U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	422 South Church Street Charlotte, NC 28242
Dates:	November 23, 1997 - January 10, 1998
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Enclosure 2

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/97-15, 50-414/97-15

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a seven-week period of resident inspection; in addition, it includes the results of announced and reactive inspections by regional reactor safety inspectors, radiation specialists, and a project manager from the Office of Nuclear Reactor Regulation (NRR).

Operations

- In general, the conduct of routine operations, including plant shutdown and startup activities associated with the Unit 1 refueling outage were professional and safety conscious. (Section O1.1)

- Operator performance during reactor and turbine startup was good as evidenced by proper procedure use, communications, and coordination. (Section O1.2)

- Unit 1 refueling activities were performed without incident and in accordance with governing procedures. (Section O1.3)

- Human performance weaknesses related to an inadvertent injection of safety injection system water into the reactor coolant system were identified as an unresolved item. (Section O4.2)

- Operators appropriately manually tripped the Unit 1 reactor (while it was shutdown) in compliance with Technical Specifications following loss of indication for a shutdown bank control rod. (Section O4.3)

- Operator response to plant conditions related to the December 30,1997, Notice of Unusual Event as a result of elevated reactor coolant system leakage was appropriate. (Section O4.4)

- The inspectors concluded that flooding the Unit 1 refueling cavity with two inoperable charging pumps would have increased the margin to boiling and would not have sufficiently diluted the reactor coolant system boron concentration to erode the required shutdown margin. However, the Technical Specification did not allow the licensee to transfer water from the refueling water storage tank to the reactor coolant system at their respective boron concentrations without some exemption from the regulations. Hence, the Plant Operations Safety Committee's conclusion that the operation did not constitute a positive reactivity change was inappropriate. (Section O7.1)

Maintenance

- Surveillance activities were conducted well with proper use of procedures and adequate communications between personnel performing the tests. (Section M1.1)

- A natural circulation test performed on Unit 1 successfully demonstrated the ability to cool the plant without forced reactor coolant system flow following the replacement of the Unit 1 steam generators in 1996. (Section M1.2)

- Outage-related maintenance activities, in general, were conducted with good workmanship, proper radiological controls, and proper adherence to procedures. (Section M1.3)

- Sections of the licensee's second 10-year interval inservice inspection program that were reviewed, complied with code requirements. Inservice inspection examinations observed were performed in a satisfactory manner. Technicians were well-trained and had good knowledge of plant equipment and procedural requirements. Inspection results were evaluated and documented with accuracy and clarity. (Section M1.4)

- The observed steam generator eddy current activity was well managed and executed in accordance with applicable procedures. Technical personnel doing data acquisition were qualified to perform their assigned tasks. The licensee took a proactive approach to resolve the problem of build-up in steam generator tube inner surfaces. The eddy current inspection plan for this outage met code and industry standards. (Section M1.5)

- The licensee continued to demonstrate a weakness in the area of welding certain production welds. Some welders lacked the necessary skills to produce radiography quality welds as evidenced by the need for repeated repairs during fabrication activities. The in-processing group had not been able to satisfy the need for experienced welders in time for training prior to the outage. (Section M1.6)

- A review of welding records associated with minor modification CE-8774/-8778 on the service water lines of the 1A emergency diesel generator disclosed that hold points were inspected as required, welders were qualified to use the process specified, the proper filler metal was issued and used to fabricate the aforementioned welds and that weld fabrication and testing met applicable code requirements. (Section M1.7)

- An unresolved item was identified concerning anti-reverse rotation devices not being installed on the Unit 1D reactor coolant pump motor before it was installed during the December 1997 refueling outage. (Section M7.1)

- A non-cited violation was identified for failure to properly test safety-related logic circuits for feedwater isolation and P-10 source range block permissives. (Section M8.1)

Engineering

- Outage-related modifications for main steam isolation valve control circuitry and low steam line pressure safety injection signals were conducted appropriately. (Section E1.1)

- In general, engineering support of Unit 1 outage activities was good. (Section E2.1)

- A minor concern was identified concerning engineering documentation of operability determinations. (Section E3.1)

- The 1997 Updated Final Safety Analysis Report revision was in compliance with 10 CFR Part 50.71. A strength was noted concerning the incorporation of pertinent changes to the revision. (Section E3.2)

- A non-cited violation was identified related to failure to perform adequate Technical Specification surveillance testing of emergency core cooling system check valves due to an inadequate procedure. (Section E8.3)

Plant Support

- The licensee was effectively maintaining controls for personnel monitoring, control of radioactive material, radiological postings, and radiation area and high radiation area controls as required by 10 CFR Part 20. (Section R1.1)

- All personnel exposures as of December 1997 were below regulatory limits. The licensee had established effective procedures for the use of respiratory protection equipment and was providing training for personnel required to wear respiratory protection equipment. (Section R1.2)

- The licensee demonstrated strong management support in the area of As Low As Reasonably Achievable (ALARA) as indicated by source term reduction efforts such as replacement of stellite valve seats, effective chemical shutdown process for the current outage, and by establishing challenging exposure goals. The inspectors viewed the overall ALARA program as a strength. (Section R1.3)

- The respiratory protection program was being implemented as required by 10 CFR Part 20 Subpart H. Survey instrumentation had been adequately maintained. (Section R2.1)

- A violation was identified for failure to revise radiation work permits to reflect changes in dress out specifications that arose from changing radiological conditions. (Section R3.1)
- The radiation protection technicians had been provided an adequate level of training to perform routine activities involving radiation and control of radioactive material. (Section R5.1)

- Emergency response activities were conducted well during the Notification of Unusual Event on December 30, 1997. Attention to detail was warranted concerning the use of wide-range versus narrow-range plant indication during events. (Section P1.1)

Report Details

Summary of Plant Status

Unit 1 began the inspection period with its end-of-life coast down in progress at 98 percent power. A power reduction was initiated and the unit entered Mode 3 on November 28, 1997, for refueling outage 1EOC10. Plant cooldown to Mode 4 and Mode 5 was accomplished on November 29, 1997. The unit entered Mode 6 on December 3, 1997, and core off-load (No Mode) was completed on December 8, 1997. Mode 6 was re-entered on December 18, 1997, and after core reload was completed, Mode 5 was entered on December 24, 1997. Heat up to Mode 4 and Mode 3 conditions occurred on December 28 and December 30, 1997, respectively. Reactor startup (Mode 2) commenced on January 4, 1998, with the unit being placed on-line January 5, 1998. Power was increased to 100 percent on January 9, 1998. The unit ended the inspection period at 100 percent power.

Unit 2 began the inspection period at 97 percent power. On November 23, 1997, a rapid power decrease was initiated because of an air leak on main generator power circuit breaker (PCB) 2B compressor skid. Power was stabilized at 49 percent at which time the pilot valve for 2B PCB was replaced. The pilot valve had seat leakage because debris on the valve seat prevented full closure. A power escalation commenced on November 23, 1997, and the unit was returned to 100 percent power on November 24, 1997. The unit operated at or near 100 percent 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 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 shift turnovers and site direction meetings to maintain awareness of overall plant status and operations. Operator logs were reviewed to verify operational safety and compliance with Technical Specifications (TS). Instrumentation, computer indications, and safety system lineups were periodically reviewed, along with equipment removal and restoration tagouts, to assess system availability. The inspectors conducted plant tours to observe material condition and housekeeping. These tours included visits to the containment building during the Unit 1 refueling outage 1EOC10. Problem Identification Process (PIP) reports were routinely reviewed to ensure that potential safety concerns and equipment problems were resolved.

Unit 1 shutdown activities for 1EOC10 were observed in accordance with Procedure OP/1/A/6100/02, Revision 131, Controlling Procedure for Unit Shutdown. In general, the conduct of operations was professional and safety-conscious.

O1.2 Startup Activities

a. Inspection Scope (71707)

The inspectors observed PT/0/A/4150/19, Revision 1, 1/M Approach to Criticality, and OP/1/B/6300/001, Revision 62, Turbine Generator. These procedures controlled approach to criticality and synchronization to the grid on January 4, 1998, and January 5, 1998, respectively, following the 1EOC10 refueling outage.

b. Observations and Findings

The inspectors observed that operators were following procedures and ensuring that plant equipment performed as expected. Reactor engineers were present and provided assistance to operators for the required reactivity plots. Reactor criticality was achieved within the allowable tolerance band of the estimated criticality conditions.

Control room operators manually aligned the unit to the offsite electrical grid after auto-synchronization was initially unsuccessful. Auto-synchronization was unsuccessful because the alternating current (AC) voltage regulator malfunctioned and subsequently tripped to the manual regulator. A bent connector on the primary side of the Y-phase potential transformer was found and repaired. Auto-synchronization to the grid was later successfully accomplished.

The inspectors observed portions of PT/0/A/4150/11C, Revision 1, Dynamic Rod Worth Measurement And Boron Endpoint. Operations performance during this evolution was good. Rod movement was well coordinated and communication between reactor engineering and control room operators was clear and concise.

c. Conclusions

Operator performance during reactor and turbine startup was good as evidenced by proper procedure use, communications, and coordination.

O1.3 Unit 1 Refueling Outage Activities

a. Inspection Scope (71707)

The inspectors observed and assessed performance of various Unit 1 outage-related activities to ensure that procedures were followed, that shutdown-risk controls were implemented, infrequently performed activities were adequately prepared for and briefed by station

personnel, and that foreign material exclusion controls were implemented where applicable.

b. Observations and Findings

In general, refueling outage activities were performed without incident and in accordance with governing procedures. Only minor discrepancies associated with equipment tag-outs and restorations were identified by the inspectors; these discrepancies were discussed with the Shift Work Manager on duty for resolution.

Containment Cleanliness Walkdown

The inspectors conducted a containment cleanliness tour of the reactor building and pipe chase on December 27, 1997, before Unit 1 entered Mode 4. In general, the licensee's efforts to remove tools and debris and to secure loose items were effective. The inspectors noted several minor discrepancies and communicated them to the Shift Work Manager for resolution.

Unit Entry into Reduced Inventory and Midloop Operation

The resident inspectors reviewed the licensee's administrative controls governing reduced reactor coolant system (RCS) inventory and midloop conditions.

At Catawba, a reduced inventory condition corresponded to 16 percent RCS level with fuel in the core. Midloop was defined as RCS water level below the top of the flow area of the hot legs at the junction of the hot legs to the reactor vessel with fuel in the core. This corresponded to 7.25 percent RCS level.

The outage included two periods of operation in reduced inventory and one period of operation in midloop. At the beginning of the outage, the unit was drained to just below the reactor vessel flange (approximately 25 percent RCS level) so the vessel head could be lifted. Once the core was off-loaded, the system was drained again for steam generator (SG) nozzle dam installation.

After the core was reloaded into the reactor vessel, the unit entered reduced inventory early on December 23, 1997, for reactor vessel head replacement and B steam generator nozzle dam removal (which provided for a large vent path in accordance with the administrative controls governing shutdown risk). Reactor coolant system level was increased to 20 percent for A-train engineered safety feature (ESF) testing. Following ESF testing late on December 23, 1997, RCS level was reduced again to 8 percent for the removal of the other SG nozzle dams and miscellaneous valve work. The unit remained at 8 percent level until December 25, 1997, when RCS vacuum refill was performed.

The inspectors reviewed NRC and industry guidance and the licensee's procedures including Nuclear System Site Directive (NSD) 3.1.30, Unit Shutdown Configuration Control and procedures for draining the RCS. The inspectors also reviewed the Technical Specification Action Item Log to verify that essential equipment was available. The inspectors verified that the licensee had reviewed their controls and administrative procedures governing shutdown risk.

The licensee conducted pre-job briefings with the operations shifts scheduled to perform RCS draining to reduced inventory conditions. The briefing package provided a description of the evolution, TS implications, NSD 3.1.30 implications, success criteria, roles and responsibilities, termination criteria, and contingency plans.

Information pertaining to shutdown risk management was updated and reviewed during the entire outage, not just during reduced inventory operations, on a daily basis. The status of boration flow paths, core fill flow paths, reactivity instrumentation, residual heat removal (RHR) and spent fuel pool cooling, power availability to the 4160 volt (V) essential switchgear, RCS level, boron concentrations, and RCS thermal margin (time to boil) was reviewed daily at the outage management meetings. The inspectors considered the routine monitoring and continuous licensee awareness of system and equipment status and risk-informative parameters a strength in maintaining a focus on defense in depth.

Control room operators were observed prior to and during the drain down to reduced inventory and midloop to verify that:

1) Containment closure was maintained with fewer than ten exceptions during reduced inventory, as required by NSD 3.1.30. No exceptions to containment closure were allowed by the licensee while the RCS was at midloop.

2) A member of the operations shift was assigned as the Containment Closure Coordinator and was responsible for maintaining the status of all penetrations.

3) Redundant core exit temperature indications were available.

4) Two independent trains of RCS level instrumentation were maintained during reduced inventory and midloop. The wide-range and mid-range (differential pressure) RCS level indications, as well as level sight glass, were available during reduced inventory. Narrow-range (ultrasonic) level indications were available during mid-loop.

5) RCS level disturbances were minimized. Site Directive 3.1.30, included guidance regarding the need to minimize RCS level disturbances such as ESF flow balancing during reduced inventory and midloop operations. The A-train ESF testing was performed

with RCS level at 20 percent between entries into reduced inventory on December 23, 1997.

6) Two independent makeup paths of borated water were available in accordance with NSD 3.1.30. The licensee's Abnormal Operating Procedure AP/1/A/5500/19, Loss of RHR, provided for aligning the ECCS pumps and gravity feed flowpaths should RHR be lost or degraded.

7) The B SG cold-side primary manway provided a large vent path for reflux cooling after the reactor vessel head was set. Once the other SG nozzle dams were removed and all SG manways and diaphragms were installed, two upper head injection isolation valves (1NC-198 and 1NC-199) were opened to provide a large vent path.

8) Two offsite and two onsite AC power sources were available during reduced inventory and midloop operation. To minimize the possibility of a loss of power to the required busses, access to these areas was restricted and work activities affecting associated switchyard equipment was controlled in accordance with OP/1/A/6150/06, Draining the Reactor Coolant System, Enclosure 4.12, Reduced Inventory Posting Requirements.

The inspector also noted that control room operators exhibited a questioning attitude and sensitivity to shutdown risk prior to ESF testing by requesting engineering and regulatory compliance support to resolve a concern regarding the operability of A-train RHR in the ESF test alignment.

c. Conclusions

The licensee conducted outage activities safely with appropriate sensitivity to shutdown risk and the availability of attendant plant equipment. Only minor housekeeping items were identified during the inspectors' containment cleanliness walkdown. Control room operators exhibited a good questioning attitude and sensitivity to shutdown risk prior to ESF testing.

04 Operator Knowledge and Performance

04.1 Prompt Onsite Response to Events - General Comments (93702)

The licensee reported three separate events to the NRC Headquarters Operations Officer via the Emergency Notification System in accordance with 10 CFR 50.72. These events occurred within 48 hours of each other near the end of the Unit 1 refueling outage. The inspectors responded to the site and reviewed the licensee's activities related to the events. Each event is described separately in sections 04.2, 04.3, and 04.4 below. The events were all reported appropriately by licensee staff with sufficient information provided and in accordance with

regulations. The event notification for the manual safety injection discussed in section O4.2 was rescinded on January 8, 1998, after the licensee revisited further the requirements of 10 CFR 50.72. The inspectors identified no violations in this area.

O4.2 Inadvertent Safety Injection Pump Discharge to RCS

a. Inspection Scope (93702)

The inspectors responded to the site and reviewed the circumstances surrounding an inadvertent injection of safety injection system water into the Unit 1 RCS and a subsequent pressurizer heatup transient on December 29, 1997. The inspectors assessed operator performance in stabilizing the plant, the root cause of the transient, and the licensee's initial corrective actions.

b. Observations and Findings

Sequence of Events

On December 29, 1997, at approximately 12:17 a.m., operators were performing Procedure OP/1/A/6200/009, Cold Leg Accumulator Operation, Revision 61, to fill the Unit 1 cold leg accumulators in preparation for unit startup from the refueling outage. The plant was in Mode 4 with RCS temperature and pressure at approximately 330 Fahrenheit (°F) and 550 pounds per square inch gauge (psig), respectively. Pressurizer surge line temperature was approximately 488°F. Low temperature over-pressure protection for the primary system was not operable, nor was it required with reactor coolant system temperature above 285°F. The operator at the control board was performing steps in Section 2 of the procedure to align the safety injection system for accumulator fill. Section 2.3 required using safety injection (NI) pump 1A. The operator read through the procedure prior to initiating the fill and marked those steps not to be used "N/A"; skipping those steps that would be used. During the performance of the procedure, Step 2.3.3, which directed the operator to close valve 1NI-118A, NI Pump 1A Cold Leg Injection Isolation was inadvertently missed. The operator stated his intention to wait and return to this step just prior to initiating the fill in order to minimize out-of-service time for the safety injection flowpath to the RCS. Moments later, an operator who had been directed to locally check the status of NI pump 1A informed the operator at the controls that the pump was ready. The operator at the controls forgot that step 2.3.3 to isolate the RCS cold leg injection header had not been performed earlier, and started the pump.

RCS pressurizer level and pressure immediately started rising while the temperature dropped as a result of the colder safety injection system water entering the RCS. Operators stated that they immediately noticed that pressurizer level was rising but did not initially attribute the

rise to the start of the NI pump because of ongoing routine heatup operations and the associated expansion of water in the system. The pressurizer level deviation annunciator was already illuminated as a result of earlier normal heatup activities. Within 3 minutes, operators realized that the additional level increase was due to the safety injection pump start; they secured the pump and monitored plant parameters.

Pressurizer surge line temperature dropped from 480°F to approximately 330°F as a result of the insurge of colder RCS water. After the safety injection pump was stopped, the temperature began to recover, increasing about 80 degrees in less than 15 minutes. Control room operators, attempting to prevent the heatup from exceeding TS 3.4.9.2 limits, initiated pressurizer spray. The spray initiation resulted in an outsurge of warmer pressurizer water through the surge line into the RCS; causing surge line temperature to jump to approximately 470°F. The change from 330°F to 470°F in less than 20 minutes exceeded the pressurizer heatup TS limit (100 degrees in any 1-hour period). Operators eventually stabilized pressurizer surge line temperature at approximately 460°F. As a result of the out-of-limit condition, an engineering evaluation was performed (see section E3.1 of this report) as required by the TS, and the pressurizer was determined to be acceptable for continued operation.

Operator Performance and Regulatory Significance

The inspectors interviewed plant personnel and determined that this event was caused by human error and failure to follow procedures. The control room operator intended to follow the procedure, but made an error in forgetting to return to the requisite step before starting the safety injection pump. The failure to follow Procedure OP/1/A/6200/009 was contrary to requirements in TS 6.8.1.a and Regulatory Guide 1.33, Revision 2, Appendix A, Section 3.d, which stated that written procedures shall be established and implemented covering operation of the ECCS (cold leg accumulators).

Late in the inspection period, the inspectors recalled a previous event during a Unit 2 shutdown in December 1996 where human error lead to an inadvertent injection of water from the cold leg accumulators into the RCS. This event was reported in Licensee Event Report (LER) 50-414/96-007 on January 14, 1997. The inspectors considered that the two events, while having low safety consequences, were significant, in that there may have been common themes present between the 1996 event and the December 29, 1997, event. Consequently, pending further review, the inspectors will track the human performance issues associated with the two events as Unresolved Item (URI) 50-413,414/97-15-01: Failure to Follow Procedures Resulting in Inadvertent Injections of ECCS Fluid Into the RCS.

Regarding the pressurizer heatup in excess of TS limits, the inspectors were concerned that the control room operators at the time were either

unaware of or unfamiliar with pressurizer outsurge phenomena prior to initiating pressurizer spray. The inspectors questioned whether initiating sprays was appropriate in view of the outsurge phenomenon, or would it have been more prudent to allow temperatures to coast upward, minimizing the thermal stresses to the pressurizer even if TS limits were inevitably exceeded as a result of the initiating safety injection event. This concern was expressed to plant management who was reviewing the circumstances and training issues surrounding operator performance during the recovery operation. The inspectors will track this issue along with the procedure adherence issue under the Unresolved Item.

As stated in paragraph O4.1, operators initially reported this event via the emergency notification system per 10 CFR 50.72. There was initially some question as to whether or not the inadvertent injection was reportable. Upon further review of related regulatory guidance, the licensee determined that the event did not meet reportability criteria specified in 10 CFR 50.72 and the event notification was rescinded on January 8, 1998. The inspectors considered the operators' initial decision to notify the NRC while considering the question on reportability, to be conservative.

c. Conclusions

Operator performance errors lead to an inadvertent injection of safety injection water into the reactor coolant system. During recovery from the safety injection, operator actions contributed to the pressurizer heatup rate exceeding Technical Specification limits. The pressurizer was evaluated to be structurally acceptable for continued operation. An unresolved item was identified related to the human performance issues.

O4.3 Manual Reactor Trip While in Mode 4

a. Inspection Scope (93702)

The inspectors reviewed the circumstances surrounding a manual reactor trip initiation for Unit 1 on December 29, 1997. The inspectors reviewed post-trip data, including control room data, Operator Aid Computer trends, and printouts from the Sequence of Events Recorder. The inspectors attended the Plant Operations Review Committee (PORC) meeting authorizing the unit startup, and reviewed the PORC meeting minutes.

b. Observations and Findings

With Unit 1 shutdown in Mode 4 and RCS temperature and pressure at approximately 336°F and 420 psig respectively, operators were withdrawing control rod shutdown banks A and B in accordance with operating procedures to provide shutdown capability. While withdrawing shutdown bank B, operators noticed that the digital rod position indication (DRPI) for rod J-3 in that bank would not advance past 48 steps withdrawn, while the other rod positions in the bank advanced

towards the 60 step indication. Operators drove bank B back to 42 steps, as indicated by DRPI, and rod J-3 indicated appropriately. Operators then consulted engineering who recommended withdrawing the bank again towards 60 steps. With the rods at 58 steps, operators received a DRPI Urgent Failure alarm. Rod J-3 general warning and rod bottom indications were received, and operators manually tripped the reactor as required by TS 3.1.3.3 and entered Abnormal Procedure AP/1/A/5500/05, Reactor Trip or Inadvertent Safety Injection Below P-10, Revision 16.

The plant responded appropriately to the trip signal, with all rods indicating at bottom. To avoid an unnecessary secondary plant transient, operators bypassed the feedwater isolation signal upon tripping the reactor and bypassed the step in the AP to manually initiate the feedwater isolation. Operators expressed that the auxiliary feedwater system had not been fully tested in preparation for entering Mode 3 and two steps later in the procedure operators were directed to restore normal feedwater. Plant management reviewed the issue of whether or not appropriate procedural guidance was provided for feedwater isolation. The PORC addressed this issue and initiated PIP-1-C97-4391. No action was specified in the PIP to address deviation from the AP. The inspectors were concerned about the deviation from the AP. This issue is characterized as Unresolved Item 50-413/97-15-02, Appropriateness of Operator Actions During Rod Testing, pending further NRC review.

The cause of the J-3 rod's indication problem was a failed detector encoder card in the A data cabinet. The failed card was replaced and the shutdown banks were withdrawn without further incident.

During a review of the licensee's reactor trip evaluation contained in Procedure PT/0/A/4150/02, Transient Investigation, the inspector noted that the engineer completing the attachments incorrectly listed pre-transient RCS pressure as 1687 psig. The correct pressure was 420 psig. The engineer had obtained the erroneous value from an operator who referred to the narrow range pressure instruments in the control room, which go off scale low below approximately 1700 psig. The correct pressure for the Mode 4 plant configuration should have been obtained from a wide range pressure instrument. The inspector had a similar observation this period during the event discussed in section P1.1 and noted that more attention to detail was warranted concerning the correct instrumentation to reference during response to plant transients.

c. Conclusions

Operator actions to initiate a manual reactor trip following a malfunction in the DRPI system were appropriate. Follow-up actions to bypass a feedwater isolation were under further review by the inspector. More attention to detail was warranted regarding the correct instrumentation to reference during events.

O4.4 Excess Reactor Coolant (NC) System Leak Rate During Unit 1 Mode 3 Heat Up

a. Inspection Scope (71707)

The inspectors reviewed the circumstances associated with the Notification of Unusual Event (NOUE) that occurred on Unit 1 during Mode 3 heat up on December 30, 1997.

b. Observations and Findings

Initial Unit 1 conditions were Mode 3 and heat up to normal operating temperature and pressure had been completed for approximately ten minutes. Approximately 17 licensee personnel were in containment performing system integrity and post-maintenance functional checks. At 5:35 p.m., an alarm was received on reactor vessel (RV) leak-off high temperature. At approximately 5:40 p.m. the control room received reactor coolant drain tank (NCDT) alarms indicating excess NC system leakage. At 5:55 p.m., the abnormal procedure for loss of NC was entered, a second charging pump was started, and the containment was evacuated. A leak rate of approximately 40 gallons per minute (gpm) was determined. The Technical Support Center (TSC) and Operations Support Center (OSC) were manned and a NOUE was declared at 7:22 p.m. due to exceeding TS leak rate criteria and impending plant cool down. Plant cool down was initiated at 7:50 p.m.. The NRC was notified at 8:06 p.m. At 8:30 p.m. the NRC was notified of the second charging pump start (four-hour notification). Cool down was secured at 10:08 p.m. with NC conditions at 1300 psig and 466 degrees F. At 1:06 a.m. on December 31, 1997, a containment entry team identified NC loop drain valves 1NC-13 and 1NC-106 cracked open and terminated the event with closure of the valves. The NRC was notified of the event termination at 1:42 a.m.

The initial review by the inspectors indicated that the operator actions were appropriate for plant conditions. Actions to initiate cool down, stabilize the plant conditions, and activate the TSC and OSC were timely and conservative. NRC notifications were consistent with regulatory requirements. Appropriate investigations were initiated to determine the root cause, review the event, and evaluate equipment performance and impact. In particular, the NCDT system was inspected and evaluated with respect to the over pressurization it experienced because of this event. Degraded equipment was inspected and refurbished. The investigation to determine the cause for the drain valves being slightly open was ongoing. This investigation was documented in PIP 1-C97-4406. A special report was being prepared to address Unit 1 start up events which includes the NC system high leak rate NOUE.

c. Conclusion

The licensee's response to the NOUE due to high NC system leakage was appropriate. Operator response was good and appropriate investigations were initiated to review event response, root cause, and plant equipment performance.

07 Quality Assurance in Operations

07.1 Plant Operations Review Committee (PORC) Meeting

a. Inspection Scope (71707)

On December 4, a PORC convened to discuss activities related to filling the refueling canal for core off-load to the spent fuel pool and TS 3.1.2.3., which stated that one charging pump in the boron injection flow path (required by a separate TS) shall be operable and capable of being powered from an operable emergency power source. The inspectors attended the PORC meeting, reviewed the TS and TS Basis, and discussed associated regulatory compliance and safety issues with NRC and plant management.

b. Observations and Conclusions

At the time of the PORC meeting, the reactor vessel head had been lifted and the RCS was in a "loops not filled" condition. The licensee was preparing to flood the refueling canal to begin core alterations. The thermal margin was 15 minutes (high decay heat condition) to core boil (upon loss of the RHR system), and the minimum RCS boron concentration required for shutdown margin was 2475 ppm. The 1B charging pump was inoperable because of lube oil system equipment problems (see section M2.1), and the 1A emergency diesel generator was inoperable for outage-related maintenance. As a result, TS 3.1.2.3 required that all operations involving positive reactivity changes be suspended.

The licensee's objective was to flood the refueling cavity by transferring water from the refueling water storage tank (FWST) and thereby increase the thermal margin for time to boil. The function of the PORC was to determine if the transfer of water from the FWST, which was at a boron concentration of approximately 2800 ppm, to the RCS, at approximately 3100 ppm, constituted a positive reactivity addition prohibited by TS 3.1.2.3. The PORC concluded that the transfer of FWST water to the RCS would constitute a "boron adjustment" and not a positive reactivity addition. The PORC unanimously endorsed proposed actions to flood the refueling canal with clarification that no core alterations would be permitted. Following some discussion with the inspectors concerning the term "positive reactivity addition," the licensee decided to postpone flooding the refueling canal until some other resolution could be obtained. The 1B charging pump was returned to service on December 5, 1997, and refueling cavity fill was initiated shortly thereafter.

c. Conclusions

The inspectors concluded that flooding the refueling cavity would have increased the thermal margin to safety and would not have sufficiently diluted the RCS boron concentration to erode the required shutdown margin. However, the TS did not allow the licensee to transfer water from the FWST to the RCS at their respective boron concentrations without some exemption from the regulations. Hence, the PORC's conclusion that this was a reactivity adjustment was inappropriate.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) LER 50-414/94-02-01: Reactor Trip Breakers Opened Due To Component Failure

The event described in this LER occurred on June 15, 1994, due to an intermittent rod control system firing card failure. The circumstances surrounding the event and the licensee's corrective actions associated with the original LER were discussed in NRC Inspection Report 50-400/96-05. The LER was supplemented on November 7, 1996, to clarify that Procedure OP/1,2/A/6150, Rod Control; not Procedure PT/0/A/4150/19, Approach to Criticality, was revised to include provisions for checking selected rod light indication at the rod control cabinets prior to withdrawing control rods.

During the review of this LER, the inspector noted that a low power physics test, Procedure PT/0/A/4150/11B, Control Rod Worth Measurement by Rod Swap, was also revised to include the status check at the rod control cabinets. The inspector recalled that the rod swap procedure was not used during the recently completed Unit 1 refueling outage and that a new method contained in Procedure PT/0/A/4150/11C, Dynamic Rod Worth Measurement and Boron Endpoint, Revision 0, was used instead. This procedure was not in existence at the time of the LER and therefore did not include the provisions for checking control rod status at the rod control cabinets. The inspector considered that the dynamic rod worth measurement method contained the same inherent risks as the procedures referenced in the LER and that it should include the same provisions. This was discussed with regulatory affairs personnel who indicated they would address the newer procedure and review the process for incorporating previous corrective actions into new procedures. This LER supplement is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments Surveillance (61726)

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

- PT/0/A/4150/11C, Revision 1, Dynamic Rod Worth Measurement And Boron Endpoint
- PT/0/A/4150/01, Revision 17, Controlling Procedure for Startup Physics Testing
- PT/0/A/4150/19, Revision 1, 1/M Approach to Criticality
- TT/1/A/9200/11, Revision 0, Natural Circulation Verification Test
- PT/1/A/4200/09, Revision 153, Engineered Safety Features Actuation Periodic Test
- IP/0/A/3710/019, Revision 24, 125 Volts Direct Current (VDC) Vital Instrumentation and Control Power System Battery Capacity Test

During these activities, the inspectors noted proper use of procedures and adequate communication between personnel performing the tests. No violations were identified.

M1.2 Natural Circulation Verification Test

a. Inspection Scope

The inspectors observed licensee performance of TT/1/A/9200/11, Revision 0, Natural Circulation Verification Test on November 29, 1997. The natural circulation verification test was performed to demonstrate the ability of the nuclear steam supply system (NSSS) to remove heat via natural circulation of the primary coolant and allow fine-tuning of the on-site simulator for natural circulation conditions for the new steam generators. The inspector reviewed the test procedure in advance, and observed licensee performance during the test to verify compliance.

b. Observations and Findings

This test was controlled by system engineers who collected the data, utilizing the operator aid computer (OAC), and determined test acceptability. The inspector attended the pre-test briefing, conducted by the RCS lead engineer. The briefing was conducted in an orderly manner, with emphasis placed on acceptance criteria, termination criteria, and expected plant response.

The test consisted of tripping all four reactor coolant pumps simultaneously while the plant was in Mode 3, with RCS temperature and pressure at 557°F and 2235 psig, respectively. Adequate decay heat was available to drive natural circulation. Establishment of natural circulation was verified by observing wide range RCS loop temperatures as well as core exit thermocouples. In addition to these parameters, pressurizer and steam generator levels and pressures, and RCS subcooling were monitored. Stable natural circulation was maintained while data was gathered for acceptance criteria determination. The test was terminated based on decreasing steam pressure of 931 psig that approached a termination test criteria for steam pressure of 900 psig. In addition to acceptance criteria, review criteria were also established. Review criteria provided additional restrictions on plant conditions during the evolution. Plant conditions required during the

test for three different review criteria were not met but were evaluated to be acceptable. The evaluation performed by engineering concluded that the test was completed satisfactorily. The inspectors' review of the test results lead to the same conclusion.

c. Conclusions

The natural circulation test was conducted in a controlled manner with good emphasis placed on monitoring critical plant parameters to detect abnormal plant trends if present. The test demonstrated that natural circulation could be achieved on Unit 1 following the loss of forced circulation. Additionally, the inspectors considered the engineering evaluation of recorded plant data to be adequate.

M1.3 General Comments Maintenance (62707)

The inspectors observed performance of and reviewed documentation associated with the following outage-related maintenance activities:

- MP/C/A/7400/044, Revision 11, Diesel Engine Crankshaft Alignment and Thrust Clearance Measurement
- MP/0/A/7150/057A, Revision 0, Residual Heat Removal Pump with Cartridge Seal Removal and Replacement and Corrective Maintenance
- MP/0/A/7150/039, Revision 29, Reactor Coolant Pump Seal Removal and Replacement

During these activities, the inspectors noted proper use of procedures, appropriate radiological controls, and good workmanship from personnel performing the maintenance. No violations were identified.

M1.4 Inservice Inspection (ISI) of Safety-Related Welds and Components (Unit 1)

a. Inspection Scope (73753)

The inspector verified by observation and document review that nondestructive examinations of safety-related welds were performed in accordance with the licensee's implementing procedures and applicable code requirements. The controlling code for Catawba's ISI activities was the American Society for Mechanical Engineers (ASME) Code Section XI, 1989 Edition with no addenda, (Code). Procedures used for examinations observed were as follows:

NDE-630, Revision 2	Ultrasonic Examination of Similar Metal Welds in Wrought Ferretic Steel
NDE-35, Revision 16	Liquid Penetrant Examination

b. Observations and Findings

The inspector reviewed activities conducted during a scheduled refueling outage, designated as End Of Cycle 10 (EOC 10) outage. This outage was the second outage of the second 10-year interval. Examinations performed on safety-related welds were identified in the licensee's ISI Database Management System. The inspector selected at random several ISI examination categories and verified by review that the number of welds selected by the licensee for examination during this outage were consistent with Tables IWB-2412-1 and IWB and C 2500-1 of the code. Examination categories selected for this review were as follows:

B-A Pressure Retaining Welds in Reactor Vessel

B-D Full Penetration Welds of Nozzles in Vessels

B-J Pressure Retaining Welds in Piping Nominal Pipe Size less than 4-inch and greater than 4-inch, branch connections and socket welds.

C-F Class B Pressure Retaining Welds in Nominal Pipe Size less than 4-inch and greater than 4-inch and branch connections and longitudinal welds.

In addition, to this work effort, the inspector observed ISI examinations performed on the following welds.

Item	Weld	Examination
C01.010.008	1ELDHX-SH-FLG	Ultrasonic (UT)
C01.020.002	1ELDHX-SH-HD	UT
C01.020.003	1ELDHX-HD-FLG	UT
C05.030.011	1N1206-2	Liquid Penetrant (PT)
C05.030.012	1N1206-3	PT
C05.030.013	1N1206-4	PT
C05.030.014	1N1206-5	PT

By work observation and associated record review, the inspector determined that the above welds were adequately examined and that the code required information and examination results were documented and evaluated satisfactorily. Examiners were adequately trained and knowledgeable, and performed their assigned tasks with attention to detail and code requirements. Equipment and materials used were properly identified and traceable to certification documents, and equipment used was in calibration.

c. Conclusion

Sections of the licensee's second 10-year interval ISI program that were reviewed, complied with code requirements. ISI examinations observed were performed in a satisfactory manner. Technicians were well trained and had good knowledge of plant equipment and procedural requirements. Inspection results were evaluated and documented with accuracy and clarity.

M1.5 Eddy Current Examination of Steam Generator (SG) Tubes (Unit 1)

a. Inspection Scope (73753)

By work observation and review of applicable procedures, the inspector determined the adequacy of the data acquisition phase of the SG tubes eddy current testing (ET) program. This ET inspection was being performed in accordance with the requirements of plant Technical Specifications, the ASME Code Section XI, 1989 Edition, with no addenda and included provisions of Code Case N-401-1 Digital Equipment. NRC Regulatory Guide 1.83, Revision 1 was applicable by reference. Other governing documents and procedures associated with data collection and analysis were as follows:

NDE-701, Revision 3	Multifrequency Eddy Current Examination of SG Tubing at Catawba Nuclear Station
NDE-703, Revision 5	Evaluation of ET data for SG Tubing

Eddy Current Guidelines, Catawba Nuclear Station, Unit 1, EOC-10

b. Observations and Findings

The inspector observed data acquisition in progress on December 19, 1997. This work effort included acquisition, verification of probe location, in line system calibration, personnel qualification, and equipment calibration. Examinations were being performed with the MIZ-30-8 acquisition system with digital and multifrequency eddy current techniques. Differential bobbin coils 0.560 and 0.540 inches in diameter were being used for this examination. The ET plan called for examination of all active tubes with bobbin coil probes in each of the four SGs. Motorized rotating pancake coil (MRPC) examinations were being performed to characterize indications identified by the bobbin coil with respect to area, orientation and morphology. Approximately 60-70 tubes were examined by MRPC. During the bobbin coil examination, the licensee determined that a deposit build-up existed on the inside diameter (ID) wall surface of tubes in the hot and cold legs of all four SGs. These deposits were having a negative impact on ET data acquisition rates because they hindered probe movement through the tubes to the extent that each tube had to be tested twice to assure full length coverage. Increased probe wear rates resulted in more frequent change-outs and contributed to the slowdown. The inspector met with the

licensee's responsible engineer and determined that immediate corrective actions taken to alleviate the problem included: changing the planned "full pull" of each tube to a two step approach to avoid having to push probes through the full length of the tubes and using smaller diameter bobbin probes 0.540 versus 0.560 inch for the examination. Results of a radioisotope and scanning electron microscope (SEM) analyses, revealed the presence of Co-58 due to activation and decay of Nickel, Cr-51 due to Inconel and Stainless material; Co-60 due to activation of Co-59 and Fe-59 due to stainless steel material. The SEM analysis showed that iron, chrome, nickel and large amounts of fluorine and carbon were also present. The latter two elements were determined to be associated with materials used in ET probe construction. The aforementioned problem was documented in PIP-1-C97-4111. Additional planned actions included aggressive cleanup of metal oxides during startup, monitoring for solids and nickel and a determination of boron concentration levels.

The inspector observed ET of SG tubes in SG A, reviewed applicable procedures, calibration records, and personnel qualification certifications for completeness and accuracy. At the close of this inspection, the licensee had examined approximately 85 percent of the total number of tubes in the four SGs and no rejectable tube indications were identified.

c. Conclusion

The observed activity was well managed and executed in accordance with applicable procedures. Technical personnel doing data acquisition were qualified to perform their assigned tasks. The licensee took a proactive approach to resolve the problem of build-up in SG tube ID surfaces. The ET inspection plan for this outage met code and industry standards.

M1.6 Minor Modification to Replace Sections of 18-inch Primary Feedwater (CF) Piping Between Containment Isolation Valves In Doghouse (Unit 1)

a. Inspection Scope (62700/55050)

The inspector determined by work observation and document review the adequacy of work activities in regards to replacement of piping material between certain CF containment isolation valves in the Unit 1 doghouse. The governing code for this activity was the ASME Section III 1974 Edition through Summer 1974 Addenda. The piping involved in this modification was classified as Duke Class B. The modification was identified as minor modification CNCE-8965. Applicable work orders included 97044910, 97044911, and 97044916.

b. Observations and Findings

By review of the modification package, the inspector ascertained that the design of Tilting Disk Swing Check Valves 1CF31, 1CF49, and 1CF58 had caused severe localized erosion in the associated 18-inch diameter

carbon steel pipe immediately downstream of the check valves. The replacement piping was made of 18-inch schedule 80 Stainless Steel SA 376/TP304 material. On December 18, 1997, the inspector observed field welds in progress and undergoing repairs in response to rejectable indications identified by radiography or ultrasonic examination. Welds involved in this work effort were as follows:

Weld No.	Size (inches)	Drawing	Comments
1CF24-1	18 x 0.938	1CF24	Repaired three times for code rejectable indications
1CF24-3	18 x 0.938	1CF24	Repaired four times for code rejectable indications.
1CF29-1	18 x 0.938	1CF29	Repaired three times for code rejectable indication.
1CF29-3	18 x 0.938	1CF29	Repaired three times for code rejectable indications.

In addition to the above work effort, on January 8-9, 1998, the inspector reviewed completed weld process control forms to verify that required quality control (QC) hold points had been performed and initialed by QC weld inspectors as required, and that filler metal material had been documented as required by the responsible welder and reviewed by the welding QC inspector. Within these areas, the inspector noted that fabrication of production welds under field conditions continued to be a challenge for the licensee as evidenced by the rejection of five out of six, 18-inch weld joints by radiography due to fabrication type defects. The licensee's PIP written to investigate this problem indicated that vendor welders provided to work on this modification did not have the proper skills to perform radiography quality welds. To resolve this problem, site welding technical support recommended that a group of welders should be identified and trained to perform quality welds in a consistent manner, that welders needed for outage work be identified well in advance of the outage to allow for additional training, and that if an adequate number of welders cannot be secured, then welding services should be contracted. For the near term, the licensee planned to allow the site welding technical support lead to evaluate the weld jobs and select specific in-house welders based on their experience and expertise or have a qualified welding contractor to satisfy the welding needs of the nuclear station. The inspector expressed his concern over the inability to obtain, train, and maintain a group of welders with demonstrated ability to produce quality work at the licensee's nuclear sites. In addition, the inspector expressed a concern over the licensee's continuing inability to secure the services of an experienced and qualified welding engineer to assume the responsibility and to provide direction to the welding program. The continuing inability to produce quality welds and the lack of commitment

to a strong welding organization was identified as a weakness. The licensee was continuing to pursue the hiring of a qualified welding engineer.

c. Conclusion

The licensee continued to demonstrate a weakness in the area of welding certain production welds. Some welders lacked the necessary skills to produce radiography quality welds as evidenced by the need for repeated repairs during fabrication activities. The in-processing group had not been able to satisfy the need for experienced welders in time for training prior to the outage.

M1.7 Deleting Certain Drain Valves and Small Bore Lines Off Emergency Diesel Generator Return Headers. (Unit 1)

a. Inspection Scope (62700/55050)

The inspectors determined by review of selected work orders whether the tasks performed and the documents generated complied with governing procedures and code requirements.

b. Observations and Findings

Corrective Minor Modifications CE-8774 and CE-8778 were issued to eliminate small bore service water (RN) piping which is susceptible to corrosion and pinhole leaks. Drain valves 1RN-74, -890, -912, -913, -945, and -961 and associated small bore piping were deleted. Also abandoned one-inch piping off the diesel generator RN return header was cut and plugged. The described work was performed under work orders (WOs), 97045405-01, 9704112Z-01 and 97041124-01. All work associated with these WOs was performed under Procedure SM/O/A/ 8140/001, Welding of QA Piping and Valves. This procedure specified QC welding hold points, required that all personnel including welders and pipe fitters doing work enter their signature on the weld record, and that filler metal used be documented.

All new field welds were classified as ASME Class C, Duke Class G. Weld process control and QC inspections required were applicable to QA Condition 1 welds. Welds fabricated under this classification and QA condition have specific QC hold points including cleanliness, fit up, and preheat, all of which were required by the Governing Procedure QAL-16, Rev. 17, Inspection of ASME Section XI, Field Piping Welds. Completed process control records of welds fabricated under these work orders were reviewed to verify that specified hold points were checked by QC as required, that welding filler material used complied with the applicable field weld data sheet (FWDS), L-250, Rev. 17, and that the filler metal had been issued to and used by welders qualified under the aforementioned FWDS requirements.

Welds whose fabrication records were reviewed were as follows:

Weld	Size	Drawing	Work Order
16	2" sch. 40 socket	1RN240	97041122-01
19	2" sch. 40 socket	1RN240	97041124-01
31, 32	1" sch. 40 socket	1RN238	97045405-01

Based on this review and discussions with QC personnel, the inspector determined that these welds were fabricated and inspected in accordance with applicable procedures and code requirements, that the information recorded was complete and accurate, and that filler metal, at the issue station, was properly stored, segregated, and issued in accordance with applicable procedures.

c. Conclusion

This record review of welding required by minor modification CE-8774/-8778 on the service water lines of the 1A EDG disclosed that hold points were inspected as required, welds were fabricated using the designated weld process, the proper filler metal was issued and used to fabricate the aforementioned welds and that weld fabrication and testing met applicable code requirements.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Charging Pump 1B Inoperability and Unplanned Entry into TS

a. Inspection Scope (62703)

On December 3, the licensee noticed that the 1B charging pump's auxiliary oil pump was running when it was expected to be idle. Maintenance technicians determined that the lube oil system was unable to maintain pressure. The 1B charging pump was declared inoperable. The 1A emergency diesel generator was inoperable for outage maintenance, and Unit 1 entered TS 3.1.2.3, which required that all operations involving core alterations or positive reactivity changes be suspended. Troubleshooting revealed a failed lube oil system relief valve and two reversed motor leads that caused the auxiliary lube oil pump to operate in the reverse direction, unable to pump oil.

b. Observations and Findings

The auxiliary oil pump is designed to run for two minutes before the charging pump is started to prime the lube oil system. When the charging pump starts and comes to full speed, the shaft-driven main lube

oil pump starts delivering oil to the lube system. System pressure will increase when the main lube oil pump starts. This will cause a pressure switch to shut off the auxiliary lube oil pump when lube oil pressure reaches a set value.

The licensee determined that the motor leads had been reversed since September 1996. The inspector reviewed various documents to determine the impact of the auxiliary oil pump's loss of function on charging pump operability. No discussion of the auxiliary lube oil pump was located in the UFSAR. According to the design basis documentation, the auxiliary lube oil pump automatically starts to bring lubricating oil pressure to 8 psig. The vendor manual, CNM 1201.05-0203 001, Operating and Maintenance Instructions for Pacific Pumps, Manual No. 2700, provides a start-up procedure step to turn on the auxiliary lube oil pump before starting the charging pump. However, neither the design basis document nor the pump vendor manual indicated that auxiliary lube oil pump operation was critical to charging pump operation. The inspector discussed the function of the auxiliary oil pump with a station engineer, who indicated that the pump's function is to minimize bearing wear by lubricating the bearings before the charging pump is started. The engineer also indicated that the auxiliary lube oil pump was not needed for the charging pump to start and perform its safety function and essentially performed an equipment service life function. The inspector noted that the charging pump had passed its quarterly TS performance test requirements since the motor leads had been installed reversed in September 1996.

c. Conclusions

The licensee exhibited conservative decision making by declaring the 1B charging pump inoperable until troubleshooting activities could reveal the cause of the low lube oil system pressure condition. The condition of the auxiliary lube oil pump, with the motor leads reversed, did not adversely affect the ability of the 1B charging pump to perform its safety function.

M7 Quality Assurance in Maintenance Activities

M7.1 Reactor Coolant Pump 1D Anti-Reverse Rotation Device Not Installed

a. Inspection Scope (62707)

The inspector reviewed circumstances surrounding anti-reverse rotation devices not being installed on the 1D reactor coolant pump motor when it was installed during the Unit 1 refueling outage.

b. Observations and Findings

On December 28, 1997, with Unit 1 shutdown in Mode 5, plant personnel noticed the 1D reactor coolant pump rotating backwards while performing checks on the pump. The pump was not operating at the time; however,

other pumps in the reactor coolant system were, causing loop differential pressure which tended to spin non-operating pumps in the reverse direction. Operations personnel secured the operating 1C pump, which allowed the 1D pump to come to a stop. Personnel at the pump successfully attempted to hand-rotate the motor (un-coupled from the pump) in both directions and identified that anti-reverse "pawls" had not been installed in the motor. The pawls (five of them) are attached to the pump flywheel and are levers that ride along a serrated, more stationary ratchet plate in the motor frame. During normal operations, the flywheel spins in the clockwise direction, and the pawls are angled such that they do not engage the ratchet plate, allowing continued operation. When the pumps are secured, the flywheel allows the pump to coast down, and the pawls eventually engage the ratchet plate as the pump tends to rotate backwards. Shock absorbers aid in preventing anti-reverse rotation.

The inspector learned that a spare pump motor had been installed during the Unit 1 refueling outage in December 1997, and that the pawls had been removed from that motor in 1983. The licensee was able to locate the 1983 work order and find the pawls, which had been placed in a storage box. The pawls were later installed in the motor, and the pump operated normally. Licensee personnel later performed a motor current signature analysis and a breakaway torque measurement (reviewed by the inspectors) to determine that the pump motor was not damaged.

Plant personnel initiated station PIP 1-C97-4360 to document this item. At the end of the inspection period, the PIP was still open as licensee personnel investigated what controls were or should have been in place to identify the missing pawls when the spare motor was installed in December. The inspectors were concerned that quality control measures for warehouse activities should be reviewed. While not specifically discussed in the Chapter 15 of the UFSAR as an accident mitigating device, the pawls were discussed in Chapter 5 for equipment protection purposes. Pending further inspector review, this item is identified as Unresolved Item (URI) 50-413/97-15-03: Anti-Reverse Rotation Devices not Installed in the 1D Reactor Coolant Pump.

c. Conclusions

An unresolved item was opened related to circumstances surrounding anti-reverse devices not being installed in the 1D reactor coolant pump during the refueling outage.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER 50-413/97-008: Inadequate Solid State Protection System Surveillance (SSPS) Testing

This LER described a deficiency during surveillance testing of SSPS universal logic boards in a memory configuration, that would not allow detection of an internal card subcomponent failure. The potential card

failure scenario could affect three circuits associated with feedwater isolation on "Hi Hi" steam generator level, feedwater isolation on a safety injection signal, and the P-10 power range permissive interlock, which allows manual reinstatement of the source range circuits when reactor power is below 10 percent. These functions were described and test requirements were delineated in TS 3/4.3.1, and TS 3/4.3.2. The licensee implemented the surveillance requirements every two months by using a semi-automatic testing feature provided within the SSPS logic cabinet by the vendor. The licensee identified the test deficiency in the method provided by the vendor during a review of the circuitry on November 11, 1997. Following identification, licensee personnel communicated the information to nuclear plants both within and external to the Duke Energy system. The test design was also discussed with the vendor, which later issued a technical bulletin communicating the generic aspects of this deficiency to the nuclear industry and recommending changes to testing methods.

The licensee revised its test procedures, specifically IP/1(2)/A/3200/002A, SSPS Train A Periodic Testing; and IP/1(2)/A/3200/002B, SSPS Train B Periodic Testing; to correct the deficiency. The inspectors reviewed the procedure revisions, and observed successful performance on Unit 1 B-train on November 11, 1997. The inspectors also verified the adequacy of the revision by comparing it to station and vendor drawings.

The safety significance of the test deficiency was reduced by the fact that the circuits passed the revised test, and the feedwater isolation circuits have been successfully tested during refueling outages. For the P-10 permissive, its function to allow manual reinstatement of source range trips was backed up by an automatic function. The licensee promptly communicated the deficiency through the operating events database which allowed other licensees to correct similar test problems at their facilities. Failure to have adequate SSPS test design and procedures for testing the feedwater isolation and P-10 permissive circuits was contrary to TS 3.3.1, and TS 3.3.2. However, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the Enforcement Policy and is identified as NCV 50-413,414/97-15-04: Failure to Have Adequate Test Procedures for SSPS Logic Associated With Feedwater Isolation and P-10 Permissive Circuits. This LER is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Outage Modifications

a. Inspection Scope (37551)

During the Unit 1 refueling outage, the licensee implemented modifications to the main steam isolation valve (MSIV) control circuitry

and to the safety injection logic. The inspector reviewed work packages associated with modifications, watched portions of the modification work in the field, and reviewed the TS and UFSAR to ensure that these documents accurately reflected the associated changes to the plant.

b. Observations and Findings

Nuclear Station Modification CN-11377 was implemented to eliminate the safety injection signal on low steam line pressure. The modification was performed to reduce the number of unnecessary safety injections, such as one that occurred during a Unit 2 loss of offsite power event on February 6, 1996, and complicated the plant response to the event. On January 3, 1997, the licensee requested a TS revision to eliminate the low steam line pressure safety injection signal. On April 3, 1997, the TS revision was approved as License Amendment Nos. 158 and 150 for Units 1 and 2, respectively. The inspector reviewed the TS and UFSAR to ensure that revisions reflected the change. The inspector identified a UFSAR discrepancy whereby information had not been updated to reflect the change. The inspector brought the discrepancy to the attention of regulatory compliance personnel, and verified that it and other discrepancies associated with the modification had been identified previously by the licensee and documented in variation notices for correction. The TS revisions had been completed for Unit 2 and were in the process of being incorporated for Unit 1.

The licensee also implemented Nuclear Station Modification CN-11373. This modification was designed to eliminate a single failure vulnerability to the MSIVs. Since 1995, three unit trips had been attributed to digital optical isolator (DOI) failures in the MSIV control circuitry that caused the valves to close while the unit was at 100 percent power. The modification involved the control board push-button circuitry, which had controlled a single relay that would in turn actuate a solenoid valve to cause the MSIV to close. The modification changed the push-button circuitry such that a *pair* of relays actuate the solenoid valve; the modification also reduced the number of DOIs in the control circuitry as well as the number of normally energized components (DOIs and relays) required for the MSIVs to remain open. The modification did not impact the MSIVs' ability to close on a main steam isolation signal from the SSPS.

c. Conclusions

The inspector concluded that the modifications were implemented in accordance with governing procedures. The inspectors identified a UFSAR discrepancy that the licensee had independently identified, in addition to others, and had documented them in variation notices for resolution.

E2 Engineering Support of Facilities and Equipment

E2.1 General Comments (37551)

In general, engineering support of plant operations, facilities, and equipment was good. This included engineering support during the RCS leak and NOUE on December 30, 1997. During and following the event, engineers thoroughly researched several design aspects of the RCS loop drain valves and compared them against plant event data to systematically consider and eliminate postulated failure scenarios. Other activities for which good engineering support was noted included reactor startup and low power physics testing.

E3 Engineering Procedures and Documentation

E3.1 General Comments (37551)

An area of minor concern to the inspectors was identified related to engineering documentation in operability evaluations. Two operability determinations reviewed this month included the pressurizer evaluation following the December 29, 1997, safety injection event; and the evaluation of increased flow to the steam generators following the loss of control power to the steam-driven auxiliary feedwater pump trip-and-throttle valve identified in November, 1997 (NRC Inspection Report 50-413,414/97-14). Both evaluations used general terms in describing the acceptability of affected equipment without providing specific background or supporting information related to acceptance criteria that engineers considered.

In the case of the pressurizer evaluation, engineers stated that the calculated hoop stress caused by the sudden increase in pressurizer pressure on December 29, 1997, was acceptable because it was significantly lower than any thermal stresses. No further discussion of the thermal stresses (specific values, assumptions, calculations, acceptance criteria) was provided. The associated engineer later performed a calculation of the assumed thermal stress values with the inspector present, and demonstrated that the stresses were within code allowable limits. For the turbine-driven pump auxiliary feedwater flow evaluation, the acceptability of higher flow rates was based on an electronic mail message from a corporate engineer stating that the higher flows were bounded by accident analysis calculations. The inspector concluded that further NRC review of those calculations (which were not provided in the documentation) was warranted before the associated unresolved item (URI 413/97-14-01) could be closed.

The inspectors discussed the documentation concern with licensee management who indicated that a further review of engineering philosophy in this area may be warranted.

E3.2 1997 Revision to the UFSAR

a. Inspection Scope (37551)

By letter dated September 25, 1997, the licensee submitted the 1997 revision to the UFSAR in accordance with 10 CFR 50.71. This regulation requires that:

> This submittal shall contain all the changes necessary to reflect information and analyses submitted to the Commission by the licensee or prepared by the licensee pursuant to Commission requirement since the submission of the original FSAR or, as appropriate, the last updated FSAR.

10 CFR 50.71 states that the updated FSAR shall be revised to include the effects of:

1. "All changes made in the facility or procedures as described in the FSAR"

2. "Safety evaluations performed by the licensee either in support of requested license amendments...." - Since this category clearly involves NRC staff approval of licensing basis changes, other changes that the staff approved (e.g., topical reports, reliefs to American Society of Mechanical Engineers (ASME) Code sections, exemptions, etc.) but were not conveyed as amendments are also implied.

   ".... or in support of conclusions that changes did not involve an unreviewed safety question" - These are evaluations performed by the licensee in accordance with the provisions of 10 CFR 50.59.

3. "All analyses of new safety issues performed by or on behalf of the licensee at Commission request" - Examples include licensee actions as a result of generic letters, bulletins, etc.

The inspector reviewed the 1997 revision of the Catawba UFSAR in-office and onsite, and met with licensee personnel on November 13, 1997, to compare with requirements and discuss various issues.

b. Observations and Findings

On June 10, 1997, the staff issued an exemption to the license. This exemption authorized the licensee to schedule UFSAR revisions to once per fuel cycle based only upon Unit 2 refueling outages. Since the last Unit 2 refueling outage was completed in early May 1997, the inspector found that the 1997 UFSAR update was submitted in accordance with the schedule specified by the June 10, 1997, exemption.

The regulation does not require the staff to review and approve the changes in the UFSAR, since the changes are presumably previously

approved, or do not require approval. Accordingly, the purpose of the review was to confirm that the changes made in the 1997 revision comply with the provisions of 10 CFR 50.71.

The inspector traced the changes in the 1997 UFSAR revision to documents in the official NRC records (amendments to the operating license, staff letters transmitting safety evaluations, annual 10 CFR 50.59 reports submitted by the licensee, NRC inspection reports, licensee letters, etc.). The inspector confirmed that changes conveyed by the 1997 revision complied with the change scope specified by 10 CFR 50.71.

By license Amendments 153 (for Unit 1) and 145 (for Unit 2), the NRC staff imposed a license condition. The condition stipulated that:

> "Accordingly, the license is hereby amended to authorize revision of the Updated Final Safety Analysis Report (UFSAR) as set forth in the application for amendment by Duke Power Company dated September 21, 1996. The licensee shall submit the revised description authorized by this amendment with the next update of the UFSAR in accordance with 10 CFR 50.71(e)."

The inspector reviewed sections in Chapter 8 of the UFSAR and found that the licensee had fully revised those sections (regarding miscoordinated circuit breakers) in accordance with the approval in the Safety Evaluation associated with Amendments 153 and 145. The inspectors therefore concluded that the licensee had fulfilled the requirement imposed by the license condition conveyed by Amendments 153 and 145.

By Amendments 159 (Unit 1) and 151 (Unit 2), the staff imposed another license condition (the first condition of Appendix D to the operating licenses), which stipulated:

> "This amendment requires the licensee to incorporate in the Updated Final Safety Analysis Report (UFSAR) certain changes to the description of the facility. Implementation of this amendment is the incorporation of these changes in the licensee's application dated March 7, 1997, as supplemented by letters dated April 2, 10, 16, 22, and 28, 1997, and evaluated in the staff's Safety Evaluation dated April 29, 1997."

The inspector reviewed Sections 15.6.3, 15.6.3.1 and 15.6.3.2 of the UFSAR and found that the licensee had substantially revised those sections (regarding the number of steam generator pressure operated relief valves required operable) in accordance with the approval in the Safety Evaluation associated with Amendments 159 and 151. The inspectors therefore concluded that the licensee had fulfilled the requirement imposed by the cited license condition conveyed by Amendments 159 and 151.

The licensee's current process to incorporate all pertinent changes into the 1997 revision, ensuring that it remained a living licensing basis document, was noted as a strength. The most significant example is the incorporation of the analysis of the weir gate drop accident in Chapter 15. This analysis had been missing from the UFSAR since the units were licensed to operate in the mid-1980s. The NRC staff's review result had been published in the form of a footnote to TS 3.9.7, even though the staff did not publish the associated safety evaluation or point out that the analysis was missing. The licensee's incorporation of this analysis in the UFSAR has prompted the staff to take remedial actions on this issue.

c. Conclusions

The inspector concluded that the 1997 revision of the Catawba UFSAR was in compliance with the requirements of 10 CFR 50.71. The inspector also concluded that the licensee has fulfilled the requirements of two license conditions reviewed for each unit. The licensee's current process to incorporate all pertinent changes into the 1997 revision, ensuring that it remained a living licensing basis document, was noted as a strength.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) VIO 50-413,414/96-10-01: Failure to Follow Procedure for Equipment Failure Analysis

This item addressed the licensee's failure to follow procedure SD 3.3.6, Failure Analysis and Trending (FATS), revision 2, which required notification of engineering when as-found instrument conditions exceeded specified out-of-tolerance (OOT) criteria. The licensee's response to the violation, dated September 19, 1996, stated the corrective actions to resolve this issue. These included training, an assessment of the FATS program and OOT reporting, and procedural guidance enhancement to ensure reporting of OOT instrument conditions. The inspector verified performance of the corrective actions which were documented in PIP 0-C96-1761 and completed on November 24, 1997. A sample review of work documentation identified no additional examples of inadequate notification of OOT instruments.

E8.2 (Closed) VIO 50-413,414/97-03-01: Failure to Follow Procedure for Receipt, Inspection, and Handling of Replacement Parts

This item addressed failure to follow procedures for receipt, inspection, and handling of parts from the spare diesel. The diesel was purchased in 1987 to provide replacement parts for the station emergency diesel generators (EDGs). The receipt inspection documentation stated that it would be placed on QC hold status and salvaged parts were to be evaluated against Duke specifications prior to use. The diesel was not stored in a designated QC hold area and although many parts were missing, there was no documentation to verify the required evaluations were performed. Periodic testing and maintenance of the EDGs indicated that EDG

performance was not degraded by the installation of parts from the spare diesel.

The licensee's corrective actions were specified in the violation response dated April 15, 1997. These actions included upgrade of the spare diesel storage building to Level B QC storage criteria, review of the spare diesel specifications against Duke specifications, review of the spare parts upgrade process, and evaluation of parts used from the spare diesel. The inspector reviewed the completed corrective actions which were documented in PIP 0-C97-0322 and closed on May 13, 1997.

E8.3 (Closed) URI 50-413,414/97-10-01: Review Corrective Action for IST Check Valves

(Closed) LER 50-413/97-005: Failure to Perform TS Surveillance

These items addressed inadequate inservice testing (IST) surveillance of ECCS check valves. The valves were not tested for reverse flow as required by the IST program specified by the TS 4.0.5. The issue was unresolved pending the completion of the licensee's extent of condition investigation. This investigation was completed on June 23, 1997, as documented in PIP 0-C97-2050. The licensee identified this deficiency during system review in preparation for an NRC inspection. The cause was determined to be an inadequate IST surveillance procedure which did not include the IST program requirements and criteria for reverse flow testing of ECCS valves 1NI-813, 2NI-813, 1NI-342, and 2NI-342. The valves were reverse flow tested at the first available opportunity and met the IST criteria. The surveillance procedures were revised to include the required test requirements. An extensiveness review was performed to determine if other check valves were not appropriately tested. The failure to reverse flow test the check valves as required by the TS and IST program is a violation of regulatory requirements. This non-repetitive, licensee identified and corrected violation is identified as a non-cited violation, consistent with section VII.B.1 of the NRC Enforcement Policy, and is identified as NCV 50-413,414/97-15-05: Failure to Perform TS Surveillance Due To Inadequate IST Surveillance Procedure.

E8.4 (Closed) VIO 50-413,414/97-09-04: Failure to Follow Procedure, Two Examples

Example one addressed 10 CFR 50.59 screening evaluations for changes to Emergency Procedures which did not include adequate detail of the basis for response to screening questions as required by the applicable procedure. Corrective actions specified by the licensee's response to the violation, dated September 15, 1997, included training and interim measures to assess 10 CFR 50.59 screening performance by the operations procedures group. Corrective action completion was documented in PIP 0-C97-1925, which was closed on October 19, 1997. The inspector reviewed the training guidance and a sample of procedure change 10 CFR 50.59 screening evaluations performed after the training. Adequate detailed justifications were documented for the sample reviewed.

Example two addressed open items and deficiencies identified during the licensee's Design Base Document (DBD) development which were not entered into the PIP tracking system as required by procedure EDM 170, Design Specifications, Revision 5. The licensee's response to the violation, dated September 15, 1997, stated that the DBD open items would be entered into the PIP tracking system. The inspector reviewed PIP 0-C97-1918, updated on June 10, 1997, which listed and addressed the DBD discrepancies previously not entered into the PIP process.

E8.5 (Closed) IFI 50-413,414/97-10-03: Resolution of FWST Set Point Inconsistencies

This item addressed inconsistencies in FWST level set point calculation CNC-1552.08-00-0264, Revision 0, related to flow values and valve operation times. The licensee resolved the inconsistencies in Revision 1 of the calculation. The calculation conclusion, which stated that the containment sump swap over would occur prior to reaching the FWST critical height for vortexing, remained valid.

E8.6 (Closed) IFI 50-413,414/97-10-04: Inaccuracies Caused by Using DEPLET Code on Different Computer Models

This item addressed a discrepancy in flow values derived from the DEPLET code when used on different computers, i.e. IBM RISC 6000 versus the IBM mainframe computer. Although the discrepancy did not impact the results of the FWST level set point calculation, it was unclear if other calculation applications of the DEPLET code had been evaluated. The issue was documented in PIP 0-C97-2417 and stated that the McGuire and Catawba FWST level set point calculations were the only applications of the DEPLET code. The discrepancies were evaluated for each of these applications.

E8.7 (Closed) VIO 50-413,414/96-05-02 (EA 97-179): Inadequate 10 CFR 50.59 Evaluation for Changes to Auxiliary Feedwater (CA) Piping Temperature

This item addressed an inadequate 10 CFR 50.59 screening review for the design temperature change of the CA piping. The screening evaluation incorrectly concluded that a 10 CFR 50.59 safety evaluation was not required for this design change. The licensee's violation response, dated June 16, 1997, identified the root cause and specified corrective actions to resolve this issue. The cause was determined to be the inappropriate use of an interim operability evaluation to make a permanent design change to the plant. Corrective actions included clarification and enhancement of the design change and 10 CFR 50.59 process, improved guidance in 10 CFR 50.59 screening, and training on these programs. Additionally, permanent design changes were made on the CA piping design temperature which included 10 CFR 50.59 evaluations. The corrective actions were being tracked on PIP 0-C97-1926. The remaining training on the revised 10 CFR 50.59 process and guidance was scheduled for the first quarter of 1998. Based on the completed and

scheduled corrective actions, the inspector concluded this item was adequately addressed.

E8.8 (Closed) LER 50-413/95-003, 50-413/95-003-1: Failure to Perform TS Surveillance Due to Unanticipated Interaction of Systems

This item addressed component cooling (KC) containment boundary valves which could adversely impact containment integrity during certain accident conditions because these valves did not meet TS isolation requirements. A containment integrity team was formed to review station containment integrity and surveillance test procedures to assure appropriate testing of containment boundary valves. An extensiveness review identified additional valves which did not meet General Design Criteria (GDC) requirements for containment integrity. The licensee's corrective actions were tracked in PIPs 0-C95-1120, C96-0043, C96-0044, C96-0045, and C96-0046. The review team developed ten positions regarding related containment integrity issues. These were submitted to the NRC for review. The NRC review identified a noncompliance with GDC 57 associated with the containment penetration for the steam turbine CA pump (CAPT) steam supply. The remaining isolation valves discrepancies were addressed by surveillance procedure changes.

The CAPT penetration isolation valves did not meet GDC 57 in that the isolation valves were not locked closed, nor capable of being remotely closed either automatically or manually. This was an original design condition. The licensee submitted an exemption request on September 2, 1997, for these penetrations based on the importance of assuring a steam supply to the CAPTs during certain accident conditions. Although this LER will be closed, this GDC 57 noncompliance issue was identified as an unresolved item associated with dual function isolation valves in a previous inspection NRC report as URI-413,414/97-14-03.
The inspector reviewed the licensee periodic test procedures and verified that the KC boundary valves were being appropriately tested. The NRC review of the exemption request was ongoing.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Tour of Radiological Protected Areas

a. Inspection Scope (83750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program as required by 10 Code of Federal Regulations (CFR) Parts 20.1501, 1502, 1601, 1802, 1902, and 1904. The review included observation of radiological protection activities including personnel monitoring controls, control of radioactive material, radiological surveys and postings, and radiation area and high radiation area controls.

b. Observations and Findings

During tours of the auxiliary building and radioactive waste storage and handling facilities, the inspectors reviewed survey data and performed selected independent radiation and contamination surveys to verify area postings. Observations and survey results determined the licensee was effectively controlling and storing radioactive material.

During plant tours, the inspectors observed that extra high radiation areas (locked high radiation areas) were locked as required by licensee procedures and all other high radiation areas observed were appropriately controlled as required by licensee procedures. The inspectors also inventoried the licensee's extra high radiation area (EHRA) and very high radiation area (VHRA) key control boxes maintained by radiological control and determined that at the time of the inspection, all keys assigned to radiological control for locked EHRAs and VHRAs were accounted for. Dosimetry controls for the EHRAs and VHRAs observed were established in radiation work permits (RWPs) and special radiation work permits (SRWPs) as required by licensee procedures.

The licensee's records showed that the licensee was maintaining approximately 152,360 square feet of floor space as a radiologically controlled area (RCA). During the current outage period, the licensee was maintaining approximately 12,500 square feet as recoverable contaminated area. Records reviewed also showed the licensee maintained less than one percent of the RCA as contaminated area during non-outage periods.

The inspectors reviewed personnel contamination event (PCE) reports prepared by the licensee to track, trend, determine root cause, and determine any necessary follow up actions. The licensee had continued efforts in 1997 to reduce personnel contaminations. Approximately 144 PCEs had occurred to date in 1997 which included 16 contamination events that occurred through December 12 during the Unit 1 outage. The inspectors reviewed and observed licensee efforts to reduce personnel contaminations which included decontamination of areas and components, use of contamination control enclosures, use of personnel contamination clothing, and portable work site ventilation systems. During tours of the facility, the inspectors discussed RWP and SRWP requirements with workers and found those workers interviewed understood their RWP and SRWP requirements. The inspectors observed workers in the auxiliary building and reactor containment building generally adhering to the requirements for properly wearing dosimetry and personnel contamination clothing as specified on the RWPs and SRWPs. The inspectors also observed radiological housekeeping in the facilities to be good.

c. Conclusions

Based on observations and procedural reviews, the inspectors determined the licensee was, except as noted later in section R3.1, effectively maintaining controls for personnel monitoring, control of radioactive

material, radiological postings, and radiation area and high radiation area controls as required by 10 CFR Part 20.

R1.2 Total Effective Dose Equivalent (TEDE) Controls

a. Inspection Scope (83750)

This area was reviewed to determine the adequacy of the licensee's use of process and engineering controls to limit exposures to airborne radioactivity, adequacy of respiratory protection program, licensee's administrative controls for assessing the TEDE in radiation and airborne radioactive material areas, assessments of individual intakes of radioactive material and records of internal exposure measurements and assessments as required by 10 CFR 20.1101, 1201, and 1502. Title 10 CFR 20.1703(a)(3) requires the licensee to maintain and to implement a respiratory protection program.

b. Observations and Findings

The inspectors reviewed and discussed with licensee representatives TEDE exposures for plant and contract personnel for 1997. Through review of selected dose records and discussions with licensee representatives, the inspectors confirmed that all TEDE exposures assigned during the period were below 10 CFR Part 20 regulatory limits.

The use of process and engineering controls to limit airborne radioactivity concentrations in the plant were discussed with licensee representatives, and the use of such controls were observed during tours of the plant. These controls included decontamination of areas, covering contaminated areas, use of worksite ventilation, and other methods used in minimizing worker time in contaminated and airborne areas. The licensee was tracking and trending respirator usage for each RWP to determine the effectiveness of the respiratory protection program. The inspectors reviewed licensee reports that indicated reductions in the use of respirators during recent refueling outages resulting from increased use of engineering controls.

The inspectors reviewed and discussed the licensee's program for monitoring internal dose and reviewed the results of assessments for personnel having indications of positive intakes of radioactive material. The licensee incurred two positive uptakes in 1997 which were still being evaluated by plant personnel for dose assessment. A preliminary review showed the doses were well below regulatory limits.

The inspectors reviewed records for eight employees who had recently worn respiratory protection equipment. The inspectors verified that for the records reviewed, each worker had successfully completed respiratory protection training, was medically qualified, and was fit-tested for the specific respirator type used in accordance with licensee procedural requirements. The inspectors also reviewed air sampling results for

several work evolutions and reviewed worker bioassay results which showed doses were being assigned as required.

The inspectors conducted an in-office review of the licensee's procedure Radiation Protection Directive No. II-1, "Radiation Area Access and Monitoring Devices," for conducting Body Burden Analysis (BBA). The procedure required a body burden analysis be performed for radiation workers terminating employment. However, the procedure stated this requirement may be waived in writing by the Station Radiation Protection Manager or his designee. The inspectors determined the licensee had performed BBAs for radiation workers terminating employment between December 1 and December 15, 1997 or had documentation reflecting why a BBA was not performed on some individuals terminating employment. The inspectors reviewed BBA information for approximately 115 individuals who had been authorized to work in radiation areas and terminated employment during this period. For those records reviewed, the inspectors determined the licensee had performed termination BBAs or documented why termination BBAs were not performed as required by licensee procedures.

c. Conclusions

All personnel exposures to date were below regulatory limits. The licensee had established effective procedures for the use of respiratory protection equipment and was providing training for personnel required to wear respiratory protection equipment.

R1.3 As Low As Reasonably Achievable (ALARA)

a. Inspection Scope (83750)

The inspectors reviewed the licensee's implementation of 10 CFR 20.1101(b) which requires that the licensee shall use, to the extent practicable, procedures and engineering controls based upon sound radiation protection principles to achieve occupational doses and doses to members of the public that are ALARA.

b. Observations and Findings

The inspectors interviewed licensee personnel and reviewed records of ALARA program results and activities. The 1997 site exposure goal was approximately 286 person-rem and included two refueling outages. The licensee was effectively tracking and trending dose rate reduction efforts in 1997 for outage and non-outage tasks.

At the time of the inspection, the licensee accumulated approximately 192 person-rem year-to-date which was consistent with year-to-date estimates. Dose estimates for the three most significant dose contributor work evolutions during the outage included: steam generator inspection at 21 person-rem, mechanical valve work at 9.5 person-rem, and shielding installation and removal at 8.5 person-rem. Planning for these evolutions was reviewed and discussed with ALARA personnel. The

inspectors concluded the ALARA activities for these evolutions were well planned. The inspectors also reviewed documentation which showed that the licensee had installed non-stellite hard facing on 52 valves to reduce source term activity in both units. The licensee had planned similar work on seven other valves with non-stellite during the current outage.

During tours of the facility the inspectors observed radiation protection (RP) technicians controlling access to work areas, in addition to observing RP technicians briefing workers in the work areas as radiological conditions changed during the outage. The inspectors observed good use of shielding, teledosimetry, remote cameras and wireless communications systems for controlling personnel exposures during outage evolutions.

The licensee had recently installed a new remote radiation monitoring system consisting of 80 radiation detectors in the auxiliary building. Final implementation of the remote monitoring system will support up to 300 detectors. This detection system provided live time general area survey data without having to enter the areas to perform surveys.

c. Conclusions

The licensee demonstrated strong management support in the area of ALARA as indicated by source term reduction efforts such as replacement of stellite valve seats, effective chemical shutdown process for the current outage, and by establishing challenging exposure goals. The inspectors viewed the overall ALARA program as a strength.

R2 Status of Radiation Protection and Chemistry Facilities and Equipment

R2.1 Breathing Air and Respirator Review

a. Inspection Scope (83750)

Title 30 CFR 11.121 requires that compressed, gaseous breathing air meet the applicable minimum grade requirements for Grade D or higher quality. Title 10 CFR Part 20 Subpart H provides requirements for respiratory protection programs. Title 10 CFR 20.1501 requires licensees ensure instruments and equipment used for quantitative radiation measurements are calibrated.

b. Observations and Findings

The inspectors reviewed and discussed with the licensee representatives the program for testing and qualifying breathing air as Grade D. The inspectors examined breathing air manifolds for physical integrity and current calibration of gauges. In addition, the inspectors further noted that the supplied air hoods and hoses available for use were compatible per manufacturer's instructions, as were air supplied respirators and

hoses All respiratory protection equipment observed during facility tours was being maintained in a satisfactory condition.

During facility tours, the inspectors noted that survey instrumentation and continuous air monitors observed in use within the RCA were operable and currently calibrated. The inspectors toured the instrument calibration room and discussed the portable instrument program with cognizant personnel. The inspectors determined the licensee had an adequate number of survey instruments available for use during the outage and the instruments were being calibrated and source checked as required by licensee procedures.

c. Conclusions

Review of breathing air testing records verified that the licensee was calibrating breathing air compressor equipment and sampling in-use breathing air systems for certification in accordance with procedural requirements. For the tests reviewed, breathing air met Grade D or better quality requirements. The respiratory protection program was being implemented as required by 10 CFR Part 20 Subpart H. Survey instrumentation had been adequately maintained.

R3 Radiation Protection and Chemistry Procedures and Documentation

R3.1 RWP Discrepancies

a. Inspection Scope (71750)

On December 19, 1997, the inspector received a briefing from RP technicians in preparation for inspection activities in the 1B RHR pump room, a contaminated area. The inspectors detected a discrepancy in the dress requirement listed in the RWP and questioned the RP technicians, who indicated that an error had been made. The inspectors reviewed the RWPs governing work in the RHR pump room, RP briefing slips, procedures governing the use of RWPs, surveys of contaminated areas, and station PIP 0-C97-4262.

b. Observations and Findings

On December 15 and 16, 1997, the inspectors received RP briefings in preparation for entering the 1B RHR pump room to inspect maintenance activities. During both of these briefings, the inspectors were informed that the "J" dress category, consisting of full dress plus extra pairs of gloves and shoe covers or booties, was required; this information was provided on an Auxiliary Building Job Form, Form 405025. On December 19, the inspectors received an RP briefing to return to the 1B RHR pump room to inspect the pump. The inspectors were informed that the "H" dress category consisting of full dress without the extra gloves and booties, was required. The inspectors asked why the dress was not "J" category as indicated on December 15 and 16, 1997. The RP technician indicated that "J" dress category was not listed on the RWP and referred to a survey or

map of the room and saw that access to the RHR pump room involved two step-off pads. The RP technician indicated that the inspectors were correct and corrected the Form 405025 to reflect the "J" dress category requirement.

Several days later, the NRC inquired about the discrepancy and determined that the licensee had initiated PIP 0-C97-4262 to document the results of an investigation they had initiated. The inspector also discussed the issue with an RP supervisor, who indicated that a review had been performed revealing additional examples of inaccurate RWPs, and that immediate steps had been taken to correct the discrepant RWPs. The inspector considered the initiation of the review, as well as actions taken to correct other identified discrepancies, responsive and proactive to address the discrepancy once it had been identified.

The licensee's review indicated that Procedure SH/0/B/2000/003, "Use of the Radiation Work Permit, Revision 00", had not been followed. Step 4.4.1 of the procedure stated that initiating temporary changes to RWPs is permissible under certain conditions: (1) personnel affected by the change are informed; (2) changes are documented in an appropriate logbook or on a survey; and (3) the effective change will be no longer than one shift change. Step 4.4.2 stated "initiate a permanent revision when radiological conditions warrant permanent changes in protective clothing, equipment, or special instructions." The licensee's review revealed incidents whereby changes in RWPs to minimize the spread of contamination during SG eddy current testing were not logged; in addition, associated changes in dress requirements were not incorporated into a permanent revision of the RWP when the changes extended beyond one shift. The licensee did not identify instances whereby the personnel affected by the change were not informed of the updated information.

The 1B RHR pump room, at the 522-foot elevation of the auxiliary building, was located in a contaminated area. Access to the contaminated area was located on the 543-foot elevation of the auxiliary building. The contaminated area on the 543-foot elevation provided access to the emergency core cooling pumps and a spiral staircase down to the RHR pump rooms. A step-off pad was provided at the access to the contaminated area on the 543-foot elevation. The licensee indicated that maintenance activity in the 1B RHR pump room involved extensive work in the pump bowl and that a second step-off pad was placed at the pump room doorway to minimize the spread of contamination outside of the pump room. The inspector asked when the second step-off pad was placed; the licensee could not furnish a record of when it was employed or the specific radiological conditions that prompted it. The inspector considered this lack of documentation an example of poor record-keeping practices.

To independently verify that the inspectors' observation was the only example whereby old information was provided during the RP briefing, the inspectors reviewed records associated with the 1B RHR pump maintenance. Numerous additional examples were identified whereby "H" dress was specified for maintenance and inspection activities instead of "J" dress.

indicating the personnel affected by the change were *not* informed of the change in dress category.

Although the inspectors did not identify any clean area or personnel contamination events as a result of workers using "H" dress rather than "J" dress, there were multiple instances whereby workers received obsolete information because the RWP governing work in the 1B RHR pump room was not revised to reflect changes in radiological conditions and associated use of the "J" dress category. These occurrences indicated a problem with procedural adherence and constitute a violation of the licensee's administrative procedure regarding the use of RWPs, characterized as Violation 50-413/97-15-06: Failure to Revise RWPs to Reflect Changes in Dress Requirements As a Result of Changing Radiological Conditions.

c. Conclusions

The inspector considered the lack of documentation associated with the placement of a second step-off pad in the 1B RHR pump room an example of poor record-keeping practices. A violation was identified for failure to revise an RWP to reflect permanent changes in radiological conditions. The licensee's initiation of a review to identify similar discrepancies, as well as actions taken to correct them, was responsive in addressing the problem.

R5 Staff Training and Qualification in Radiation Protection and Chemistry

R5.1 Training of RP Technicians

a. Inspection Scope (83750)

The inspectors reviewed training of RP Technicians to determine whether the technicians had been provided adequate training in procedures to minimize radiation exposures and control radioactive material as required by 10 CFR Part 19.12.

b. Observations and Findings

The inspectors reviewed training requirements and records for the RP technicians. The inspectors also reviewed the continuing training curriculum for the period January 1, 1997, through December 10, 1997, which included topics to minimize radiation exposure. During facility tours the inspectors interviewed RP personnel and observed work practices to determine the effectiveness of radiation protection training.

c. Conclusions

Based on the training activities reviewed and interviews, the inspectors determined the radiation protection technicians had been provided an adequate level of training to perform routine activities involving radiation and control of radioactive material.

P1 Conduct of EP Activities

P1.1 Notification of Unusual Event (NOUE) on December 30, 1997

a. ection Scope (71750)

The inspector observed emergency response activities during the NOUE on December 30 - 31, 1997. This emergency action level was declared following an excessive RCS leak on Unit 1 which required a plant cooldown.

b. Observations and Findings

The TSC and OSC were both manned beginning at 6:20 p.m. on December 30, 1997, following indications of excessive RCS leakage (approximately 40 gallons per minute) on Unit 1. The inspectors were onsite at the time of initiation and observed the emergency response activities from both the control room and the TSC. OSC activities were observed via a video conference monitor provided in the TSC. The TSC became operational at 7:30 p.m. after it was fully manned; emergency coordination was then transferred there from the control room. The inspectors considered that 70 minutes seemed long for TSC activation following initial notice to staff it. This was discussed with the TSC Site Emergency Coordinator (SEC) after the event who indicated that the TSC was fully manned before 7:30 p.m., but control was not transferred earlier because a decision had not been made as to which of the qualified SEC personnel would take over. The inspector noted that the 70 minutes was within 75-minute criteria established in licensee procedures and NRC guidance.

Good command and control was noted throughout TSC operation, and plant status update briefings were effective. The various TSC activities were conducted professionally, including technical support activities and NRC, State, and county notifications. The video conferencing capability between the TSC and OSC was effective. Radiological protection activities were also conducted appropriately.

In general, correct information regarding plant status was effectively communicated and logged in the TSC. One exception was noted concerning pressurizer pressure when RCS cooldown and depressurization activities were placed on hold. TSC personnel incorrectly communicated the pressure as 1695 psig and this value was entered in the computer log. As a result, this incorrect information was communicated by the inspector to offsite NRC personnel. Later discussions with TSC personnel indicated that the actual value was 1300 psig, and the incorrect value was taken from a narrow-range pressure indication when a wide-range instrument should have been referenced. This error had minor significance at the time but could create confusion and cause inappropriate response given a different set of circumstances. The inspector noted that this error was similar to a mistake made during a post-trip review associated with Unit 1 a day earlier (discussed in Section O4.3). More licensee attention to detail was warranted in this area.

c. Conclusions

Emergency response activities were conducted well during the Notification of Unusual Event on December 30-31, 1997. More attention to detail was warranted concerning the use of wide-range versus narrow-range plant indication during and following events.

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 January 14, 1998. 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

NRC

N. Economos
D. Forbes
R. Moore
N. Stinson

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 55050:	Nuclear Welding General Inspection
IP 61726:	Surveillance
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73753:	Inservice Inspection
IP 83750:	Occupational Exposure
IP 92901:	Followup - Operations
IP 92903:	Followup - Engineering
IP 92902:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-413,414/97-15-01	URI	Failure to Follow Procedures Resulting in Inadvertent Injections of ECCS Fluid into the RCS (Section O4.2)
50-413/97-15-02	URI	Appropriateness of Operator Actions During Rod Testing (Section O4.3)
50-413/97-15-03	URI	Anti-Reverse Rotation Devices Not Installed in the 1D Reactor Coolant Pump (Section M7.1)
50-413,414/97-15-04	NCV	Failure to Have Adequate Test Procedures for SSPS Logic Associated With Feedwater Isolation and P-10 Permissive Circuits (Section M8.1)
50-413,414/97-15-05	NCV	Failure to Perform TS Surveillance Due to Inadequate IST Surveillance Procedure (Section E8.3)
50-413/97-15-06	VIO	Failure to Revise Radiation Work Permits to Reflect Changes in Dress Requirements As a Result of Changing Plant Conditions (Section R3.1)

Closed

50-414/94-002-01	LER	Reactor Trip Breakers Opened Due to Component Failure (Section O8.1)
50-413/97-008	LER	Inadequate Solid State Protection System Surveillance Testing (Section M8.1)
50-413,414/96-10-01	VIO	Failure to Follow Procedure for Equipment Failure Analysis (Section E8.1)

50-413,414/97-03-01	VIO	Failure to Follow Procedure for Receipt, Inspection, and Handling of Replacement Parts (Section E8.2)
50-413,414/97-10-01	URI	Review Corrective Action for IST Check Valves (Section E8.3)
50-413/97-005	LER	Failure to Perform TS Surveillance (Section E8.3)
50-413,414/97-09-04	VIO	Failure to Follow Procedure, Two Examples (Section E8.4)
50-413,414/97-10-03	IFI	Resolution of FWST Set Point Inconsistencies (Section E8.5)
50-413,414/97-10-04	IFI	Inaccuracies Caused by Using DEPLET Code on Different Computer Models (Section E8.6)
50-413,414/96-05-02	VIO	Inadequate 50.59 Evaluation (EA-97-179) for Changes to Auxiliary Feedwater (CA) Piping Temperature (Section E8.7)
50-413/95-003 and 50-413/95-003-1	LER	Failure to Perform TS Surveillance Due to Unanticipated Interaction of Systems (Section E8.8)

LIST OF ACRONYMS USED

1EOC10	Unit 1 Refueling Outage
AC	Alternating Current
ALARA	As Low AS Reasonably Achievable
AP	Abnormal Procedure
ASME	American Society of Mechanical Engineers
BBA	Body Burden Analysis
CA	Auxiliary Feedwater
CAPT	Steam Turbine CA Pump
CFR	Code of Federal Regulations
CGA	Compressed Gas Association
DBD	Design Basis Document
DOI	Digital Optical Isolator
DRPI	Digital Rod Position Indication
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generators
EHRA	Extra High Radiation Area
ESF	Engineered Safety Feature
°F	Degrees Fahrenheit
FATS	Failure Analysis and Trending

FSAR	Final Safety Analysis Report
FWDS	Field Weld Data Sheets
FWST	Refueling Water Storage Tank
GDC	General Design Criteria
GPM	Gallons Per Minute
IST	Inservice Testing
KC	Component Cooling
LER	Licensee Event Report
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NC	Reactor Coolant
NCDT	Reactor Coolant Drain Tanker
NI	Safety Injection
NOUE	Notification of Unusual Event
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSD	Nuclear System Directive
NSSS	Nuclear Steam Supply System
OAC	Operator Aid Computer
OOT	Out of Tolerance
OSC	Operations Support Center
PCB	Power Circuit Breaker
PCE	Personnel Contamination Event
PIP	Problem Investigation Report
PORC	Plant Operations Safety Committee
PPM	Parts Per Million
PSIG	Pounds Per Square-Inch Gage
QC	Quality Control
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RII	NRC Region 2 Office
RN	Service Water
RP	Radiation Protection
RWP	Radiation Work Permit
RV	Reactor Vessel
SG	Steam Generator
SRWP	Special Radiation Work Permit
SSPS	Solid State Protection System
TEDE	Total Effective Dose Equivalent
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
V	Volts
VDC	Volts - Direct Current
VHRA	Very High Radiation Area
VIO	Violation
WO	Work Order