UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-413/96-02 and 50-414/96-02

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-413 and 50-414 License Nos.: NPF-35 NPF-52

Facility Name: Catawba Nuclear Station Units 1 and 2

Inspection Conducted: February .., 1996 - March 23, 1996

Inspectors: R. J. Freudenberger, Senior Resident Inspector Date Signed 4/22/96

R. Baldwin, Region II, Reactor Engineer (paragraphs 2.2, 2.3, 2.6, 2.7, and 2.8)
P. Balmain, Resident Inspector
N. Economos, Region II, Reactor Inspector (section 3.2)
D. Forbes, Region II, Radiation Specialist (paragraphs 5.2-5.13)
E. Girard, Reactor Inspector (section 3.1)
W. Holland, Region II, SRI Sequoyah (paragraphs 2.4, 2.5, 2.6, 2.7, and 2.9)
L. King, Region II, Reactor Inspector (section 4.6)
M. Miller, Region II, Reactor Inspector (section 3.2)
R. Moore, Region II, Reactor Inspector (paragraph 4.6)
C. Rapp, Region II, Reactor Inspector (paragraph 3.2)
E. Testa, Region II, Senior Radiation Specialist (paragraphs 5.2-5.13)
R. Watkins, Resident Inspector

Approved by: R. V. Crlenjak, Chief
Projects Branch 1
Division of Reactor Projects
Date Signed 4/22/96

SUMMARY

Scope: Inspections were conducted by resident and regional inspectors in the areas of plant operations, maintenance, engineering and plant support. As part of this effort, backshift inspections were conducted.

ENCLOSURE 2

Results:

Plant Operations The primary cause of an inadvertent opening of a steam generator power operated relief valve (PORV) while placing Unit 2 on line was assessed as an operator knowledge deficiency (paragraph 2.3). The Technical Specification Interpretations concerning Emergency Diesel Generator fuel oil day tank manual bypass valve alignment lack adequate supporting analysis (paragraph 2.5). The Technical Specification Interpretation concerning Emergency Diesel Generator fuel oil tank manual bypass valve alignment lacked adequate supporting analysis (paragraph 2.5). Control room observations indicated that operators were attentive to plant status conditions, operators displayed a questioning attitude, and turnover briefings were appropriately formal. Some congestion and added noise level was noted following turnover briefings due to informal discussions. Operator Logs were sparse (paragraph 2.6). A number of handwritten operator aids were identified in the Auxiliary Building (paragraph 2.8). Operations management initiatives as a result of self-assessments appeared to be focused on appropriate areas (paragraph 2.9). A Nuclear Safety Review Board meeting provided constructive feedback on the licensee's containment integrity assessment and Unit 2 systems' response during the February 6, 1996, loss of offsite power event (paragraph 2.10).

Maintenance Contrary to their January 23, 1995, letter, the licensee had not completed their implementation of Generic Letter (GL) 89-10 for Group 1 Motor Operated Valves (MOVs). Four issues requiring specific licensee attention were identified. These have been identified as Inspector Followup Items (IFIs) 96-02-01 through -04 (paragraphs 3.1.4 and 3.1.5). The licensee's lack of promptness in resolving the issues associated with IFIs 03 (MOV operating thrust) and 04 (unpredictable behavior or pressurizer PORV) was noted. The licensee had not undertaken any independent assessment of their implementation of GL 89-10, which was considered a weakness (paragraph 3.1.7). Strengths were observed in that: (1) the licensee calculations reviewed were complete, accurate, and logically formulated; (2) the licensee's MOV engineering staff were well-qualified and had a good understanding of most industry issues; and (3) the licensee had shown initiative and developed good engineering approaches to resolving the issues involved in GL 89-10 (paragraph 3.1.8). In general, the licensee's actions to address previous issues described in the Integrated Performance Assessment Program Report are having a positive effect on the conduct of maintenance as evidenced by the Self-Assessment Process, the Electrical Support System

Critiques, and Operations involvement in maintenance. However, because some of these programs are relatively new, it was not possible to observe clear evidence of their effect on performance (paragraphs 3.2.1 - 3.2.10). Multiple instrument failures were attributed to severe cold weather for a third consecutive season, indicating that weaknesses in the licensee's cold weather protection program continue to exist (paragraph 3.4). The installation of pressure transmitters with plastic shipping plugs, rather than permanent metal plugs, in the unused conduit ports was characterized as a poor work practice (paragraph 3.5).

Engineering

Unresolved Item 96-02-05 was identified pending the licensee's completion of a reportability and failure evaluation for a previous stroke time failure of a Unit 1 Main Steam Isolation Valve. The licensee's initial evaluation of the failure which had been ongoing for several months was of poor quality and lacked rigor (paragraph 4.1). Unresolved Item 96-02-06 was identified pending further NRC evaluation of an auxiliary feedwater piping allowable temperature increase, given that it apparently placed auxiliary feedwater system operation outside the design basis (paragraph 4.3). The intermittent failures of the Unit 1 turbine-driven auxiliary feedwater pump trip and throttle valve for approximately two years was identified as an example of untimely equipment problem resolution (paragraph 4.5). Plant practices, procedures, and parameters for the Spent Fuel Pool (SFP) were consistent with the licensing basis description. The SFP design included connections which could result in draw down of the SFP below the level required for shielding, although the racked fuel assemblies would remain covered. This deviated from the Final Safety Analysis Report (FSAR) description of the design and the design recommended by industry standards. Accordingly, this was identified as Violation 96-02-07 (Example 1) for failure to revise the FSAR. The decay heat loads resulting from routine full core off load during refueling had been analyzed and were within the capacity of the SFP cooling system (paragraph 4.6).

Plant Support

Violation 96-02-07 (Example 2) regarding not revising the FSAR to reflect the use of activated charcoal instead of silver zeolite to sample gaseous effluent, and one minor FSAR inconsistency were identified (paragraph 5.2). The licensee had implemented an effective Water Chemistry Program to ensure the safe and reliable operation of the plant (paragraph 5.3). The licensee's Annual Radioactive Effluent Release Reports satisfied Technical Specification (TS) requirements (paragraph 5.5). The licensee had an effective program in place to monitor radiological effluents

and detect radiation, etc. due to plant operations and the Annual Radiological Environmental Operating Report was in compliance with the TSs. In 1994, plant operations caused minimal impact to the environment and virtually no dose to the general public from those effluents (paragraph 5.6). The licensee's Radiation Protection program was effectively implemented (paragraph 5.12). The licensee continued to implement internal and external exposure programs with all exposures less than 10 CFR Part 20 limits (paragraphs 5.9 and 5.10). The audit and appraisal program was adequate in identifying potential issues. Contamination control and overall radiological housekeeping practices were also considered adequate (paragraph 5.12). The licensee was improving upon ALARA initiatives, particularly in the area of shutdown chemistry to reduce outage doses (paragraph 5.13). The licensee had also made progress in eliminating hot spots in the plant (paragraph 5.12). Violation 96-02-09 was identified regarding a failure to lock a key box containing keys to Locked High Radiation Areas (Paragraph 5.9).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 9.0

1.0 PERSONS CONTACTED

Licensee Employees

Addis, B., Training Manager
* Copp, G., NRIA Manager
Coy, S., Radiation Protection Manager
* Forbes, J., Engineering Manager
Funderburk, W., Work Control Superintendent
Harrall, T., IAE Superintendent
Kimball, D., Safety Review Group Manager
* Kitlan, M., Regulatory Compliance Manager
* Lowery, J., Compliance Specialist
McCollum, W., Catawba Site Vice-President
Miller, W., Operations Superintendent
Nicholson, K., Compliance Specialist
* Patrick, M., Safety Assurance Manager
* Peterson, G., Station Manager
Propst, R., Chemistry Manager
Rogers, D., Mechanical Superintendent
Tower, D., Regulatory Compliance Engineer

* Attended ex t interview.

Other licensee employees contacted included technicians, operators, mechanics, security force members and office personnel.

2.0 PLANT OPERATIONS (NRC Inspection Procedures 40500, 71707 and 92901)

Throughout the inspection period, control room observations and facility tours were conducted to observe operations activities in progress. During these inspections, discussions were held with operators, supervisors, and plant management. Some operations activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections evaluated whether the facility was being operated safely and in conformance with license and regulatory requirements. In addition, the inspection assessed the effectiveness of licensee controls and self-assessment programs in achieving continued safe operation of the facility.

2.1 PLANT STATUS

Unit 1 Summary

Unit 1 began the report period operating at approximately 100% power. On February 14 a power reduction to 46% power was completed to facilitate

main electrical bus repairs. On February 19 main bus repairs were completed and a power increase was initiated. The unit reached 100% power on February 20. On March 15 a power reduction to approximately 90% power commenced to facilitate the end of life moderator temperature coefficient measurement. The unit returned to 100% power on March 16 and operated at essentially full power through the end of the inspection period.

Unit 2 Summary

Unit 2 began the report period shutdown in Mode 5 to complete main electrical bus repairs. The unit entered Mode 4 on February 14 and Mode 3 on February 15. The unit was started up and entered Mode 1 on February 16. On February 17 the main turbine tripped while it was being rolled up to speed. The unit reached full power on February 18 and operated at essentially full power through the end of the inspection period.

2.2 UNIT 2 TURBINE TRIP

On February 17, 1996, the Unit 2 main turbine tripped while it was being rolled up to speed. The turbine tripped on low lube oil pressure. The inspectors reviewed PIP C96-0430 which documented the results of a Failure Investigation Process review of the trip performed by the licensee and discussed the issue with the responsible system engineer. The FIP team postulated five different failure modes. All but one of the failure modes that could have caused the problem were eliminated. The most plausible failure mode was that the lube oil booster pump needs adjustment for flow due to normal wear over the life of the pump. Interim adjustments were made to increase lube oil pressure during low speed operation and allow plant startup. Although the licensee's evaluation was not complete, the inspector determined that the licensee had taken a good approach in determining the root cause and resolving the problem. The final corrective action will not be able to be implemented until the turbine is offline. A final flow balance of the lube oil system was planned to be performed at the next available opportunity.

2.3 STEAM GENERATOR PORV OPERATION WHILE PLACING MAIN TURBINE ON LINE

On February 18, 1996, the "A" S/G PORV operated while placing the Unit 2 Main Turbine on line. The inspector reviewed PIP C96-0432 to understand the event. The inspector determined from the PIP review and subsequent review of OP/2/B/6300/01, Turbine Generator, that step 2.60 was not clear. The step requires the operator to ensure that the megawatt feedback loop is disabled. During the performance of this step the operator determined that the megawatt feedback was not disabled. When the operator disabled this circuit the operator recognized that target megawatts changed from 60 MW to 183 MW. Review of OP/2/B/6300/01, step 2.60 did not provide guidance or a note to remind the operator of

specific plant responses prior to this step. When the operator reduced the target to 60 MW and placed the system to GO, the turbine control system started reducing turbine load to 60 MW at a decreasing rate of 12 MW/min. This decrease in turbine load caused steam generator pressure to increase. Steam dumps were in the Tave mode of operation. There was no arming signal present to actuate steam dump operation. Ultimately the "A" S/G PORV opened. The operator noticed that the PORV opened and placed the Turbine in HOLD, stopping the turbine load decrease.

The licensee's training department conducted on-shift training concerning the operation of the turbine control panel MW IN and MW OUT position. The inspector attended one of these training sessions and determined the training provided pertinent and necessary information for the operation of the turbine control panel. During the training the inspector noted that the control system functions in such a way that a bumpless transfer would occur and the turbine control system operated as designed.

Licensee management responded quickly by informing operators using on-shift training rather than waiting for Requalification Training to review lessons learned from the event. The inspector concluded that enhancements to procedure OP/2/B/6300/01 concerning the operation of the main turbine control panel when transferring from MW IN to MW OUT would be appropriate and a deficiency in operator knowledge of system operation was the cause of the S/G PORV operation.

2.4 ESSENTIAL POWER REALIGNMENT DIFFICULTY

On February 25, 1995, the licensee attempted to realign the power supply for the Unit 1, B train essential power board from the alternate power supply to the normal power supply. Realignment required that D/G 1B be paralleled to the essential power board to carry loads prior to opening the alternate breaker. After the D/G was aligned to the board, several attempts to parallel to the normal supply were unsuccessful. Also, attempts to parallel back to the alternate power supply were unsuccessful. This condition resulted in the D/G being the only power source available for carrying loads on the B train essential power board. The licensee immediately commenced troubleshooting of D/G 1B sync check relay to determine the cause of the problem. The initial checkout of the relay did not identify any problems. During subsequent troubleshooting, the licensee was able to parallel the essential power board back to the normal power supply; however, the cause of the initial problem was not identified.

The licensee wrote PIP C96-0480 to address the issue. In addition, engineering reviewed the current essential board alignment and determined the B train essential power supply was operable. The inspector reviewed the licensee's actions for the time frame the problem existed. He determined that the required Technical Specification LCO ACTION was entered during the period from identification of the problem

until the normal power supply to the essential bus was restored. In addition, the inspector reviewed the PIP operability evaluation dated February 29, 1996, and considered it adequate. A review of FSAR Section 8.3.1 supported the licensee's operability determination.

The PIP also noted that no root cause had been identified for the problem of not being able to parallel D/G 1B with offsite power. A followup work order was initiated to further investigate the problem.

2.5 2B DIESEL GENERATOR FUEL OIL DAY TANK MANUAL BYPASS VALVE ALIGNMENT

On February 26, 1996, the inspector became aware that the D/G 1B automatic fuel oil transfer valve from the 7-day tank to the day tank was inoperable. The valve was inoperable due to level switch problems on the day tank. Technical Specification LCO 3.8.1.1.a.3 requires "a separate fuel transfer valve" to be OPERABLE during unit operation in MODES 1, 2, 3, and 4. The licensee had opened the manual by-pass valve from the 7-day tank to the day tank to satisfy the TS requirement. The inspector questioned the operators regarding this alignment and was informed the configuration was acceptable based on a TS Interpretation. The inspector requested that the licensee provide the documentation supporting the TS Interpretation.

On February 27, 1996, the inspector noted that PIP C96-0487 had been written late the previous day identifying that station documents were not consistent with D/G operability requirements. Specifically, the Design Basis Document, Technical Specification Interpretations and the Annunciator Response Procedure for High Level in the day tank had conflicting data about what was required to keep the D/G operable when the automatic makeup (fuel oil transfer) valve to the day tank fails or is not working properly.

Over the next three days, the inspector reviewed the specific issues identified in the PIP, including a Technical Specification operability notification sheet dated February 27, 1996. Discussions were held with the system engineer and engineering management regarding actions taken in response to the PIP. The licensee determined that the issues identified related to documentation discrepancies only and clarifications to the Design Basis Document and Annunciator Response Procedures were all that was required as corrective action. The inspector reviewed the discrepancies, proposed corrective actions, and FSAR section 9.5.4. It was concluded that the licensee's actions were adequate and the D/G was operable with the manual fuel transfer bypass valve open. However, the inspector also concluded that the Technical Specification Interpretation in place on February 26, 1996, lacked adequate supporting analysis.

2.6 CONTROL ROOM OBSERVATIONS

The inspectors conducted several control room tours, including

observations of operations shift turnovers. The following observations were noted:

Control room operators were attentive of plant status conditions. Examples included continuous control panel monitoring, consistency in annunciator acknowledgements and repeat-backs, and consistency in use of annunciator response procedures. Nonetheless, the inspectors identified three indicator lights not lit on control room panels. One annunciator light associated with the cross-feed of Unit 1 essential busses from Unit 2, which should be illuminated during cross-feed, was found to be dark. This was pointed out to the Unit 1 RO. He found that the bulb was burned out when he tested the annunciators and the bulb was replaced. The other two lights were on the balance of plant back panel on Unit 1. The inspector pointed out to the control room SRO that valve 1VQ15 indication was not lit. The control room SRO verified that the bulb was burned out. Later that same day the inspector verified that the valve 1VQ15 indicator bulb was replaced and found valve 1VP6 not indicating. The control room SRO verified that the bulb was popped out of the fixture. The bulb was reinserted and valve position was found to be appropriate.

Operators displayed a good questioning attitude when confronted with conditions or situations that were not clear. One example included operators challenging performance of test activities scheduled for one shift involving main turbine valve testing and control rod movement testing on both units. Some evolutions were subsequently rescheduled to better balance the evolutions over several shifts.

The control room SRO maintained appropriate overview of control room activities. However, during periods of increased activity, the control room SRO appeared to be very busy in monitoring activities for both units and also coordinating other business in the "at the controls" area.

Operations shift turnovers were held in the control room and were conducted in a formal manner. Inconsistencies noted between the shifts included the use of microphones and the review of fire brigade member duties. After the turnovers were completed, the inspector noted that several crew members held conversations in the turnover area which increased the control room noise levels significantly. These observations were communicated to the licensee and action was taken to minimize congestion in the control room following turnovers before the end of the report period.

The inspectors noted that the logs lacked detail. Little information regarding equipment operability status was documented. In order to determine operability status of a particular piece of equipment, a number of separate logs needed to be reviewed.

2.7 PLANT TOURS/MEETING OBSERVATIONS

The inspector conducted plant tours including both turbine buildings, safety-related pump areas in the auxiliary building, and several tours of the emergency diesel generator rooms. Housekeeping in the turbine building areas was considered to be very good. In addition, Unit 1 or Unit 2 designations throughout the plant were obvious. Housekeeping in the auxiliary building was good; however, several housekeeping discrepancies were noted. Examples included: burnt out lights in pump rooms; yellow tape on line adjacent to valve 1NV289 and on valve 1VI3222 in the Unit 1, B train charging pump room and the Unit 1, B train safety injection pump room, respectively; contamination boundaries extending around some charging and safety injection pumps; and several remote valve operators with unclear open/close valve indications. Examples of the unclear remote valve indications were remote operators for valves 1NV285, 1NV265, 1NV256, 1NV328, and 2NV265.

The inspector attended several plant daily meetings, including the 6:30 a.m. Operations Shift Manager Turnover Meeting and the 8:30 a.m. Site Direction Meeting. The meetings provided appropriate discussion and direction for upcoming activities. The inspector observed good safety focus in the Site Direction Meeting by plant management. During the meeting on February 29, 1996, the inspector observed a good questioning attitude by a licensee manager in questioning whether appropriate post maintenance testing was completed on auxiliary feedwater valve 1CA015A after it failed to close during testing.

2.8 COMPONENT LABELLING

The inspectors performed a walkdown of portions of the charging systems. During the walkdown of the charging pumps, evidence of hand printed operator aids was noted. One valve did not have any label on it other than the hand wheel. The valve (2NV-267) did have a hand printed number on it. During the walkdown of the Unit 1 valves on the 1A charging pump and the 1B charging pump the inspector noticed handwritten operator aids on a number of gauges. Each of these gauges had the silver tab label that was attached in accordance with the facility labelling program. The Unit 1 gauges and valves that had handwritten operator aids were as follows:

Gauge NV PMP 1A MTR CLR FLO (8280 handwritten on bracket)
Gauge NV PMP 1B MTR CLR FLO (8730 handwritten on bracket)
Gauge NV PMP 1A SPD RED AND BRG OIL CLR (8330 handwritten on bracket)
Gauge NV PMP 1B SPD RED AND BRG OIL CLR (8780 handwritten on bracket)
Gauge 1NVPG 5550 (5550 hand written on wall bracket)
Gauge 1NVPG 5790 (5790 hand written on wall bracket)
Valve 1NV265 (remote hand operator had valve number written on the handwheel)

The inspector also noted that the flow element (1NFG 5770) did not have

a label on the equipment in the plant as is designated on drawing CN-1554-1.7.

Additionally, handwritten labels on the component cooling water and jacket cooling water system piping on both Unit 1 and 2 Emergency Diesel Generators were identified. The following are examples of handwritten operator aids found in the Emergency Diesel Generator Rooms. These were consistent with the nomenclature listed on the tag:

Gauge 2RN TH 589
Gauge RN IN KD HX
Gauge RN OUT KD HX
Gauge KD OUTLET

No misoperation or other adverse consequence was attributable to the hand written operator aids observed. The inspector communicated the observations to the licensee for resolution.

2.9 OPERATIONS SELF-ASSESSMENTS

The inspector reviewed ongoing activities associated with assessment of operations performance. Discussions were held with the Operations Special Project Manager and Operations Superintendent regarding ongoing efforts to improve operations performance. In addition, recent assessment reports were reviewed. The inspector noted that operations recognized that improvement was needed in the areas of communication and quality of work. Several initiatives had been implemented including observation tours by operations management to assess job performance, and creation of a operations group to help schedule control room activities. The inspector considered these initiatives to be focused on the appropriate areas.

2.10 NUCLEAR SAFETY REVIEW BOARD

On February 28-29, a meeting of the Nuclear Safety Review Board (NSRB) was conducted at the McGuire Nuclear Station. The Catawba resident inspector attended the meeting on the afternoon of the second day, during which time an overview of Catawba performance and results of Catawba plant tours by NSRB members were presented. The inspector also attended a presentation to the NSRB of the results of a station effort to resolve various containment integrity concerns that arose at Catawba in the fall of 1995.

The NSRB provided some valuable critical feedback on recent efforts to account for all containment penetrations for integrity. Board members suggested that the basis for the review of penetrations, which consisted of a review of plant drawings and diagrams, could have been more rigorous if a walkdown had been conducted to verify the accuracy of the drawings and diagrams. The NSRB also discussed various issues that arose from the February 6, 1996, Loss of Offsite Power, specifically the

appropriateness of systems' responses to the initiating and cascading events and the fidelity of the control room simulator for training applications. Some Board members also provided positive feedback in the area of housekeeping and plant material condition. The inspector concluded that the NSRB's discussions of the Catawba site were insightful, probing, and constructive.

3.0 **MAINTENANCE** (NRC Inspection Procedures TI 2515/109, 62700, 62703, 61726 and 92902)

Throughout the inspection period, maintenance and surveillance testing activities were observed and reviewed. During these inspections, discussions were held with operators, maintenance technicians, supervisors, engineers and plant management. Some maintenance and surveillance observations were conducted during backshifts. The inspections evaluated whether maintenance and surveillance testing activities were conducted in a manner which resulted in reliable, safe operation of the facility and in conformance with license and regulatory requirements.

3.1 IMPLEMENTATION OF GENERIC LETTER 89-10 (TI 2515/109)

3.1.1 BACKGROUND AND INSPECTION CRITERIA

This inspection continued an NRC assessment of the licensee's implementation of GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." Previous inspections were documented in NRC Inspection Reports 50-413,414/92-15 and 94-05.

The licensee committed to implement GL 89-10 in stages for motor-operated valves (MOVs) with active safety functions. The subject valves were categorized as either Group 1 (important to core melt) or Group 2 (not important to core melt). The licensee committed to complete their commitment for the Group 1 and low capability margin Group 2 MOVs by December 28, 1994. The remainder of the Group 2 MOVs were to be completed by the end of refueling outage 2EOC8 (scheduled May 1997). In a letter dated January 23, 1995, the licensee informed the NRC that they had completed their commitment to implement GL 89-10 for their Group 1 and low margin Group 2 MOVs. This inspection generally focused on Group 1 and low margin Group 2 MOVs because of their reported completion.

In performing this inspection the inspectors utilized guidance described in an NRC memorandum of July 12, 1994, "Guidance on Closure of Staff Review of Generic Letter 89-10 Programs" and in Temporary Instruction (TI) 2515/109, "Inspection Requirements for Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance."

The inspection was conducted through a review of the licensee's GL 89-10 implementing documentation and through interviews with involved licensee

personnel. Documents reviewed included the related program, thrust and torque calculations, design-basis documents, applicable FSAR sections, special studies, tests, flow diagrams, valve drawings, maintenance records, engineering evaluations, and trend reports. To assess details of the licensee's implementation of GL 89-10, the inspectors selected the sample of valves tabulated following this paragraph for particular attention. These valves were selected as representative of the population of valves for which implementation was reported complete, with selection biased toward valves which the licensee had determined to have lower capability margins. While emphasis was generally placed on these valves during the inspection, other valves were addressed in inspecting some aspects of the licensee's GL 89-10 implementation because of the valves' greater importance to the area being assessed.

Valve No.	Size	Type	Functional Name
1NI115A	2 in.	Globe	Safety Injection Pump Miniflow Isolation Valve
1KCC37A	6 in.	Globe	Component Cooling Train A Miniflow Isolation Valve
2CA015A	6 in.	Gate	Aux. Feedwater Pump Suction from Nuclear Service Water Isolation Valve
1CA042B	4 in.	Gate	Aux. Feedwater Pump Discharge to Steam Generator D Discharge Valve
1NC031B	3 in.	Gate	Pressurizer PORV Block Valve
2ND001B	12 in.	Gate	Residual Heat Removal Pump Suction Isolation Valve
1NI009A	4 in.	Gate	Charging Pump Discharge to Cold Leg Injection Isolation Valve
2NI100B	8 in.	Gate	RWST to Safety Injection Pump Suction Isolation Valve
1RN250A	6 in.	Gate	Train 1A Supply to Auxiliary Feedwater Pump Isolation Valve
2SV27A	6 in.	Gate	Steam Generator (S/G) B PORV Block Valve
1KCC01A	20 in.	B'fly	Auxiliary Building Non-Essential Return Header Isolation

3.1.2 PROGRAM SCOPE

Catawba's program scope currently consisted of 282 Group 1 and 192 Group 2 MOVs for a total of 474 of which 90 had been dynamically tested. The scope was originally reviewed and accepted by NRC inspectors (see

Inspection Report 92-15). At that time the program included 336 Group 1 and 204 Group 2 for a total of 540 valves. Noting a difference of 66 MOVs in the totals the inspectors reviewed the MOVs that had been removed. Licensee personnel stated that these MOVs had been removed from the program either because they did not perform an active safety function or because they were not valve types addressed by GL 89-10 (gate, globe, or butterfly valves). Catawba Generic Letter 89-10 MOV List CNM-1205.19-0081, Rev. 0, identified the licensee's GL 89-10 Group 1 and 2 MOVs, as well as the valves that had been removed (not included in either group). From a review of the list the inspectors found that almost a third of the removed valves were ball, plug, or diaphragm valves. In a letter dated August 5, 1993, the NRC staff agreed with the licensee that GL 89-10 focused on gate, globe, and butterfly valves but stated that the licensee should have justification for the capabilities of the ball, plug, and diaphragm valves. To assess the remainder, the inspectors selected a sample and reviewed their safety functions as described in the applicable Design Basis Calculations, FSAR sections, and flow diagrams. The sample consisted of the following 18 MOVs: 1(2)CA007A, 1(2)CA009B, 1(2)CA011A, 1(2)ND090, 1(2)ND091, 1(2)RN067A, 1(2)RN069B, 1(2)RN429A, and 1(2)RN432B. In the case of containment isolation valves RN429A and RN432B, additional information was required as evidence for exclusion. For these valves the licensee provided a tagout record (15-1183) to show that they were closed with power removed and a January 11, 1996, Technical Specification change request stating the valves were no longer used and that a modification was planned to remove their wiring and control room instrumentation. The inspectors found that the licensee's removal of the 18 valves was justified. They concluded that the scope of the licensee's program was consistent with the recommendations of GL 89-10. The inspectors noted that Catawba had the largest number of valves in its program of any plant they had inspected.

3.1.3 DESIGN-BASIS REVIEWS

The inspectors performed their assessment of this area by evaluating the differential pressure, system flow, and minimum motor terminal voltage used by the thrust calculations for determining adequate MOV switch settings. Catawba's design-basis review documents were typically organized by system and evaluated an MOV's operation under normal, design, and accident conditions. During review of the design-basis calculation summary for the S/G B PORV Block Valve (2SV027A), the inspectors noted that the stated worst case system flowrate was inconsistent with the value contained in design-basis documents. The summary listed the design-basis flow as 16,200 lbm/hour, when it should be listed as approximately 6,600 lbm/minute. The inspectors verified that the calculation error was subsequently identified for correction by the licensee in PIP C96-0588. The inspectors found that the error did not have a significant impact. However, correction did cause the licensee to realize that the differential pressure test was conducted much closer to design-basis conditions than was previously assumed. No

other errors were noted in the calculations or design-basis documents and they were concluded to be generally satisfactory.

Catawba's degraded voltage calculations were documented in CNC-1381.05-00-0070, Vol. 1, Rev. 4, dated January 11, 1994, and CNC-1381.05-00-0168, Rev. 1, dated August 2, 1995. The inspectors reviewed the applicable material and determined that the calculations were satisfactory.

In performing their review in this area, the inspectors noted a discrepancy between the location of Valve 1SV027A identified in Calculation 1205.19-00-0055, Attachment 3, Rev. 1, and that shown on Flow Diagram CN-1593-1.0, Rev. 15. The calculation identified the valve as the Steam Generator B PORV Block Valve, whereas the flow diagram showed the valve to be associated with Steam Generator A. In response to questioning by the inspectors, licensee personnel reported that the flow diagram was in error. The locations of valves 1(2)SV027A and 1(2)SV028A were stated to have been reversed on both the Unit 1 and Unit 2 flow diagrams. The inspectors noted that they had observed revision 14 of the same flow diagram in the FSAR and that it showed the valves in the same (apparently incorrect) locations as revision 15. The inspectors did not consider this single drawing error significant, but verified that the licensee identified it for correction on PIP C96-0588.

3.1.4 MOTOR OPERATED VALVE SIZING AND SWITCH SETTINGS

General

The inspectors found that Catawba's thrust calculations utilized standard industry equations. Mean seat diameter was used to calculate valve seat area. Stem coefficient of friction and load sensitive behavior values were generally established from analyses of in-plant licensee test results. Minimum thrust requirements for setting actuator torque switches were adjusted to account for diagnostic equipment inaccuracy and torque switch repeatability.

Valve Factor and Grouping

The inspectors found that the licensee's thrust equation typically incorporated a valve factor of 0.50 to 0.60 for rising stem gate valves and 1.10 for globe valves. The globe valve population was reviewed and the inspectors confirmed that a guide-based area term was used by the thrust equations, where appropriate. A stem friction coefficient of 0.20 was used for determination of actuator output. Catawba used in-plant dynamic test results from similar valves to establish valve factors for non-dynamically tested MOVs, where test data was available. For valve families where in-plant testing was possible, the inspectors noted that adequate dynamic tests were performed to comply with the guidance provided in GL 89-10, Supplement 6. For example, the Auxiliary

Feedwater system contained 14 Anchor Darling 4-inch flex wedge gate valves, of which 8 were dynamically tested. From their review the inspectors found that licensee personnel had analyzed the available test data and had used a bounding method to determine that a 0.65 valve factor was appropriate for this valve family. This was considered appropriate.

During review of Catawba's generic letter program, the inspectors noted valve groups where no members of the group were dynamically tested, and the supporting valve factor information was weak. This included groups of Borg Warner gate valves that have been shown by industry testing to have higher than expected valve factors. Groups that were reviewed are discussed in the following paragraphs.

- Residual Heat Removal: 12-inch Borg Warner gate valves (1/2ND001, 1/2ND002, 1/2ND036, and 1/2ND037) with open and close safety functions. The thrust calculations for these MOVs used a valve factor of 0.60, based on a dynamic test conducted at the Perry nuclear power plant. A thrust margin of 32 percent was also included in the minimum required thrust to account for load sensitive behavior. This group had a minimum closing thrust margin of 17 percent, and a minimum open thrust margin of 89 percent. The Perry test resulted in a measured valve factor of 0.37. The inspectors noted that Catawba personnel did not use the Perry test conditions and diagnostic traces to determine valve factor. Instead, the valve factor information was accepted directly from Perry.

- Auxiliary Feedwater: 6-inch Borg Warner gate valves (1/2CA015, 1/2CA018, 1/2CA085, and 1/2CA116) with open safety functions. The thrust calculations for these MOVs used a valve factor of 0.86, based on the performance of a valve tested by the Electric Power Research Institute's (EPRI) performance prediction program (PPP). This group had a minimum open thrust margin of 32 percent.

- Service Water: 6-inch Walworth gate valves (1/2RN250 and 1/2RN310) with open safety functions. The thrust calculations for these MOVs used a valve factor of 0.40, based on the performance of a valve tested by the EPRI PPP. This group had a minimum open thrust margin of 13 percent.

The inspectors found that the thrust requirements for the above valves did not appear adequately established, as each group relied on the results of a single test. Further, in one instance (12-inch Borg Warner gate valves) it was not clear that the licensee had sufficient information from even the one test. GL 89-10, Supplement 6, indicated that reliance on testing from a single valve was insufficient to establish the capabilities of a group. The licensee's resolution of this issue was identified as Inspector Followup Item 50-413, 414/96-02-01: Reliance on Testing of a Single Valve to Support the Capabilities

of a Group.

Load Sensitive Behavior

Catawba generally selected a thrust margin of 30 percent to address load sensitive behavior for MOVs that had not been dynamically tested. In selected cases, the licensee justified use of a 20 percent margin. The 30 percent was included as a bias margin and was based on information contained in Duke Power calculation DPC-1205.19-00-0002, "Evaluation Of Rate-Of-Loading Effects," dated March 13, 1995, which evaluated test results from Duke plants and results from EPRI's PPP. The Duke Power in-plant analysis determined that Anchor/Darling, Crane, Velan, Walworth-Aloyco, Walworth-Greensburg, and Westinghouse MOVs (Group B) tended to be more sensitive to load sensitive behavior. A correction factor of approximately 0.65 (equivalent to a 35 percent margin) was required to bound 96 percent of the test results for this group of valves. Borg-Warner, Pacific, Powell, Rockwell, and Walworth valves (Group A) were identified as being less sensitive to load sensitive behavior. For these valves, a correction factor of approximately 0.84 (16 percent margin) bounded 93 percent of the tests. EPRI testing tended to confirm Duke's results. The inspectors did not identify any concerns related to Catawba's methods to address load sensitive behavior for the close direction.

Catawba's method for determining capability requirements for the open direction did not include any margin to account for potential changes in stem friction coefficient caused by load sensitive behavior. Given Catawba's use of an assumed 0.15 Stem Friction Coefficient (see discussion below), the inspectors believe that a margin is appropriate.

Stem Friction Coefficient

Catawba used an assumed Stem Friction Coefficient (SFC) value of 0.15 when determining an actuator's output thrust capability. This selection was based on a review of in-plant test data (using the mean, plus one standard deviation of the data). Duke Power's corporate justification for SFC (DPC-1205.19-00-0001, "Evaluation of Stem Factor and Stem C.O.F. Assumptions," dated June 21, 1995) included data that was gathered at Catawba and the other Duke facilities. The inspectors noted that this justification had not been updated to include test results from Catawba's last outage. In addition, the inspectors found the justification to be weak because 8 out of 63 static tests had measured SFC values above 0.15, and 12 out of 63 differential pressure tests had measured SFC values above 0.15. Catawba personnel stated that the load sensitive behavior margin would account for SFC values above 0.15. However, no load sensitive behavior margin was considered for the open direction. Further, Catawba had not analyzed open SFC performance due to concerns related to the reliability of open diagnostic thrust measurements. The inspectors noted that the NRC had accepted values of

coefficient of friction based on the mean of in-plant test results plus two standard deviations. The licensee's resolution of this issue was identified as Inspector Followup Item 50-413,414/96-02-02: Stem Coefficient of Friction for MOV Opening Setting Calculations.

Diagnostic Equipment Uncertainties

In response to an NRC inspection finding at the McGuire Nuclear Station, Catawba issued PIP 0-C95-0879, "MOV Program Open Direction Evaluations Incomplete" June 7, 1995. This PIP addressed large uncertainties associated with VOTES thrust measurements taken in the open direction. The problem identified by this PIP was that the opening direction evaluations of GL 89-10 MOVs were incomplete due to large measurement uncertainties. The corrective actions were originally scheduled for completion in July 1995. This completion date was later revised to January 31, 1996. The corrective actions were not complete by that date, so it was again revised to March 1, 1996. However, at the time of the inspection, this activity was not yet complete. The inspectors expressed concern that this issue remained open too long, especially considering that the licensee informed the NRC that GL 89-10 implementation was complete for their Group 1 and low margin Group 2 MOVs in a letter dated January 23, 1995. Satisfactory licensee resolution of this issue was identified as Inspector Followup Item 50-413,414/96-02-03: MOV Opening Thrust Requirement Uncertainties.

Valve Degradation

Generic Letter 89-10, Supplement 6, Enclosure 1, identified the need for control switch settings to provide adequate margin to account for degradations until the next test. The inspectors found that Catawba's setup methodology did not include a margin for degradation with age. Calculation DPC-1205.19-00-0001 referenced test results from two test programs as proof that significant degradation of stem friction coefficient would not take place with their stem lubricant (FelPro N-5000) in sequential, highly-loaded valve strokes. The inspectors noted that this analysis did not consider the effects of age-related degradation of the stem lubricant. The inspectors informed licensee personnel of this concern and stated that the adequacy of the minimum margin provided for degradation would be subject to further NRC review when the licensee's completion of GL 89-10 is assessed.

3.1.5 DESIGN-BASIS CAPABILITY

The inspectors reviewed Appendix G1 "VOTES Differential Pressure Test Analysis Guideline - Gate Valves," Rev. 4, dated July 5, 1994, of Duke Power's MOV Test Analysis Guideline, and special test procedures for the selected valves.

During their review of the licensee's dynamic testing, the inspectors noted that the test evaluation procedures did not directly evaluate the

open direction performance. Open valve factors were calculated and open thrust requirements were calculated. However, no formal comparison to the actuator's output capability was made (no margin was calculated). Licensee personnel explained that no comparison had been made in the past because of the (large) uncertainty associated with open VOTES measurements. The inspectors found that Catawba had revised their diagnostic procedures to obtain calibrated open thrust measurements. This permits determination of open thrust values and margins with greatly reduced uncertainty. Licensee personnel stated they would revise their test evaluation procedures to calculate an open thrust margin similar to methods used to calculate a close thrust margin. The inspectors verified that the licensee entered the need for this change in PIP C96-0588.

Valve 2NI100 was listed on Catawba's valve matrix as having minimal thrust margin. After further review, it was determined that the design-basis differential pressure calculation was based on assumed check valve leakage. Actual testing had determined that the check valve was not leaking and this valve only has to seal for a short period of time during switchover to long-term circulation. Therefore, the valve only opens against the static head of the water left in the Refueling Water Storage Tank (RWST). Licensee personnel stated that they intend to increase the torque switch setting for 2NI100, when possible, to assure that increased pressure from any future check valve leakage can be accommodated.

The inspectors found that the Pressurizer PORV Block Valves (1/2NC031, 1/2NC033, and 1/2NC35), which are 3-inch Anchor Darling Double Disc gate valves, had been setup based on preliminary results from a prototype test program conducted by Duke Power. A 0.45 valve factor was used in the thrust calculations for these valves. The test program included six steam flow tests that were conducted at conditions similar to the design-basis requirements for the valves. The results from this testing were still under review by the licensee and the valve vendor because of apparent damage that occurred during the testing. The inspectors expressed concern that the tests had been completed in 1994 but the licensee's review remained incomplete. The inspectors reviewed several of the preliminary test documents and noted that the prototype valve experienced nonpredictable behavior prior to flow isolation. This was most evident during the third dynamic test (identified as "Test 3" in the test sequence). The highest apparent valve factor for this test was approximately 0.55. Subsequent dynamic tests showed improved valve performance. Catawba personnel stated that the Test 3 dynamic test results were not considered representative of valve performance. They further stated that the test conditions were considered far more severe than would be experienced in an actual design-basis event, as steam flow from the test arrangement exceeded design by 82 percent. Given the nonpredictable behavior and damage observed in the licensee's testing, the inspectors considered that the results of the tests and the licensee's review should be evaluated by the NRC in a subsequent

inspection of the licensee's implementation of GL 89-10. Satisfactory licensee resolution of this issue was identified as Inspector Followup Item 50-413,414/96-02-04: Unpredictable Behavior Experienced in Pressurizer PORV Block Valve MOV Testing. The inspectors also noted to the licensee that, as only one block valve was being prototype tested the concern identified by IFI 50-413,414/96-02-01 also applied to these valves.

3.1.6 PRESSURE LOCKING AND THERMAL BINDING

The inspectors examined the licensee's efforts to identify and provide corrective actions for MOVs that may become operationally compromised through pressure locking or thermal binding. Supplement 6 to GL 89-10 indicated that pressure locking and thermal binding were considered to be within the existing design bases to be addressed in setting and sizing MOVs. Subsequently, GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gates Valves," was issued requesting specific licensee actions and submittals to the NRC to address pressure locking and thermal binding.

Licensee personnel indicated that there had been evaluations and corrective actions for pressure locking and thermal binding prior to GL 89-10, but that further evaluations and corrective actions had not been performed until GL 95-07 was issued. The inspectors verified that the licensee had submitted the 180-day response requested by GL 95-07, providing summary information on the licensee's evaluation and corrective actions to address pressure locking and thermal binding. The licensee's GL 95-07 evaluation identified 12 valves per unit whose long-term capability to overcome potential pressure locking was based on a calculation developed by Commonwealth Edison.

In reviewing the results of the calculations which the licensee had performed for the 12 valves referred to in the previous paragraph, the inspectors noted that valve 2NS001B was shown marginally incapable (-2.6 percent) of overcoming potential pressure locking. The licensee had performed a test to demonstrate that this valve would not pressure lock under current conditions. The inspectors verified the adequacy of the test, but noted that it was only sufficient to demonstrate the operability of the valve for the current operating cycle. Licensee personnel stated that this was understood and that long-term corrective actions were under evaluation.

In examining the licensee's submittal the inspectors observed that several valves identified as having opening safety functions in the licensee's GL 89-10 program, were evaluated by the licensee and found not to have opening safety functions for GL 95-07. When questioned by the inspectors, licensee personnel stated that there were detailed evaluations to support the GL 95-07 decisions for these valves. Licensee personnel stated they would verify that the valves' safety functions had been correctly determined for GL 95-07. These valves were

identified 1(2)ND032A, 1(2)ND065B, and 1(2)NI183B.

For closure of Generic Letter 89-10, licensees were expected to have initiated comprehensive engineering reviews to identify susceptible MOVs and to have taken timely corrective actions. The inspectors concluded that the actions taken by the licensee were sufficient for GL 89-10 closure. The current inspection did not assess the adequacy of the licensee's pressure locking and thermal binding evaluations and corrective actions. The adequacy of the evaluations and corrective actions will be determined in a subsequent NRC review of the licensee's response to GL 95-07.

3.1.7 MOTOR OPERATED VALVE PROGRAM SELF-ASSESSMENTS

The inspectors asked what QA, QC, or other independent assessment had been conducted by the licensee to assess the adequacy of their actions to implement GL 89-10. They were informed that none had been performed. The inspectors stated that, considering extent of effort and length of the licensee's program, the lack of any independent assessment would be considered a weakness.

3.1.8 MOTOR OPERATED VALVE PROGRAM SUMMARY AND CONCLUSIONS

The inspectors found that the licensee's program had required a particularly large effort because of the number of valves to be addressed. Further, based on their review, the inspectors concluded that the actions which the licensee was taking to implement GL 89-10 recommendations were generally satisfactory. However, issues were identified which require particular licensee attention. The four IFIs above cover each of these issues. The inspectors expressed concern to the licensee regarding their lack of promptness in resolving the issues encompassed in IFIs 50-413,414/96-02-03 and 96-02-04. The incomplete resolution of these issues, both of which involve the licensee's Group 1 MOVs, indicated that the licensee had not completed GL 89-10 implementation for these MOVs, contrary to their January 23, 1995, letter. The inspectors found that the licensee had not performed any independent assessment of their GL 89-10 program and considered this a weakness, in view of the length of the program and the extent of effort involved.

The inspectors noted that a closure inspection of the licensee's implementation of GL 89-10 would be performed following notification of completion for all Group 1 and 2 valves. In addition to the IFI's identified above that inspection will examine MOV capability margins, implementation of periodic verification, and implementation of appropriate maintenance and modification testing. Review of setting and sizing calculations, as well as design-basis test records for an additional sample of MOVs is also anticipated.

The inspectors observed the following licensee strengths during their

review:

- The reviewed licensee calculations were complete, accurate, and logically formulated.

- The licensee's MOV engineering staff were well-qualified and had a good understanding of most industry issues.

- The licensee had shown initiative and developed good engineering approaches to resolve the issues involved in GL 89-10. For example, stem coefficient and rate of loading had been measured and assessed for a large number of valves. Further examples included special programs that were implemented to address specific valves or classes of valves, such as the licensee's prototype testing of Pressurizer PORV Block Valves.

3.2 IPAP MAINTENANCE/SURVEILLANCE ISSUES FOLLOWUP

3.2.1 LESSONS LEARNED PROCESS

The Lessons Learned Process was chartered as a communication tool for the distribution of information on problems/issues and success to the Electrical Support System (ESS) group. It was used by the ESS group to capture, analyze/trend, and share best practices and areas for continuous improvement of activities. Information is compiled from various sources (i.e., nuclear outage critiques, site specific issues, improvement ideas, safety assessments, PIP, etc..) for analysis trending and documentation in periodic reports for feedback as needed.

The information provided was used to develop goals for job improvement in the form of job focus packages used by workers on specific tasks. In general, these job focus packages highlight particular problems to be avoided and successes to be duplicated.

This program was implemented in each of the licensee's three nuclear stations during their last refueling outage. A review of the Lessons Learned Report generated by ESS for Catawba's recent outage (2EOC-7) disclosed that pre-established goals were met in such areas as safety, LERs, dose, solid and liquid radwaste, housekeeping, lead shielding, steam generator work (secondary manways), and vent path in mid-loop. Areas where improvement was needed included human error reduction, attention to detail, ESS contamination, rework, foreign material exclusion (FME), and personal safety.

3.2.2 PROCEDURAL ADHERENCE

As identified in paragraph 4.4 of IPAP Inspection Report 50-413,414/95-15, lack of procedural adherence was a significant contributor to poor performance during maintenance activities. The licensee had identified

this problem during the May 1994 Unit 2 refueling outage and stopped all work. The licensee issued several memoranda to all maintenance personnel addressing expectations for procedural adherence. These memoranda stressed personal accountability and directed increased supervisor oversight to ensure procedures were used and followed.

As part of the Self-Assessment Program, the licensee reviewed Problem Identification Process (PIP) reports and work observation cards for trends on procedural adherence. Based on this trending, the two memoranda were effective in reducing procedural adherence related problems; however, the licensee identified that procedural adherence related problems still existed. The licensee identified this issue for a comprehensive review and issued PIP C96-0392, dated 2/13/96, to track the corrective actions. This PIP also included corrective actions for inadequate procedures and work practices/Foreign Material Exclusion.

3.2.3 SCHEDULING SURVEILLANCE/WORK CONTROL PROGRAM

IPAP Report 95-15, paragraph 4.4, found that lack of an integrated surveillance test process contributed to a missed surveillance. The licensee consolidated individual scheduling databases into a single database called Work Management System (WMS). This provided for a more integrated approach to scheduling surveillances with due and drop-dead dates tracked. The drop-dead date was the inoperability date for Technical Specification related items. WMS directly updated the site activities schedule once a model work order was manually entered. This ensured that work orders for surveillance were automatically generated based on the previous performance date and the surveillance frequency. Any conflicts due to equipment unavailability were identified between the scheduler and the work crews. The surveillance was then rescheduled for when the equipment would be available. This ensured the current surveillance was not missed and work orders generated for the next required interval. Procedure Maintenance Management Practice (MMP) 3.5 provides administrative control over the scheduling and planning process. The inspectors reviewed Procedure MMP 3.5, revision 11, and found the licensee's implementation was adequate.

3.2.4 OPERATIONS INVOLVEMENT IN REVIEWING WORK REQUESTS

Operations personnel review the type of work and the scheduling window to ensure plant configuration can support the activity. This includes assisting with development of the schedule and reviewing the schedule prior to implementation. Also, the Site Directors Meeting provides Operations management with a direct communication for expectations on return-to-service allowing for earlier detection of potential LCO expiration problems. The Work Control Center (WCC) was run by Operations to further control work orders and scheduling changes. Only one major and one minor activity per unit was allowed at any given time, to reduce distractions to the control room operators. A questioning

attitude by Senior Reactor Operators concerning the work to be done, why it was being done, and the effect on unit operations was another factor that enhanced Operations overall involvement.

3.2.5 STRUCTURED TROUBLESHOOTING PROCESS

Paragraph 4.4 of IPAP Report 95-15 identified that a lack of structured troubleshooting adversely affected corrective maintenance activities. The licensee had developed and implemented the Failure Investigation Process (FIP) to address this weakness. The FIP provided a detailed methodology to determine the root cause or causes of a failure and the corrective actions to prevent the failure from recurring. The FIP consisted of preserving the failed components, interviewing personnel present at the time of the failure, analysis of the failed components, determination of apparent causes, reviewing similar systems or components for susceptibility to the same failure mechanism, and developing corrective actions. The PIP was used to facilitate tracking and trending of FIP information.

The licensee was in the process of finalizing Nuclear Site Directive 212, Cause Analysis, to provide formal guidance for the FIP. However, the licensee had used the FIP in several cases. The inspectors reviewed a FIP report dated 9/19/95 for 2B diesel generator (D/G) turbocharger mounting bolts that were found failed following 2B D/G operation. The FIP report provided detailed information on the failed components and the potential causes for the failures. Cross-disciplinary engineering reviews were then conducted to either confirm or dismiss these potential causes as a probable failure mechanism. Once the probable failure mechanisms were identified, corrective actions to address each failure mechanism were implemented.

The inspectors determined the FIP provided an adequate structured process to investigate component failures and identify appropriate corrective measures.

3.2.6 MAINTENANCE SELF-ASSESSMENT PROCESS INITIATIVE

Self Assessment was part of the licensee's Quality Assurance program and was described under Section 17.3.3 of the Duke-1 Topical Report. Procedure MMP 1.14, which was recently approved for implementation and was the controlling document used to implement this process. Procedure NSD-607, revision 2, was used for administration, reporting and documentation purposes. Self-Assessment provided a method for evaluating and improving maintenance performance and effectiveness at Duke's nuclear power stations. It was used as a tool to assess job tasks, equipment failures and adherence to technical and administrative procedures applicable to maintenance activities. Information used for this assessment process was obtained from various sources including, regulatory reports, PIP trends, maintenance rework program feedback, and

field observations. Basically there were two levels of Self-Assessments performed by plant personnel. Level I Self-Assessments were performed by, and were the responsibility of, maintenance managers and supervisors who observed and evaluated field activities on a daily and/or periodic basis using observations cards (Blue Cards) for documentation purposes. Level II Self-Assessments involved evaluations by work groups targeting weaknesses identified by the Level I Self-Assessments and various other trending indicators used to assess the conduct of maintenance. Within these areas, the inspectors reviewed the following completed Self-Assessment reports:

- Year End Maintenance Field Observation Program, MNT-01-96, 1/15-17/96

- 1995 PIP Trend Report, MNT-01-96, 1/25/96

- Maintenance Rework Program, MNT-01-96, 1/1/95-12/31/95

The Field Observation Program Report identified 10 out of 22 work related processes which occurred more frequently. They included procedure, drawings, housekeeping, foreign material exclusion, proper equipment, tools/instruments, safety, and communications with other groups. Through discussions with licensee personnel, the inspectors ascertained that the licensee was taking appropriate measures to improve performance. A review of future Assessment Reports should show whether performance improvements have been attained.

The 1995 PIP Trend Report indicated that problems existed in adherence to technical and administrative procedures, equipment failures, and work executions. These problem areas appear to have persisted over the last two years and remained at the same level or showed an increasing trend. Recommendations to improve performance and reverse the trend in this area were reviewed and discussed with cognizant licensee personnel who indicated that these problem areas have become key management issues. Corrective actions have been established with responsibility assigned to supervisors and/or managers to assure accountability of results.

The Maintenance Rework Program Report evaluated the 1995 repeat maintenance events and the causes associated with these findings. Through discussions with the licensee, the inspectors ascertained that between March 1995 to the end of the year, 120 potential rework events were assessed and, of these, 74 were confirmed as rework. Of these, there were 41 work practice deficiencies which accounted for 55% of the total population. The licensee's evaluation and analysis determined that these problems were attributed to a lack of self-checking, inadequate independent verification, and skill-based discrepancies. Other areas of significant rework associated problems included design or equipment problems and written or verbal communications.

Three areas where maintenance activities showed relative strength

included steam generator secondary side, HVAC chillers, and pipe supports. Areas in the Rework Program identified by the licensee as requiring improvements to enhance the effectiveness of this program included: retention of data from previous years; timeliness of rework assessments; definition of rework; and training of ESS and station personnel on work order documentation. Specific areas where rework continues to adversely affect good performance included valves, pumps, heat exchangers, and instrumentation and pipe repair. In all cases, the majority of the reasons for rework was attributed to poor work practices.

Within these areas the inspectors have determined that the licensee is monitoring these activities and has implemented a program to reduce rework.

3.2.7 WORK ORDER BACKLOG REDUCTION

In January 1996 the licensee established a Backlog Reduction Team to address and bring under control the growing backlog of work orders >180 days old. Through discussions and data review the inspectors ascertained that, as of the time of this inspection, work orders greater than one year old were reduced from 80 to 51. The total population of work orders greater than 180 days old were approximately 273; however, the licensee's goal was to reduce these down to ten. The total work order inventory before the Unit 2 trip on February 6, 1996, was approximately 1,290 and had increased to approximately 1,327 by February 12, 1996. The licensee's goal was to reduce this inventory at the rate of about 30 to 40 per week down to about 550.

3.2.8 INNAGE WORK ORDER PROGRAM

This program was established by the licensee's Control Group for the purpose of reviewing work schedules from an operations point of view. This relatively new group is staffed by personnel with strong plant operations background and is headed by an individual with experience as operations shift manager.

The group's activities includes: review of tag outs for technical adequacy; providing operations with scheduling windows for work to be performed; and initiating reviews which take into account PRA considerations. This group also works with the Work Scheduling Group to restrict control room activity to one major and one minor work effort per unit at a time. Under this program, tag outs are issued for review before refueling outages and in a similar manner, work orders are made available for review at least two weeks before execution. This approach is intended to allow for concerns or problems to be identified to the planners for resolution. In the area of work scheduling, Work Control has adopted the NRC's Maintenance Rule on significant system identification for maintenance work scheduling purposes. As such, the licensee had increased the number of these systems from 13 to 125.

Maintenance for these systems is planned on a fixed 12 week rotating cycle which facilitates planning and execution of maintenance activities. Because this program had not been fully implemented, no evaluation was possible at this time.

3.2.9 WORK OBSERVATIONS

Unit 1 Power Range Nuclear Instrument Testing

The inspectors observed the performance of a channel operability test on Unit 1 Power Range Nuclear Instrument (PRNI) N42. No procedural deficiencies were noted and the test was completed satisfactorily. However, verification of High Flux High Power bistable actuation caused a control room annunciator to be generated. The technicians did not inform the operator at the controls the annunciator was due to the work activity being conducted. Because the annunciator was a common alarm, the operator at the controls was not able to distinguish between an alarm due to testing and a valid alarm. Furthermore, the operator at the controls did not question the cause of the annunciator.

Work Order (WO) 96004078 01 was issued for generation of a detector plateau curve for PRNI N42 and was released to the technicians at the same time as the channel operability test. However, when the technicians reviewed the prerequisites of Procedure IP/0/A/3240/13, Excore Nuclear Instrumentation Detector Plateau Curve Plotting, revision 1, they found that plant conditions were not appropriate. Specifically, Procedure IP/0/A/3240/13 required reactor power to be greater than or equal to 95%. Unit 1 reactor power had been reduced to 47% as part of preplanned work to support Unit 2 restart prior to this work order being released. The inspectors reviewed the WO and found that it clearly stated reactor power was to be greater than 75%. The inspectors noted the WO was generated on 1/15/96 as part of routinely scheduled surveillance; however, the work order was not released by the Work Control Center (WCC) until 8:00 a.m., on 2/14/96. The WCC personnel attended shift turnover meetings and were apprised of plant status, including reactor power. Unit 1 reactor power had been reduced to 47% at about 3:00 a.m., on 2/14/96. A shift turnover meeting would have occurred after Unit 1 reactor power was reduced and before the work order was released by the WCC. Also, the arrangement of the WO did not facilitate review of the WO requirements. The section for WCC release preceded the section detailing plant configuration requirements such as reactor power level. The licensee had issued PIP C96-0418 to track the corrective actions.

The inspectors also noted that the WO and Procedure IP/0/A/3240/13 differed in reactor power requirements. The inspectors discussed this discrepancy with the licensee who indicated that the

responsible engineer provided the interface between procedural and WO changes. However, the licensee did not know if the prerequisites for Procedure IP/0/A/3240/13 had been changed recently. As a corrective action for this discrepancy, the licensee had removed the reactor power level requirement from the work order. PIP C96-0418 also included investigating and correcting this discrepancy.

The inspector concluded the work was performed satisfactorily.

Pressurizer Relief Tank Diaphragm Relief Inspection

The inspectors entered containment to inspect a damaged pressure relief diaphragm on the Pressurizer Relief Tank (PRT). The PRT was equipped with two vent ports both of which contained a metallic relief diaphragm. The damage occurred when Unit 2 tripped because of a loss of off-site power. This caused a safety injection actuation resulting in overfilling of the PRT and rupturing the subject diaphragm.

The overfill caused one of the two diaphragms to burst while the second experienced plastic deformation. While in the area, the inspector noted that the water coming out the PRT vent ports had damaged the mirror insulation on the A loop piping between the reactor and the RC pump. The damaged insulation was replaced sometime between 2/8 and 2/12/96. The damaged diaphragms were replaced under WO 9601476 on 2/9/96. The inspector reviewed the work order package for content and adequacy. The replacement diaphragms were 18 inches diameter and were made of 316 type stainless steel material. The diaphragms were designed to rupture between 93 and 103 pig. The inspector concluded that the work order package was adequate.

Diesel Generator "B" Emergency Start Test

On February 13 the inspectors observed B Diesel Generator (D/G) emergency start test. The test was performed utilizing procedure PT/1/A/4350/B, Monthly Operability PT on the "B" D/G. The initial test commenced at approximately 10:35 a.m. and was stopped shortly thereafter due to a malfunctioning voltage trace recorder used to measure voltage and frequency soon after the start signal. The test was categorized as invalid and provisions were made to repeat the test following repairs to the recorder. At approximately 4:00 p.m. the diesel generator was restarted per the applicable test procedure and allowed to run until the test was completed. The inspectors verified that operating parameters were attained within specified time limits. Theses included rpms, frequency, voltage, and time to synchronize and load the diesel generator to the specified power range. Other operating parameters observed included power factor, field voltage and current, cylinder exhaust temperature, water jacket and lube oil temperatures, as well as

pressure for lube oil and fuel oil. All indications were well within acceptance criteria delineated in Technical Specification 4.8.1.1.2 and the subject procedure. The inspector concluded that the personnel performing the test were very knowledgeable of procedural requirements and acceptance criteria, and that they performed the test in a well coordinated and organized manner.

Fuse Block Replacements

On February 5, 1996, the inspectors observed electrical maintenance personnel perform corrective maintenance on MCC 1PHP1B in cubicles F02D and F02E in accordance with WO 95007986 and WO 95007988. During a thermography scan of the MCC, exceptionally high temperatures of approximately 160 degrees F were noted in the two cubicles compared to 132 degrees F in all the other cubicles. In both cubicles, the electrician replaced the fuse blocks and associated cables. The work and testing were performed in accordance with the instructions from procedures IP/0/A/3850/009, Inspection And Maintenance Procedure For Motor Control Center Breakers, and IP/0/A/3850/23, Molded Case Circuit Breaker Inspection And Testing Procedure.

Even though the equipment was not classified as safety-related, the maintenance and testing were performed as if it was. The inspectors concluded that the work was performed in a satisfactory manner. In addition, the use and quality of the thermographs to identify potential problems was considered a strength.

On February 5, 1996, the inspectors walked down the Measurement and Test Equipment (M&TE) Calibration Facility to determine housekeeping conditions. The calibration area was cluttered with equipment, including several humidifiers. The technicians explained that the humidity was difficult to control in this area. It was too humid in the summer and not humid enough in the winter to meet the calibration requirement for humidity for some of the M&TE. The inspectors concluded that the lack of humidity control in the M&TE Calibration Facility was a weakness in the maintenance area.

3.2.10 IPAP MAINTENANCE/SURVEILLANCE ISSUES FOLLOWUP - CONCLUSION

In general, the licensee's actions appear to be having a positive effect on the conduct of maintenance as evidenced by the Self Assessment Process, the ESS Critiques, and Operations involvement in maintenance. However, because some of these programs are relatively new, it was not possible to observe clear evidence of their effect on performance.

3.3 STEAM GENERATOR PORV BLOCK VALVE PACKING LEAK

In NRC Inspection Report 50-413,414/95-24 inspectors reviewed the licensee's corrective actions for a severe packing leak on S/G PORV Block Valve 1SV-27A. The inspectors reviewed the associated flow

diagram, design-basis specification, GL 89-10 calculation, and valve drawing to establish the design requirements and capabilities of the valve. They reviewed the corrective actions as documented in PIP 1-C95-2328 and in WOs 95049804 (completed) and 95092326 (for future valve replacement) and discussed the corrective actions with the licensee's valve engineers. The inspectors concluded that the licensee's actions were appropriate.

The inspectors did note an apparent error. The PIP indicated that Valve 1SV27A served S/G 1A, whereas the GL 89-10 MOV Calculation CNC 1205.19-00-0055 associated the valve with S/G 1B. This appeared to be the result of the flow diagram error discussed previously in section 3.1.3 above.

3.4 COLD WEATHER PROTECTION PROGRAM

Temperatures dropped below freezing during the early part of the week of February 5, causing a number of instrumentation problems to occur. The inspector reviewed the circumstances surrounding each instrument failure and corrective actions to prevent recurrence during potential severe temperature drops during the remainder of the winter season. Because multiple failures were attributed to cold weather, the inspector also reviewed the licensee's cold weather protection program for its effectiveness and thoroughness.

A channel of Refueling Water Storage Tank (RWST) level instrumentation failed during the cold weather. The licensee attributed the failure to an inability of the heaters located in the pressure transmitter box to compensate for the cold weather period encountered during February 4-5. The heat tracing and heaters did not fail, but the temperature setpoints for heater actuation were not sufficient to ensure the cold temperatures could be adequately managed. Four channels of RWST level are available, and the system is operable with one level channel inoperable. Since no TS action statements were entered as a result of the failure, the safety impact is minor.

Several other cold weather-induced problems were experienced during the same cold period. The inspector reviewed the licensee's program for implementing preventive measures during the fall for plant equipment cold weather protection. The program consists of cabinet inspections to verify that cabinet heaters are functioning, insulation inspection, and heat trace inspection. The inspector also reviewed work orders associated with these three cold weather protection areas to verify that preventive measures had been implemented during the fall of 1995 in preparation for winter weather.

Although only one channel of RWST level was lost during the cold period and the other failures did not pose a challenge to safety-related equipment, the inspector noted that a cold weather-induced failure of a channel of RWST level indication also had occurred during the previous

winter (documented in NRC Inspection Report 50-413,414/95-07). Cold weather failures from two years ago were documented in NRC Inspection Report 50-413,414/94-04. The inspector considered recurring problems in this area indicative of ineffective programmatic enhancements to prevent recurrence and symptomatic of a continued lack of sensitivity to cold weather protection. The licensee is currently evaluating vulnerabilities in cold weather protection programs at all three Duke Power Company nuclear stations on a utility-wide basis.

3.5 PRESSURE TRANSMITTERS INSTALLED WITH PLASTIC SHIPPING PLUGS

The inspector has observed a number of pressure transmitters in the plant that have been installed with the plastic shipping plugs as opposed to permanent metal plugs installed in unused electrical cable ports. The practice was questioned because temporary plugs do not provide the same level of protection against particle contamination and condensation; therefore, they are not as effective as permanent metal plugs in preventing environmental degradation. Although the inspector did not identify shipping plugs in safety-grade transmitters or transmitters that provide control functions, the pressure transmitters that have been identified provide control room indication for safety-related system parameters (specifically Auxiliary Feedwater).

Following the Unit 2 loss of offsite power event that occurred on February 6, 1996, the inspector toured the auxiliary feedwater pump room which had flooded because of check valve backleakage in the floor drain header and the floor drain/turbine-driven pump sump common drain header. The room was very warm and humid, and the inspector was aware that several pump discharge and suction pressure transmitters in the pump pits were not permanently plugged. Subsequent to the event, the inspector questioned the potential of environmental conditions impacting operation of the pressure transmitters that had been installed with the plastic shipping plugs rather than permanent metal plugs.

The licensee has characterized the installation of pressure transmitters without permanent metal plugs as a poor work practice and documented the issue in PIP C96-0799. Although corrective actions have not yet been specified in the PIP, the licensee plans to correct the potential degradation of the transmitters by installing metal plugs in the unused cable ports of transmitters currently installed with the plastic shipping plugs either under a work order for that specific task or as an additional task during routing calibrations or maintenance.

3.6 (Closed) Unresolved Item 50-413,414/94-05-01: No Periodic GL 89-10 Failure Trending and Analysis for MOVs

This unresolved item documented a finding that the licensee had not implemented failure trending and analysis for MOVs as required by their commitment to GL 89-10. The inspectors questioned what action the licensee had taken to address this commitment and was informed that

trending of MOV failures was being issued in quarterly reports. They were provided copies of trend data and evaluations from the licensee's "Failure Analysis and Trending System." Individual evaluations were provided for Electric Motor Operators, Globe Valves, Gate Valves, and Butterfly Valves. Quarterly failures were graphically presented and covered four to five quarterly periods. The licensee stated that they were considering how other data obtained in maintenance and periodic verifications might be trended to indicate any degradation. Currently, new data from diagnostic tests were compared with any previous test results.

Based on their review, the inspectors considered the trending being performed by the licensee sufficient to meet the recommendations of GL 89-10. Further, the GL 89-10 recommendations for trending has been interpreted to only require implementation by the conclusion of the implementation period. As the licensee was found to have implemented trending prior to their commitment date for completion of GL 89-10 implementation, the matter was satisfactorily resolved.

3.7 (Closed) Violation 50-414/94-15-01: Five Examples of Improper Procedure Use and Adherence

The violation cited five examples of improper procedure use and adherence issues identified in the maintenance and operations areas. The inspector reviewed the licensee's response dated August 12, 1994, and corrective action documentation associated with the violation.

The licensee's immediate corrective actions to reinforce procedure use and adherence standards included a site wide management communication in the form of "timeout" meetings with all individuals in the Operations, Maintenance, Chemistry, Radiation Protection, and Engineering Departments involved in the preparation and/or execution of technical procedures. The inspectors reviewed this corrective action in NRC inspection report 50-413,414/94-15 and found it to be effective.

The inspector verified by reviewing corrective action documentation (PIPs C94-0542, 0552, and 0566) that procedure revisions were also initiated to correct weaknesses that contributed to the violation. In view of the human performance improvement initiatives that have been undertaken site-wide, in conjunction with the specific corrective actions taken for these issues, this violation is closed.

4.0 **ENGINEERING** (NRC Inspection Procedures 37550, 37551 and 92903)

Throughout the inspection period, the inspectors reviewed engineering evaluations, root cause determinations, and modifications. During these inspections, discussions were held with operators, engineers, and plant management. The inspection evaluated the effectiveness of licensee controls in identifying and appropriately documenting problems, as well

as implementing corrective actions.

4.1 EXCESSIVE STROKE TIME FOR MAIN STEAM ISOLATION VALVE

During this inspection period the inspector reviewed the licensee's reportability evaluation and failure determination for an excessive stroke time measured for Unit 1 main steam isolation valve 1SM-1. The stroke time issue for 1SM-1 arose during the licensee's resolution of a valve inservice testing program issue that dealt with the required method for performing quarterly stroke time tests of actuators equipped with dual train actuation solenoids. Prior to this, the licensee performed stroke time testing of dual train valves from both solenoids only during refueling outages when the plant was in cold shutdown. The licensee determined on 11/9/95 that stroke time testing from both solenoids was required to be performed quarterly.

Once the licensee made the determination that quarterly stroke testing from both solenoids of dual train solenoids was required, the licensee took appropriate actions to declare the affected valves on both units inoperable as required by TS 4.0.5, Surveillance Requirements for Inservice Testing. The inspector reviewed corrective action documentation (PIP 0-C95-2136) and verified that licensee completed quarterly stroke time testing for the dual train valves within 24 hours as required by TS 4.0.3, Failure to Perform a Surveillance Requirement. All valves tested met stroke time acceptance criteria.

The licensee also reviewed surveillance documentation for dual train solenoid valves which are only tested during cold shutdown (includes the main steam isolation valves) to verify stroke times measured during the previous refueling were also within acceptance criteria. All of these valves were determined to be operable as a result of this review. However, records for MSIV 1SM-1 showed that this valve had an excessive stroke time during B train testing performed in March 1995. The licensee performed maintenance and retested the valve with acceptable results on March 17, 1995, but personnel performing the test did not initiate a PIP for the test failure or recognize that a reportability evaluation for the failure was appropriate.

The inspector discussed the evaluation sequence with engineering and safety assurance personnel, and reviewed the signature history report associated with the reportability evaluation (PIP 0-C-95-2136). The licensee's initial reportability determination took almost four months to complete. The evaluation focused on determining if the 1SM-1 was past operable with a stroke time of greater than 10 seconds when the valve was stroked with the B train solenoid.

TS full closure stroke time requirements state that the MSIV should close within 8 seconds (TS 3.7.1.4, Main Steam Isolation Valves) and response time requirements for steam line isolation initiated by low

steam line pressure or high containment pressure require a total response time of less than or equal to 10 seconds (TS 3.3.3.2, Engineered Safety Features Actuation System Instrumentation).

The licensee's engineering evaluation of past operability was forwarded to safety assurance personnel in December 1995. In January 1996 safety assurance returned the evaluation several times for additional information to support past operability. On January 29, safety assurance personnel refused concurrence again due to inadequate information to support the past operability evaluation. Following this, the licensee continued evaluation of past operability and reportability until 3/5/96 when the licensee determined the event was reportable per 10CFR 50.73 as a condition prohibited by TS. Evaluations performed in February attempted to justify rounding the measured stroke time from 10.2 seconds to 10 seconds. The inspector subsequently reviewed the actual surveillance records of the stroke time and found the actual time to have been 10.6 seconds. The inspector reviewed the safety significance of the event and observed, based on the licensee's evaluation, that the excessive stroke time of 1SM-1 would be bounded by the assumptions of the current FSAR and was not safety significant.

The inspector could not determine if the failure to initiate a PIP following the initial stroke time failure of 1SM-1 was an isolated personnel error or a programmatic concern. The licensee plans to perform an in plant review of PIP initiation for conditions that exceed test acceptance criteria to determine if failing to initiate a PIP for test failures is a widespread problem. The inspector will review the results of the licensee's in plant review audit when it is completed. The inspector observed that the licensee's evaluation of the 1SM-1 stroke time failure was of poor quality and lacked rigor. As of the end of the inspection period the licensee's final reportability and failure evaluation was not completed. Pending the licensee's completion of this evaluation and an in-plant review of PIP initiation performance, this issue will be identified as Unresolved Item 50-413/96-02-05: Review Results of MSIV 1SM-1 Reportability Evaluation and In-Plant Review of PIP Initiation Performance.

4.2 UNIT 2 LETDOWN PIPING ASSESSMENT

On February 11 the inspectors performed a walkdown of a portion of the Unit 2 letdown piping in the immediate vicinity of 2NV14, Letdown Orifice Header Relief Valve. The walkdown was performed prior to the restart of Unit 2 following the loss of offsite power event that occurred on February 6. During the event a potential water hammer or pressure pulse was suspected to have occurred in the letdown system.

The inspectors verified during the walkdown that letdown system piping and supports were not damaged and that no active leakage from valves was present that would have indicated a significant water hammer. An NRC reactive inspection team reviewed the licensee's engineering assessment

of the letdown piping prior to Unit 2 restart and documented this review in NRC Inspection Report 50-413,414/96-03.

4.3 AUXILIARY FEEDWATER CHECK VALVE LEAKAGE

On January 17, in preparation for a pump head verification performance test of the Unit 1 turbine-driven auxiliary feedwater pump, the pump's discharge was aligned to the upper surge tank (UST). A manual valve (1CA-67) in the test flowpath to the UST leaked and drew warm water past the turbine-driven auxiliary feedwater pump discharge check valves and into the turbine-driven auxiliary feedwater common header piping upstream from the check valves. Temperatures in pump discharge piping reached up to 340°F in two of the four lines of piping to the steam generators. The temperature increase indicated backleakage through 1CA-37 (to 1"D" steam generator) and 1CA-65 (to 1"A" steam generator).

The system engineer was contacted, but could not provide an explanation of how the leakage might have occurred. The licensee estimated that the pressure in the pump discharge piping was around 1000 psi; therefore, the risk of steam voiding was very low at 340°F. The system engineer proposed that operations perform the procedure for cooling the check valves and reattempt the UST alignment for testing. Power was reduced to 99% and the turbine-driven auxiliary feedwater pump was run to cool the check valves. Realignment to the UST was attempted a second time and temperatures at discharge piping associated with the 1A, 1C, and 1D steam generators again increased up to 340°F.

The piping between the pump and the check valves is rated to 160°F according to the Auxiliary Feedwater System Flow Diagrams, Drawing Nos. CN-1592-1.1 and CN-2592-1.1 for Units 1 and 2, respectively. After the second unsuccessfully attempted test alignment the licensee recognized that the thermal rating had been exceeded. An operability evaluation was performed to demonstrate that no piping or hanger/support degradation had occurred. The inspector reviewed the evaluation, documented in PIP C96-0120, and discussed the evaluation with engineering personnel. No concerns with the operability evaluation for the peak to 340°F were identified, although the inspector did question the repetitive exposure of the pump's discharge piping to temperatures above the design rating because of ongoing check valve backleakage problems.

To cool turbine-driven auxiliary feedwater pump discharge piping (heated from check valve backleakage), operations personnel had been running the turbine-driven auxiliary feedwater pump when temperatures in the discharge piping reached 225°F. Since Unit 2 restart from the October-November 1995 refueling outage, the Number 2 turbine-driven auxiliary feedwater pump had been run up to two or three times per shift in response to 2CA-53 backleakage (a problem previously documented in NRC Inspection Report 50-413,414/96-01). To avoid pump degradation from

excessive starts, the operations organization requested engineering support for changing the temperature criterion from 225°F to 250°F in Enclosure 4.12 of procedure OP/1/A/6250/02, Auxiliary Feedwater System. Engineering performed an evaluation to increase the temperature rating from 160°F to 300°F in support of the procedure change. The results of the associated stress analysis showed that at 300°F a number of pipe support loads exceeded those specified in the licensee's design criteria. Based upon guidance included in NRC Bulletin 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts, which allowed interim operation with reduced pipe support load margin, the analysis was referenced as a technical basis for determining that the piping was still operable at a 300°F temperature.

On February 21, Enclosure 4.12 of procedure OP/1/A/6250/02 was changed to reflect a temperature criterion for running the pump at 250°F. The inspector questioned the technical justification for the temperature change, given that without reliance on Bulletin 79-02 guidance, it apparently placed auxiliary feedwater system operation outside the design basis. Pending further NRC evaluation by an appropriate specialist, this issue is characterized as Unresolved Item 50-413,414/96-02-06: Auxiliary Feedwater Piping Temperature in Excess of Design.

4.4 OPERABILITY OF 2"D" STEAM GENERATOR POWER OPERATED RELIEF VALVE

On February 6, following a Unit 2 loss of offsite power, operations requested that engineering reevaluate the operability status of the "D" steam generator PORV (2SV-1) so that it could be used to facilitate plant cooldown. The PORV had been declared inoperable on January 31 when the test conditions for the performance of a PORV inservice test (PT/2/A/4200/31) could not be established.

The test provides for the PORV block valve to be closed and the PORV to be placed in manual and opened (normal valve position is closed). By procedure, a jumper is then placed to simulate a high steamline pressure signal, which sends an open signal to the PORV. The valve is placed in automatic and remains open in response to the simulated high steamline pressure signal. A safety-grade solenoid is deenergized to fail the valve closed, and the stroke time is measured.

During preparation for the stroke time test, the valve would not stay open when placed in automatic. The procedure directed that the valve be declared inoperable if the valve did not stroke to initial test position, and the crew performing the test considered the valve's inability to remain in the initial test position (open) to meet this criterion. Therefore, a Technical Specification Operability Notification Sheet (TSONS) was completed and provided to Operations to document the inoperability of the PORV. In addition, Work Request 96004596 was initiated for repair of the valve.

On February 2 troubleshooting was performed under Work Order 96009676-01 and revealed that a contact for main steamline pressure switch 2SMPS5491 would not actuate. The pressure switch was replaced per I/P/0/A/3890/017 and the inservice test was attempted again on February 6. The same problem was experienced during test preparation, and the valve remained inoperable pending resolution of the issue.

During plant recovery from the loss of offsite power and subsequent unit trip and safety injection, natural circulation was established in three of the four primary system loops. Because the PORV associated with the "D" SG was inoperable and in the closed position, natural circulation was inhibited in that loop. To facilitate natural circulation by cycling the PORV, Operations requested that Engineering provide an operability evaluation for declaring the PORV operable.

Engineering personnel reviewed the circumstances surrounding the initial declaration that the valve was inoperable and determined that the valve appeared to be failing to its primary safety position (closed) for containment isolation. Its secondary safety function, to facilitate a controlled plant cooldown, could be provided manually. Therefore, engineering personnel concluded that the PORV was operable.

Nuclear Station Directive (NSD) 203: Operability (Rev 4., 9/21/95), states that the evaluation documentation is usually completed before notification is sent to the Operations Shift Manager by way of an Operability Notification Form. However, the operability of the PORV was communicated to Operations verbally on February 6, 1996. A Technical Specifications Operability Notification, Attachment 1 of Catawba Site Directive 3.1.15, was not provided to Operations until February 10, following replacement of a failed solenoid in the nitrogen supply to the actuator and a successful stroke test of the PORV.

The inspector concluded that the operability evaluation of the PORV was reasonable and the return of the PORV to operable status was appropriate. The inspector also verified that the stroke test, completed on February 10, was successfully performed before the surveillance interval time had expired. The verbal communication of the valve's operability was determined to be appropriate for the circumstances and not contrary to the administrative procedures governing operability. No concerns were identified by the inspector.

4.5 AUXILIARY FEEDWATER PUMP TRIP & THROTTLE VALVE FAILURE TO REMAIN CLOSED

During this inspection period the inspector reviewed the resolution and troubleshooting of a previously identified problem with valve 1SA-145, Turbine Driven AFW Pump Trip & Throttle Valve. 1SA-145 is a normally open valve located on the inlet of the steam supply to the AFW pump turbine that functions to close and isolate the steam supply when a mechanical or electrical overspeed signal is generated from the AFW pump turbine.

The licensee had identified problems with the operation of 1SA-145 in June 1994 when the valve would intermittently reopen after being closed electrically. At this time, the licensee determined that 1SA-145 would operate normally and remain closed if the valve received a mechanical overspeed trip. Accordingly, it was not an operability concern. In January 1996, the licensee was troubleshooting 1SA-145 to complete corrective actions from the June 1994 failure and the problem of the valve opening recurred. Following this failure licensee management initiated a root cause evaluation team to investigate the continuing problems with 1SA-145. The inspector reviewed the results of the root cause evaluation and found it to be very thorough and comprehensive. The evaluation determined that the intermittent reopening problem with 1SA-145 actually began in December 1993, but was viewed as nonrecurring spurious failure at that time. The evaluation team also determined that several factors contributed to the slow resolution of the problem, including poor work prioritization, high PIP initiation threshold, inappropriate PIP screening when a PIP was ultimately initiated, and inadequate interface between organizations.

The inspector witnessed further maintenance troubleshooting performed in March 1996 (work order 96009530-01) and observed that the failure was suspected to be a sticking relay in the valve actuator opening circuit. The licensee simulated the failure by placing a jumper around this relay. Based on this troubleshooting the licensee replaced the relay and sent the failed relay to a testing facility for failure analysis.

Based on this review, the inspector concluded that the licensee's failure to determine and repair the cause of an intermittent failure of 1SA-145 for approximately two years is an example of untimely equipment problem resolution. The inspector also recognized that the licensee's root cause evaluation of this issue was thorough and comprehensive.

4.6 SPENT FUEL POOL

The inspectors reviewed the plant practices, procedures, calculations, and parameters associated with the Spent Fuel Pool (SFP) and support systems to determine if these were consistent with the description in the licensing basis as described in the Final Safety Analysis Report (FSAR) and related Safety Evaluation Report (SER). Sections 9.1.2, 9.1.3, 9.1.4 and 15.7.4.2.1 of the FSAR described the SFP systems and structures. Additionally, the inspectors reviewed the potential for SFP draw down and applicability to Catawba Nuclear Station of the Millstone SFP issue.

<u>Spent Fuel Pool Final Safety Analysis Report Description</u>

The SFP and support system configuration described in the FSAR was verified by review of system drawings and field verification. Licensee procedures, modifications, open work requests, logs, and Technical Specifications were reviewed to determine if FSAR referenced parameters

and operating conditions were consistent with the FSAR description. Critical parameters reviewed included predicted decay heat loads, SFP bulk water temperature, and SFP level. The calculations were specifically reviewed to verify that the SFP decay heat loads specified in the FSAR for various SFP loading configurations were evaluated and the cooling system was adequately sized to maintain SFP temperatures within the values specified for the corresponding loading conditions.

There are two SFPs at Catawba; one pool for each unit. Each Unit has two separate strings of pumps, heat exchangers, filters and associated equipment which are joined into a single discharge line prior to entering the pool. There is one purification loop for each SFP. Makeup to the pool is available from the RWST (Refueling Water Storage Tank), RHT (Recycle Holdup Tank), and RMWST (Reactor Makeup Water Storage Tank). Assured make up was provided by the Service Water System. The inspectors reviewed OP/1/A/6200/05, Spent Fuel Cooling System, dated March 8, 1995, and AP/1/A/5500/26, Loss of Refueling Canal or Spent Fuel Pool Level, dated October 12, 1995, which contained steps for addition of makeup to the pool. Both Spent Fuel Temperature and SFP level had indication and alarms in the control room. The instrumentation associated with the SFP was not safety-related. The alarm point for SFP temperature was set at 135 °F to protect the demineralizer resins in the purification system. This was being changed to alarm at 125 °F to account for a nine degree instrument string error. The refueling canal for each unit is separated by a weir wall from the SFP. Prior to refueling, the weir gate is installed and the transfer canal drained to perform the necessary surveillance on the up-ender. The fuel transfer tube in the transfer canal was isolated from the containment by a gate valve on the SFP side and a blank flange on the containment side which is leak tested to ensure containment integrity.

The inspectors reviewed both CNC-1223.20-00-0007, Spent Fuel Cooling System Design Verification, dated January 17, 1984, and CNC-1201.30-00-0014, Decay Heat and SFP Temperature Calculation for Fuel Enrichment Upgrade, revision 3. The latter calculation superseded the previous heat load calculation, CNC-1223.20-00-0007. The nominal heat load condition described in the FSAR and assumed in the calculation was one-third core with full irradiation and 7 day decay, one full core of open spaces, and the remainder of the pool filled with fully irradiated spent fuel. The maximum heat load condition was defined in a Duke letter to the NRC dated June 19, 1995. The maximum load was a full core discharge, 7 days decayed, and the remaining filled with consecutively discharged batches of 76 assemblies to fill the 1409 fuel assembly cells. The original predicted heat loads in the FSAR for these conditions was 17.0 E6 BTU/HR (nominal) and 39.0 E6 BTU/HR (maximum). The predicted heat loads for the increased enrichment fuel was 18.5 E6 BTU/HR (nominal) and 47 E6 BTU/HR (maximum) as determined in calculation CNC-1201.30-00-0014. Amendments 134/128, which referenced the increased heat load values, had not yet been incorporated into the FSAR.

The calculations referenced above included verification that the SFP cooling system was adequate to maintain the bulk water temperatures below 150 °F with the cooling system configurations specified in the FSAR. The licensee performed field testing of the SFP heat exchangers which was documented in CNC-1201.30-00-0014. The testing demonstrated close agreement between calculated heat loads on the component cooling side and the SFP cooling side. The inspectors reviewed the SFP coolers heat exchanger specifications and data sheets and found agreement with the FSAR and calculations used to verify meeting SFP temperatures under design conditions.

Potential Spent Fuel Pool Draw Down

The FSAR description of the SFP in sections 9.1.2.3 and 9.1.3.1.3 stated there were no connections which could result in inadvertent draining of the pool below the level for shielding. However, the Catawba SFP included a connection which could permit SFP draw down below the level required for shielding. The supply line to provide Reactor Coolant Pump (RCP) seal water in a Safe Shutdown System (SSS) event was connected to the fuel transfer tube in the annulus at an elevation below the top of the SFP fuel assembly racks. Due to the Weir wall separating the SFP from the fuel transfer canal, SFP level decrease would be limited to the 573 foot elevation, which was adjacent to the top of the racked fuel assemblies. This condition assumed there was no operator action. This level would be below the level required for shielding. This deviation from the SFP design specified in the FSAR is identified as Violation 50-413,414/96-02-07 (Example 1): Failure to Revise FSAR to Reflect SFP Configuration.

The inspectors reviewed the barriers which would reduce the potential for SFP draw down or mitigate the consequences. The consequences from SFP level decrease would be loss of cooling and radiation shielding. The SSS piping was seismically qualified for the Safe Shutdown Earthquake; therefore, the potential for piping failure was limited. This flow path was provided for RCP seal supply in an SSS event only; therefore, the potential for misoperation was limited. Isolation for the piping was provided in the SFP via manual isolation of the fuel transfer tube. The SFP low level alarm annunciator response procedure required isolation of the fuel transfer tube as an immediate action. The licensee analyzed the response time available if the seismically qualified three inch SSS piping in the annulus ruptured and determined that five hours were available before level decreased to a point at which radiation shielding was compromised (i.e., ten feet above the racked fuel assemblies). The inspectors concluded that barriers were available to prevent or mitigate the impact of level loss due to this piping interface.

The licensee analyzed the level decrease expected during an event which required activation of the SSS and provision of RCP seal water. The level decrease resulting from boil off and RCP seal supply in 72 hours

would be approximately down to 7.9 feet above the racks. The corresponding radiation dose was determined to be 7.5 R/hr. This analysis assumed no operator action to establish SFP refill. Abnormal operating procedures included guidance for refill of the SFP from either of the three available sources, primarily gravity drain from the RWST. The inspectors concluded that SFP level decrease during the SSS event would not significantly impact the shielding or cooling function of the SFP.

Millstone Issue - SFP Loading Condition Not Evaluated

The inspectors reviewed the SFP loading conditions evaluated by the predicted decay heat load analysis referenced in paragraph 4.1 of this report. SFP loading considerations included heat loads and criticality. The calculations for predicted decay heat load assumed a 7-day decay time following reactor shutdown before transferring a full or one third core to the SFP. FSAR section 9.1.3.1.1 specified a similar 7-day decay time in its descriptions of SFP load decay heat conditions. Technical Specification 3.9.3 and fuel transfer administrative controls specified a 72 hour (3 day) delay prior to fuel movement. The inspectors concluded there were no administrative controls which assured the 7-day assumption in the decay heat load analysis was valid.

The inspectors reviewed the licensee's refuelling practices to determine if the 7-day assumption had been met. Additionally the procedures were reviewed to determine what barriers would assure the SFP heat loads did not exceed the cooling system capacity. The control room logs from the previous RFOs and the schedule for the upcoming Unit 1 RFO demonstrated that fuel assembly transfers were not performed or planned until at least the eighth day after the reactor was shutdown. A barrier was provided by the fuel transfer procedure requirement to discontinue fuel transfer if the SFP temperature reached 150 °F. The procedures also required routine monitoring of SFP temperatures. A high temperature alarm would be annunciated in the control room at 135 °F. The capacity of the SFP cooling system was based on maintaining the 150 °F temperature limit; therefore, this administrative control provided assurance that the SFP capacity to remove decay heat was not exceeded.

Nominal and maximum decay heat loads define specific loading conditions for evaluation that supported sizing of cooling systems and SFP bulk water temperature criteria. The significant difference was that the maximum heat load included a full core off load rather a one third core off load. Catawba has routinely performed a full core off load during refueling outages since 1982. This condition was not prohibited by the licensing basis. FSAR section 9.1.3.1.1 referenced a full core off load to the SFP. The calculations included the full core off load in the evaluation of heat load conditions for sizing the cooling system. The FSAR references and supporting calculations demonstrated that the full core off load condition was evaluated.

SFP loading configuration based on criticality analysis was specified by TS 3.9.13. These loading restrictions were added to the TS in August 1995 to address the increased fuel enrichment. The restrictions were scheduled to be incorporated into procedures prior to the upcoming Unit 1 Refueling Outage.

The inspectors concluded that the full core off load condition had been adequately evaluated and verified within the capacity of the SFP cooling systems at Catawba. Sufficient administrative controls assured the SFP loading was consistent with the configuration specified in the FSAR and incorporated as assumptions in the analysis. The Millstone issue was not applicable at Catawba.

Spent Fuel Pool Issues Self-Assessment

The inspectors reviewed the licensee's self-assessment in this area. A team of engineering and licensing personnel were assembled in the week prior to the inspection to review the SFP design and licensing basis compliance. The team concluded that Catawba was in compliance with the SFP design and licensing basis. The inspectors concluded the licensee performed an adequate review of the SFP licensing and design basis.

5.0 **PLANT SUPPORT** (NRC Inspection Procedures 82701, 84750, 83750, 86750, 71750 and 92904)

Throughout the inspection period, facility tours were conducted to observe activities in progress. Some tours were conducted during backshifts. The tours included entries into the protected areas and the radiologically controlled areas of the plant, including emergency response facilities. Observations included assessments of radiological postings and work practices. During these inspections, discussions were held with radiation protection and security personnel. The inspections evaluated the effectiveness of the programs to assess whether activities were performed safely and in conformance with license and regulatory requirements.

5.1 ANNUAL EMERGENCY PREPAREDNESS EXERCISE

On March 12, the licensee's annual emergency preparedness exercise was conducted. The exercise was a full participation exercise which involved NRC, State and Local participation. During the exercise all of the licensee's emergency organization facilities were staffed and activated. NRC personnel participated in the simulator control room, Technical Support Center, Operations Support Center and Emergency Operations Facility. An NRC inspection team also evaluated performance during the exercise. The results of the NRC inspection are documented in NRC Inspection Report 50-413,414/96-04.

5.2 RADIOACTIVE EFFLUENT MONITORING INSTRUMENTATION

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and plant practices, procedures, and/or parameters observed by the inspector.

Chapter 11.5.1.2.2.5 of the UFSAR titled Control Room Air Intake Monitors states " Gaseous activity in a control room air intake which exceeds a preset limit actuates an alarm in the control room and automatically initiates isolation of the affected air intake." This system is described in three other sections in the UFSAR correctly (Chapter 6.4.3, 9.4.1.1, & 9.4.1.3). Should a high radiation level or a smoke concentration level be detected in the intake, station procedures direct the actions of the operator to manually close the most contaminated intake. The automatic to manual operation, by procedure, was changed in 1991. A 50.59 evaluation was performed (CNC-1503.13-00-0369) Titled 50.59 review of NSM CN - 50422/00 VC System Mode. This was completed on February 28, 1991. The licensee committed to correct the one incorrect reference (Chapter 11.5.1.2.2.5) in the next UFSAR Revision. This was judged to be a minor inconsistency.

Chapter 11.5.1.2.2 Titled Airborne Monitoring states that "The Catawba Nuclear Station uses continuous air samplers to monitor radioactive iodines and particulates contained in the plant gaseous effluent. The monitors utilize silver zeolite cartridges for iodine sampling to minimize interference from high levels of noble gases." The inspector was informed by the licensee that they had never used silver zeolite in this manner. The licensee stated that they had always used activated charcoal for this monitoring. The licensee has outlined a corrective action plan including procedures review, calculational review, collection efficiency review and a thorough review of the UFSAR to ensure that any other inconsistencies or deviations in the airborne monitoring and use of sampling media are identified and corrected. This is identified as a Violation of 10 CFR 50.71. <u>Violation 50-413, 414/96-02-07 (Example 2): Failure to Revise FSAR to Reflect The Use of Silver Zeolite to Sample Gaseous Effluent.</u>

The inspector reviewed records of Radiation Monitor (EMF) Reliability for 1995 and observed that the system average availability for Technical Specification/Selected Licensee Commitments (TS/SLC) EMF monitors was >97 percent and slightly >93 percent for the non TS/SLC monitors. EMF failures were being tracked and trended. Power Supplies and Signal Cable Connectors were listed as the largest contributor to subcomponent failures.

The inspector questioned the licensee about the temperature qualifications for the beta scintillation detectors in use for the Control Room Ventilation System. These detectors (EMF43A, EMF43B) sample outside air. At the time of the inspection the licensee had no qualification data on their monitors; however, these detectors were similar to detectors that were only qualified to 40 degrees F. The licensee opened PIP item C96-0520 to address the issue. The licensee was informed that this item will be tracked as Inspector Followup Item 50-413,414/96-02-08: Temperature Qualification of Control Room Intake Air Radiation Monitors.

One violation, one minor discrepancy in the UFSAR, and one IFI were identified.

5.3 PLANT WATER CHEMISTRY

During the inspection, Unit 1 and Unit 2 were operating at one hundred percent power. The inspector reviewed the plant chemistry controls and operational controls affecting primary plant water chemistry since the last inspection in this area. TS 3/4.4.7 specifies that the concentrations of dissolved oxygen (DO), chloride, and fluoride in the Reactor Coolant System (RCS) be maintained below 0.10 parts per million (ppm), 0.15 ppm, and 0.15 ppm, respectively. TS 3/4.4.8 specifies that the specific activity of the primary coolant be limited to less than or equal to 0.58 microcuries/gram (μCi/g) dose equivalent iodine (DEI) for Unit 1 and 1.0 (μCi/g) DEI for Unit 2 whenever the reactor is critical or the average temperature is greater than 500°F.

These parameters are related to corrosion resistance and fuel integrity. The oxygen parameter is established to maintain levels sufficiently low to prevent general and localized corrosion. The chloride and fluoride parameters are based on providing protection from halide stress corrosion. The activity parameter is based on minimizing personnel radiation exposure during emergency operation and maintenance.

Pursuant to these requirements, the inspector reviewed selected graphical summaries for both units which correlated reactor power output to chloride, fluoride, and DO concentrations, and specific activity of the reactor coolant. For both Units 1 and 2, the period of January 1, 1995, through February 29, 1996, was reviewed and the parameters were determined to have been maintained well below TS limits.
The inspector concluded that the Primary Water Chemistry was maintained well within the TS requirements.

No violations or deviations were identified.

5.4 PROCESS AND EFFLUENT MONITORS

TS 3/4.3.3.1 defines the operation and surveillance requirements for

monitors of radioactive (or potentially radioactive) streams. This instrumentation is provided to monitor and control the releases of radioactive materials during normal and abnormal plant conditions, as well as in effluents during effluent releases. The alarm/trip setpoints for the effluent monitors are calculated in accordance with the procedures in the Off-site Dose Calculation Manual (ODCM) to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR 20. The alarm/trip setpoints for the process monitors are specified by the TSs.

The inspectors walked down 1EMF43A & 1EMF43B Control Room Air intake and 1EMF37 Unit Vent Iodine, 1EMF35 Low and High Vent Particulate and 2EMF36(L) Unit Vent Gas, 2EMF37, Unit Vent Iodine, process and effluent monitoring stations to become familiar with their physical location in the plant and to observe their state of maintenance and operability. The inspector verified that the licensee had a heat trace preventative maintenance program to check the operability of the heat tracing for the EMF sample lines. Work Order No. 90042266 was reviewed and it identified the elements and tasks to be completed in the preventive maintenance program. The monitors were found to be well-maintained and operable.

No violations or deviations were identified.

5.5 RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

TS 6.8.4.g required the licensee to provide a program to monitor the radiation and radionuclides in the environs of the plant as described in Chapter 16 of the Final Safety Analysis Report (FSAR). The sampling locations, types of samples or measurements, sampling frequency, types and frequency of sample analysis, reporting levels, and analytical lower limits of detection (LLD) were specified in Section 16.11-13 of the SLC.

TS 6.9.1.6 and Section 16.11-16.1 of the SLC delineated the requirements for submitting, the submittal dates, and the content of the Annual Radiological Environmental Operating Report. The report was required to be submitted prior to May 1 of the following year and to provide an assessment of the observed impact on the environment resulting from plant operations during the previous calendar year.

The inspector reviewed the licensee's 1994 Annual Radiological Environmental Operating Report and discussed its content with the licensee. The report was submitted prior to May 1, 1994, and included the following: a description of the program, a summary and discussion of the results for each exposure pathway, analysis of trends and comparisons with previous years and preoperational studies, and an assessment of the impact on the environment resulting from plant operations. The report also included the results of the Land Use Census and the results of the Interlaboratory Comparison Program. The following observations for the various exposure pathways were produced

by the licensee's evaluation of the 1994 environmental monitoring program data, and documented in the report, or were noted by the inspector during the review of the report.

Dose estimates calculated from environmental monitoring program data correlated well with dose estimates calculated from effluent data and were within 40 CFR 190 dose limits. The highest dose calculated from environmental sampling (excluding TLD results) for 1994 was 0.27 mrem. The report summary section indicated that the contribution to the environmental radioactivity resulting from plant operation was small and had no significant radiological impact on the health and safety of the general public.

- Airborne: 265 samples were analyzed (212 from indicator stations and 53 from control stations) for radioiodine and gross beta as part of the Radiological Environmental Monitoring Program (REMP) during 1994. Naturally-occurring K-40 and Be-7 were routinely detected on the charcoal cartridges. Cs-137 activity was detected on one charcoal cartridge, but not on the particulate filter. The licensee determined it to be inherent to the charcoal and was not included as an environmental indicator. All other concentrations of radioisotopes were less than the LLD. Naturally-occurring Be-7 activity was routinely detected on particulate samples, while naturally-occurring K-40 was occasionally detected. No other radionuclides were detected in any 1994 airborne particulate samples.

- Surface Water: K-40, Be-7 and H-3, all of which occur naturally, were detected in surface water samples. Tritium (H-3) was detected in all four composite samples collected from the Indicator Location 208, the discharge canal from the plant to Lake Wylie, at concentrations exceeding background. The highest concentrations observed were less than half of the required reporting limit. Liquid effluents from the plant appear to be responsible for the higher observed H-3 concentrations in the surface water samples from the discharge canal.

- Ground Water: Naturally-occurring K-40 was the only radionuclide detected in ground water samples collected during 1994 and the concentrations were consistent with those of previous years (i.e., they were determined to be at ambient background levels).

- Drinking Water: Naturally-occurring K-40 was the only radionuclide detected in drinking water samples collected in 1994. The observed concentration was consistent with ambient background levels and was probably not affected by plant effluents.

- Shoreline Sediment: Mn-54, Co-58, Co-60, Cs-134, and Cs-137 were detected in most of the twelve shoreline samples collected from the discharge canal (Locations 208-1S, 208-2S, and 208-3S).

Evaluation of the data collected since 1988 indicated that the concentrations of these radionuclides in the discharge canal shoreline sediment exhibit an increasing trend and are correlated with their activities released in liquid effluents.

- Milk: A total of seventy-eight milk samples were collected from three dairies, fifty-two samples were collected from two indicator dairies and twenty-six were collected from the control dairy. Cs-137 was detected in one sample collected from one indicator dairy (Location 209), the maximum being at less than one per cent of the reporting level. Evaluation of data collected during both preoperational and operational periods indicated that the low levels of Cs-137 were not attributable to plant effluents.

- Fish: Twenty-four fish samples were taken, twelve from Indicator Location 208 and twelve from Control Location 216, during 1994. Mn-54, Co-58, Co-60, and Cs-137 were detected in the fish samples collected. No Cs-134 was identified in fish samples in 1994. The highest concentration observed for those radionuclides was 2.1 percent of the quarterly reporting level. The detection of those radioisotopes indicated that these concentrations were primarily dependent upon the annual and cumulative activities released by the plant via liquid effluents.

- Broadleaf Vegetation: In 1994 Cs-137 was the only radionuclide detected (in low concentrations) in the samples collected from both the Indicator Locations (Locations 200, 201, and 226) and the Control Location (Location 217). The maximum quarterly average percent of the reporting limits was 2.93 percent, attributable to the Cs-137 activity of samples taken during the third quarter at Location 226. Evaluation of data collected during both preoperational and operational periods indicated that the low levels of Cs-137 were probably attributable to remanents of weapons testing.

- Direct Gamma Radiation: Exposures measured at forty locations during 1994 were not significantly different from exposures measured during preoperational studies.

Based on the above review, the inspector concluded that the licensee had complied with the sampling, analytical, and reporting program requirements and that the radiological environmental monitoring program had been effectively implemented. No reporting limits were exceeded and the dose to the public was a small percentage of regulatory limits.

No violations or deviations were identified.

5.6 RADIOLOGICAL EFFLUENTS

Technical Specification (TS) 6.9.1.7 and Section 16.11-16.2 of the

Selected Licensee Commitments (SLC) Manual described the reporting schedule and content requirements for the Annual Radioactive Effluent Release Reports. Summaries of the quantities of radioactive liquid and gaseous effluents released from the facility and an assessment of the radiation doses due to those releases were required to be included in the reports.

The inspector reviewed the quantities of radioactive liquid and gaseous effluents released by the facility and determined that the releases resulted in doses much less than the regulatory limits (all doses were <10% of the limit). Based on the above reviews, the inspector concluded that the licensee had implemented and maintained an effective program to control liquid and gaseous radioactive effluents. The projected offsite doses resulting from those effluents were well within the limits specified in the TSs and 40 CFR 190.

The effluent reports indicated that there was one unplanned release on November 2, 1994, at approximately 1600 hours. The unplanned release occurred when licensee personnel were cycling a Waste Gas System Valve and gas leaked from the moisture trap. The release lasted about 210 minutes and a total of 8.88 Ci of noble gas was released. The total body dose calculated for this release was 2.63 E-03 mrem. No release limits and no dose limits were exceeded. A minor system modification was implemented which replaced the moisture traps.

The licensee submitted changes to the Off-site Dose Calculation Manual (ODCM) and Process Control Program (PCP) to the NRC for review on January 5, 1995. The inspector did not review or evaluate these changes.

The following table summarizes solid radwaste shipments for burial or disposal for 1994 and the previous three years. These shipments typically included spent resins, filter sludge, dry compressible waste, and contaminated equipment.

Catawba Solid Radwaste Shipments

	1991	1992	1993	1994
Number of Waste Disposal Shipments	10	31	7	13
Volume (cubic meters)	115.8	207.3	154.2	223.4
Activity (curies)	335.5	988.6	105.2	312.5

The inspector concluded that the Annual Radioactive Effluent Release Report was complete and satisfied TS requirements.

No violations or deviations were identified.

5.7 RADIATION PROTECTION AND CHEMISTRY ACTIVITIES AUDIT

TS 6.5.2.9 states that audits of site activities shall be performed under the cognizance of the Nuclear Safety Review Board (NSRB). These audits shall encompass: (1) The Radiological Environmental Program and the results thereof; (2) The Process Control Program and implementing procedures for processing and packaging of radioactive wastes; and (3) The performance of activities required by the Quality Assurance Program for effluent and environmental monitoring.

The inspector reviewed Departmental Audit NG-94-02(CN) Radiation Protection and Chemistry Activities dated April 13, 1994. This audit was conducted March 7 through March 29, 1994. The items identified during the audit were entered into the PIP program and assigned to the appropriate group for response. The audit was conducted in the following areas: Radiation Protection, Personnel Monitoring/Dose Records, Internal Dosimetry, Instrument Control, Radioactive Materials Control, Effluent Releases, Offsite Dose Calculation Manual Implementation, Respiratory Protection, Qualification/Training Chemistry - Lab QC, Technical Specification Sampling/Analysis, Procedures/Instructions, and Qualification/Training. The audit was detailed, probing and provided a valuable independent assessment of the chemistry area. The inspector noted that the items identified by the audit were tracked and assigned to appropriate individuals for close out. The inspector determined that the audit met the TS requirements.

No violations or deviations were identified.

5.8 RADIATION CONTROL SELF-ASSESSMENT PROGRAMS

Licensee activities and self-assessment programs were reviewed to determine the adequacy of identification and corrective action programs for deficiencies or weaknesses related to the control of radiation or radioactive material.

10 CFR 20.1101(c) requires that the licensee periodically review the RP program content and implementation at least annually.

The licensee's independent self-assessment in the radiation control area consisted of formal audits per TS requirements, documented observations and specific surveillance. A qualified auditor with health physics and chemistry qualifications experience was assigned to implement the licensee's assessment activities. The inspector reviewed licensee efforts to self identify potential radiological issues or problems while performing annual audits and internal self-assessments of the RP program.

Observations by the inspector and discussions with cognizant licensee personnel indicated that Quality Assurance audits and self-assessment efforts in the area of RP were accomplished by reviewing RP procedures,

observing work, reviewing industry documentation, and performing plant walkdowns to include surveillance of work areas by supervisors and technicians during normal work coverage. Documentation of problems by licensee representatives was included in Quality Assurance Audits and Self-Assessment Reports.

As part of the corrective actions program, the licensee's Problem Investigation Process was also used to report and resolve deviations from proper health physics practices, policies, or procedures in order to reduce radiation exposures to the public and plant personnel, and to provide safe radiological work conditions. The inspector reviewed selected PIPs, which included recommendations for corrective actions and final assessment of corrective actions.

The inspector concluded that the completed self-assessments met licensee UFSAR commitments and were of good quality.

No violations or deviations were identified.

5.9 EXTERNAL EXPOSURE CONTROL

Administrative Controls for External Exposure

This area was reviewed to determine whether personnel dosimetry, administrative controls, and records and reports of external radiation exposure met regulatory requirements.

10 CFR 20.1201(a) requires in part, that each licensee to control the occupational dose to individual adults.

The inspector reviewed and discussed with licensee representatives TEDE exposures for plant and contract personnel for the period of 1995. Through review of selected dose records and discussions with licensee representatives, the inspector confirmed that all TEDE exposures assigned during the period were within 10 CFR Part 20 limits.

From a review of selected records and discussions with licensee representatives, the inspector concluded that radiation worker doses were below regulatory limits.

Personnel Dosimetry

10 CFR 20.1502(a) requires in part, each licensee to monitor occupational exposure to radiation and supply and require the use of individual monitoring devices.

The licensee's dose tracking system tracked personnel exposures in order to ensure adherence to procedural administrative allowances, as well as 10 CFR Part 20 limits.

The licensee continued to implement both Electronic Dosimeters (EDs) and self-reading pocket dosimeters (SRPDs); however, the former were being used as the primary devices for containment entries. The inspector observed personnel logging into the Electronic Dosimetry (ED) system. SRPDs were primarily staged for emergency use. From observations, the inspector noted personnel were properly utilizing the ED system. The inspector conducted random interviews with radiation workers in the RCA. The radiation workers were knowledgeable of their personal dose, and proper response to ED alarms.

Based on direct observation, discussion and review of records, the inspector determined personnel dosimeters were being effectively utilized. During tours of the RCA, the inspector noted that personnel observed were wearing EDs and TLDs properly.

High Radiation Areas

Technical Specification 6.8.1 requires, in part, that written procedures be established, implemented and maintained covering the activities referenced in the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, dated February 1978. Paragraph 7.e of Appendix A to Regulatory Guide 1.33 states that the licensee should have written radiation protection procedures.

Duke Power Company, System Radiation Protection Manual, Procedure No. III-15, titled "Access Controls for High, Extra High and Very High Radiation Areas," Revision 5, dated January 20, 1995, states that the purpose of this procedure is to establish and define the proper control for access to High, Extra High, and Very High Radiation Areas. Section 5.2.3 of this procedure required Extra High Radiation Area keys be maintained in a locked key box.

Contrary to the above, during facility tours on February 29, 1996, the inspector observed a lock on a box containing keys to Extra High Radiation Areas that was not secured. Upon discovery of the unlocked key box, the inspector informed the licensee of the condition and the key box was secured. The inspector discussed High Radiation Area Key controls with licensee representatives and reviewed key control methods. The licensee performed an inventory of the key box and determined all keys were accounted for. The inspector did note during tours of the facility with licensee representatives that doors to Extra High Radiation Areas (Locked High Radiation Areas) and Very High radiation Areas were appropriately locked. However, the inspector informed the licensee that failure to lock the key box was a violation of licensee procedure, System Radiation Protection Manual. Violation 50-413,414/96-02-09: Failure to Maintain Positive Control of Locked High Radiation Area Keys.

Based on observations, discussions with licensee representatives and procedure reviews, the inspector determined the licensee was controlling

High Radiation Areas appropriately with the exception of the unlocked key control box noted.

One violation was identified. No deviations were identified.

5.10 INTERNAL EXPOSURE CONTROL

This area was reviewed to determine the adequacy of 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 materials areas, and assessments of individual intakes of radioactive material and records of internal exposure measurements and assessments.

10 CFR 20.1502(b) requires each licensee to monitor the occupational intake of radioactive material by and assess the committed effective dose equivalent to:

(1) Adults likely to receive, in one year, an intake in excess of 10 percent of the applicable ALI in Table 1, Columns 1 and 2 of Appendix B to 10 CFR 20.1001-20.2401.

(2) Minors and declared pregnant women likely to receive, in one year, a committed effective dose equivalent in excess of 0.05 rem.

The inspector reviewed the licensee's respiratory protection program. The inspector discussed with the licensee, respirator reduction efforts with respect to engineering control methods to be used by the licensee for future respirator reductions to enhance ALARA concepts such as, worker training, successful decontamination efforts, and various engineering controls to include worksite ventilation and face shields.

Selected assessment results for personnel having indications of positive intakes of radioactive material were reviewed by the inspector. The licensee informed the inspector that they were tracking internal exposures greater than .01 Rem per year, which was a small fraction of the regulatory requirement. Only 2 workers received internal exposure in 1995; both of which were slightly above .01 Rem. The licensee reported no internal exposure to date for 1996. The inspector verified that records of workers' respiratory protection training, medical qualifications, and fit-testing for the specific respirator type used in accordance with licensee procedural requirements was being checked prior to issuing an individual a respirator.

Based on observations of respiratory protection equipment, a review of records, and discussions with licensee personnel, the inspector determined that the licensee had made efforts to maintain TEDE exposures ALARA. The licensee's program for monitoring, assessing, and controlling internal exposures was conducted in accordance regulatory

and procedural requirements. No exposures in excess of 10 CFR Part 20 limits were identified.

No violations or deviations were identified.

5.11 OPERATIONAL AND ADMINISTRATIVE CONTROLS

Radiation Work Permits

The inspector reviewed selected routine and special RWPs for adequacy of the radiation protection requirements based on work scope, location, and conditions. For the RWPs reviewed, the inspector noted that appropriate protective clothing, respiratory protection, and dosimetry were required. During tours of the plant, the inspector observed the adherence of plant workers to the RWP requirements and discussed the RWP requirements with selected plant workers and RP personnel. The inspector reviewed Radiological Survey Maps posted outside rooms/spaces in the plant used to enhance RWP information. The inspector noted personnel were being briefed on RWP requirements upon initial entry into an RCA. The inspector also performed independent radiation surveys of selected areas in the Auxiliary Building and waste handling areas to confirm RWP information.

The inspector found the licensee's program for RWP implementation to adequately address radiological protection concerns and to provide for proper control measures. Independent NRC surveys confirmed licensee survey information.

Notices to Workers

10 CFR 19.11(a) and (b) require, in part, that the licensee post current copies of 10 CFR Part 19, Part 20, the license, license conditions, documents incorporated into the license, license amendments and operating procedures, or that a licensee post a notice describing these documents and where they may be examined.

10 CFR 19.11(d) requires that a licensee post form NRC-3, Notice to Employees. Sufficient copies of the required forms are to be posted to permit licensee workers to observe them on the way to or from licensee activity locations.

During the inspection, the inspector verified that NRC Form-3 was posted properly at plant locations permitting adequate worker access. In addition, notices were posted referencing the location where the license, procedures, and supporting documents could be reviewed. The inspector interviewed selected personnel and verified personnel were familiar with the requirements of 10 CFR 19.11(d).

Based on a review of the RWP area, no problems were noted.

No violations or deviations were identified.

5.12 RADIOACTIVE MATERIALS AND CONTAMINATION, SURVEYS, AND MONITORING

This program area was reviewed to determine whether survey and monitoring activities were performed as required and control of radioactive materials and contamination met regulatory requirements and UFSAR commitments.

Surveys

10 CFR 20.1501(a) requires each licensee to make or cause to be made such surveys as (1) may be necessary for the licensee to comply with the regulations and (2) are reasonable under the circumstances to evaluate the extent of radioactive hazards that may be present.

The inspector reviewed selected records of routine and special radiation and contamination surveys performed and discussed the survey results with licensee representatives. During tours of the plant, the inspector independently verified radiation levels in portions of the Auxiliary Building with the focus being on the adequacy of labeling hotspots in accordance with licensee procedures. No concerns with the adequacy or frequency of the radiological survey activities were identified.

The inspector reviewed licensee progress regarding the elimination of a large number of radiation hotspots in the plant. In 1993, 170 hotspots were being tracked by the licensee and an IFI was identified in NRC Inspection Report 50-413,414/93-23. The licensee was continuing to track and trend radiation hotspots in the plant and to shield or flush out spots where practical to minimize exposure. The licensee was prioritizing the elimination of hotspots based on location and exposure potential. At the time of the inspection, the number of hotspots had been reduced to 102. Based on the licensee's plans and actions for reducing hotspots, the inspector informed the licensee that Inspector Followup Item 50-413,414/93-23-03: Elimination of large Number of Hotspots Throughout Plant, was closed.

The inspector also reviewed the licensee's corrective actions to a previously identified NRC violation identified in NRC Inspection Report 50-413,414/95-05: Failure to perform radiation surveys necessary to detect and post a radiation area in the Auxiliary Building associated with spent fuel pool cooling piping. The licensee had revised procedures to require surveys be performed around the spent fuel pool cooling piping upon commencement of refueling activities. No deficiencies in posting radiation areas was noted during the inspection and based on licensee corrective actions, the inspector informed the licensee that Violation 50-413,414/95-05-02: Failure to Make Surveys Necessary to Detect and Post a Radiation Area in the Auxiliary Building, was closed.

Based on observations, procedure reviews, and independent radiation surveys, the inspector determined the licensee was conducting surveys required by procedures at the time of the inspection.

Radiological Postings and Control of Contamination and Radioactive Material

10 CFR 20.1904(a) requires the licensee to ensure that each container of licensed material bears a durable, clearly visible label bearing the radiation symbol and the words "Caution, Radioactive Material," or "Danger, Radioactive Material." The label must also provide sufficient information (such as radionuclides present, and the estimate of the quantity of radioactivity, the kinds of materials and mass enrichment) to permit individuals handling or using the containers, to take precautions to avoid or minimize exposures.

During facility tours, the inspector noted that all containers and materials inspected were labeled to identify the radiological hazards present. The inspector discussed labeling procedures, practices, and storage of radioactive material with licensee management during the facility tours. The licensee was reducing the volume of radioactive waste in storage facilities at the time of the inspection.

The inspector concluded the licensee was posting and controlling radiation areas, HRAs, VHRAs, airborne radioactivity areas, radioactive material, and radioactive material storage areas in accordance with requirements.

Control of Contaminated Areas

During facility tours, the inspector observed contamination control and general housekeeping practices. At the time of the inspection contaminated square footage was approximately 0.5 percent (806 square feet) of the total Radiological Controlled Area (RCA) of 151,775 square feet.

Based on tours of the facility, selected independent survey reviews, and general work practices observed, the inspector concluded contamination control practices and housekeeping were adequate.

Personnel Contaminations

The inspector reviewed personnel contamination records for 1995 and 1996. In 1995, the licensee accumulated 274 PCEs. Dual Unit refueling outages occurred in 1995. At the time of the inspection, the licensee had accumulated 14 PCEs in 1996. The threshold for a PCE is contamination greater than 100 counts per minute above background.

Records reviewed determined the licensee was tracking and trending

personnel contamination events and no adverse trends in personnel contamination controls was noted during the inspection.

Radiation Detection and Survey Instrumentation

During facility tours, the inspector noted that survey instrumentation and continuous air monitors observed in use within the RCA were operable and calibrated. The inspector toured the instrument calibration room and observed additional instruments staged for issue. The inspector further noted an adequate number of survey instruments were available for use to support routine activities.

No violations or deviations were identified.

5.13 PROGRAM FOR MAINTAINING EXPOSURES AS LOW AS REASONABLY ACHIEVABLE

10 CFR 20.1101(b) requires that each licensee 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.

This program area was reviewed to determine the adequacy of the ALARA program for meeting UFSAR commitments. Areas reviewed included organization support, training, radiation source reduction, worker awareness and involvement, ALARA plans and reviews, and ALARA results in the implementation of the licensee's ALARA program.

The inspector interviewed selected ALARA staff members including the ALARA manager and determined the organizational structure and responsibilities for the ALARA staff were clearly defined in organizational charts. The inspector determined that the licensee's ALARA policy and objectives were adequately addressed in General Employee Training.

The inspector reviewed and discussed with licensee representatives the ALARA program implementation and planning initiatives for recent work performed and future work planned. Areas reviewed included source term reduction, ALARA accomplishments, and future ALARA plans. A discussion with licensee representatives and a review of pertinent records determined the licensee had established an annual site exposure goal for 1995 of approximately 410 person-rem. The licensee's 1995 annual site exposure goal was based on operational exposure and dual Unit refueling outages. Site exposure actually accrued in 1995 was approximately 462 person-rem for an average 1995 dose per reactor of 231 person-rem. The sites 3 year average through 1995 was approximately 159 person-rem per Unit. The 1995 Unit 1 Cycle 8 outage contributed approximately 40 additional person-rem to the dose over-run primarily from failure to perform crud burst activities adequately and cleanup activities during shut down operations. The original exposure goal for the Unit 1 Cycle 8 outage was approximately 199 person-rem compared to the actual outage

exposure of approximately 262 person-rem. Management attention focused on implementing refined crud burst/shutdown procedures during the following Unit 2 Cycle 8 outage and outage doses were significantly reduced to approximately 139 person-rem for the outage. The Unit 2 Cycle 8 original exposure goal was 162 person-rem. A number of ALARA initiatives contributed to lower exposures during the Unit 2 Cycle 8 outage, some of which included: improved scheduling of work activities; increased use of shielding and enhanced shielding technique for movement in and out of lower containment which reduced shielding installation by 100 hours from previous outages; use of teledosimetry for monitoring crud burst activities; increased use of video cameras; wireless communications with workers; use of a shielded bucket for workers performing cavity decontamination; and setting the reactor head prior to cavity floor decontamination. The licensee's steam generator dose was the lowest since Unit 2 Cycle 1. The licensee had established a 1996 site exposure goal of approximately 479 person-rem was also based on operational dose, a Unit 1 Cycle 9 refueling outage and a Unit 1 steam generator replacement. This included approximately 47 person-rem for operational exposure, 111 person-rem for the upcoming Unit 1 Cycle 9 outage, and 320 person-rem for steam generator replacement.

An Inspection Followup Item (IFI 93-29-01) was identified in NRC Inspection Report 50-413,414/93-29 for lack of quality training for steam generator maintenance nozzle dam installation/removal which had a potential for resulting in additional radiation exposure for personnel performing the tasks. The inspector reviewed licensee procedure, "Steam Generator Nozzle Dam Installation and Removal," dated February 13, 1995, which encompassed a checklist with step by step signoffs for performing the assigned task. Duke Power Nuclear Policy Manual, Nuclear System Directive: 105., "Control of Non-Assigned Individual(s) and Organizations," dated September 21, 1995, established requirements for the site representative to review non-assigned employees qualifications to perform skill-of-the-craft task. Licensee procedure "Employee Training and Qualifications Manual, Standard 902., Employee Qualification Component," dated December 1, 1994, established that first line supervisors are responsible for assigning work only to qualified individuals or to ensure that a qualified individual is supervising the work of a non-qualified individual. Based on identifying an individuals training qualifications and or providing appropriate level of supervision for performing task involving radiation exposure, the inspector informed the licensee that Inspector Followup Item 50-413,414/93-29-01: Lack of Quality Training for Nozzle Dam Installation/Removal, was closed.

The inspector determined since the Unit 1 Cycle 8 outage, the site was establishing challenging goals for maintaining occupational exposures ALARA and meeting UFSAR commitments.

No violations or deviations were identified.

6.0 OTHER NRC PERSONNEL ON SITE

During the week of March 11, inspectors lead by Mr. W. Sartor were on site for the Catawba Annual Exercise. Their observations will be documented in NRC Inspection Report 50-413,414/96-04.

7.0 REVIEW OF UFSAR COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and plant practices, procedures, and/or parameters observed by the inspectors.

REPORT SECTION #	DISCREPANCY (FSAR REFERENCE)
3.1.3	FSAR Figure 10-5 (Drawing CN-1593-1.0, Rev. 14) included incorrect valve locations for valves 1(2)SV027A and 1(2)SV028A (S/G PORV Block Valves). The valves were shown to be associated with the wrong steam generators. (Figure 10-5)
4.6	50.71 VIOLATION 96-02-07 (Example 1): FSAR 9.1.2.3 and 9.1.3.1.3 describe the design of the Spent Fuel Pool (SFP) and state that no connections would result in inadvertent draining of the SFP below a level of ten feet above the racked fuel assemblies. The safe shutdown system interface to provide reactor coolant pump seal water could permit draining of the SFP to the top of the racked fuel assemblies. (9.1.2.3 and 9.1.3.1.3)
4.6	FSAR 9.1.4.3.4 described the refueling bridge trolley and stated that the raising of fuel assemblies was limited by a limit switch and mechanical stop to prevent raising fuel above a level required for shielding (10 feet of water above the fuel assembly). The height was limited by a limit switch. No mechanical stop was provided to limit height to assure adequate shielding. (9.1.4.3.4)

REPORT SECTION #	DISCREPANCY (FSAR REFERENCE)
4.6	FSAR 9.1.3.3.1 describes the effect on the SFP at maximum heat load of a Safe Shutdown event due to boil off and reactor coolant pump seal water supply. This description is not valid because with a full core off load required by the maximum decay heat load, RCP seal water was not required. Level loss in this condition would be due to boil off only. In the normal heat load condition, the time to boiling would be different than the 24 hours stated. (9.1.3.3.1)
4.6	FSAR 9.1.3.1.1 described the SFP loading conditions for normal and maximum decay heat loads and include the criteria of a 7-day decay time before a full or one-third core off load to the SFP. This decay time was included as an assumption in the decay heat load analysis for the loading conditions. No administrative controls assure this 7-day criteria is met. Licensee records indicated that the criteria had not been exceeded. (9.1.3.1.1)
4.6	FSAR 9.1.4.2.3 describes the refueling trolley and hoist and references Rod Control Cluster (RCC) mast/handling devices. The RCC was removed on Unit 1 in 1995. These references which include descriptions of interlocks are not valid for Unit 1. (9.1.4.2.3)
5.2	50.71 VIOLATION 96-02-07 (Example 2): Unit vent monitors contain charcoal elements. FSAR 11.5.1.2.2 states elements contain silver zeolite. (11.5.1.2.2)
5.2	FSAR 11.5.1.2.2.5 Control Room Air Intake Monitors states "Gaseous activity in a control room air intake which exceeds a preset limit actuates an alarm in the control room and automatically initiates isolation of the affected air intake." The system was modified in 1991 to require manual action to isolate the most contaminated intake. (11.5.1.2.2.5)

8.0 EXIT

The inspection scope and findings were summarized on March 28, 1996, by R. Watkins with those persons indicated by an asterisk in paragraph 1. Interim exits were conducted on February 15, February 29, March 7, and March 15. In addition, the cited violations were discussed via telephone with the Catawba Site Vice President and the Region II Branch Chiefs for Engineering and Plant Support on April 22, 1996. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description/Reference
50-414/94-15-01	Closed	VIO - Five Examples of Improper Procedure Use and Adherence (Paragraph 3.7)
50-413,414/93-23-03	Closed	IFI - Elimination of large number of Hotspots throughout Plant (Paragraph 5.12)
50-413/93-29-01	Closed	IFI - Lack of Quality Training for Nozzle Dam Installation/Removal (Paragraph 5.13)
50-413,414/95-05-02	Closed	VIO - Failure to Make Surveys Necessary to Detect and Post a Radiation Area in the Auxiliary Building (Paragraph 5.12)
50-413,414/94-05-01	Closed	URI - No Periodic GL 89-10 Failure Trending and Analysis for MOVs (Paragraph 3.6)
50-413,414/96-02-01	Open	IFI - Reliance on MOV Testing of a Single Valve to Support the Capabilities of a Group (Paragraph 3.1.4)
50-413,414/96-02-02	Open	IFI - Stem Coefficient of Friction for MOV Opening Setting Calculations (Paragraph 3.1.4)
50-413,414/96-02-03	Open	IFI - MOV Opening Thrust Requirement Uncertainties (Paragraph 3.1.4)
50-413,414/96-02-04	Open	IFI - Unpredictable Behavior Experienced in Pressurizer PORV Block Valve MOV Testing (Paragraph 3.1.5)

50-413/96-02-05	Open	URI - Review Results of MSIV, 1SM-1 Reportability Evaluation and In-Plant Review of PIP Initiation Performance (Paragraph 4.1)
50-413,414/96-02-06	Open	URI - Auxiliary Feedwater Piping Temperature in Excess of Design (Paragraph 4.3)
50-413,414/96-02-07	Open	VIO (Example 1) - Failure to Revise the FSAR to Reflect Spent Fuel Pool Connection Which Could Allow Draining Below Level Required for Shielding (Paragraph 4.6)
50-413,414/96-02-07	Open	VIO (Example 2) - Failure to Revise the FSAR to Reflect the Use of Activated Charcoal Instead of Silver Zeolite to Sample Gaseous Effluent (Paragraph 5.2)
50-413,414/96-02-08	Open	IFI - Temperature Qualification of Control Room Intake Air Radiation Monitors (Paragraph 5.2)
50-413,414/96-02-09	Open	VIO - Failure to Maintain Positive Control to Extra High Radiation Area Keys (Paragraph 5.9)

9.0 ACRONYMS

AFW	-	Auxiliary Feedwater
ALARA	-	As Low As Reasonably Achievable
CACST	-	Auxiliary Feedwater Condensate Storage Tank
CFR	-	Code of Federal Regulations
Ci	-	curie
CNS	-	Catawba Nuclear Station
DAW	-	Dry Active Waste
DEI	-	Dose Equivalent Iodine
DEV	-	Deviation
D/G	-	Diesel Generator
DO	-	Dissolved Oxygen
DOT	-	Department of Transportation
E6 BTU/hr		1 million British Thermal Units per hour
ED	-	Electronic Dosimetry
EMF	-	*Radiation Monitor*
EPRI	-	Electric Power Research Institute
ESS	-	Electrical Support System
°F	-	degrees Fahrenheit
FIP	-	Failure Investigation Process

FSAR	-	Final Safety Analysis Report
g	-	gram
GET	-	General Employee Training
GL	-	Generic Letter
gpm	-	gallons per minute
HRA	-	High Radiation Area
HVAC	-	Heating, Ventilation and Air Conditioning
IAE	-	Instrument and Electrical
IFI	-	Inspector Followup Item
INEL	-	Idaho National Engineering Laboratory
IPAP	-	Integrated Performance Assessment Process
IR	-	Inspection Report
l	-	liter
lb	-	pound
lbm	-	pound mass
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LLD	-	Lower Limits of Detection
LSA	-	Low Specific Activity
μCi	-	micro-Curie (1.0E-6 Ci)
μm	-	micro-meter (1.0E-6 meter)
m	-	meter
ml	-	milli-liter
MCC	-	Motor Control Center
MMP	-	Maintenance Management Procedure
MOV	-	Motor-Operated Valve
MSIV	-	Main Steam Isolation Valve
MW	-	Megawatts
No.	-	Number
NRC	-	Nuclear Regulatory Commission
NSM	-	Nuclear Station Modification
NSRB	-	Nuclear Safety Review Board
ODCM	-	Off-site Dose Calculation Manual
PCE	-	Personnel Contamination Event
PCP	-	Process Control Program
PIP	-	Problem Investigation Process (Report)
PORV	-	Power Operated Relief Valve
ppb	-	parts per billion
ppm	-	parts per million
PPP	-	Performance Prediction Program
PRNI	-	Power Range Nuclear Instrumentation
PRT	-	Pressurizer Relief Tank
QA	-	Quality Assurance
QC	-	Quality Control
R/hr	-	Roentgen per hour
R&R	-	Removal and Restoration (Tagging Order)
RC	-	Reactor Coolant
RCA	-	Radiological Control Area
RCM	-	Reactor Make Up
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System

Rem	-	Radiation Equivalent Man
REMP	-	Radiological Environmental Monitoring Program
RFO	-	Refueling Outage
RHT	-	Recycle Holdup Tank
RMWST	-	Reactor Makeup Water System Tank
RO	-	Reactor Operator
RP	-	Radiation Protection
RWP	-	Radiation Work Permit
RWST	-	Refueling Water Storage Tank
SER	-	Safety Evaluation Report
S/G	-	Steam Generator
SFC	-	Stem Friction Coefficient
SFP	-	Spent Fuel Pool
SLC	-	Selected Licensee Commitments
SRO	-	Senior Reactor Operator
SRP	-	Standard Review Plan
SRPD	-	Self Reading Pocket Dosimeter
SSF	-	Safe Shutdown Facility
SSS	-	Safe Shutdown System
TEDE	-	Total Effective Dose Equivalent
TI	-	Temporary Instruction
TLD	-	Thermo-Luminescent Dosimeter
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
UST	-	Upper Surge Tank
VHRA	-	Very High Radiation Area
VIO	-	Violation
VOTES	-	Valve Operation Test and Evaluation System
WCC	-	Work Control Center
WMS	-	Work Management System
WO	-	Work Order