinguished "DC Power On" light for the Unit 1 turbine-driven AFW pump for more than three days. The impact of the blown fuse on pump operability will be reviewed during closeout of the URI.

O1.4 Management of Technical Specification (TS) Limiting Conditions for Operation

a. Inspection Scope (71707)

During a surveillance test of the Unit 2 reactor trip system instrumentation on October 10, 1997, a problem associated with the overpower differential temperature (OPDT) reactor trip logic was identified. The inspector discussed the test failure with operations shift personnel, read the associated TS, and reviewed station PIP 2-C97-3271.

b. Observations and Findings

During the performance of IP/2/A/3200/002A, Solid State Protection System (SSPS) Train A Periodic Testing, Revision 21, on October 10, 1997, the OPDT reactor trip logic test acceptance criterion was not met. A red lamp illuminated to indicate that a malfunction of the logic testing was detected (a green lamp would have illuminated if the logic test had been acceptable). The surveillance test began at 9:56 a.m., and the failure was identified some time before noon. Test technicians backed out of the test, and the reactor trip system was removed from the TS Action Item List at 12:10 p.m. Engineering personnel were involved to assist operations personnel in determining the extent of the operability concern (i.e., was the problem limited to OPDT trip logic or

did it affect all of the solid state protection system). Engineering personnel concluded that the problem was limited to the OPDT trip logic and communicated their conclusion to operations personnel at around 1:00 p.m. The A train of Automatic Trip and Interlo[illegible] unctional Unit 19 of TS 3.3.1, Table 3.3-1) was declared inope[illegible] 0 p.m. placing the unit in a six hour action statement [illegible] the function or be in Hot Standby (Mode 3) in the following six [illegible]

The inspectors questioned operations shift personnel about the decision to enter the required action at 1:00 p.m. rather than when the OPDT reactor trip logic test failure occurred. The response was that engineering involvement was needed to determine the scope of the problem (and inoperability) so that the appropriate TS action could be taken. After the inspectors discussed the issue with the operations shift personnel, they recognized that determining the scope of the inoperability was independent of the time after which actions were required.

Engineering personnel determined that a failed circuit card caused the test failure. The circuit card was replaced, and testing was completed successfully. The action statement was terminated at 4:30 p.m. that same day.

c. Conclusions

The inspectors concluded that operations personnel inappropriately entered the TS action statement more than one hour after the test failure of a reactor trip system logic function. The failed function was repaired, successfully retested, and returned to service before TS actions were required.

O2 Operational Status of Facilities and Equipment

O2.1 Cold Weather Protection Preparations

a. Inspection Scope (71714)

The inspectors reviewed Nuclear System Directive (NSD) 317, Freeze Protection Program, Revision 1; interviewed the freeze protection coordinator; reviewed procedures and work orders to determine what actions had been taken to prepare for cold weather; and independently inspected some vulnerable equipment exposed to the environment for freeze protection.

b. Observations and Findings

The licensee completed NSD 317 in March 1997. The NSD governs the freeze protection plans at all three Duke nuclear stations. During the previous cold weather season, the NSD had not been finalized and a formal program was not in place for ensuring that effective measures

were in place to protect plant equipment and systems from sub-freezing conditions.

The station assigned a freeze protection coordinator to monitor the status of preparation activities. An equipment freeze protection program was developed to identify operating plant systems, structures and components (SSCs) that may be subjected to freezing temperatures during the cold weather season. An engineering support program was initiated to ensure that specific freeze protection measures for vulnerable SSCs were identified to facilitate the preparation and completion of a pre-seasonal checkout. Pre-seasonal checkouts were executed via various model work orders for inspection and testing of electrical heat trace and instrument box heaters. The freeze protection plan includes surveillance procedures to inspect SSCs considered to be critical to plant operation on a monthly interval and as necessary during extreme cold weather.

The inspectors discussed the status of freeze protection preparations with the freeze protection coordinator. According to the coordinator, the annual preventive maintenance activities had been completed by the end of the inspection report period, and work orders or work requests had been generated to address identified discrepancies. The freeze protection coordinator had performed inspections of vulnerable areas and submitted a list of discrepancies to the maintenance organization. Most of these discrepancies were resolved by the end of the inspection period.

The inspectors conducted inspections of equipment that historically had been vulnerable to cold or freezing temperatures. The inspectors notified the freeze protection coordinator of a few minor discrepancies. The inspectors also reviewed the work orders associated with the annual preventive maintenance (PM) and verified that work had been completed.

c. Conclusions

Nuclear System Directive 317 provided structure and delineated responsibilities for freeze protection. Proceduralized activities were initiated and completed in a timely manner, and work orders or work requests were initiated to resolve identified discrepancies. The inspector concluded that the licensee's efforts to effectively protect plant equipment and systems from freezing conditions had improved since the previous cold weather season.

02.2 Prompt Onsite Response to Events (93702)

The licensee reported four unrelated events to the NRC Headquarters Operations Officer via the Emergency Notification System in accordance with 10 CFR 50.72. The following events were all reported in a timely fashion with sufficient information being provided.

Oil Sheen on Lake Wylie on October 15

On October 15, the inspectors were notified of a thin oil sheen that was discovered on Lake Wylie during a main fire pump test. The source of the oil was determined to be an overflowing pump bearing reservoir which caused oil to spill around the fire pump motor and eventually into the lake. The oil sheen was contained by a boom beneath the pump structure. The licensee notified the South Carolina Department of Health and Environmental Controls and the National Response Center, which in turn required notification of the NRC in accordance with 10 CFR 50.72(b)(2)(vi).

Plant Shutdown Required By TS on October 20

As discussed in Section 08.2 of this report, the licensee initiated a Unit 2 shutdown on October 20 when it entered TS Limiting Condition for Operation 3.6.3 action statement following the inoperability of the 2A steam generator main feedwater isolation valve 2CF-33. The unit was held at 15 percent power after the valve was deactivated and gagged shut. The valve was repaired and a forced unit shutdown was avoided. This item was reported to the NRC in accordance with 10 CFR 50.72(b)(1)(i)(A).

Potential Non-Conservatism in a Calculation Used to Distinguish Between Reactor Coolant System Flow Versus Reactor Power Restricted and Prohibited Operating Regions

On October 23, the licensee reported a potential nonconservatism in each units' TS 3/4.2.5, Departure from Nucleate Boiling (DNB) Parameters, Figure 3.2-1, Reactor Coolant System Total Flow Rate Versus Rated Thermal Power - Four Loops in Operation. Essentially, licensee personnel determined that the curve provided in Figure 3.2-1 for each unit permitted potential plant operation at reduced power levels with reactor coolant system flow rates that could possibly challenge DNB ratio design limits for certain analyzed transients. As a precaution, until this condition could be resolved, the licensee implemented administrative restrictions requiring reactor coolant system flow rates to be maintained above those specified as the permissible operation region for 100 percent power. These restrictions were verified to be in place by the resident inspectors. Long-term corrective actions included completing an analysis to allow a revision to the TS requirements to eliminate the non-conservatism. This item was reported in accordance with 10 CFR 50.72(b)(2)(iii)(D). The licensee documented this issue in a 30-day written follow up Licensee Event Report (LER 50-413/97-007) near the end of the inspection period. Further inspector review of this issue will be conducted and tracked under the LER in subsequent inspection reports.

Potential for Overfilling Steam Generator During a Postulated Accident

On November 18, the licensee reported a single failure vulnerability involving the loss of 125 Volt DC vital instrument and control distribution center EDE or EDF during a postulated steam generator tube rupture event coincident with a loss of offsite power. The licensee determined, following a detailed analysis, that the loss of either of these busses would result in the inability to isolate turbine-driven auxiliary feedwater pump flow to a ruptured steam generator. The steam generator would be potentially overfilled, resulting in uncontrolled releases of radioactivity to the atmosphere.

Because of this potential, and until further corrective actions are determined, the licensee implemented conservative administrative controls limiting the amount of dose equivalent iodine in the reactor coolant system to ensure the consequences of the Chapter 15 steam generator tube rupture analysis remain bounding. These restrictions were contained in procedure CMP 3.4.17.1, Primary Chemistry, Revision 28 and verified by the inspectors. At the close of the inspection period, the licensee was evaluating several options for long-term corrective actions. This item was reported to the NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B).

04 Operator Knowledge and Performance

04.1 Residual Heat Removal (RHR) System Potentially Placed In An Unanalyzed Condition

a. Inspection Scope (71707)

The inspectors reviewed the circumstances involving an August 20, 1997, tagout in which the RHR system was potentially placed in an unanalyzed condition. The inspector reviewed the Catawba Design Basis Document (DBD) CNS-1561.ND-00-0001; the UFSAR, Section 6.3 and Chapter 15; and PIP 2-C97-2722. The inspectors also reviewed the licensee's root cause investigation, completed during this inspection period, and discussed this issue with engineering and operations personnel.

b. Observations and Findings

Residual heat removal system valve ND59B is a motor-operated globe valve located in the minimum flow lines of the 1B and 2B RHR pumps. Valve ND59B and its associated miniflow line normally protect either B train pump from cavitation at low flow conditions or following a complete loss of suction during the decay heat removal or emergency core cooling modes of operation.

On August 20, 1997, at 3:38 a.m., operations issued removal and restoration (R&R) tagout 27-1498 to support work on the Unit 2 Train B RHR miniflow loop. Unit 2 train B RHR was declared inoperable and

entered into the Technical Specification Action Item Log (TSAIL). The planned work included a miniflow valve controlling set point modification, a gauge replacement, and an instrument calibration. The R&R tagged valve ND59B open with power removed. Approximately 2-1/2 hours later at 6:00 a.m., work control personnel realized that the tagout was in conflict with Catawba Design Basis and Criteria, Specification CNS-1561.ND-00-0001, Revision 5, which stated that "with ND59B stuck open and incapable of closing, the resulting diversion of RHR pump fluid to the recirculation loop is an unanalyzed condition." At that time, operations personnel cleared the tagout and closed the valve. Station PIP 2-C97-2722 was initiated and the licensee later determined that a past operability evaluation was required.

Engineering personnel completed the past operability evaluation on September 8, 1997, and concluded that the RHR system was operable during the time the miniflow valve was tagged open. The inspectors discussed this conclusion with licensee personnel and upon reviewing UFSAR Table 6-7, Catawba Nuclear Station Emergency Core Cooling System Flow Rates, arrived at the same conclusion. This was based on the fact that the RHR flow capacity (approximately 500 gallons per minute) normally diverted from the reactor coolant system recirculation loop by miniflow valve ND59B, when subtracted from the total RHR flow capacity, still resulted in sufficient RHR flow being delivered to the RCS during the post-accident recirculation mode. However, the inspectors considered the tagging discrepancy to represent a problem that could have had adverse plant impact.

A root cause investigation of the improper tagging incident was completed by the licensee during this inspection period which concluded that engineering personnel improperly communicated a 1993 DBD revision to affected groups. The RHR DBD had been revised then to provide a discussion of the "unanalyzed condition." However, this analysis did not take into consideration lesser flow requirements assumed in UFSAR Table 6-7 for the post-accident long-term recirculation mode of operation, the time at which the RHR system alignment would be changed and the miniflow valve would become a diversion flow path.

The inspectors considered other human performance weaknesses contributed to the tagging error. When the calibration work order from which the tagout was generated (PM 95054445) was developed in July 1995, a note was added for operations personnel to tag the miniflow valve open. Although personnel involved in planning the set point change modification were aware of the DBD statement, and verbiage was included in the modification package to ensure the tagout was correct and would not place the RHR system in an unanalyzed condition, the set point modification was performed under an existing tagout for the preventive maintenance work, which had the valve opened on August 20.

The inspectors noted that the DBD had not been consulted when the tagout associated with the August 20, 1997, activities was developed a week

earlier. The inspectors discussed this with licensee management, who stated that the 1995 PM work order note likely contributed to an overriding operating philosophy that tagging the valve open during maintenance was appropriate. Several corrective actions were generated for PIP-2-C97-2722, including developing a policy for communicating engineering document revisions to affected groups and designating a specific work management system panel to document engineering recommendations and special notes. The inspector asked whether or not the DBD reference to the "unanalyzed condition" would be deleted to reflect the engineering analysis discussed above. Licensee management indicated they would evaluate changing the DBD.

c. Conclusions

The inspectors concluded that although having the Unit 2 train B RHR pump out of service with valve ND59B de-energized open did not place the plant in an unanalyzed condition, examples of poor performance were identified concerning activities leading up to the valve inappropriately being tagged open during planned maintenance.

O8 Miscellaneous Operations Issue (92901)

O8.1 (Closed) LER 50-414/95-01: Reactor Trip Due to Closure of a Main Steam Isolation Valve

The event described in this LER involved an automatic reactor trip due to the failure of a digital optical isolator (DOI) in the B main steam isolation valve control circuit that caused the valve to close. This LER was discussed in NRC Inspection Report 50-413,414/97-12 and remained open pending further NRC review.

Planned corrective action 2 was to develop a PM program to periodically monitor continuously energized E-max DOIs with model numbers 175C156 and 175C157 in critical applications. Instead, the licensee initiated a PM program to replace DOIs that perform a control function and that have AC voltage for their input power supply every twelve years. The inspectors determined that the NRC had not been apprised of the change.

In light of recent DOI failures that resulted in manual reactor trips in July and August 1997, the inspectors asked the licensee if monitoring the DOIs could have revealed the root cause (degraded resistors) of the recent DOI failures. The licensee indicated that the test methodology that would have been used to periodically monitor the DOIs would not have revealed degraded resistors (the cause of the 1997 failures). The inspectors concluded that, while testing the DOIs had the potential to reveal degraded DOIs during periodic testing, the likelihood that it would have done so was low. Therefore, the commitment change did not substantially reduce the opportunity to identify degraded DOI resistors and take subsequent actions to prevent the 1997 DOI failures.

According to Nuclear System Directive (NSD) 214, Commitment Management Program, Revision 2, Licensee Event Reports are a source of NRC commitments. Section 214.8.4, Remove or Change a Commitment, stated that the regulatory compliance (RGC) group should be notified if a commitment change is needed, and that RGC will determine, in part, if the NRC should be notified. The NSD incorporates a 1994 draft document prepared by the Nuclear Energy Institute (NEI), entitled "Guideline for Managing NRC Commitments."

According to NSD 214, when a commitment is changed, the original commitment will be modified with a description of the change in the appropriate section of the PIP database (which is used to track NRC commitments to resolution). The NSD further stated that if the change is determined to be significant enough, a new commitment may be generated. However, proper cross-references shall be provided to link the original commitment to the revised commitment. The licensee determined that the NRC was not apprised of the commitment change because the corrective actions representing the commitment were improperly cross-referenced. As a result, the changed corrective action was not identified as an NRC commitment, and RGC was not notified. The inspector concluded that the licensee failed to notify the NRC of a commitment change regarding planned corrective actions delineated in LER 50-414/95-01. This issue is characterized as one example of Deviation 50-413,414/97-14-02: Changing NRC Commitments Without Properly Notifying the NRC.

This item is closed.

08.2 (Open) Violation 50-413/97-08-01: Inadequate Alarm Response Results in Inadequate and Untimely Corrective Actions for Valve Operability Determination

The inspectors reviewed Violation 50-413/97-08-01 for an April 3, 1997, incident following a similar occurrence on October 20, 1997, where a feedwater isolation valve became inoperable after a nitrogen leak developed on its accumulator.

On the morning of October 20, 1997, just before shift turnover, the Unit 2 control room operators received a computer alarm indicating low nitrogen gas pressure in the accumulator associated with the 2A steam generator main feedwater isolation valve, 2CF-33. The valve was declared inoperable and TS Limiting Condition for Operation (LCO) 3.6.3 was immediately entered. Nitrogen pressure was checked and found to be at 1640 psig, which was below the low operability limit of 2050 psig. The accumulator was recharged to 2760 psig and the TS LCO was exited. Approximately 2-3 hours later at 9:55 a.m., another low pressure alarm was received, and operators again entered the 4-hour TS LCO action requirement to either return the valve to operable status, de-energize (gag) it shut, or initiate plans to be in Hot Standby in the following 6 hours. After the second alarm, the accumulator was found to be at 1810

psig and a leak was detected from a solenoid valve at the actuator. The nitrogen accumulator was again recharged, but could not be maintained above the low pressure limit. Technical Specification 3.6.3 required that the plant to be in Hot Standby (Mode 3) by 7:55 p.m.

Plant management decided that a power reduction would be initiated shortly after 1:00 p.m. The unit was reduced to approximately 15 percent power and the valve was gagged shut just before the TS LCO action to be in Hot Standby was required, thus avoiding a forced shutdown. A leaking O-ring at a solenoid-to-tube connection was detected. The solenoid was replaced and the valve was tested successfully. Unit 2 exited the LCO action statement and was returned to 100 percent power on October 21.

The inspectors reviewed Violation 50-413/97-08-01 which documented a similar occurrence on April 3, 1997, involving feedwater isolation valve 1CF-51. Following the April 3, 1997, incident, plant personnel determined that the control room OAC alarm set point was set at or near the pressure at which the valve became inoperable. One of the planned corrective actions documented in the licensee's written response to the violation dated July 22, 1997, was for engineering personnel to evaluate whether the alarm set point could be raised to provide more margin between it and the operability limit thereby allowing operators more time to react to an actuator leak. According to the licensee's letter, this action was to be completed by September 30, 1997. Following the October 20, 1997, occurrence, the inspectors inquired about the status of the engineering evaluation. Licensee personnel indicated that it had not been performed and that engineering personnel had been internally granted an extension of the due date from the safety assurance group to October 31.

The inspectors noted that the NRC had not been notified of this commitment change and upon inquiring further, were told that an administrative error in the data entry process for the PIP associated with the April 3, 1997, incident allowed engineering to be granted an extension without evaluating the impact of changing this commitment. Upon discovery of the error, licensee personnel corrected it in the PIP database and an engineering evaluation was completed by the new deadline. A modification was subsequently initiated to raise the accumulator alarm set points for all of the feedwater isolation valves and provide greater margin above their operability limits.

The inspectors determined that the failure to perform the engineering evaluation in a timely manner further increased the chances of a feedwater isolation valve becoming inoperable prior to the control room receiving the alarm. The inspectors reviewed the documents associated with NRC commitment management programs described in Section O8.1 above and determined that the failure to perform this evaluation by September 30, 1997, constituted a Deviation from NRC commitments. This issue is characterized as the second example of Deviation 50-413,414/97-14-02:

Changing NRC Commitments Without Properly Notifying the NRC. Violation 50-413/97-08-01 will remain open pending completion of all of the licensee's corrective actions and further review by the inspectors.

Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726)

The inspectors observed portions of the following surveillance and inspection activities:

- NPP-312, Nuclear Fuel And Core Component Receipt Inspections.
- PT/1/A/4200/09A, Auxiliary Safeguards Test Cabinet Periodic Test.
- PT/1/A/4400/06A, Nuclear Spray (NS) Heat Exchanger 1A Heat Capacity Test.
- PT/1/A/4400/09, Cooling Water Flow Monitoring For Asiatic Clams And Mussels Quarterly Test.
- PT/1/A/4200/04B, Containment Spray Pump 1A Performance Test.
- PT/1/A/4350/002B, Diesel Generator 1B Operability Test, Retype No. 28

During these activities, the inspectors noted proper use of procedures, properly calibrated measuring and test equipment, effective radiological controls, and adequate communication between personnel performing the tests.

M1.2 New Fuel Movements (62707)

The inspector observed movement of new fuel from the dry storage racks to the spent fuel pool in preparation for the upcoming Unit 1 end-of-cycle 10 refueling outage. This activity was conducted under Work Order 97063472-01, Move New Fuel from New Fuel Vault to Spent Fuel Pool. The technicians used procedures OP/1/A/6550/011, Retype 21, Internal Transfer of Fuel Assemblies and Components; and OP/1/A/6550/006, Retype 11, Transferring Fuel with the Spent Fuel Manipulator Crane. The inspector noted, for the fuel assemblies observed, that they were placed correctly in locations referenced by the procedure attachment. Proper radiological controls were observed. Crane checklist prerequisites had been completed as required. This work activity was conducted well.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Inspector Follow Up Item (IFI) 50-413,414/97-08-04: Reportability of Nuclear Service Water (NSW) System Actuations.

This item was opened to determine the reportability of NSW system actuations. The licensee generated station PIP 0-C97-1715 to document the clarification. The licensee determined that the NSW system is

required for support of the Engineered Safety Features (ESF). As such, the NSW system is characterized as an ESF support system in the UFSAR, Section 7.3.1.1.5, ESF Support Systems. The licensee concluded that, since the NSW system is not an ESF, and since 10 CFR 50.72 and 50.73 require licensee's to report any event or condition that results in a manual or automatic actuation of any ESF, actuations of the NSW system were not reportable.

The inspector reviewed applicable sections of NUREG 1022, Event Reporting Guidelines 10 CFR 50.72 and 50.73; NUREG 0800, the Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants, Light Water Reactor Edition, June 1987; the UFSAR; and Nuclear System Directive 202, Reportability, Revision 8. The characterization of the NSW system as an ESF support system was in agreement with the SRP, which referred to service water systems as auxiliary systems that directly support ESF systems. However, Chapter 6 of the UFSAR, Engineered Safety Features, does not contain a listing of ESF systems; a listing, which does not include the NSW system, is located in Nuclear System Directive 202, Reportability, Revision 8, Appendix A, Engineered Safety Features. Chapter 7 of the UFSAR, Instrumentation and Controls, Section 7.3.1.1.1 lists ESF functions initiated by the Engineered Safety Features Actuation System (ESFAS); the NSW pumps, which provide cooling water to the component cooling system heat exchangers and are thus the heat sink for containment cooling, are listed.

Based on this review, the inspectors determined that NSW system actuations are not reportable. This item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Operation Of Dual Function Containment Isolation Valves-Temporary Instruction (TI) 2515/136 (Closed)

a. Inspection Scope

The inspectors used TI 2515/136, Operation of Dual Function Containment Isolation Valves, to determine if the licensee had procedures in place to remotely close containment isolation valves when required while a safety injection or a containment spray signal was present. The inspector discussed this issue with engineering personnel, and reviewed the UFSAR and design basis documentation.

b. Observations and Findings

The TI included a questionnaire survey with four items. Item 1 requested that the inspectors identify the dual function valves as listed in the UFSAR and determine whether differences existed in the

plant. Licensee personnel provided a list of containment isolation valves, which included dual function valves. The inspector compared the valve list to the valves shown on UFSAR Table 6-77, Containment Isolation Valve Data. All valves identified by the licensee were found to exist in Table 6-77.

During the inspectors' review, it was noted that two of the valves listed, SA-1 (Penetration M-261, B Main Steam to Auxiliary Feedwater Pump Turbine) and SA-4 (Penetration M-393, C Main Steam to Auxiliary Feedwater Pump Turbine), did not comply with 10 CFR 50, Appendix A, General Design Criterion 57. General Design Criterion (GDC) 57, Closed System Isolation Valves, specifies that each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked closed, or capable of remote manual operation. Valves SA-1 and SA-4 are manual gate valves and normally in the locked open position. These valves and containment penetrations exist in both Catawba Units 1 and 2. The GDC 57 noncompliance had been previously identified and an exemption request (from GDC 57) was submitted on September 2, 1997. This item is being tracked as Unresolved Item 50-413,414/97-14-03: Noncompliance With 10 CFR 50, Appendix A, General Design Criterion 57, Closed System Isolation Valves.

Item 2 asked whether or not a safety-related dual function valve could be closed from the control room with a switch and remain closed in the presence of a containment spray or safety injection signal. As indicated by the licensee's list, reset and closure capability existed with remote, manual control on all safety-related dual function valves with the exception of SA-1 and SA-4, which were locked open. Some valves, as indicated on the licensee's list, would require the emergency diesel generator (EDG) load sequencer be reset in addition to normally resetting the ESF (or Safety Injection) signal. The EDG Load Sequencer system engineer indicated that resetting the ESF signal would not affect the configuration or operating status of any safety-related equipment, and that resetting the EDG Load Sequencer would not affect the EDG or any components being powered from the safety-related 4160 volt busses. While the inspectors were familiar with the reset capability for the safety injection signal, further NRC inspection was necessary to verify that resetting the EDG Load Sequencer during an accident would not adversely impact the operation of safety-related plant equipment. This review effort will be conducted under URI 50-413,414/97-14-03 discussed above.

Item 3 requested, for valves that do not have a switch for remote closure [i.e., SA-1 and SA-4], if any proceduralized method existed (such as deenergizing circuits or lifting leads or installing leads) that would facilitate remote closure. Since valves SA-1 and SA-4 are locally operated manual valves, no remote method of closure existed.

Item 4 requested, for valves that do not have any remote method of closure available [i.e., SA-1 and SA-4], whether there were any other means that the licensee had to close the isolation valve. The licensee provided a list of eight emergency procedures that contain provisions to isolate Penetration M-261 or M-393 as required. Two isolation options were provided. The first option utilizes the SA-1 or SA-4 valve as required located in the plant doghouses. The second option isolates the penetration by closing valves SA-3 or SA-6 located downstream of SA-1 and SA-4 in the Penetration Area if SA-1 and SA-4 were inaccessible. The inspectors reviewed these procedures and found that the procedural guidance to establish containment isolation manually for penetrations M-261 and M-393 was available to operators when needed.

c. Conclusions

An unresolved item was identified concerning containment penetrations associated with steam supply lines to both units' turbine-driven auxiliary feedwater pumps, which were not in compliance with 10 CFR 50, Appendix A, GDC 57. The licensee had submitted an exemption request to the NRC for this issue. Remote manual closure capability existed for dual function containment isolation valves; however, the action involved resetting the emergency diesel generator load sequencer, an action requiring further evaluation to be conducted under the above-mentioned unresolved item.

E2 Engineering Support of Facilities and Equipment

E2.1 Solid State Protection System (SSPS) Testing Deficiency

a. Inspection Scope (37551)

The inspectors reviewed the licensee's discovery of a logic testing deficiency associated with both trains of each unit's SSPS on November 11, 1997.

b. Observations and Findings

The test deficiency involved the failure to perform adequate testing of two universal cards associated with feedwater isolation functions and the P-10 source range nuclear instrumentation reactor trip block permissive. The universal cards contained previously unidentified parallel circuit paths which were not being isolated and independently verified to actuate the logic circuitry associated with each function. Both units entered TS 4.0.3 after identifying the missed surveillance testing. The procedures were revised and the testing conducted satisfactorily before each unit exited TS 4.0.3.

The test anomaly was identified by personnel in the licensee's General Office and was immediately communicated to the SSPS vendor and to various other nuclear power facilities via operating experience data

banks. Several facilities have since identified the same or similar deficiencies in their SSPS logic testing procedures.

c. Conclusion

The licensee has issued LER 50-413/97-08 to document the missed TS surveillances and discuss the safety consequences and corrective actions taken for the deficiency. Further NRC review will be conducted during closeout of the LER.

E8 **Miscellaneous Engineering Issues** (92903)

E8.1 (Closed) Inspector Follow Up Item 50-413,414/96-18-04: Quantification of Refueling Water Storage Tank (FWST) Heat Losses Through Tank Roof Including a Wind Velocity Factor.

This item involved minor modification CNCE-8309 to de-energize one of four FWST heater clusters. The licensee performed an evaluation to demonstrate that minimum required tank temperature of 70 degrees Fahrenheit (°F) could be maintained with the three remaining heaters. The evaluation involved a calculation, CNC-1249.00-00-0065, Operability Determination for PIP 1-C96-1870 - Heater Sizing for the FWST, that quantified heat losses from the tank assuming a minimum temperature of -5°F and wind velocity of up to 20 miles per hour (mph). The calculation indicated that the total FWST heat loss at was 81.88 KW.

The inspector noted that the calculation accounted for wind-induced heat losses from the tank walls, but not from the tank roof. To address this observation, the licensee completed Revision 1 of calculation CNC-1249.00-00-0065 and concluded that, accounting for heat losses from the FWST roof assuming a 5 mph average wind velocity, the total FWST heat loss was 93.46 KW at an FWST temperature of 75°F and environmental temperature of -5°F. With one heater cluster inoperable and de-energized, the total heater capacity available is 90 KW. The licensee indicated that the environmental temperature selected for design comparison in the calculation was below the coldest temperature ever recorded at the site, it was unlikely that temperatures would drop to that temperature. The licensee also indicated that the heat loss would be 87.42 KW if the tank wall temperature were assumed to be 70°F (the TS value), and therefore within the heating capacity of the three remaining heater clusters. Based on these and other conservative heat loss assumptions applied to the calculation, the licensee asserted that the remaining heater capacity was marginal to maintain the FWST at 75°F, but that it was adequate to prevent a temperature drop below the TS-required value of 70°F.

Refueling water storage tank temperature indications are available in the control room. In addition, a low temperature alarm will be generated at 74°F. The alarm response would be to dispatch an operator to verify heater operation. A Lo-Lo temperature alarm would be

generated when tank temperature reaches 70°F. The response then would be to declare the FWST inoperable per the appropriate TS. Based on the heat loss calculation, monitoring capabilities and response procedures, the inspector concluded that FWST temperature was not likely to drop below the TS-required value of 70°F as a result of this minor modification. Should a low temperature alarm be generated, effective measures were in place to ensure that action will be taken to correct the low temperature condition or place the unit in a safe condition. In addition, the licensee planned to correct the heater leakage, re-energize the heater and return it to service during the upcoming end-of-cycle 10 refueling outage, scheduled to begin in late November.

The inspector noted that the wind velocity assumed for heat losses from the tank walls was 20 mph, whereas it was assumed to be only 5 mph for heat losses from the tank roof. While no explanation for this discrepancy was provided in the calculation, the inspector concluded that, since the heater was to be returned to service in December 1997, this discrepancy did not pose a safety concern. This item is closed.

E8.2 (Closed) Unresolved Item 50-413,414/97-11-04: Use of Aluminum High Efficiency Particulate Air (HEPA) Filter Separators Inside Containment.

This item involved the licensee's identification of aluminum HEPA filter separators in the containment ventilation system's containment auxiliary charcoal filter units (CACFUs) that had not been accounted for in the station's aluminum inventory records. The licensee initiated an evaluation to determine the root cause of the inappropriate material usage.

The licensee's evaluation revealed that the HEPA filters had contained aluminum since 1986 or before. Design Specification CNS-1211.00-3, Containment Auxiliary Charcoal Filter Units, Section 5.5, High Efficiency Filter Section, states that "Separators, if used, shall be 304 stainless steel." The licensee determined that the original HEPA filters were a separatorless, nuclear grade filter without aluminum. However, at some undetermined point in time, the station began to use a different HEPA filter, containing aluminum, in the CACFUs. The licensee could not locate any documentation to support the change in filters and terminated the root cause evaluation, which was not likely to reveal the origination of the discrepancy.

The inspector concluded that, although the error leading to the discrepancy had occurred over ten years ago, the licensee has since established a process that would prevent a similar oversight from occurring at the present time. A change in filter components (or other components inside containment) would involve the modification process. Essentially, NSD 301, Nuclear Station Modifications, dated September 30, 1997 required that a Technical Issues Checklist be completed for any temporary, minor, or nuclear station (permanent and major) modification. The Technical Issues Checklist, located in Appendix A of the NSD,

addressed containment issues and hydrogen control. The question "Does the change add aluminum or zinc that could potentially increase the amount of hydrogen generated inside the containment post accident?" would likely prompt a review for this potential during the current modification process.

The licensee re-evaluated the original hydrogen generation calculation and determined that the amount of hydrogen generated inside containment following a design basis accident that would be produced by the additional aluminum did not exceed revised allowable limits. Therefore, the safety consequences were minor. However, measures were not effective in preventing the selection of these filters for use in an unsuitable application as required by 10 CFR Part 50, Appendix B, Criterion III. This constitutes a violation of minor significance and is characterized as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy. This item is identified as NCV 50-413,414/97-14-04: Failure to Control Use of Aluminum Inside The Containment Building.

The inspector determined that the licensee had been informed by Westinghouse of the potential that certain HEPA filters were being manufactured with aluminum separators. The information was conveyed via Vendor Information Letter 96-30 in September 1996. The licensee's response to the information was to consult the design specification (CNS-1211.00-3) to determine if aluminum was specified. Upon finding that the specification required the use of 304 stainless steel, the licensee concluded that the CACFU's HEPA filters did not contain aluminum. The inspector concluded that the original review in response to the Westinghouse information letter was cursory and ineffective in revealing this discrepancy. The inspector reviewed the revised hydrogen generation calculation; no concerns or discrepancies were identified.

This item is closed.

IV. Plant Support

R1 Radiological Protection (RP) and Chemistry Control

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

a. Inspection Scope (71750)

The inspectors periodically toured the RCA during the inspection period. Radiological control practices were observed and discussed with radiation protection personnel, including RCA entry and exit controls, survey postings, and radiological area material conditions.

b. Observations and Findings

On November 17, the inspectors noticed an RCA exit door propped wide open with a brick. The doorway was on the 594 foot elevation of the auxiliary building at the end of corridor number 517 and provided RCA access from the outside. Two stanchions with a roped sign hanging between them normally blocked access past the door into the RCA, but the stanchions and sign had been moved to the side and out of view. The sign was intended to warn personnel that they were about to enter the RCA and directed them to contact radiation protection personnel for assistance. At the time of the inspector's observation, no personnel were present to control access at this RCA entry point.

The inspectors notified radiation protection (RP) personnel who immediately responded to the location and closed the door. Later, the same sign was attached to a swing gate which was placed at the entrance. The gate would close after allowing personnel pre-approved access across the boundary. The inspectors were informed by RP personnel that a maintenance crew had been using the door to bring scaffolding into the plant in preparation for the upcoming Unit 1 refueling outage. The maintenance crew had received permission from RP to use the door. The crew had moved the sign, blocked the door open, and temporarily left the area to conduct other activities.

The inspectors discussed with licensee personnel the need to properly control access to the RCA. Licensee personnel generated PIP O-C-97-3670 to document this deficiency. The incident was discussed in a subsequent daily management meeting. In addition to the immediate corrective actions above, RP management discussed this incident with scaffolding supervisors who later discussed it with their crew members to reinforce proper procedures for entering the RCA.

The inspectors later observed that general access to this area from the outside was limited to the scaffold crew because of a second external barrier that had been placed outside to control personnel traffic. While this barrier was not intended for RCA access control, it reduced the significance of the inspectors' finding.

c. Conclusions

An example of poor performance was identified related to an RCA boundary being compromised. This minor discrepancy was immediately corrected by plant personnel and properly addressed by licensee management.

R1.2 Transportation of Radioactive Materials

a. Inspection Scope (86750)

The inspectors evaluated the licensee's transportation of radioactive materials programs for implementing the revised Department of

Transportation (DOT) and NRC transportation regulations for shipment of radioactive materials as required by 10 Code of Federal Regulations (CFR) 71.5 and 49 CFR Parts 100 through 177.

b. Observations and Findings

The inspectors reviewed procedures and determined that they adequately addressed the following: assuring that the receiver has a license to receive the material being shipped; assigning the form, quantity type, and proper shipping name of the material to be shipped; classifying waste destined for burial; selecting the type of package required; assuring that the radiation and contamination limits are met; and preparing shipping papers.

Licensee's records for the six shipments of radioactive material performed in 1997 were reviewed and the inspectors determined the shipping papers contained the required information. The inspectors also determined the licensee had maintained records of shipments of licensed material for a period of three years after shipment as required by 10 CFR 71.91(a). In addition, the licensee possessed a current certificate of approval (NRC Form 311) for their "Quality Assurance Program Description for Radioactive Material Shipping Packages Licensed Under 10 CFR 71." The licensee had also maintained current NRC certificate of compliance for the NRC approved cask in use.

The inspectors reviewed the training records for selected individuals authorized to sign shipping papers and handle radioactive waste which included a [illegible] area supervisor who was assigned to the area of transportation the week of the inspection. The training specifically addressed the new rules for the following topics: low specific activity (LSA) and surface contaminated object (SCO) hazards, definitions, and requirements; placarding, labeling, and marking of vehicles and packages; use of *Systems Internationals* (SI) units on shipping papers, labels, and emergency response instructions after April 1, 1997; package selection; waste classification; shipping papers; and receipt procedures and surveys. The inspectors concluded that personnel involved with radioactive material shipping were maintaining current training qualifications.

c. Conclusions

The licensee had effectively implemented a program for shipping radioactive materials required by NRC and DOT regulations.

R1.3 Radiological Protection and Chemistry Controls

a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection and chemistry program. The review

included observation of radiological protection activities for the control of radioactive material as required by 10 CFR Parts 20.1801, 1802, 1902, and 1904.

b. Observations and Findings

The inspectors reviewed licensee goals for waste generated and buried and determined the licensee was meeting these goals. During tours of the auxiliary building and radwaste building facilities, the inspectors reviewed survey data and performed selected independent radiation and contamination surveys of radioactive material storage areas. During a tour of the hot tool issue room on November 19, 1997, the inspectors found a vacuum cleaner with radiation dose rates higher than indicated on the radioactive material label, dated 1995, affixed to the vacuum cleaner. The tag stated radiation levels to be 1.5 millirem per hour on contact and 0.5 millirem at 30 centimeters. However, the inspectors determined and the licensee confirmed radiation levels to be up to 40 millirem per hour contact and 2-3 millirem at 30 centimeters. Also, the vacuum cleaner hose was not taped or capped on the end as required by licensee procedure for vacuum cleaners in storage. Licensee procedure required vacuum cleaners to be surveyed after use and that current survey information was to be included on the radioactive material label (yellow tag). The licensee taped over the vacuum hose and performed independent radiation and contamination surveys of the vacuum cleaner and the general area. The licensee determined contamination had not been spread as a result of the open hose. The licensee also relabeled the vacuum cleaner to include current survey information.

Duke Power Company, System Radiation Protection Manual, Procedure No. III-18, titled Use of Vacuum Cleaners In Radiologically Controlled Areas, Revision 3, dated August 1, 1996, states that vacuum cleaners should be surveyed during and after use and update dose rates on yellow tags, if applicable, each time a radiation survey is performed.

10 CFR 20.1904(a) requires, that the licensee shall ensure that each container of licensed material bears a durable, clearly visible label bearing the radiation symbol and the words CAUTION RADIOACTIVE MATERIAL or DANGER RADIOACTIVE MATERIAL. The label must also provide sufficient information (such as radionuclides present, an estimate of the quantity of radioactivity, radiation levels, kinds of materials, and mass enrichment) to permit individuals handling or using the containers or working in the vicinity of the containers, to take precautions to avoid or minimize exposures.

The inspector informed the licensee that failure to provide current survey information on the radioactive material label constituted a violation of licensee procedure Use of Vacuum Cleaners In Radiologically Controlled Areas, III-18, Revision 3 and a violation of 10 CFR 20.1904(a). This item is identified as Violation 50-413,414/97-14-05: Failure to Label Radioactive Material As Required by 10 CFR 20.1904.

c. Conclusions

The licensee was meeting established goals for radioactive waste generation. During plant tours, radiological facility conditions and housekeeping in radioactive waste storage areas were observed to be good. One violation was identified for failure to provide current dose rate information on a radioactive material label as required by licensee procedure and 10 CFR 20.1904(a).

P1.4 Water Chemistry Controls

a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's water chemistry control program for monitoring primary and secondary water quality as described in the TS limits, the Station Chemistry Manual, and the UFSAR. The review included examination of program guidance and implementing procedures and analytical results for selected chemistry parameters.

b. Observations and Findings

The inspectors reviewed selected analytical results recorded for Units 1 and 2 reactor coolant primary water chemistry samples taken between May, 1997 and November, 1997, and secondary system water chemistry samples taken between August, 1997 and November, 1997. The selected parameters reviewed for primary water chemistry included dissolved oxygen, chloride, pH, and fluoride. The selected parameters reviewed for secondary water chemistry included hydrazine, dissolved oxygen, sodium, copper, and chloride. Those primary system parameters reviewed were maintained well within the relevant TS limits for power operations. Those secondary system parameters reviewed were maintained according to station procedures.

The inspectors reviewed and discussed the licensee's system for tracking performance indicators in the areas of primary and secondary water chemistry. The inspectors noted the licensee had maintained a high level of success in human performance and equipment reliability in 1997 based on performance indicators for these areas which included no missed surveillances and no mispositioning of components.

c. Conclusions

Based on the above reviews, it was concluded that the licensee's water chemistry control program for monitoring primary and secondary water quality had been implemented, for those parameters reviewed, in accordance with TS requirements and the Station Chemistry Manual for pressurized water reactor water chemistry. The licensee had maintained a high level of success in human performance and equipment reliability in 1997.

R3 Radiation Protection and Chemistry Procedures and Documentation

R3.1 Radiation Protection and Chemistry Procedures and Documentation

a. Inspection Scope (84750)

The inspectors reviewed licensee effluent release limits and pathways as described in the licensee's Offsite Dose Calculation Manual and in Chapter 16 of the Selected License Commitments Manual.

b. Observations and Findings

The inspectors reviewed annual effluent data for 1996 and compared the data to previous annual reports back to 1992. Annual Radioactive Effluent Release Reports were required to be submitted to the NRC prior to May 1 of each year. Summaries of the quantities of radioactive materials in liquid and gaseous effluents released from the facility and an assessment of the radiation doses due to those releases were required to be included in the reports. The inspectors reviewed the supporting data for the effluent release report covering 1996. The amount of activity released during 1996 as dissolved gases in liquid effiuents and fission gases, and that released as iodines and particulates in gaseous effluents was generally within the ranges observed in past years. The annual average per unit radiation doses for an individual from the liquids and gaseous effluents were only a small percentage of their respective annual limits. The total body dose as calculated by environmental sampling data, was 0.902 millirem for 1996. There were no abnormal releases reported in 1996.

c. Conclusions

Based on the above reviews, it was concluded that the licensee had maintained an effective program to monitor and control liquid and gaseous radioactive effluents, thereby limiting dose to members of the public. The projected offsite doses resulting from those effluents were well within the limits specified in the TS, Offsite Dose Calculation Manual, and 40 CFR 190.

R7 Quality Assurance in Radiation Protection and Chemistry Activities

R7.1 Quality Assurance in Radiation Protection (RP) and Chemistry

a. Inspection Scope (84750)

Licensee activities and self assessment programs were reviewed to determine the adequacy of corrective action programs for identified deficiencies in the areas of RP and chemistry.

b. Observations and Findings

Reviews by the inspectors determined that Quality Assurance audits and self assessments in the RP and chemistry areas were accomplished by reviewing procedures, observing work, reviewing industry documentation, and performing plant walkdowns to include surveillance of work areas by supervisors and technicians during normal work coverage. Documentation of problems by licensee representatives was included in Quality Assurance Audits and self assessment reports. Corrective actions were included in the licensee's PIPs and were being completed in a timely manner.

c. Conclusions

The inspectors determined the licensee was effectively conducting formal RP and chemistry audits as required by the TS and was completing corrective actions in a timely manner.

R8 Miscellaneous Radiation Protection and Chemistry Issues (92904)

R8.1 (Closed) URI 50-413,414/97-05-02: Determine the Applicability of Monitoring Requirements of Criterion 64 of 10 CFR 50, Appendix A; and Reporting Requirements of 40 CFR 190 and 10 CFR 50.36a Regarding Potential Unmonitored Release Pathways.

This item was closed using guidance from Regulatory Guide 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I. The specific guidance was found in Appendix D1. No violation of regulatory requirements was identified. This item is closed.

P2 Status of Emergency Protection Facilities, Equipment, and Resources

P2.1 General Comments (71750)

The inspectors toured the Emergency Operations Facility located in downtown Charlotte, North Carolina on November 18, 1997. The inspectors observed that the facility and associated equipment, including emergency communication telephones and plant computer screens and controls were functioning and in good repair. During tours of the Technical Support Center, facility equipment was also noted to be in working order and of good condition and repair.

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 December 3, 1997. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Birch, Safety Assurance Manager
M. Boyle, Radiation Protection Manager
R. Glover, Operations Superintendent
J. Forbes, Engineering Manager
R. Jones, Station Manager
K. Nicholson, Compliance Specialist
M. Kitlan, Regulatory Compliance Manager
G. Peterson, Catawba Site Vice-President
R. Propst, Chemistry Manager

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71714: Cold Weather Preparations
IP 71750: Plant Support Activities
IP 84750: Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 86750: Solid Radioactive Waste Management and Transportation of Radioactive Materials
IP 92901: Follow up - Operations
IP 92902: Follow up - Maintenance
IP 92903: Follow up - Engineering
IP 92904: Follow up - Plant Support
IP 93702: Prompt Onsite Response to Events
TI-2515/136: Operation of Dual Function Containment Isolation Valves

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-413/97-14-01	URI	Control Power Unavailable to the Unit 1 Turbine-Driven AFW Pump's Trip and Throttle Valve (Section O1.3)
50-413,414/97-14-02	DEV	Changing NRC Commitments Without Properly Notifying the NRC (Section O8.1 and O8.2)
50-413,414/97-14-03	URI	Noncompliance With 10 CFR 50 Appendix A General Design Criterion 57 (Section E1.1)
50-413,414/97-14-04	NCV	Failure to Control Use of Aluminum Inside the Containment Building (Section E8.2)
50-413,414/97-14-05	VIO	Failure to Label Radioactive Material As Required by 10 CFR 20.1904 (Section R1.3)

Closed

50-414/95-01	LER	Reactor Trip Due to Closure of a Main Steam Isolation Valve (Section O8.1)
50-413,414/97-08-04	IFI	Reportability of Nuclear Service Water System Actuations (Section M8.1)

50-413,414/96-18-04	IFI	Quantification of Refueling Water Storage Tank Heat Losses Through Tank Roof Including a Wind velocity Factor (Section E8.1)
50-413,414/97-11-04	URI	Use of Aluminum HEPA Filter Separators Inside Containment (Section E8.2)
50 413,414/97-05-02	URI	Determine the Applicability of Monitoring Requirements of Criterion 64 of 10 CFR 50, Appendix A; and Reporting Requirements of 40 CFR 190 and 10 CFR 50.36a Regarding Potential of Unmonitored Release Pathways (Section R8.1)
TI 2515/136	TI	Operation of Dual Function Containment Isolation Valves (Section E1.1)

Discussed

50-413/97-08-01	VIO	Inadequate Alarm Response Results in Inadequate and Untimely Corrective Actions for Valve Operability Determination (Section O8.2)

LIST OF ACRONYMS USED

AFW - Auxiliary Feedwater
CACFU - Containment Auxiliary Charcoal Filter Units
CFR - Code of Federal Regulations
DC - Direct Current
DBD - Design Basis Documents
DEV - Deviation
DOI - Digital Optical Isolator
DOT - Department of Transportation
DNB - Departure From Nucleate Boiling
EDG - Emergency Diesel Generator
ESF - Engineered Safety Features
ESFAS - Engineered Safety Features Actuation System
FWST - Refueling Water Storage Tank
GDC - General Design Criterion
HEPA - High Efficiency Particulate Air
KW - Kilowatt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LSA - Low Specific Activity
MPH - Miles Per Hour
NEI - Nuclear Energy Institute
NRC - Nuclear Regulatory Commission

NS	-	Nuclear Spray
NSD	-	Nuclear System Directive
NSW	-	Nuclear Service Water
OAC	-	Operator Aid Computer
ODCM	-	Offsite Dose Calculation Manual
OPDT	-	Overpower Differential Temperature
PCB	-	Power Circuit Breaker
PDR	-	Public Document Room
PIP	-	Problem Investigation Report
PM	-	Preventive Maintenance
PORVS	-	Power Operated Relief Valves
PSIG	-	Pounds per Square Inch Gauge
RCA	-	Radiological Control Area
RGC	-	Regulatory Compliance
RHR	-	Residual Heat Removal
RP	-	Radiation Protection
R&R	-	Repair and Restoration
SCO	-	Surface Contaminated Object
SI	-	System Internationale
SRP	-	Standard Review Plan
SSC	-	Structures, Systems, and Components
SSPS	-	Solid State Protection System
TS	-	Technical Specification
TSAIL	-	Technical Specification Action Items List
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VIO	-	Violation
WO	-	Work Order