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

Report Nos.: 50-413/96-01 and 50-414/96-01

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: December 31, 1995 - February 10, 1996

Inspectors: R E Carroll for per tel con 3/11/96
R. J. Freudenberger, Senior Resident Inspector Date Signed

P. A. Balmain, Resident Inspector
L. King, Regional Inspector (paragraphs 4.3, 4.4, 4.5 and 4.6)
R. Moore, Regional Inspector (paragraphs 4.2 and 4.7)
R. L. Watkins, Resident Inspector

Approved by: ______________________________ ____________
R. V. Crlenjak, Chief Date Signed
Projects Branch 1
Division of Reactor Projects

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.

Results:

Plant Operations Operator actions taken in response to several equipment failures and control of a Unit 1 Technical Specification required shutdown were sound (paragraph 2.2). The licensee's self-assessment of the most recent refueling outage was consistent with NRC observations of outage activities (paragraph 2.3).

Maintenance The condition of the Unit 2 ice condenser was found to be acceptable following the loss of offsite power event. The inspector's walkdown and review of maintenance/surveillance activities performed on the ice condenser and ice baskets

ENCLOSURE

revealed no appreciable melting as a result of the event (paragraph 3.2).

Engineering — The licensee has developed an extensive capability for identification of plant equipment system problems. Monitoring and trend information provided a basis for identifying equipment problems to management. Action plans were being implemented to address the identified problems which demonstrated management's alignment of resources to improve plant reliability (paragraph 4.2). The licensee performed an indepth and exhaustive review of containment integrity issues (paragraph 4.3). Non-cited violation 50-413,414/96-01-01 was identified regarding a failure to leak rate test portions of the containment penetrations associated with the containment hydrogen analyzers (paragraph 4.6).

Plant Support — The licensee's precautionary activation of the Technical Support Center and Operations Support Center was beneficial in providing support to safely take Unit 2 to a cold shutdown condition following a loss of offsite power event (paragraph 5.1).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 9.0.

1.0 PERSONS CONTACTED

Licensee Employees

Addis, B., Training Manager
Bhatnager, A., Operations Superintendent
Coy, S., Radiation Protection Manager
Crawford, T., Manager, Mechanical Systems Engineering
Estep, N., Rotating Equipment Engineer
Forbes, J., Engineering Manager
Funderburk, W., Work Control Superintendent
* Harrall, T., IAE Superintendent
Kammer, J, Mechanical Systems Engineer
Kimball, D., Safety Review Group Manager
* 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
* Taylor, Z., Regulatory Compliance Manager
Tower, D., Regulatory Compliance Engineer

* Attended exit 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 93702)

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 period operating at 100% power. On January 5 the unit was shutdown to Mode 3 to comply with TS action requirements when the A train reactor trip breaker could not meet surveillance test acceptance criteria. On January 9 the unit was taken critical and placed online. Power ascension stopped on January 10 with the unit at 83% power for evaluation of primary to secondary leakage indications. Power ascension resumed later on January 10 and the unit reached 100% power on January 11. On January 17 power was decreased to 97% to replace the 1C2 heater drain tank pump motor breaker following electrical ground indications. The unit was returned to full power later on January 17. On January 18 power was reduced to 65% power for 1A main feedwater pump turbine control circuitry repairs. Unit power was further decreased to 49% because of TS quadrant power tilt ratio limits. On January 20 main feedwater pump turbine control circuitry repairs were completed and the unit returned to 100% power. The unit operated at full power for the remainder of the period.

Unit 2 Summary

Unit 2 began the period operating at 100% power. On January 18 power was decreased to 85% for auxiliary feedwater flow testing following replacement of a turbine driven AFW pump discharge check valve. The unit returned to 100% power on January 19. On February 6 a Notification of Unusual Event was declared when a loss of offsite power occurred that resulted from the failure of two resistor bushings located in electrical buswork adjacent to the unit's main step-up transformers. The loss of offsite power caused all reactor coolant pumps to trip, a subsequent automatic reactor trip and turbine trip. An automatic safety injection also occurred after the reactor trip. One source of offsite power was restored and a natural circulation cooldown of the unit was initiated later on February 6. The unit reached cold shutdown on February 7 and exited the Unusual Event on February 8. The unit remained shutdown in Mode 5 for the remainder of the report period. A special team inspection of this event was performed, which is documented in NRC Inspection Report 50-413,414/96-03.

2.2 Control Room Operator Response to Equipment Failures

During the inspection period, the inspectors reviewed control room operator performance with emphasis on operator response to off-normal conditions. The review evaluated the adequacy of actions taken in diagnosing the conditions, as well as the response taken to implement corrective actions. The inspectors made the following observations regarding control room operator performance:

- On January 2, while performing a Unit 1 monthly control rod movement test procedure to satisfy TS 4.1.3.1.2, the operator noted that the bank selector switch did not snap into position when shutdown bank C was selected. Expected indications with shutdown bank C were not obtained. The control rod movement test was halted to allow troubleshooting of the problem. After collecting "as found" information, the bank selector switch was returned to the "Auto" position and normal indication for that position was verified. The bank select switch knob was found to be loose on the shaft. The knob was replaced and the control rod movement test was completed satisfactorily later the same day.

- On January 5, a Unit 1 shutdown was initiated to comply with TS action requirements when the A train reactor trip breaker could not meet surveillance test acceptance criteria. The inspector observed the shutdown and observed that shift management coordinated the evolution well and ensured that the unit reached the required condition in a controlled manner.

- On January 9, indications of increased Unit 1 primary to secondary leakage were received in the main control room (high steamline radiation alarms and elevated condenser air ejector radiation levels). Operators secured the power increase, stabilized the unit at 83% power, and coordinated with Chemistry, Radiation Protection and Engineering groups to evaluate the indications. Prior to resuming the power increase, the primary to secondary leakage was quantified and determined to be well within required limits.

- On January 18, during a 25 gallon boration to commence a Unit 2 power reduction to 85% in support of an auxiliary feedwater pump turbine flow balance, the control room operator noticed that the boric acid totalizer was reading approximately two times that of the total make-up totalizer. The power decrease was halted, and the operator pursued troubleshooting of the problem. Instrument and electrical technicians determined that the flow discrepancy was caused by instrument inaccuracy attributed to low boric acid flow rate, and the difference in the span of the two instruments. It was recommended that the flow rate be increased to minimize the difference between the flow indications. The flow rate was increased, and boration resumed without incident.

Based on this review, the inspectors concluded that operator actions taken in response to these apparent off-normal conditions were appropriate. In addition, the inspectors noted improved operator attentiveness to control panels following licensee management focus on this area based on self-assessment results.

2.3 Unit 2 End of Cycle 7 Post Outage Assessment

The Unit 2 End of Cycle 7 Refueling Outage began on October 6 and ended on November 30, 1995. Following the outage the licensee performed a self-assessment of the outage which was documented in a Post Outage Report and PIP 96-0234. The inspector reviewed the Report and the PIP, and attended a Plant Operations Review Committee meeting on February 1 which included a review of the Post Outage Report.

The licensee's assessment identified good performance as well as areas for improvement. Examples of good performance included: the new crud burst cleanup procedure; PORC involvement in infrequently performed evolutions; the conduct of zero power physics testing; and the trial use of the Outage Risk Assessment and Management computer tool. The success with the crud burst and cleanup contributed good performance in overall personnel exposure. In addition, solid contaminated waste generation and personnel error performance was strong.

Areas for improvement included: more attention to unplanned work integration into the outage; consideration of the potential for special flush or cleanup plans which receive significant work, such as the Component Cooling Heat Exchanger Retubing; minimization of the use of inter-dependent tagouts; investigation of the replacement of the RHR pump seals due to transient leakage from the seals, which requires engineering resources to evaluate; and evaluation of improvements to minimize RCS level instrumentation disagreements during system draining. Maintenance Rework and Foreign Material Exclusion continue to be challenges. In the radiological controls area the number of personnel contamination events was in excess of licensee goals.

Based on the inspection described above, the inspector concluded that the licensee's self-assessment was consistent with inspector observations from the outage and the licensee had effectively assessed performance.

3.0 **MAINTENANCE** (NRC Inspection Procedures 62703 and 61726)

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 Unit 2 Auxiliary Feedwater Discharge Check Valve Replacement

During this inspection period the inspector reviewed replacement activities associated with Unit 2 check valve ?CA-53, the turbine-driven auxiliary feedwater pump discharge to 'B' steam generator check valve. Following startup from the Unit 2 End of Cycle 7 Refueling Outage the licensee identified elevated AFW piping temperatures that cycled from a normal temperature range of approximately 120°F to 220°F. These temperatures were attributed to seat leakage past 2CA-53 (refer to NRC IR 50-413,414/95-24). The check valve functions to protect the pump from gas-binding by preventing backleakage of high temperature feedwater through the discharge piping and into the auxiliary feedwater pump. Operating procedures require running the auxiliary feedwater pumps when this temperature increases to cool the piping to eliminate the potential of steam void formation.

The pump was removed from service on January 17 and the valve was cut out. The inspector obtained a copy of the tag-out list and verified that isolations were performed as planned. The inspector also observed portions of the welding and grinding during the installation of the new valve. No personnel safety or equipment protection concerns were identified.

A Management Oversight Plan was drafted and a briefing was prepared to evaluate the auxiliary feedwater system discharge control valve throttling procedure for performing a system flow balance (turbine-driven auxiliary feedwater pump to steam generators 2B and 2C) following the replacement of 2CA-53. The inspector attended the control room briefing, which was conducted primarily to brief operators on the implications of the test for reactivity management and reactor power. The replacement valve was welded into place on January 17. On January 18 the unit was downpowered to 85% power to allow tempering flow to be isolated from the 2B and 2C steam generator auxiliary feedwater nozzles so that flow measurements would be associated with testing only. The flow balance was successfully completed on January 19.

After the flow balance was completed, piping temperature upstream of 2CA-53 went from 85°F to 205°F and remained around 200°F after the valve replacement was completed. The persistent high temperature indicated that the check valve replacement was not effective in correcting the check valve leakage problem. Even a small amount of leakage past any one of the four check valves in the turbine-driven auxiliary feedwater pump discharge piping causes the common discharge header (to all four steam generators) to heat up and pressurize. As pressure builds over time, the pressure across all of the check valves is equalized and differential pressure no longer maintains a closing force. The licensee is considering a modification to replace the existing check valves with spring-loaded check valves to ensure that a closing force is maintained independent of differential pressure.

The inspector concluded that the valve replacement reduced the risk of cyclic fatigue failure, although it was not effective in resolving the problem of turbine-driven auxiliary feedwater pump discharge check valve leakage. The inspector observed that management attention remains properly focused on resolving the issue and has placed AFW discharge valve seat leakage on the Top Equipment Problem Report.

3.2. Unit 2 Ice Condenser Inventory

Following the February 6 loss of offsite power event mentioned above, a safety injection actuation occurred and the reactor coolant system went solid. A pressurizer PORV lifted and the pressurizer relief tank filled, eventually relieving through the rupture disk. The pressure of the spill into containment and loss of normal lower containment cooling caused ice condenser doors to be open for approximately 36 hours. Due to the event, the ice condenser refrigeration system was inoperable for approximately 36 hours as well. The licensee conducted a visual inspection of the ice baskets to determine the extent of melting and found that very little of the ice inventory was lost during the event. Some dripping and sublimation was observed from several of the ice baskets in areas closest to the ice condenser doors.

The licensee performed Technical Specification surveillances to determine ice basket weight, to verify ice bay flow paths were free of debris and blockage, and that lower inlet doors and ice condenser floor drain valves and drain lines were operable (TS 4.6.5). These surveillances were conducted under work order 96011389-01 and 96011390-01. The inspector reviewed the work orders and procedures associated with the conduct of these surveillances and verified that ice weights were above the minimum weights required by Technical Specifications. The inspector performed a walkdown of the ice condenser lower and intermediate decks, verifying that lower inlet doors were free from ice and blockage, and that no indications of gross melting and inventory loss had occurred.

The inspector also discussed the work performed on the ice condenser with the system engineer, who indicated that a total of more than 500 ice baskets were weighed (including 144 baskets randomly selected to be representative of the population per Technical Specification surveillance requirements) to provide additional assurance that the ice inventory was sufficient prior to restart. The total sample was comprised of baskets for Technical Specification surveillance verification, baskets from which dripping or icicles was seen after the event, and a number of high-risk baskets highlighted by a database used to predict sublimation rates. The database (Iceman) generates a composite sublimation rate for each ice basket based on 2,000 to 3,000 days of sublimation history. This data is used to generate a prediction of basket inventory and select baskets that are most likely to incur inventory loss over time from sublimation.

Based upon review of completed surveillance procedures, maintenance work order documentation, general inspection of the ice condenser and discussion with licensee staff, the inspector concluded that the licensee's evaluation of the ice condenser inventory was appropriate and thorough.

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. The inspection also focused the effectiveness of equipment and systems performance monitoring.

4.1 Review of Unit 2 Restart Assessments

During this inspection period the inspectors reviewed the results of assessments which the licensee performed of equipment problems or unexpected conditions that occurred during the Unit 2 loss of offsite power event. These assessments, which were completed by the licensee prior to restart of Unit 2, are addressed below:

- 2A Charging Pump High Motor Air Temperature Alarm

  Following the LOOP event, the licensee identified a 2A charging pump high motor air temperature alarm during a review of pump operating parameters. The inspector was initially concerned that the alarm condition could have indicated that the motor operated in a state that could have led to degradation. The inspector discussed this issue with engineering personnel and reviewed the licensee's assessment of the high temperature alarm condition (PIP 2-C96-0317).

  The inspector observed that the alarm did not represent an actual high motor temperature condition but alarmed due to a faulty temperature switch combined with a poor temperature sensor location. The inspector verified by reviewing the licensee's assessment that normal operating temperatures for the motor were not exceeded and based on motor qualification calculations the motor did not operate in conditions that would lead to degradation.

- Residual Heat Removal Pump 2B Seal Leak

  Residual Heat Removal pump 2B was started on February 7 during the plant cooldown after the loss of offsite power and subsequent turbine and reactor trips. Operations personnel visually identified a pump seal leak of approximately 150 ml/minute. Licensee maintenance and engineering personnel subsequently measured and quantified this leakage rate as 90 ml/minute.

The inspector reviewed the licensee's assessment of the seal leakage and pump operability (PIP 2-C-96-0308). The inspector verified that leakage measured during the event remained less than the licensee's previously established operability limit of 179 ml/minute (PIPs 2-C-95-2184 & 2233). Based on the previous operability evaluations, the licensee determined that alignment of the 2B pump with the primary loop for cool down was acceptable. The pump was aligned at approximately 8:30 a.m., on February 7, and no observable leakage was identified on the pump by noon that day.

The licensee attributes pump seal leakage to pressure swings when the pump was in miniflow during initial operation. The inspector concluded that the engineering evaluation of the RHR pump seal leakage was appropriate.

- Component Cooling Water Pump 2B2 Seal Leak

On February 7, at 7:00 a.m., the B-train component cooling water pumps had been placed in service following the Unit 2 loss of offsite power event. The operators identified mechanical seal leakage of approximately 90 drops per minute from the component cooling water pump 2B2 outboard seal at the time that the pump was started. Technicians were dispatched to the pump to evaluate the leakage, which had decreased to 60 drops per minute by 7:30 a.m. The licensee continued to monitor seal leakage as it changed to roughly 25 drops per minute at 1:45 p.m. and 32 drops per minute at 4:55 p.m. later that day.

During the previous Unit 2 refueling outage, elevated particulate contamination levels were introduced into the component cooling water system during heat exchanger retubing activities. As a system flush was not conducted before the equipment and systems were returned to service, the particles were entrained in the fluid system and deposited on the seal faces, which resulted in the leakage. The inspector reviewed the licensee's operability evaluation (PIP 2-C96-0310) and verified that current seal leakage was less than the maximum allowed leakage.

- Reactor Coolant Pump Seal Performance

Prior to the restart of Unit 2 following the LOOP event the licensee performed an assessment of reactor coolant pump performance. The inspector discussed the results of the assessments with engineering personnel and reviewed associated documentation (PIP 2-C96-0325).

When Unit 2 lost power the normal seal injection return flow path to the Volume Control Tank was isolated automatically and diverted through a relief valve to the Pressurizer Relief Tank. This alignment created pressure oscillations that caused #1 seal leakoff flowrates to fluctuate. The inspector reviewed seal leakoff data and observed that the #1 seal leakoff flowrates for three of the reactor coolant pumps showed a slight increase from data taken prior to the event. The licensee believes that pressure oscillations may have allowed the #1 seals to have rubbed slightly, which caused the changes in #1 seal performance. The inspector verified that even with increased leakage all of the #1 seal leakoff flows were within the acceptable operating range for the reactor coolant system pressure conditions that existed when the data was taken. The inspector also reviewed the results of the licensee's reactor coolant pump motor oil analysis and verified the sample results did not indicate water contamination.

4.2 Equipment and Systems Monitoring

Equipment problem identification was provided by the rotating equipment monitoring program and the Failure Analysis and Trending System. Engineering was implementing the systematic program for monitoring rotating equipment performance. The equipment and parameters to be monitored had been recently identified and a draft Engineering Directives Manual guideline was developed to define the program. The initial Rotating Equipment Engineering Programs Status Report was issued in January 1996. Rotating equipment problems identified since 1993 included vibration, alignment, bearings, and seal problems on pumps. This included vibration and seal problems on the component cooling water pumps. As a result, three Unit 2 component cooling water pumps were rebuilt in November 1995.

Engineering solutions for the component cooling water pump problems included improved bearing clearances and oil seal modifications. Routine monitoring of the component cooling water pumps demonstrated that the performance of these pumps had been improved. It was identified that the pumps were not operating at the optimal design conditions with respect to the pump curves, which contributed to degraded pump performance and increased maintenance. Engineering was developing a modification to alter the normal pump operating configuration (one pump versus two pumps per unit) to improve further pump performance.

The FATS was implemented in the first quarter of 1995. The program scope included equipment important to safety and power generation. Performance goals related to failures were established for each piece of equipment included in the program. Action plans were developed and implemented for equipment which did not meet the established goals. Equipment which did not meet goals included ventilation chillers, generator power circuit breakers, diesel generators, motors, and pumps.

For example, a major cause for chiller failures was refrigerant leaks. Engineering solutions implemented to address this cause included installation of refrigerant detectors in chiller spaces, and a new refrigerant sealant which was not subject to age degradation. Similar action plans were developed to address other equipment problems.

System performance was monitored and communicated to management by Systems Engineering Newsletters every two months. The September/October 1995 Systems Engineering Newsletter provided a comprehensive overview of system performance and highlighted specific system performance problems. Engineering was developing a Plant Systems Health Report to provide management a monthly assessment of key plant performance indicators which represent overall plant health. The initial Plant Systems Health Report was in draft.

The inspector concluded that the licensee had developed significant capabilities for the identification of plant equipment and system problems. The action plans being developed and implemented demonstrated an appropriate capability to address identified problems. Management awareness of equipment and systems performance was demonstrated by alignment of resources to accomplish the recommended corrective actions for identified problems. The improvements related to component cooling water pumps and chiller performance indicated the programs effectiveness in improving equipment reliability.

4.3 Containment Integrity Issues

Background

In April 1995, the licensee identified that inadequate procedures for calibration of containment pressure indication resulted in containment integrity not being maintained during calibration of Containment Pressure Control System pressure transmitters. LER 414/95-02 was submitted regarding this issue. NRC Inspection Report 50-413,414/95-18 addressed the issue and characterized it as a non-cited violation.

In July 1995, a licensee Self Initiated Technical Audit of the Component Cooling Water System identified vent and drain valves associated with component cooling water penetrations servicing the excess letdown heat exchanger and the reactor coolant drain tank heat exchanger that should have been considered part of the containment boundary, but were omitted. LER 413/95-03 was submitted regarding this issue. As a result of this second issue involving containment integrity, the licensee initiated a broad scope self-assessment of containment integrity programs at the site.

After the self-assessment was initiated, two more issues were identified by the licensee. The first (Unresolved Item 50-413,414/95-19-01) involved the use of procedures which had not been revised to correct the previous problem during calibration of the Containment Pressure Control

System transmitters. The second issue (LER 413/95-05) involved the Containment Hydrogen Analyzer system leakage downstream of containment isolation valves in sections of the system that were not leak tested, but would be in service during accident scenarios. Other issues identified by the licensee's self-assessment which were not reportable, were entered into the Problem Investigation Process.

Scope

The scope of this inspection included: review and disposition of the open items mentioned above; a sampling review of issues identified by the licensee's self-assessment to verify reportability determinations and resolution; and a review of the licensee's self-assessment report to evaluate scope, overall effectiveness, and corrective actions.

Inspection

The inspector reviewed in detail all of the PIPs, LERs and URIs associated with containment integrity issues at the plant. The FSAR and design basis documents were reviewed to determine the design basis for containment integrity issues. The disposition of the LERs and the URI are discussed in this section. The inspectors concluded that the licensee team which was formed to look into the containment integrity issues was manned by knowledgeable personnel who performed an in depth and exhaustive study of the issues.

The scenario assumed by the licensee to determine what testing was required was conservative. For example, the inspector reviewed in detail PIP 0-C95-1120 and LER 413/95-003. The Component Cooling Water System Self Initiated Technical Audit identified a deficiency in that the piping located downstream of the excess letdown heat exchanger vent and drain valves was considered nonsafety-related and as such was neither seismically qualified nor evaluated for High Energy Line Break interactions. The licensee concluded that the valves which separate the safety-related from nonsafety-related piping should have been included in PT/1(2)/A/4200/02B, Cold Shutdown Inside Containment Verification, which satisfies the surveillance requirements of Technical Specification 3.6.1.1. The scenario involves a Design Basis Earthquake coincident with a LOCA. As a result, a Loss of Offsite Power and a loss of Lake Wylie (the nonsafety-related portion of the Ultimate Heat Sink) is postulated. A failure of the B train Diesel Generator on the LOCA unit is assumed with the other unit's B train Diesel Generator not available. The heat exchanger is also assumed to be in service and the nonsafety-related piping is assumed to fail.

The described scenario requires a detailed analysis with knowledge of the interactions of systems. The licensee identified this as one of the weaknesses in determining which valves required testing.

The inspectors interviewed the licensee individual responsible for the evaluation of High Energy Line Break interactions and requested a copy of the criteria used. The inspector determined that in 1985 the licensee evaluated all of the component cooling water system piping that is near high energy lines and took actions to either restrain the high energy lines, evaluate if the piping could withstand the jet impingement, or had operations evaluate the affected piping as not necessary for a safe shutdown.

The licensee also took action to add more detail to section 18.0, Containment Isolation, of the Modification Technical Issues Check List to improve the effectiveness of evaluations of plant changes which may affect containment integrity.

It was apparent from a review of the issues, that a problem with communication existed within the licensee's organization. Examples of this are the disconnect between McGuire and Catawba with regard to the actions taken on penetration M-322. McGuire had not made Catawba aware of the problem. Another example within Catawba was the licensee's failure to communicate to the SPOC the position taken by engineering on testing of containment pressure control system penetrations. The SPOC team was not made aware that procedures were placed on hold. As a result SPOC began troubleshooting an affected penetration without realizing a TS action had been entered for containment entry. The licensee had recognized problems with communication within the organization and considered these examples reflective of performance in mid 1995. Licensee management has taken action to improve communication in conjunction with human performance initiatives that have been implemented company wide.

4.4 (Open) LER 413/95-03, Rev. 1, Failure to Perform TS Surveillances due to Unanticipated Interaction of Systems (PIPs C95-1120 & 1319)

The SITA identified component cooling water valves associated with the excess letdown heat exchanger and the reactor coolant drain tank heat exchanger that should have been considered part of containment integrity boundary. The corrective actions included a review of all penetrations for other valves which may have been omitted. This LER was left open until the corrective actions in PIPs 0-C96-0043, 44, 45 and 46 are completed.

The licensee issued the results of their SITA investigation in a detailed report titled "Catawba Nuclear Station Site Initiated Review of Containment Integrity." This report contains several followup actions. The inspectors noted that the main issues have already been addressed, but there are several followup actions that need to be completed. This LER will remain open until these items are completed.

The inspector's review of the above report noted that the licensee has established positions with regard to Containment Integrity Testing. The inspectors identified as a significant position (of the ten position statements) the licensee's position VIII with regard to testing vents and drains relative to TS 3.6.1. TS 4.6.1.1.a specifies a 31-day surveillance requirement with respect to test vents and drains located between the credited containment isolation valves. The licensee's position is that the "surveillance requirement 4.6.1.1.a applies only to penetrations that are REQUIRED TO BE CLOSED DURING ACCIDENT CONDITIONS and have (1) INOPERABLE AUTOMATIC containment isolation valves or (2) MANUAL containment isolation valves as defined in FSAR Table 6-77." The licensee gives several pages of documentation to support this position. This LER remains open pending further NRC review of the licensee's position.

4.5 (Closed) URI 50-413,414/95-19-01, Evaluation of Ineffective Corrective Actions Associated with Containment Integrity Issue (PIP C95-1302)

This issue involved the use of containment pressure control system calibration procedures which had been placed on administrative hold and was described in paragraph 4.3 as an example of poor communication. The licensee's evaluation of the significance of this issue and determined it did not represent a violation.

4.6 (Closed) LER 413/95-05, TS Violation Due to Inadequate Written Communications (PIP C95-1369)

This issue involved Containment Hydrogen Analyzer system leakage down stream of containment isolation valves in sections of the system that were not leak tested which would be in service during accident scenarios. Appropriate corrective actions were documented in the LER. This failure to adequately leak rate test a portion of the containment penetration associated with the Containment Hydrogen Analyzer system constituted a violation of TS 6.8.1, Procedures and Programs. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. NCV 50-413,414/96-01-01: Failure to leak rate test portions of the containment penetration associated with the containment hydrogen analyzers.

4.7 (Open) Violation 50-413,414/94-30-01, Inadequate Corrective Action for Temporary Modification Program Deficiency

In July 1994 the licensee's Problem Identification Program and an NRC non-cited violation identified that the licensee failed to perform required periodic audits of active Temporary Station Modifications. The corrective actions for this item were completed in November 1994. An NRC inspection in December 1994 identified that although the audit was performed as required, 30 active TSMs were not verified by the audit; therefore, the corrective actions were inadequate.

The inspector reviewed the corrective actions stated in the licensee's March 22, 1995, response to violation 50-413,414/94-30-01. The actions were completed. The inspector additionally reviewed the fourth quarter 1995 TSM audit to verify that all active TSMs were included in the audit and noted that 5 of 34 TSMs were not verified. The inspector noted that the audit process notified responsible engineers of the required review, but did not provide guidance for failure of the engineers to respond. Additionally, the audit process did not require a report to management indicating the completion or results of the audit. The inspector concluded that although audit performance had improved the item was not fully resolved. This item remains open pending licensee actions to resolve these program deficiencies and verification of corrective action effectiveness.

5.0 **PLANT SUPPORT** (NRC Inspection Procedure 71750)

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 Activation of Technical Support Center and Operations Support Center

On February 6, Unit 2 offsite power was lost because of the failures of two resistor bushings associated with the Unit 2 A and B main power system. The licensee appropriately classified the event as a Notification of Unusual Event. Although not required for this classification, licensee management decided to implement a precautionary activation of onsite emergency response facilities to assist in recovery efforts. The TSC and OSC were staffed and activated during the event and supported the restoration of offsite power and cooldown of Unit 2. The facilities were deactivated on February 8, after the Notification of Unusual Event condition was exited. The inspector considered that the licensee's precautionary activation of the TSC and OSC was beneficial in supporting the safe shutdown of Unit 2 following the event. This event was reviewed in detail by an NRC reactive inspection team and the results of this inspection are documented in NRC IR 50-413,414/96-03.

6.0 **Other NRC Personnel Onsite**

On February 6, members of NRC management were onsite to meet with members of Duke Power Company management to discuss the status of the licensee's performance improvement initiatives. This meeting was postponed due to the Unit 2 loss of offsite power event. A reactive inspection team was onsite from February 8 through February 13 to evaluate the Unit 2 loss of offsite power event.

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 description highlighted the need for a special review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. During a portion of the inspection period (February 1-10, 1996) the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

8.0 EXIT

The inspection scope and findings were summarized on February 15, 1996, by Peter Balmain with those persons indicated by an asterisk in paragraph 1.0. Interim exits were conducted on January 11, 1996, and January 25, 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.

Type	Item Number	Status	Description and Reference
VIO	50-413,414/ 94-30-01	Open	Inadequate Corrective Action for Temporary Modification Program Deficiency (paragraph 4.7).
LER	413/95-03 R1	Open	Failure to Perform TS Surveillances due to Unanticipated Interaction of Systems (paragraph 4.4).
URI	50-413,414/ 95-19-01	Closed	Evaluation of Ineffective Corrective Actions Associated with Containment Integrity Issue (paragraph 4.5).
LER	413/95-05	Closed	TS Violation Due to Inadequate Written Communications (paragraph 4.6).
NCV	50-413,414/ 96-01-01	Closed	Failure to Leak Rate Test Portions of the Containment Penetration Associated with the Containment Hydrogen Analyzers (paragraph 4.6).

9.0 ACRONYMS

AFW - Auxiliary Feedwater System
CFR - Code of Federal Regulations

FSAR - Final Safety Analysis Report
FATS - Failure Analysis and Trending
IAE - Instrumentation and Electrical
IFI - Inspector Followup Item
IR - Inspection Report
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
NCV - Non-cited Violation
NRC - Nuclear Regulatory Commission
OSC - Operations Support Center
PIP - Problem Investigation Process Report
PORC - Plant Operations Review Committee
PORV - Power Operated Relief Valve
RCS - Reactor Coolant System
SITA - Self Initiated Technical Audit
SPOC - Single Point of Contact
TS - Technical Specifications
TSC - Technical Support Center
TSM - Temporary Station Modifications
URI - Unresolved Item
UFSAR - Updated Final Safety Analysis Report
VIO - Violation
WO - Work Order