UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-8931

January 31, 2008

EA-08-034

Duke Power Company LLC
d/b/a Duke Energy Carolinas, LLC
ATTN: Mr. J. R. Morris
Site Vice President
Catawba Site
4800 Concord Road
York, SC 29745-9635

SUBJECT: CATAWBA NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000413/2007005 AND 05000414/2007005

Dear Mr. Morris:

On December 31, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Catawba Nuclear Station Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on January 10, 2008, with Mr. Bill Pitesa and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents four NRC-identified findings of very low safety significance (Green) which were determined to be violations of NRC requirements. In addition, one licensee-identified violation is also listed in this report. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you contest any NCV in this report, you should provide a written response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC, 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC, 20555-0001; and the NRC Senior Resident Inspector at the Catawba Nuclear Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

James H. Moorman, III, Chief
Reactor Projects Branch 1
Division of Reactor Projects

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

Enclosure: Integrated Inspection Report 05000413/2007005 and 05000414/2007005 w/Attachments: (1) Supplemental Information; and (2) Status of Generic Letter (GL) 2004-02 Commitments for Catawba 2

cc w/encl: (See page 3)

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Letter to J. R. Morris from James H. Moorman, III dated January 31, 2008

SUBJECT: CATAWBA NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000413/2007005 AND 05000414/2007005

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-413, 50-414
License Nos.:	NPF-35, NPF-52
Report No.:	05000413/2007005 and 05000414/2007005
Licensee:	Duke Power Company LLC
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	York, SC 29745
Dates:	October 1 through December 31, 2007
Inspectors:	A. Sabisch, Senior Resident Inspector G. Williams, Resident Inspector E. Rodriguez-Cruz, General Engineer B. Miller, Reactor Inspector (Sections 1R08, 4OA5.2) C. Peabody, Reactor Inspector (Section 4OA5.1)
Approved by:	James H. Moorman, III, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000413/2007005, 05000414/2007005; 10/01/2007 - 12/31/2007; Catawba Nuclear Station, Units 1 and 2; Inservice Inspection Activities, Maintenance Risk Assessments, Permanent Plant Modifications, and Post-Maintenance Testing.

The report covered a three-month period of inspection by two resident inspectors, one general engineer, and two reactor inspectors. Four Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Green non-cited violation (NCV) of 10 CFR 50.55a(g)(4) for the failure to perform periodic leakage testing of buried piping portions of the service water system as required by Section XI of the ASME Code for the second 10-year Inservice Inspection interval for Units 1 and 2. The licensee entered this issue into their corrective action program for resolution.

  This finding is more than minor because it affects the Equipment Performance attribute of the Mitigating Systems cornerstone objective of ensuring availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding is of very low safety significance because it did not represent an actual loss of a system’s safety function. (Section 1R08.1)

- Green. The inspectors identified a Green NCV of 10CR50.65(a)(4) for the failure to manage and minimize the risk associated with the replacement of portions of the nuclear service water (RN) system. More specifically, the licensee failed to develop a Complex Lift Plan as required by Corporate procedures and develop appropriate risk management actions as part of the Critical Activity Plan.

  The finding was more than minor because it was associated with the “Protection Against External Factors” attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability and capability of systems designed to prevent undesirable consequences was maintained. An unexpected loss of the 2A train of spent fuel pool cooling (from an inadequately controlled RN piping lift above it) could have resulted in undesirable consequences with the recently off-loaded reactor core being in the spent fuel pool. The inspectors completed a Phase 1 screening of the finding using Appendix K of Inspection Manual Chapter 0609, “Maintenance Risk Assessment and Risk Significance Determination Process,” and determined that the performance deficiency represented a finding of very low safety significance on the basis that the actual RN piping replacement had not begun at the time the deficiencies were identified and the lifts were deferred until the appropriate actions were developed and implemented. The finding directly involved the cross-cutting area of Human Performance under the "Safety Significant/Risk Significant Decisions" aspect of the "Decision Making" component (H.1.a), in that the licensee failed to develop a lift plan and applicable risk management actions in accordance with station and corporate requirements to ensure the risk associated with moving RN piping over in-service spent fuel pool cooling piping was controlled and minimized. This finding was entered into the licensee's corrective action program. (Section 1R13)

- Green. The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion X, Inspections, for the licensee's failure to adequately implement inspections of the new Unit 2 emergency core cooling system (ECCS) containment sump to ensure it was installed in accordance with design specifications so as to support operability when required by Technical Specifications (TSs).

  The finding was more than minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences was maintained. Following final inspections of the ECCS containment sump modification, inspectors identified deficiencies that required resolution prior to declaring the sump operable as required by TSs to support unit restart. The inspectors determined that the finding was of very low safety significance using the Phase 1 Screening Worksheet of Inspection Manual 0609, Maintenance Risk Assessment and Risk Significance Determination Process, based on the fact that Unit 2 had not yet entered an operational mode in which the ECCS containment sump was required to be operable at the time the construction deficiencies were identified. The finding directly involved the cross-cutting area of Human Performance under the "Human Performance and Error Prevention" aspect of the "Work Practices" component, in that the licensee failed to implement the required inspections of the ECCS sump to ensure the permanent modification was installed in accordance with design specifications and would remain operable under all postulated accident conditions (H.4.a). This finding was entered into the licensee's corrective action program. (Section 1R17)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, for the licensee's failure to promptly identify and correct a significant condition adverse to quality affecting the ability of both control room area ventilation system (CRAVS) chillers to operate as designed following a station blackout (SBO).

The finding was more than minor because it was associated with the Configuration Control attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers provide protection from radio-nuclide releases caused by accidents or events. While the CRAVS would have remained operable in terms of filtering air in the areas it services, without chilled water providing cooling, operators would have had to bypass the filtered air paths using abnormal operating procedure (AP) guidance in order to maintain area temperatures at values needed to ensure equipment in the areas remained operable. The inspectors determined the finding to be of very low safety significance using the Phase 1 Screening Worksheet of Inspection Manual 0609, Maintenance Risk Assessment and Risk Significance Determination Process, based on the fact that the issue would only become evident if one CRAVS chiller was out-of-service at the time of a SBO event and the time available to restore at least one chiller before the AP would have had to be entered and the filtered air flow paths bypassed. Based on a review of station Probabilistic Risk Assessment data, the likelihood of a SBO event in conjunction with one chiller being inoperable was determined to be extremely low. The finding directly involved the cross-cutting area of Problem Identification and Resolution under the “Thorough Evaluation of Identified Problems” aspect of the “Corrective Action Program” component, in that the licensee failed to take the necessary actions to identify and correct the cause (i.e., high resistance fuse installed in temperature reset circuit) of the “A” CRAVS chiller failing to restart during engineered safety features (ESF) testing to ensure both chillers would function as designed under all postulated transients (P.1.c). This finding was entered into the licensee’s corrective action program. (Section 1R19)

B. <u>Licensee-Identified Violations</u>

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken by the licensee have been entered into the licensee’s corrective action program. This violation and the licensee’s corrective action program tracking number are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

Unit 1 began the inspection period operating at 100 percent Rated Thermal Power (RTP) and remained at 100 percent RTP through the end of the inspection period.

Unit 2 began the inspection period in a refueling outage that started on September 14, 2007. The reactor achieved criticality on November 14, 2007, and the main generator was placed on-line for the first time on November 15, 2007. Physics testing and power ascension was performed through November 21, 2007, when 100 percent RTP was achieved. The unit remained at 100 percent RTP through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather (Preparation)

a. Inspection Scope

The inspectors reviewed the licensee's preparations for adverse weather associated with cold ambient temperatures. This included field walkdowns to assess the material condition and operation of freeze protection equipment (e.g., heat tracing, instrument box heaters, area space heaters, etc.), as well as other preparations made to protect plant equipment from freeze conditions. Risk significant systems reviewed included the standby shutdown facility, nuclear service water (RN) pump house, and the refueling water storage tanks. In addition, the inspectors conducted discussions with operations, engineering, and maintenance personnel responsible for implementing the licensee's cold weather protection program to assess the licensee's ability to identify and resolve deficient conditions associated with cold weather protection equipment prior to cold weather events. Documents reviewed during this inspection are listed in Attachment 1 of this report.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors walked down the four partial system alignments listed below and assessed whether critical portions of equipment alignments for selected trains remained operable while the redundant trains were inoperable. Plant documents were reviewed to find the correct system and power alignments, and the required positions of select valves and breakers. The inspectors determined if the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact mitigating system availability. Documents reviewed during this inspection are listed in Attachment 1 of this report.

- Protection of “A” train equipment designated in the Critical Activity Plan supporting the two planned Limiting Condition for Operation (LCO) entries associated with removing the safety-related portion of the “B” train of RN from service to relocate valves and install new piping
- Protection of “B” train equipment designated in the Critical Activity Plan supporting the planned LCO entry associated with removing the safety-related portion of the “A” train of RN from service to relocate valves and install new piping
- Protection of equipment associated with the “A” and “B” trains of spent fuel pool cooling (KF) with the recently offloaded core in the spent fuel pool when RN piping replacement was in-progress in close proximity to the KF piping
- Protection of equipment designated in the Risk Management Actions supporting the emergent repairs on the 2B Diesel Generator (DG) Battery Charger with transformer 2ATD unavailable

b. Findings

No findings of significance were identified.

2. Complete System Walkdown

a. Inspection Scope

The inspectors conducted one detailed walkdown/review involving the alignment and condition of both of the Unit 1 DGs and associated support systems within the diesel generator rooms. The inspectors utilized licensee procedures, as well as licensing and design documents to determine whether the system (i.e., pump, valve, and electrical) alignment was correct. During the walk downs, the inspectors also assessed whether: valves and pumps exhibited leakage that would impact their function; major portions of the system and components were correctly labeled; hangers and supports were correctly installed and functional; and essential support systems were operational. In addition, pending design and equipment issues were reviewed to determine if the identified deficiencies significantly impacted the system’s functions. Items included in this review were: the operator workaround list, the temporary modification list, System and Component Health Reports, and outstanding maintenance work requests/work orders. A review of open Problem Investigation Process reports (PIPs) was also performed to ascertain if the licensee had appropriately characterized and prioritized diesel generator-related equipment problems for resolution in the corrective action program. Documents reviewed during this inspection are listed in Attachment to this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors walked down accessible portions of the plant to assess the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. The inspectors observed the fire protection suppression and detection equipment to determine whether any conditions or deficiencies existed which could impair the operability of that equipment. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis, probabilistic risk assessment based on sensitivity studies for fire related core damage accident sequences, and summary statements related to the licensee's 1992 Initial Plant Examination for External Events Submittal to the NRC. The inspectors toured the eight areas important to reactor safety listed below. The documents reviewed during this inspection are listed in Attachment 1 of this report.

- Unit 2 Annulus
- Unit 1 "A" and "B" Safety Injection (NI) Pump rooms, 543 foot elevation
- Unit 2 Refueling Water Storage Tank
- Unit 2 "A" and "B" Containment Spray (NS) pumps, 522 foot elevation
- Auxiliary Building, 560 foot elevation, Room 300
- Unit 1 Auxiliary Feedwater (CA) Pump room and pits for the 1A, 1B and #1 CA pumps
- Standby Shutdown Facility, 594 and 611 foot elevations
- Unit 1 Turbine Building, 568 foot elevation

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance – Annual Resident Inspection

a. Inspection Scope

The inspectors reviewed the performance of Periodic Test PT/1/A/4400/0067E; KD Heat Exchanger 1A Heat Capacity Test, Rev. 24, and evaluated the test data for acceptable performance of the diesel generator jacket water cooling water (KD) system. The inspectors reviewed the system configuration associated with the test, heat load requirements, the methodology used in calculating heat exchanger performance, and the method for tracking the status of tube plugging activities via the data logger and computer processing equipment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

.1 Inservice Inspection activities other than Steam Generator Tube Inspections, PWR Vessel Upper Head Penetration Inspections, and Boric Acid Corrosion Control

a. Inspection Scope

From September 24 - October 5, 2007, the inspectors reviewed the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system (RCS) boundary and other risk significant piping system boundaries for Unit 2. The inspectors selected a sample of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI required examinations for review.

The inspectors conducted an on-site review of nondestructive examination (NDE) activities to evaluate compliance with Technical Specifications (TS) and the applicable editions of ASME Section V and XI (1989 Edition/No Addenda for examinations credited to the second 10-year ISI interval, and 1998 Edition/2000 Addenda for examinations credited to the third 10-year ISI interval), and determine that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of ASME Section XI acceptance standards.

Specifically, the inspectors directly observed the NDE activities described below and reviewed the corresponding NDE procedures, NDE reports, equipment and consumables certification records, and personnel qualification records:

- Ultrasonic (UT) examination CN-2SM-059 weld numbers 2, 4A-A, and 01 (Main Steam piping, ASME Class 2)
- Liquid Penetrant examination of CN-2NC-52 weld numbers 6, 7, and 8 (Charging line injection to Reactor Coolant System, ASME Class 1)

The inspectors reviewed the following NDE reports with recordable indications to ensure they were properly dispositioned in accordance with the applicable ASME Section XI acceptance criteria:

- VT-3 examination of rigid pipe support F01.020.033/2-R-ND-0323
- VT-3 examination of rigid pipe restraint F01.021.091/2-R-NS-1208

The inspectors reviewed a welding activity performed during this outage and one activity since the last refueling outage. The inspectors reviewed welding procedures, procedure qualification records, welder qualification records, and NDE reports for the following welds:

- Weld Overlay of 2NC8-3V, Pressurizer Surge Nozzle to Pipe, ASME Class 1
- Weld 2NI 2492-NI.00-139-25, Safety Injection Accumulator Circumferential weld, ASME Class 2

The inspectors also reviewed the results of the Nuclear Service Water (RN) piping inspections performed during the second 10-year ISI interval to determine compliance with the requirements of the ASME Code, Section XI, Article IWA-5244.

b. Findings

Introduction: The inspectors identified a Green Non-Cited Violation (NCV) of 10 CFR 50.55a(g)(4) for failure to perform periodic leakage testing of buried piping sections of the RN system as required by Section XI of the ASME Code for the second 10-year ISI interval for Units 1 and 2.

Description: On October 2, 2007, the inspectors identified that the licensee had not performed the required change in flow rate test for buried piping portions of the RN system during the second 10-year ISI interval in accordance with the 1989 Edition of the ASME Code, Section XI, Article IWA-5244. The licensee was committed to this Code Edition for the second interval. Both units are currently in the third ISI interval and the one-year period allowed to submit for regulatory relief following the second interval has expired. The failure to perform the requirements of IWA-5244 constitutes a violation of the ASME Code. Article IWA 5244 Part (b) required, in part, that in redundant systems where the buried components are non-isolable, the visual examination VT-2 shall consist of a test that determines the change in flow between the ends of the buried components. The licensee had not performed this change in flow test during the second interval.

The buried RN piping is carbon steel and susceptible to corrosion by the raw water that is pumped through it. The licensee has previously conducted crawl through inspections of the buried RN headers and coated the piping weld surfaces to inhibit corrosion. These coatings, however, do not cover the lengths of piping between the welds. System flow tests were successfully completed on a bi-annual basis to verify sufficient flow was maintained to downstream components. However, and notwithstanding, the Code required means of confirming structural and leakage integrity of this buried piping was through the periodic leakage testing required by IWA 5244 Part (b).

Analysis: The inspectors determined the failure to perform the required periodic testing of RN buried piping was a performance deficiency. This finding was more than minor because it affects the Equipment Performance attribute of the Mitigating Systems cornerstone objective of ensuring availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Should a significant leak, rupture, or piping collapse occur due to undetected degradation, this piping could not reliably deliver cooling water to downstream mitigating system components which are relied upon to respond to an initiating event. This finding was evaluated using Phase 1 of Inspection Manual Chapter 0609, “Significance Determination Process

(SDP)." This finding is of very low safety significance (Green) because it did not represent an actual loss of a system's safety function.

Enforcement: 10 CFR 50.55a(g)(4) requires, in part, that throughout the service life of a boiling or pressurized water reactor facility, components classified as ASME Code Class 1, 2, and 3 must meet the requirements set forth in Section XI of the ASME Code. The 1989 Edition of Section XI, IWA-5244 "Buried Components" paragraph (b) states, in part, "In redundant systems where the buried components are non-isolable, the visual examination VT-2 shall consist of a test that determines the change in flow between the ends of the buried components." Contrary to this, the licensee failed to perform the required testing on buried portions of the Class 3 RN system during the second 10-year ISI interval for which the 1989 Edition of the ASME Code was applicable. Therefore, because this finding is of very low safety significance and because this issue was entered into the licensee's corrective action program (PIP C-07-05738), it is being treated as a Non-Cited Violation (NCV) consistent with Section VI.A.1 of the Enforcement Policy: NCV 050000413,414/2007005-01, Failure to Perform Required ASME Code Section XI Leakage Testing.

.2 Boric Acid Corrosion Control (BACC) Inspection Activities

a. Inspection Scope

The inspectors reviewed the licensee's BACC activities to ensure implementation in accordance with applicable industry guidance documents and the requirements of 10 CFR 50 Appendix B. Specifically, the inspectors performed an on-site record review of procedures, self assessments, and completed boric acid walkdown procedures from this outage and the forced outage in May 2006. The inspectors also accompanied licensee personnel during the Mode 3 containment walkdown.

The inspectors reviewed a sample of engineering evaluations completed for boric acid found on piping and components of borated water systems to establish that leak evaluations were being properly completed in accordance with program and procedure requirements. The inspectors also reviewed licensee corrective action documents initiated for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code, 10 CFR 50 Appendix B Criterion XVI, and licensee BACC procedures. Specifically, the inspectors reviewed the following boric acid engineering evaluations (documented in corrective action documents):

- PIP C-07-01970, Pipe cap on boron recycle valve 2NB-503 has gone from inactive to active leak
- PIP C-07-01978, Dried boron found on body to bonnet, stud, and nut material on valve 2KF-19
- PIP C-07-02546, Boron between cap and body of fueling water storage valve 2FW-53

b. Findings

No findings of significance were identified.

.3 Steam Generator (SG) Tube Inspection Activities

a. Inspection Scope

From October 1 - 5, 2007, the inspectors reviewed the Unit 2 SG tube eddy current testing (ECT) examination activities to ensure compliance with TSs, applicable industry operating experience and technical guidance documents, and ASME Code Section XI requirements.

The inspectors reviewed licensee SG inspection activities to ensure that ECT inspections were conducted in accordance with the licensee's SG Program and applicable industry standards. The inspectors reviewed the SG examination scope, ECT acquisition procedures, site-specific Examination TS Sheets, the most recent SG degradation assessment, and the last condition monitoring and operational assessment. The inspectors reviewed documentation to ensure that the ECT probes and equipment configurations used were qualified to detect the expected types of SG tube degradation, and a sampling of tube data was reviewed with a qualified analyst. The inspectors also found that appropriate inspection scope expansion criteria were applied based on inspection results. The inspectors ensured that all tubes with relevant indications were appropriately screened for in-situ pressure testing. No tubes met the criteria for in-situ testing. Additionally, the inspectors monitored the licensee's secondary side activities, which included a foreign object search and recovery for loose parts, and sludge lancing.

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

The inspectors performed a review of ISI related problems, including welding, BACC and SG ISI, that were identified by the licensee and entered into the corrective action program as PIPs. The inspectors reviewed the PIPs to confirm that the licensee had appropriately described the scope of the problem and had initiated corrective actions. The inspectors performed this review to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" requirements. The corrective action documents reviewed by the inspectors are listed in Attachment 1 of this report.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed Licensed Operator Requalification Training Scenario OP-CN-LOR-S-07 to assess the performance of licensed operators during a training session. The exercise included a loss of normal letdown, slow failure of a 125VDC vital inverter, anticipated transient without scram, loss of secondary heat sink due to a condensate line break and subsequent loss of feedwater, and the establishment of bleed and feed to remove heat from the primary system. The inspection focused on high-risk operator actions performed during implementation of the abnormal and emergency operating procedures, and the incorporation of lessons-learned from previous plant and industry events. The classification and declaration of the Emergency Plan by the Shift Technical Advisor and Operations Shift Manager was also observed during the scenario. Being a training session, immediate feedback was provided to the operators by the instructors when warranted. The documents reviewed during this inspection are listed in Attachment 1 of this report.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing the four maintenance activities listed below. This review included an assessment of the licensee's practices pertaining to the identification, scope, and handling of degraded equipment conditions, as well as common cause failure evaluations and the resolution of historical equipment problems. For those structures, systems, and components scoped in the maintenance rule, the inspectors assessed whether reliability and unavailability were properly monitored, and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. The documents reviewed during this inspection are listed in Attachment 1 of this report.

- Maintenance and repair activities on the 2B DG during the Unit 2 end-of-cycle (EOC) 15 refueling outage including the post-maintenance operability run at the completion of the maintenance work
- Troubleshooting and repair of the failure of the Unit 2 rod control system to move shutdown banks C, D and E during pre-start up rod cluster control assembly (RCCA) movement testing
- Troubleshooting and repair of the N-9 shutdown bank control rod position indication
- Repair of the #8 stud hole on 2D SG cold leg primary manway during 2EOC15

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the licensee's assessments concerning the risk impact of removing from service those components associated with the five work items listed below. This review primarily focused on activities determined to be risk-significant within the Maintenance Rule. The inspectors also assessed the adequacy of the licensee's identification and resolution of problems associated with maintenance risk assessments and emergent work activities. The inspectors reviewed Nuclear System Directive (NSD) 415, Operational Risk Management (Modes 1-3), and NSD 403, Shutdown Risk Management (Modes 4,5,6, and No Mode), for appropriate guidance to comply with 10 CFR 50.65 (a)(4). The documents reviewed during this inspection are listed in Attachment 1 of this report.

- Review of planned work associated with removing the safety-related return header of the "A" RN system from service to support relocation of valves and installation of new piping
- Review of new methodology of purging air from the steam generator U-tubes to support reactor coolant system refill
- Review of licensee's assessment of the potential for continued operation with both units at power using the SATB transformer in place of 2ATD
- Review of planned and emergent work during the period 2B DG and battery charger were unavailable which placed Unit 2 in an Orange risk profile
- Assessment of post modification testing associated with the automatic voltage regulator and risk management actions developed to support the testing

b. Findings

Introduction: The inspectors identified a Green NCV of 10CR50.65(a)(4) for the failure to manage and minimize the risk associated with the replacement of portions of the RN system. More specifically, the licensee failed to develop a Complex Lift Plan as required by Corporate procedures and develop appropriate risk management actions as part of the Critical Activity Plan.

Description: During the Fall 2007 Unit 2 refueling outage, several portions of RN piping located in the Auxiliary Building were scheduled to be replaced due to ongoing internal corrosion issues. The modification replaced the existing carbon steel piping with piping consisting of a chrome-molybdenum alloy in sections weighing up to 1,300 pounds. Due to the limited space surrounding the piping, which was located in the overhead area of the 577 foot elevation in the Auxiliary Building, contract master riggers were brought in to remove the old piping and re-install the new piping utilizing Duke procedural guidance. KF piping was located directly beneath the RN piping being replaced. At the point in the outage where the piping was scheduled to be removed, the Unit 2 core had been transferred from the reactor vessel into the spent fuel pool and the KF piping beneath the RN piping was providing cooling to the spent fuel pool to remove decay heat. The calculated time-to-boil in the spent fuel pool with a loss of both trains of KF was approximately 17.5 hours.

The inspectors asked the work crew at the job site was asked for a copy of the lift plan associated with the piping replacement project; however, a lift plan could not be located. Follow-up discussions with the Major Projects Group, which was responsible for the implementation of the modification, determined that while a lift plan was required by the Duke Energy Nuclear Lifting Program, one had not been developed for the piping replacement to ensure the safety-related KF piping in the area was adequately protected. This was due to a misinterpretation of the requirements contained in the Duke Energy Nuclear Lifting Program by those reviewing the modification implementation package.

Based on the increased risk resulting from removing the “B” train of RN for greater than 50 percent of the allowed LCO time to support the piping replacement, NSD 213, “Risk Management Process”, dictated that a Critical Activity Plan be developed to support the activity. While a Critical Activity Plan had been developed for the work in accordance with NSD 213, the potential consequences resulting from a pipe drop had not been considered in the plan’s development. As a result, no risk mitigation actions were defined to ensure the adjacent KF piping was adequately protected during movement of the RN piping.

Once it was determined that a lift plan had not been developed for the piping work nor risk management actions established to address the adverse consequences of a pipe drop, the licensee suspended all work until a load drop analysis was completed and the procedurally-required actions were properly documented and implemented. At the time the work was suspended, no actual movement of RN piping had taken place.

Analysis: The inspectors determined that the licensee’s failure to develop a complex lift plan and establish risk management actions as required by the corporate and station procedures to support the replacement of RN piping and protect adjacent safety-related equipment was a performance deficiency. The finding was more than minor because it was associated with the “Protection Against External Factors” attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability and capability of systems designed to prevent undesirable consequences was maintained. An unexpected loss of the 2A train of KF and inadvertent draining of the spent fuel pool could have resulted in undesirable consequences with the recently off-loaded reactor core being in the spent fuel pool.

The inspectors completed a Phase 1 screening of the finding using Appendix K of Inspection Manual Chapter 0609, “Maintenance Risk Assessment and Risk Significance Determination Process,” and determined that the performance deficiency represented a finding of very low safety significance (Green) on the basis that the actual RN piping replacement had not begun at the time the deficiencies were identified, and that the lifts were deferred until the appropriate actions were developed and implemented.

The finding directly involved the cross-cutting area of Human Performance under the “Safety Significant/Risk Significant Decisions” aspect of the “Decision Making” component, in that the licensee failed to develop a lift plan and applicable risk management actions in accordance with station and corporate requirements to ensure the risk associated with moving RN piping over in-service KF piping was controlled and minimized. This finding has been entered into the licensee’s Corrective Action Program as PIPs C-07-5440 and C-07-5447.

Enforcement: 10CFR50.65(a)(4), Requirements for monitoring the Effectiveness of Maintenance at Nuclear Power Plants, requires in part, that prior to performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

NSD 403, Operational Risk Management (Modes 4, 5, 6 and No-Mode) per 10CFR50.65(a)(4), implements the requirements set forth in 10FR50.65(a)(4) during shutdown conditions. NSD 403 in part states that prior to performing maintenance activities, risk assessments shall be performed to assess and manage the increased risk that may result from the proposed maintenance activities. Section 403.7.3.7 defines the requirement to establish and implement appropriate prevention measures to minimize the likelihood and consequences of a load dropping and striking equipment.

NSD 213, Risk Management Process, specifies the requirements of station personnel to identify, direct, control and manage risk-significant activities at the station, including the development of Critical Activity Plans to manage and minimize the risk resulting from the planned activity. The NSD states that a Critical Activity Plan is required if an activity is planned to exceed 50 percent of the allowed LCO time in TSs (which the RN piping replacement work required) and specifies the requirement to assess the activity, identify potential adverse consequences, and develop contingency plans or risk management actions to minimize the potential impact on the plant.

The Duke Energy Nuclear Lifting Program Manual, Appendix E, Lift Plan Checklist, Revision 13 states in part that a lift evolution is considered to be a complex lift, requiring a documented lift plan that includes a risk assessment and contingency actions, if during the lift an uncontrolled movement or loss of the load could adversely affect any decay heat removal systems.

Contrary to the above, on September 27, 2007, it was determined that the licensee had failed to identify the need to develop and document a complex lift plan as required by the

Duke Energy Nuclear Lifting Program Manual in preparation for the replacement of several sections of RN system piping located above the operating 2A train of KF. In addition, the Critical Activity Plan that controlled the piping replacement project failed to assess the potential consequences of a pipe drop event on the KF piping and develop risk mitigation actions to minimize the risk associated with the activity as required by NSD 213 and NSD 403.

Because this finding is of very low safety significance and has been entered into the licensee's corrective action program as PIPs C-07-5440 and C-07-5447, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000414/2007005-02, Failure to Develop a Lift Plan and Risk Management Actions for the Replacement of Piping Over a Safety-Related Systems, Structures and Components (SSCs).

1R15 Operability Evaluations

a. Inspection Scope

For the ten operability evaluations listed below, the inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) to determine whether the system or component remained available to perform its intended function. In addition, the inspectors reviewed compensatory measures implemented to find that they worked as stated and that they were adequately controlled. The inspectors also reviewed a sampling of PIPs to determine if the licensee was identifying and correcting any deficiencies associated with operability evaluations. The documents reviewed during this inspection are listed in the Attachment to this report.

- PIP C-07-4984; A piece of yellow duct tape was found adhered to the side of the trough below the suction header in the 2A ECCS containment sump
- PIP C-07-5347; Immediate Determination of Operability concerning the inability to perform TS surveillance requirement SR 3.8.1.8 on Unit 1 for B train power due to the issues related to transformer 2ATD
- PIP C-07-5441; Potential non-conservatism with the methodology used to calculate Net Positive Suction Head margins for the ND and NS pumps
- PIP C-07-6578; Immediate Determination of Operability of the ice condenser ice baskets replenished during 2EOC15
- PIP C-07-6675; Evaluation is required to assess the voltage drops and loading of SATA and SATB for accident loading when either Unit is in Mode 1 through 4 and is supplying power to one of the vital buses through these transformers
- PIP C-07-5046; ECCS motor coolers were found to have cooling water supply and return lines installed incorrectly

- PIP C-07-6479; The "A" Controlled Area Chilled Water (YC) chiller failed to start

during “A” train engineered safety feature (ESF) testing on Unit 2 / PIP C-07-6503; Unplanned Technical Specification Action Item Log (TSAIL) entry for the “B” YC chiller failure to restart during “B” train ESF testing
- PIP C-07-7048; Small leak identified on the 2B Chemical and Volume Control (NV) system pump at the discharge head-to-pump casing mechanical joint
- PIP C-07-6273; Evaluation needed to address the inability to meet the acceptance criteria of the ECCS Flow Balance surveillance due to the replacement of NV pump 2B rotating element
- PIP C-07-7544; A vulnerability exists for a pocket of gas to be trapped in the Unit 2 NS pump A and B suction headers

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the following four permanent plant modifications to ascertain the adequacy of the modification packages, and to evaluate the modifications for adverse affects on system availability, reliability and functional capability. Documents reviewed during this inspection are listed in the Attachment to this report.

- CD201296; Modify Unit 2 reactor coolant system loop drain lines to preclude inadvertent loss of reactor coolant system inventory
- CD201528; Add stop and modify arms on the Unit 2 submarine hatch between lower and upper containment
- CD200863; Install body vent valves on two refueling water system valves (2FW-27A and 2FW-55B) to eliminate to potential for pressure locking of the valves if required during a Mode 4 loss of coolant accident (LOCA)
- CD200490; Unit 2 ECCS containment recirculation sump strainer modification

b. Findings

Introduction: The inspectors identified a Green NCV of 10CFR50, Appendix B, Criterion X, Inspections, for the licensee’s failure to adequately implement inspections of the new Unit 2 ECCS containment sump to ensure it was installed in accordance with design specifications, so as to support operability when required by TS.

Description: Catawba installed a modified ECCS containment sump on Unit 2 during the Fall 2007 refueling outage. The sump utilized an entirely new design that incorporated individual strainer assemblies known as top hats attached to a series of plenums affixed to a section common to both the “A” and “B” ECCS suction headers. The elimination of the train separation found on the old sump design greatly increased the potential for a common mode failure of the ECCS system if foreign material was allowed to enter the sump during a LOCA that required transitioning to hot or cold leg ECCS recirculation. This vulnerability was identified and addressed through detailed assembly instructions and Quality Control checks that specifically inspected for any gaps that could allow foreign material to bypass the strainers, enter the ECCS system, and subsequently impede flow through either throttle valves or orifices in the system.

On November 10, 2007, the inspectors identified a gap between a strainer assembly and the sump plenum on the newly installed ECCS containment sump during the pre-Mode 4 containment cleanliness inspection. This gap was subsequently found to be greater than the 1/16 inch acceptance criteria. To ensure the ECCS sump was properly assembled, the licensee re-inspected 100 percent of all strainers on the two side sections and as much of the center section as possible without performing a total disassembly of the sump. No additional gaps exceeding the 1/16 inch criteria were identified through these supplemental inspections.

While observing the licensee's plenum-top hat gap inspections, the inspectors identified insufficient thread engagement on three nut-to-stud connections holding the stainless steel banding in place that covered the gaps where individual plenum sections were joined together. Following an evaluation of the condition by the licensee and the engineering firm that designed the sump, the threaded stock was replaced with longer ones and the nuts were affixed as depicted in the assembly drawings.

These deficiencies were identified after Quality Control inspectors assigned to the ECCS sump project had signed off their final inspection document and Engineering had completed their formal inspection of civil structures within the containment building. The deficiencies were identified by the inspectors after the licensee had completed all sump inspections and had declared it operable (i.e., ready to support entry into Mode 4 and subsequent power ascension).

<u>Analysis</u>: The inspectors determined that the licensee's failure to take the necessary actions to ensure the new ECCS containment sump was constructed in accordance with the design specifications and commitments made to the NRC in the associated license amendment request was a performance deficiency. The finding was more than minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences was maintained. Following final inspections of the ECCS containment sump modification, inspectors identified deficiencies that required resolution prior to declaring the sump operable as required by TSs to support unit restart. The inspectors determined the finding to be of very low safety significance (Green) using the Phase 1 Screening Worksheet of Inspection Manual 0609, "Maintenance Risk Assessment and Risk Significance Determination Process", based on the fact that Unit 2 had not yet entered an operational mode in which the ECCS containment sump was required to be operable. In addition, the likelihood of sufficient debris entering the sump structure

through the single gap that exceeded 1/16 inch to adversely affect either train of ECCS was determined to be extremely low. This finding has been entered into the licensee's Corrective Action Program as PIP C-07-6876.

The finding directly involved the cross-cutting area of Human Performance under the "Human Performance and Error Prevention" aspect of the "Work Practices" component, in that the licensee failed to implement the required inspections of the ECCS sump to ensure the permanent modification was installed in accordance with design specifications and would remain operable under all postulated accident conditions (H.4.a).

Enforcement: 10CFR50, Appendix B, Criterion X, Inspection, states in part that "A program for inspection of activities affecting quality shall be established and executed by the organization performing the activity to verify conformance with the documented instructions, procedures, and drawings. Examinations, measurements, or tests of material or products processed shall be performed for each work operation where necessary to assure quality."

Contrary to the above, on November 10, 2007, inspectors identified deficiencies associated with the assembly of the new Unit 2 ECCS containment recirculation sump following the completion of the final operability inspections by both the Quality Control and Engineering groups. These deficiencies required rework, additional inspections, and replacement of components in order to declare the sump operable to support unit restart.

Because this finding is of very low safety significance and has been entered into the licensee's corrective action program as PIP's C-07-6876, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000414/2007005-03, Inspections of the ECCS Containment Sump Installation Failed to Identify Deficiencies Prior to Declaring the Safety-Related Structure Operable.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the five post-maintenance tests listed below to determine whether procedures and test activities ensured system operability and functional capability. The inspectors reviewed the licensee's test procedures to determine if: (1) the procedures adequately tested the safety function(s) that may have been affected by the maintenance activities; (2) the acceptance criteria in the procedures were consistent with information in the applicable licensing basis and/or design basis documents; and (3) the procedures had been properly reviewed and approved. The inspectors also witnessed the tests and/or reviewed the test data to establish whether the test results adequately demonstrated restoration of the affected safety function(s). The documents reviewed during this inspection are listed in the Attachment to this report

- PT/2/A/4350/002B; Diesel Generator 2B Operability Test, performed following

planned maintenance and repairs during the 2EOC15 refueling outage
- PT/2/A/4350/002A; Diesel Generator 2A Operability Test, performed following planned maintenance during the 2EOC15 refueling outage
- OP/2/A/6100/001, Controlling Procedure for Unit Startup, Rev. 144, Enclosure 4.1, Unit Startup – sections that performed functional checks of the pressurizer heaters following reconnection of the heater power cables removed during the performance of the Alloy 600 weld overlay project in 2EOC15
- Restoration of 6.9kV transformer 2ATD to service following replacement and removal of transformer SATB from service and placing it in standby
- Post-maintenance testing and troubleshooting activities associated with the failure of the “A” and “B” YC chillers to restart during portions of ESF testing conducted during the 2EOC15 refueling outage

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, for the licensee’s failure to promptly identify and correct a condition adverse to quality affecting the ability of both control room area ventilation system (CRAVS) chillers to operate as designed following a station blackout (SBO).

Description: On October 25, 2007, the “A” train of the ESF circuitry was being tested on Unit 2 during the 2EOC15 refueling outage. While performing the section of the procedure that simulated a SBO in conjunction with a LOCA, the “A” control room area chiller, which had been in operation, failed to restart after receipt of a start signal from the diesel generator load sequencer following the load-shed that occurred on loss of power as designed. There are two CRAVS chillers that are shared between the two units and provide chilled water to maintain the areas cooled by the CRAVS below 90°F. Consequently, following the failure of the “A” chiller to restart, both units entered a 30-day TS LCO action statement to restore the “A” chiller to operable status.

Troubleshooting identified a valve that supplied cooling water to the chiller’s oil cooler out of the correct throttle position, resulting in elevated oil temperatures. Personnel involved in the troubleshooting focused on the cooling water valve position as the cause for the oil temperature approaching the trip/reset setpoints; thereby, preventing the chiller from restarting as expected. The valve was adjusted and the “A” CRAVS chiller was restarted using the guidance contained in the system operating procedure for a normal start. The chiller ran satisfactorily for approximately 16 hours prior to being secured and placed in standby. The portion of the test that simulated a SBO with a LOCA was not re-performed based on the decision that the sole cause of the original failure of the “A” chiller to restart was the mispositioned oil cooler cooling water supply valve.

On October 27, 2007, while performing the “B” train ESF testing, the “B” CRAVS chiller also failed to restart during the section that tested the overall plant response to a SBO in conjunction with a LOCA. Initial troubleshooting for this event did not find any cooling water valve alignment issues as had been experienced on the “A” train two days earlier. A multi-disciplinary team was assembled to determine the cause of the “B” chiller failing to restart following receipt of the load-shed signal when sequenced on by the diesel generator sequencer circuit. The team discovered that a fuse which had been replaced earlier in 2007 as a like-for-like replacement (same part number and amperage rating) had a significantly higher resistance than the original fuse. This additional resistance in the temperature monitoring circuit on both chillers resulted in approximately a 45°F shift in the measured temperature versus actual temperature of the oil. As a result, when a station blackout signal was received and the chiller’s power was lost, the sensed temperature was above the reset temperature and the contacts would not re-close in order for the chiller to be restarted when called upon to do so by the diesel generator sequencer circuit.

The licensee implemented a modification that removed the fuse from the temperature circuit and following testing, which included a simulated SBO and LOCA signal, declared the “B” chiller fully operable. Once the testing confirmed that the fuse had been the cause of the chiller failing to restart following a SBO rather than the mispositioned cooling water valve, the “A” chiller was declared inoperable until the same modification could be installed in its circuitry. TS 3.0.3 was entered for the time when both the “A” and “B” chillers were inoperable and was exited 23 minutes later after the “B” chiller was returned to fully operable status.

The earlier fuse replacement had occurred on the “A” chiller on April 10, 2007, and on the “B” chiller on January 3, 2007. During the time period in which the replacement fuse was in the temperature circuit and the opposite CRAVS chiller was inoperable, neither chiller would have been available if called upon following a SBO event.

Analysis: The licensee’s failure to conduct adequate troubleshooting and post-maintenance testing following failure of the “A” CRAVS chiller to restart during ESF testing, resulted in an existing condition adverse to quality to remain undetected and uncorrected. This inadequate corrective action was determined to be a performance deficiency. The finding was more than minor because it was associated with the Configuration Control attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers provide protection from radio nuclide releases caused by accidents or events. While the CRAVS would have remained operable in terms of filtering air in the areas it services, without chilled water providing cooling, operators would have had to bypass the filtered air paths using abnormal operating procedure (AP) guidance in order to maintain area temperatures at values needed to ensure equipment in the areas remained operable.

The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 Screening Worksheet of Inspection Manual 0609, “Maintenance Risk Assessment and Risk Significance Determination Process”, based on the fact that the issue would only become evident if one CRAVS chiller was out-of-service at the time of a SBO event and the time available to restore at least one chiller before the AP would have had to be entered and the filtered air flow paths bypassed. Based on a review of station Probabilistic Risk Assessment data, the likelihood of a SBO event in conjunction with one chiller being inoperable was determined to be extremely low. The finding directly involved the cross-cutting area of Problem Identification and Resolution under the "Thorough Evaluation of Identified Problems" aspect of the "Corrective Action Program" component, in that the licensee failed to take the necessary actions to identify and correct the cause of the "A" CRAVS chiller failing to restart during ESF testing to ensure both chillers would function as designed under all postulated transients (P.1.c). This issue has been entered into the licensee's Corrective Action Program as PIPs C-07-6848 and C-07-6503.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that "measures shall be established to assure that significant conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected."

Contrary to the above, on October 25, 2007, the licensee failed to conduct adequate troubleshooting and post-maintenance testing to ensure the cause for the "A" CRAVS chiller failing to restart during ESF testing was promptly identified and corrected. The actual cause was not identified until a subsequent similar failure of the "B" CRAVS chiller occurred which placed both units in TS 3.0.3 for a limited period of time. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program as PIPs C-07-6848 and C-07-6503, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000413, 414/2007005-04), Failure to Promptly Identify and Correct a Significant Condition Adverse to Quality Affecting the Ability of Both CRAVS Chillers to Operate as Designed Following a SBO due to Inadequate Troubleshooting and Post-Maintenance Testing.

1R20 Refueling and Outage Activities

.1 Unit 2 2EOC15 Refueling Outage Activities

a. Inspection Scope

The inspectors evaluated licensee outage activities to determine whether the licensee: considered risk in developing outage schedules; adhered to administrative risk reduction methodologies they developed to control plant configuration; adhered to operating license, TS, and Selected Licensee Commitment requirements, as well as procedural guidance that maintained defense-in-depth; and developed mitigation strategies for losses of the key safety functions identified below:

- Decay Heat Removal
- Inventory Control
- Reactivity Control

- Containment Control
- Spent Fuel Cooling
- Power Availability

The inspectors reviewed the licensee's outage risk control plan to assess the adequacy of the risk assessments that had been conducted and that the licensee had implemented appropriate risk management strategies as required by 10CFR50.65(a)(4).

Following core reload and cavity drain-down, the inspectors performed an inspection of the reactor vessel bottom head to determine if any potential leakage had occurred at the welds associated with the bottom head penetrations and assess the overall cleanliness of the reactor vessel bottom head. This inspection was done in conjunction with the licensee's Engineering personnel.

The inspectors observed the items or activities described below, to substantiate that the licensee maintained defense-in-depth commensurate with the outage risk control plan for the key safety functions identified above and applicable TS when taking equipment out-of-service.

- Clearance activities; hanging and removing safety tags
- Reactor Coolant System Instrumentation
- Realigning electrical power
- Establishing and maintaining Decay Heat Removal
- Maintaining Spent Fuel Pool Cooling
- Inventory control including reduced inventory conditions
- Controlling reactivity
- Establishing and maintaining Containment Closure

The inspectors reviewed the licensee's responses to emergent work and unexpected conditions, to establish that resulting configuration changes were controlled in accordance with the outage risk control plan.

The inspectors also observed fuel handling operations (core reload) and other ongoing activities, to determine that those operations and activities were being performed in accordance with TS and procedural guidance. Additionally, the inspectors observed refueling activities to substantiate that the locations of the fuel assemblies were tracked through core reload. The inspectors viewed the final in-core fuel assembly position verification video prior to re-installation of the reactor internals and head.

Prior to mode changes and on a sampling basis, the inspectors reviewed system lineups and/or control board indications to substantiate that TSs, license conditions, and other requirements, commitments, and administrative procedure prerequisites for mode changes were met. Also, the inspectors periodically reviewed the setting and maintenance of containment integrity, to establish that the RCS and containment boundaries were in place and had integrity when necessary.
Prior to reactor startup, the inspectors walked down upper and lower containment to

observe that debris had not been left which could affect performance of the containment ECCS sumps. In addition, the inspectors performed a walkdown of the upper and lower ice condenser areas to establish that debris had not been left which could affect ice condenser performance.

The inspectors observed the “Just-in-Time” training conducted for the personnel involved in the unit startup on November 1, 2007, which simulated bringing the unit from Mode 3 to criticality and through portions of the power ascension process.

The inspectors observed the reactor startup/pull to criticality on November 8, 2007, unit synchronization to the grid, and portions of the subsequent power ascension to assure procedure compliance and that systems performed as designed. The inspectors reviewed reactor physics testing results to determine that core operating limit parameters were consistent with the core design.

Periodically, the inspectors reviewed the items that had been entered into the licensee’s corrective action program, to establish that the licensee had identified problems related to outage activities at an appropriate threshold and had entered them into the corrective action program.

Documents reviewed in support of the Unit 2 2EOC15 refueling outage are listed in Attachment 1 of this report.

b. Findings and Observations

No findings of significance were identified.

.2 NRC Operating Experience Smart Sample FY2007-03

a. Inspection Scope

In response to operational experience concerns regarding reactor vessel head lifts (NRC Operating Experience Smart Sample FY2007-03), the inspectors reviewed licensee programs and procedures to determine whether past and current practices were within the licensing basis. The inspectors observed the Unit 2 reactor vessel head removal and replacement during the Fall 2007 EOC15 Catawba Unit 2 refueling outage. The inspectors reviewed the documents listed in Attachment 1 to this report related to heavy load lifts of the reactor vessel head, and conducted discussions with licensee personnel involved in the development of lifting plans and conducting the actual lifts.

b. Findings

The inspectors identified the following issues:

- The licensee could not demonstrate that the Updated Final Safety Analysis Report (UFSAR) had been adequately updated to reflect information and analyses provided to the NRC in response to generic communications regarding heavy loads.
- The licensee could not demonstrate that their reactor vessel head lifts, which prior to the Fall 2007 Unit 2 outage had lifted the head to approximately 40 feet over the irradiated fuel in the reactor vessel, were bounded by the design calculations which evaluated the drop of the head through air onto the reactor vessel, upper internals, and irradiated fuel for distances up to 16 feet through air or 18 feet through air followed by 24 feet through water.
- Until revised prior to the Fall 2007 Unit 2 refueling outage, the licensee could not demonstrate that their procedures for the reactor vessel head removal and installation ever limited their head lifts to the bounds contained in an August 17, 1984, letter sent to the NRC concerning a load drop analysis for reactor vessel head lifts.

Failure to update the Final Safety Analysis Report pursuant to 10 CFR 50.71(e) to reflect aspects of handling the reactor vessel head was considered a potential violation.

The NRC has found industry uncertainty regarding the licensing bases for handling of reactor vessel heads, and as a result issued Enforcement Guidance Memorandum 07-006, Enforcement Discretion for Heavy Load Handling Activities, on September 28, 2007. The Nuclear Energy Institute has informed NRC of industry approval of a formal initiative that specifies actions each plant will take to ensure that heavy load lifts continue to be conducted safely and that plant licensing bases accurately reflect plant practices. The NRC staff believes implementation of the initiative will resolve uncertainty in the licensing bases for heavy load handling, and enforcement discretion related to the uncertain aspects of the licensing basis is appropriate during the implementation of the initiative.

The inspectors determined that the licensee implemented the following actions prior to the specified lifts in accordance with the industry initiative to warrant enforcement discretion:

(1) For all heavy load lifts within the reactor building, the licensee has defined and implemented safe load paths, load handling procedures, and standards for training of crane operators, use of special lifting devices, use of slings, and design, inspection, testing, and maintenance of the reactor building polar crane.

(2) To support the Fall 2007 Unit 2 refueling outage, the process for lifting the reactor vessel head was changed to ensure the lift was conducted within the bounds of the 1984 reactor vessel head load drop analysis with respect to load weight, load height, and medium present under the load. The licensee

maintained the bottom of the reactor vessel head less than 15 feet above the reactor vessel or the refueling cavity water surface when the head was lifted to ensure consequences of a load drop event were bounded by the original analysis. Once the cavity was fully flooded to greater than 23 feet above the reactor vessel flange, the reactor vessel head was allowed to be lifted to approximately 16 feet above the water surface as necessary to lift the head above immovable structures around the refueling cavity. This change has been made to the procedures used on both Catawba units.

(3) Westinghouse has been contracted to re-analyze the reactor vessel head drop event prior to the Spring 2008 Unit 1 refueling outage to determine if additional margin is available to allow greater flexibility in defining a safe load path for the reactor head once it clears the reactor head guide studs. Any changes to the current process which ensures the 16 foot bounding distance is maintained will be done with sufficient time for a multi-disciplinary review to be performed prior to the start of the refueling outage.

(4) The movement of heavy loads will have administrative controls and risk assessments established as required to implement the requirements of 10 CFR50.65(a)(4).

Therefore, consistent with the intent of Enforcement Guidance Memorandum 07-006, enforcement discretion (EA-08-034) is being exercised for the violation described above in accordance with Section VII.B.6 of the NRC Enforcement Policy without any enforcement action.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and/or reviewed the 15 surveillance tests listed below to determine that TS surveillance requirements and/or Selected Licensee Commitment requirements were properly complied with, and that test acceptance criteria were properly specified. The inspectors determined whether proper test conditions were established as specified in the procedures, that no equipment pre-conditioning activities occurred, and that acceptance criteria had been met. Additionally, the inspectors also determined if equipment was properly returned to service and if proper testing was specified and conducted to ensure that the equipment could perform its intended safety function. The documents reviewed during this inspection are listed in Attachment 1 of this report.

Surveillance Tests

- PT/2/A/4350/002 B, Diesel Generator 2B Operability Test, Rev. 89
- PT/2/A/4350/002 A; Diesel Generator 2A Operability Test, Rev. 89
- PT/2/A/4550/001 D; Reactor Building Manipulator Crane Load Test, Rev. 12
- PT/0/A/4600/031; NAC-UMS Cask Surveillance, Rev. 00
- PT/2/A/4200/001A, Containment Integrated Leak Rate Test, Rev. 011
- SM/0/A/8510/008, Ice Condenser Foreign Material Exclusion Inspection, Rev. 003
- PT/2/A/4200/009A; Auxiliary Safeguards Test Cabinet Periodic Test, Rev 191; Enclosures 13.27 (Containment Ventilation Isolation, Train A), 13.28 (Containment Ventilation Isolation, Train B), and 13.36 (Containment Isolation Phase A, Train B)
- PT/2/A/4600/001, RCCA Movement Test, Rev. 30
- IP/2/A/3200/001A; Solid State Protection System (SSPS) Train A Periodic Testing, Rev. 005
- PT/2/A/4350/002A; Diesel Generator 2A Operability Test, Rev. 089
- PT/2/A/4150/001D; RCS Leakage Calculation, Rev. 64

<u>In-Service Tests</u>

- PT/1/A/4200/021 A; Component Cooling Water (KC) Valve Inservice Test, Rev. 072
- PT/1/A/4200/004B; Containment Spray Pump 1A Performance Test, Rev. 059

<u>Containment Isolation Valve Tests</u>:

- PT/2/A/4200/001 I; As Found Containment Isolation Valve Leak Rate Test, Rev. 013 -Testing of Penetration M220 for 2VI-79, 2VI-312A and 2VI-77B

<u>Ice Condenser Tests</u>

- MP/0/A/7150/006, Ice Condenser Lower Inlet Doors (LID) Inspection and Testing, Rev. 029, Sections 11.4 (Door Inspection), 11.5 (LID Initial Opening Force As-Left Test) and 11.6 (LID 40 Degree As-Left Testing)

b. <u>Findings</u>

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed and evaluated the licensee's performance during two emergency drills conducted on February 21 and March 7, 2007. The inspectors observed licensee activities in the Control Room Simulator and in the Technical Support Center. The NRC's assessment focused on the timeliness and accuracy of the emergency classification, offsite agency notifications, and the licensee's response to the event. The performance of the emergency response organization was evaluated against the applicable licensee procedures and regulatory requirements. The inspectors attended the post-exercise critique for the drills to evaluate the licensee's self assessment process for capturing potential deficiencies relating to classification, notification and response to the failures in the scenarios. Documents reviewed are listed in Attachment 1of this report.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Initiating Events, Mitigating Systems, and Barrier Integrity

a. Inspection Scope

The inspectors sampled licensee data to establish the accuracy of the data reported for the 14 performance indicators (PI) listed below. To determine the accuracy of the reported PI elements, the reviewed data was assessed against PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Indicator Guideline.

Initiating Events

- Unplanned Scrams per 7,000 Critical Hours, Unit 1 - The inspectors reviewed the Unplanned Scrams per 7,000 Critical Hours Performance Indicator results for the period of October 1, 2005, through September 30, 2007, for Unit 1. The inspectors reviewed operating logs, PIPs, and monthly operating reports associated with any manual and automatic scrams that occurred in that period and determined whether the data reported for the PI corresponded to the unit's power profile. The documents reviewed during this inspection are listed in Attachment 1 of this report.

Mitigating Systems

- Mitigating System Performance Indicator - The inspectors reviewed the licensee's procedures and methods for compiling and reporting the PIs listed below, including the Reactor Oversight Program Mitigating System Performance Indicator (MSPI) Basis Document for Catawba. The inspectors reviewed the raw data for the PIs listed below for the first, second, and third quarters of 2007. The inspectors also independently screened TSAIL logs, selected control room logs, work orders and surveillance procedures, and maintenance rule failure determinations to determine if unavailability/unreliability hours were properly reported. The inspectors compared the licensee's raw data against the graphical representations and specific values contained on the NRC's public web page for the first, second and third quarters of 2007. The inspectors also reviewed the past history of PIP's for systems affecting the MSPI indicators listed below for any that might have affected the reported values. The inspectors reviewed NEI 99-02, Regulatory Assessment Performance Indicator Guideline, to determine whether industry reporting guidelines were applied. Additional documents reviewed during this inspection are listed in Attachment 1 of this report.

    - Mitigating Systems Performance Index - High Pressure Safety Injection, Units 1 and 2
    - Mitigating Systems Performance Index – Heat Removal, Units 1 and 2
    - Mitigating Systems Performance Index – Residual Heat Removal, Units 1 and 2
    - Mitigating Systems Performance Index – Emergency AC Power, Units 1 and 2
    - Mitigating Systems Performance Index – Cooling Water Systems, Units 1 and 2

Safety System Functional Failures, Units 1 and 2 - The inspectors reviewed the Safety System Functional Failures Performance Indicator results for the period of October 1, 2006 through September 30, 2007 for Units 1 and 2. The inspectors reviewed licensee event reports, maintenance rule reports and selected work orders to ensure that any failure that prevented or could have prevented the fulfillment of a safety function in that period was identified and reported for the PI. The documents reviewed during this inspection are listed in the Attachment to this report.

Barrier Integrity

- Reactor Coolant System Leakage, Unit 2 - The inspectors reviewed the Reactor Coolant System Leakage PI results for the period of October 1, 2005, through September 30, 2007, for Unit 2. The inspectors reviewed the Auto Log entries which captured the results of the daily RDS leakage calculations compared to the Technical Specification limiting value of 10 gallons per minute for identified reactor coolant system leakage. In addition, the inspectors reviewed the performance of an RCS leak rate calculation by control room operators and discussed the results of the completed surveillance with the on-shift personnel.

The documents reviewed during this inspection are listed in Attachment 1 of this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Daily Review

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed screening of items entered into the licensee’s corrective action program. This was accomplished by reviewing copies of PIPs, attending daily Site Direction and PIP screening meetings, and accessing the licensee’s computerized database.

.2 Annual Sample Review

(1) Hydrostatic Seals

a. Inspection Scope

The inspectors reviewed PIPs, work orders and action requests associated with licensee actions taken in response to hydrostatic seal issues that resulted in multiple internal flooding events at Catawba in 2006. The hydrostatic seals had been installed during initial construction and were designed to prevent water intrusion into below-grade areas of the plant containing safety-significant or risk-significant equipment. As part of the root cause investigation, the licensee developed corrective actions to implement revised PM inspections of selected seals, assess the material and processes used to seal below-grade penetrations, and ensure drawings accurately reflect the as-built configuration of conduit manholes, penetrations and conduit seals. Inspectors reviewed the actions taken in response to past events at the station to assess their timeliness and effectiveness. The inspectors interviewed Engineering and Maintenance personnel involved in the development and implementation of the corrective actions and conducted field walkdowns of selected hydrostatic seals. The documents reviewed during this inspection are listed in Attachment 1 of this report.

b. Findings

No findings of significance were identified.

(2) Airlock Penetration

a. Inspection Scope

The inspectors selected one PIP for detailed review. PIP C-05-03781 involved testing failures on the Unit 1 airlock penetration, PC24, that met the performance level criteria for maintenance rule a(1) status. The PIP was reviewed to determine whether the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the PIP against the requirements of the licensee's corrective action program document and 10 CFR 50, Appendix B. The inspectors interviewed Engineering and Maintenance personnel involved in the development and implementation of the corrective actions to address the failures and remove the airlock penetration from (a)(1) status as required by the 10CFR50.65.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, the inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screenings discussed in section 4OA2.1 above, licensee trending efforts, and licensee human performance results. The inspectors' review primarily considered the six-month period of July 2007 through December 2007, although some examples expanded beyond those dates when the scope of the trend warranted. The review also included issues documented outside the normal CAP in major equipment problem lists, plant health team lists, Independent Nuclear Oversight Team reports, system and component health reports, self-assessment reports, maintenance rule reports, and Safety Review Group Monthly Reports. The inspectors compared and contrasted their results with the results contained in the licensee's latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy.

b. Assessment and Observations

The inspectors followed the actions being implemented by the licensee in response to the trend previously identified by the inspectors associated with insufficient management oversight and control of vendors and contractors (non-station personnel). This trend statement has been discussed in the following NRC Inspection Reports: 05000413,414/2005005, 05000413,414/2006003, 05000413,414/2006005 and 05000413,414/2007003, Semi-Annual Review to Identify Trends. Based on the inspectors' initial identification of this trend, the licensee had concluded that a major contributor to the adverse trend was a lack of guidance in the Duke Nuclear Site Directive 105, Control of Non-Assigned Individuals. The licensee stated in corrective action documents generated in response to this adverse trend that this deficiency was evident in large projects undertaken at Catawba such as the raw water piping project and the refueling outages conducted in 2006, as well as at Oconee during the steam generator replacement project and McGuire during the installation of the new Unit 1 Emergency Core Cooling System sump strainer. Senior Duke Management revised fleet procedures to incorporate specific decision points into the planning and approval process for major projects to ensure oversight controls are considered and developed as part of an overall project development plan. Catawba station management recognized the need for additional attention in this area and worked on implementing corrective actions prior to the start of the Fall 2007 Unit 2 refueling outage. These actions included the development of a Human Performance Improvement Plan directed at non-site assigned personnel, assignment of additional supervisors qualified to station standards to oversee work activities staffed primarily with non-station personnel, providing additional details in project oversight plans, and holding daily plan-of-the-day meetings with all crew members conducting work at Catawba.

During the Fall 2007 Unit 2 refueling outage approximately 2,000 non-station personnel were on-site performing work to support the outage scope. Overall, the corrective actions taken by the licensee were shown to be effective in providing a formal structure for supervising work conducted at Catawba by non-station personnel and enabled a number of complex activities to be performed with only minimal issues being identified. The licensee is continuing to monitor progress in this area and implement additional corrective actions as needed. Accordingly, this trend statement will no longer be followed in subsequent integrated inspection reports.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 05000413/2007003-00, Under-Voltage Condition Resulted in the Actuation of the Emergency Diesel Generators. On August 25, 2007, a transformer fault occurred at a generating facility located within the Duke electrical grid but operated by another utility. Protective relaying at the facility failed to isolate the fault from the grid as designed. The resulting degraded voltage condition on the grid was sensed at the Catawba switchyard and reached 75% of nominal voltage. Once the setpoint for degraded voltage on the 4.16kV vital busses was reached, all four diesel generators received an auto-start signal. The diesels started; however, since protective relaying on the Duke electrical grid functioned as designed and isolated the fault, the diesel generator output breakers were not required to close in and supply power to the 4.16kV vital buses. The licensee made the required 8-hour notification to the NRC for the diesel generators receiving a valid auto start signal due to low voltage on the 4.16kV vital busses. Once grid conditions were determined to have stabilized and the fault at the remote location was isolated from the Duke system, the diesel generators were secured and equipment restored to the standby alignment. Both units at Catawba remained at 100 percent RTP during the event. A team consisting of members from Catawba and the General Office has been established to conduct an additional assessment of the Catawba switchyard and associated Duke Energy relaying to ensure adequate protection against external perturbations exists. The system engineer for the diesel generators at Catawba assessed the performance of the diesels and the associated relaying, and determined that the equipment had functioned as designed. This LER is closed.

.2 (Closed) LER 05000413/2007002-00 Technical Specification Violations Associated with Divider Barrier Integrity. On June 10, 2007, an unexpected entry into TS LCO 3.6.14.c (Containment Systems; Divider Barrier Integrity) was made due to the containment submarine hatch on both units found in the unlatched position when checked on weekly operator rounds. These hatches provide emergency egress from lower containment to upper containment; however, if opened, would provide a pathway that would bypass the ice condenser and result in elevated post-accident containment pressures. They are required to be secured in the closed position when in Modes 1 to 4. The hatches on both units were found to have their locking mechanism out of position, which would have allowed the hatch to open if a higher pressure existed beneath the hatch such as experienced during a LOCA. The hatches were resecured in the closed position as required. The licensee implemented Fleet and Site procedures to assess the issue and implemented applicable compensatory actions until the assessment was completed. A modification to the hatch was developed which included: a positive stop on the hatch closing mechanism to allow personnel to ensure the door is properly secured; painting the hatch to provide easy visual verification of the hatch position; and installation of a local alarm that indicates if the hatch is not secured. This modification was installed on Unit 2 during the Fall 2007 refueling outage (see section 1R17) and is scheduled to be installed on Unit 1 in the Spring 2008 refueling outage. Interim corrective actions being taken on Unit 1 include providing additional guidance to operators conducting weekly checks of the submarine hatch and enhanced procedural instructions for installing the tamper seal which was used in June 2007 when the Unit 1 hatch was resecured. This issue was captured in the licensee's CAP as PIPs C-07-02911 and C-07-02912. Bypass analysis indicates that this failure to comply with TS 3.6.14.c constitutes a violation of minor significance; therefore, it is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This LER is closed.

.3 (Closed) LER 05000414/2007001-00; Failure to Comply with Action Statement in Technical Specification 3.3.1 for Loss of a Channel of the Solid State Protection System.

On May 10, 2007, while replacing a failed 48VDC power supply in the 2B Solid State Protection System, the channel 4 over-temperature delta-temperature (OTDT) trip function became inoperable due to a failure of the axial flux imbalance circuit card. When attempting to reinstall a fuse associated with the power supply, an arc occurred within the cabinet. An unexpected control room annunciator was received; however, neither the maintenance technicians nor control room operators recognized that the OTDT channel was inoperable following the receipt of the alarm. As a result, the inoperable channel was not placed in the tripped condition within 6 hours as required by Technical Specification 3.3.1. Additional troubleshooting was performed on the following shift, and in the course of this activity, the failed axial flux imbalance circuit card was identified in the SSPS cabinet. Once the failed card was identified, the channel was declared inoperable and placed in the tripped condition in accordance with TS. This action was taken approximately 13 hours after the actual failure occurred. The card was replaced and operability restored for the affected channel approximately 8.5 hours later. The OTDT circuitry is designed to protect the reactor from approaching conditions that could produce a Departure from Nucleate Boiling and potentially challenge fuel cladding integrity. It operates on a two-out-of-four logic and generates a reactor trip protection signal when the calculated setpoint is reached. While the Channel 4 OTDT trip function was inoperable for approximately 21.5 hours, the remaining three channels were operable and would have generated a protection system signal if actual conditions had existed that required an OTDT trip signal to be generated. The licensee conducted training specific to this event with personnel in Operations, I&C and Engineering to ensure proper actions are taken when unexpected alarms/indications are received during maintenance activities. Enhancements were made to the model work orders used when conducting work within the 7300 cabinets. This event has been captured in the licensee's corrective action program as PIPs C-07-2365 and C-07-2484. As indicated above, this failure to comply with TS 3.3.1 constitutes a violation of minor significance; therefore, it is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This LER is closed.

.4 (Closed) LER 05000413/2007004-00; Control Area Chilled Water system inoperable in excess of Technical Specification requirements due to Unanticipated Component Interactions.

On October 25, 2007, while performing the section of a test procedure that simulated a SBO in conjunction with a loss of coolant accident (LOCA), the "A" control room area chiller - which had been in operation - failed to restart. Due to the two station control room area chillers being shared between the two units, both units entered a 30-day TS LCO action statement with the "A" chiller inoperable. Troubleshooting initially identified a mispositioned cooling water throttle valve; however, following the repositioning of the valve, inadequate testing was performed to ensure that the valve position had been the actual cause of the chiller failure. On October 27, 2007, the "B" chiller failed to restart while performing the same section of the procedure. A more rigorous assessment of the failure determined that a fuse, which had been installed on both chillers earlier in the year was introducing an error into the sensed oil temperature; thereby, keeping the chiller from restarting if it had been in operation and a station blackout event caused the chiller to trip.

The licensee implemented a modification that removed the fuse from the temperature circuit and following testing which included a simulated SBO and LOCA signal, declared the "B" chiller fully operable. Once the testing found that the fuse had been the cause of the chiller failing to restart following a SBO rather than the mispositioned cooling water valve, the "A" chiller was declared inoperable until the same modification could be installed in its circuitry. TS 3.0.3 was entered for the time when both the "A" and "B" chillers were inoperable and was exited 23 minutes later after the "B" chiller was returned to fully operable status. A non-cited violation was identified due to the inadequate troubleshooting and post-maintenance testing that was performed after the first failure of a chiller to restart occurred (see Section 1R19 of this report). The licensee entered this issue into their corrective action program and implemented several corrective actions including enhancing the troubleshooting guidance document to ensure proper retest requirements are specified when resolving issues related to safety-related equipment. This LER is closed.

.5 Identification of Tritium in Ground Water Samples from Within the Protected Area

a. Inspection Scope

On October 8, 2007, elevated levels of tritium were detected in one of the newly-installed ground water monitoring wells within the protected area of the Catawba site. Based on the communication protocols established under the NEI Ground Water Protection Initiative, the licensee notified the NRC, the South Carolina Department of Health and Environmental Control (SC DHEC), York County Emergency Management Services and the local news media. Representatives from SC DHEC took samples from on-site and surrounding drinking water wells for analysis. They provided the licensee with split samples from these locations to allow for independent analysis to be performed. Subsequent analysis of these samples by both the licensee and SC DHEC did not identify any other locations where tritium levels approached the Environmental Protection Agency (EPA) limit for drinking water. Five additional monitoring wells were installed in the vicinity of the one well found to have elevated levels of tritium. Initial sample results confirm that the ground water containing tritium at levels above the EPA limit for drinking water was being contained within the protected area boundary of the site. On December 6, 2007, a public meeting was held with representatives from the NRC, SC DHEC and Duke Energy providing a presentation on tritium, the results of the sampling that had been conducted and actions being taken by the licensee. The resident inspectors and Region II will continue to monitor and assess the licensee's actions in response to this issue.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) Temporary Instruction (TI) 2515/166, Pressurized Water Reactor Containment Sump Blockage (NRC Generic Letter 2004-02) - Unit 2

a. Inspection Scope

The inspectors reviewed Unit 2 implementation of the licensee's commitments documented in their September 1, 2005, response to Generic Letter 2004-02, Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors. These commitments included the permanent modification of the Containment Building ECCS sump strainer assembly, and trash racks. The inspectors reviewed the sump strainer assembly design change packages, corresponding 10 CFR 50.59 evaluation, and ECCS sump inspection requirements. The inspectors also reviewed variation notices (field changes) and corrective actions related to the strainer installation. The inspectors conducted a visual walkdown to verify the installed strainer assembly configuration was consistent with drawings and specifications provided in the design change packages.

b. Findings and Observations

No findings of significance were identified in the completion of this Temporary Instruction. However during other baseline inspection activities, the resident inspectors observed a violation of 10 CFR 50 Appendix B; Criterion X “Inspections” pertaining to QA/QC inspections associated with the installation of the new ECCS containment sump. That finding is documented in Section 1R17 of this report.

The inspectors determined the following answers to the Reporting Requirements detailed in TI 2515/166-05 issued 5/16/07:

05.a Duke Energy implemented plant modifications and procedure changes at Catawba Unit 2 committed to in their GL 2004-02 response for Unit 2. A list of commitments and their respective completion dates is listed in Attachment 2, Status of GL 2004-02 Commitments for Catawba 2, of this report.

05.b Duke Energy updated the Catawba 2 licensing bases to reflect the corrective actions taken in response to GL 2004-02.

05.c Catawba Unit 2 has received an extension of the December 31, 2007 deadline set forth in GL 2004-02. This extension pertains to additional time required to analyze the results of ongoing chemical effects testing to validate the replacement strainer design. The extended deadline for Unit 2 chemical effects is April 30, 2008.

Catawba Unit 1 has also received a general extension of the 12/31/2007 deadline as the Unit 1 strainers will be replaced in the Spring 2008 refueling outage. The general deadline extension for Unit 1 expires May 19, 2008. Some station-wide procedural changes apply to this extension.

TI 2515/166 is closed for Catawba Unit 2, as no additional modifications or procedural changes under GL 2004-02 are anticipated.

.2 (Closed) TI 2515/150, Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Order EA-03-009) - Unit 2

a. Inspection Scope

From September 24 to October 1, 2007, the inspectors reviewed the licensee's activities related to the non-destructive examination (NDE) of the reactor pressure vessel head (RPVH) nozzles, the bare metal visual (BMV) examination of the RPVH nozzles and head surface area, and the visual examination to identify potential boric acid leaks from pressure-retaining components above the RPVH. These activities were reviewed during the Unit 2-Fall 2007 refueling outage in order to verify licensee compliance with the regulatory requirements of NRC Order EA-03-009 Modifying Licenses dated February 20, 2004 (hereinafter the NRC Order) and gather information to help the NRC staff identify possible further regulatory positions and generic communications.

The inspector's review of the NDE of RPVH nozzles included: a) review of NDE procedures; b) assessment of NDE personnel training and qualification; c) review of NDE equipment certification and performance demonstration; and d) observation and assessment of ultrasonic (UT) and surface penetrant test (PT) examinations. The inspectors also held discussions with contractor representatives (Areva) and licensee personnel involved in the RPVH examination. Specifically, the inspectors reviewed a sample of NDEs as follows:

- Observed portions of in-process UT scanning for RPVH nozzles with thermal sleeves
- Reviewed the UT data sheets and electronic data for RPVH nozzle Nos. 4, 8, 18, and 32.
- Reviewed the UT data sheets for RPVH nozzle Nos. 54, 67, 76, and 77, and the PT and UT data sheets for the RPVH vent line penetration
- Reviewed the results of the UT examination performed to assess for leakage into the annulus between the RPVH penetration nozzle and the RPVH low-alloy steel (interference fit zone) for penetration Nos. 4, 8, 18, 32, 54, 67, 76, and 77.
- Reviewed training and qualification records for NDE personnel who performed the above volumetric and surface examinations
- Reviewed certification, performance demonstration, and calibration records for NDE equipment used to perform the above volumetric examinations
- Reviewed Areva's examination procedures used to perform the above volumetric and surface examinations.

The inspector's review of the BMV examination for the RPVH nozzles and head surface area included: a) review of procedures used to perform the examination; b) direct observation of a portion of the examination; and c) review of results as documented in a corrective action document.
The inspector's review of the visual examination to identify potential boric acid leaks from pressure-retaining components above the RPVH consisted of the review of

licensee procedures used to meet this requirement and the results from the visual examinations performed in the Unit 2-Fall 2007 refueling outage.

The inspectors also reviewed the licensee's effective degradation years calculation, which was performed to determine the RPVH's susceptibility category and its examination requirements.

b. Observations and Findings

In accordance with the requirements of TI 2515/150, the inspectors evaluated and answered the following questions:

1) Were the examinations performed by qualified and knowledgeable personnel?

Yes. The inspectors reviewed personnel training and qualifications to verify that volumetric and surface NDEs were performed by trained and qualified personnel. All examiners were qualified in accordance with the ASME Code and had additional training on RPVH examination, as required in Areva's "Written Practice for the Qualification and Certification of NDE Personnel" document.

2) Were the examinations performed in accordance with demonstrated procedures?

Yes. Catawba's RPVH (Unit 2) has 78 control rod drive mechanism (CRDM) penetrations and 1 vent line penetration. Fifty seven (57) of the 78 penetrations contain thermal sleeves and the remaining 21 penetrations have open bores. All penetration nozzles, including the vent line, were examined by remote automated UT from the inside diameter (ID) surface in accordance with Areva approved procedures 54-ISI-604-004 for open bore penetrations, 54-ISI-603-003 for sleeved penetrations, and 54-ISI-605-03 for small bore penetrations (i.e. vent line).

In addition to the CRDM and vent line penetrations, Catawba's RPVH has 4 auxiliary head adapter penetrations. These penetrations consist of an Alloy 600 nozzle welded to the top of the RPVH with a dissimilar metal full penetration weld. These welds were not examined as part of the NDEs required to meet the NRC Order. However, these welds were included within the scope of the Inservice Inspection Program as required by Section XI of the ASME Code.

The inspectors found that Areva examination procedures for CRDM nozzles were demonstrated to be able to detect and size flaws in the RPVH nozzles in accordance with Electric Power Research Institute (EPRI) NDE Center's protocol contained in "Materials Reliability Program: Demonstration of Vendor Procedures for the Inspection of Control Drive Mechanism Head Penetrations

(MRP-89)." Areva's equipment demonstration took place from August 14 to August 24, 2006. Areva had performed a similar demonstration in 2002, as documented in MRP-89. However, because Areva modified its equipment including changing the essential variables of the demonstration in 2002, the demonstration was repeated. The 2006 demonstration was performed with three RPVH nozzle mockups with multiple tube flaws representing the expected field degradations. These mockups were different from the ones used during the demonstration performed in 2002 (i.e. demonstration documented in MRP-89). The demonstration adopted security provisions from the EPRI Performance Demonstration Initiative protocol by restricting the access to the mockups and making them available to Areva only when the EPRI NDE personnel were present. EPRI letter to Duke Energy Corporation, dated September 5, 2007, documents the comparison of the recent Areva's equipment demonstration with the previous demonstration performed in 2002. The letter states that the scatter observed is within the variability of the examination and the reliability of the examinations conducted with the new instrumentation will be comparable to the previous demonstration.

The procedure used for the RPVH vent line was not demonstrated under a specific program because one doesn't exist. However, the procedure was developed with NDE techniques similar to the CRDM procedures with regard to basic fundamental ultrasonic techniques. The procedure used for the PT examination of the vent line weld surface was developed in accordance with the ASME Code.

3) Was the examination able to identify, disposition, and resolve deficiencies?

Yes. All indications of cracks or interference fit zone leakage are required to be reported for further examination and disposition as specified in Areva's NDE procedures. Based on observation of the examination process and discussions with vendor personnel, the inspectors considered that deficiencies would be appropriately identified, dispositioned, and resolved. UT indications associated with the fabrication of the J-groove weld and nozzle tube material were identified at several RPVH penetrations. These indications did not exhibit crack-like characteristics and were documented for future reference.

4) Was the examination capable of identifying the primary water stress corrosion cracking (PWSCC) and/or RPVH corrosion phenomena described in the NRC Order?

Yes. The NDE techniques employed for the examination of RPVH CRDM nozzles had been previously demonstrated under the EPRI MRP/Inspection Demonstration Program as capable of detecting PWSCC type manufactured cracks. Based on the review of performance demonstration documents, observation of in-process examinations, and review of NDE data, the inspectors considered that the licensee was capable of identifying PWSCC and/or corrosion as required by the NRC Order.

5) What was the physical condition of the RPVH (e.g. debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

A bare metal visual (BMV) examination was performed per licensee procedure MP/0/A/7150/042D by engineering personnel and two VT-2 qualified inspectors. All RPVH penetrations were inspected either by direct visual examination or visual examination using a mirror on a pole and flashlights. The CRDM shroud was removed and the examiners were able to have access to essentially 100% of the required examination surface. No evidence of boron deposits indicating active leakage from the annular gaps around the penetrations was observed. The licensee did identify minor general surface corrosion on the dome area of the RPVH and light boron stains on some CRDM penetrations, but they were not indicative of active RCS leakage. The licensee compared the results from this BMV examination with the previous one and found no changes that would indicate pressure boundary leakage.

The inspectors observed part of the BMV examination and performed an independent assessment of the RPVH condition and found no indications of leakage from the RPVH nozzles and no significant corrosion of the RPVH top surface area around the penetration nozzles. The head surface was generally clear of dirt, insulation, and debris.

6) Could small boron deposits, as described in NRC Bulletin 2001-01, be identified and characterized?

Yes. As noted above, the licensee was able to have access to essentially 100% of the required examination surface. The examination procedure established requirements for the illumination and resolution of the examination equipment. Per procedure, the light intensity (minimum of 50 ft-candles) must allow the examiner to see a 0.105 inch lower case character height at a 6 ft distance. Based on the inspector's assessment of the BMV examination implementation, the review of personnel qualifications, the review of the BMV examination procedure, and the review of the licensee's observations captured in the examination results, the inspectors considered that the licensee had the ability to identify and characterize small boron deposits in the examination area.

7) What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

There were no identified examples of RPVH penetration cracks, leakage, material deficiencies, or other flaws that required repair. As indicated above, UT indications were identified at several RPVH penetrations but were dispositioned as fabrication indications (not crack-like or service induced).

8) What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

The required volumetric examination coverage extends from a minimum of 2 inches above the highest point of the J-groove weld to the maximum coverage possible below the lowest point of the J-groove weld, with a minimum of 1 inch coverage if justified by a stress analysis. A stress analysis was performed and justified the minimum 1 inch coverage below the weld. All examinations met this requirement except for thermocouple penetrations 74 -78. The worst case examination coverage for these penetrations was 0.70 inches below the lowest point at the toe of the J-groove weld. The examination coverage limitation was due to the nozzle length, the weld profile on the downhill side of the nozzle, and the ID tapered tip of the thermocouple nozzle. At the time of the NRC inspection, the licensee was working on a request for relaxation from the NRC Order requirements.

The BMV examination did not have any impediments to performing an effective exam.

9) What was the basis for the temperature used in the susceptibility ranking calculation?

The inspectors reviewed the susceptibility ranking calculation and the basis for the RPVH temperature used in the calculation. The calculation determined the RPVH Effective Degradation Years (EDY) and susceptibility ranking since the first operating cycle until the current operating cycle using best estimate values of effective full power days (EFPD). This calculation has been updated at the end of every operating cycle since the NRC Order was effective. The temperature used for the calculation was the reactor coolant system cold leg temperature. The use of this temperature was based on the RPV upper internals temperature documented in WCAP-13493, “Reactor Vessel Closure Head Penetration Key Parameters Comparison,” and WCAP-9404, “Study of Reactor Vessel Upper Head Region Fluid Temperature.”

10) During non-visual examinations, was the disposition of indications consistent with the NRC flaw evaluation guidance?

There were no indications considered to be flaws found during the RPVH examination.

11) Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the RPVH?

Yes. Procedure MP/2/A/7150/042, "Reactor Vessel Head Removal and Replacement," was implemented, in part, to conduct inspection activities required by the NRC Order to identify potential boric acid leaks from pressure-retaining components above the RPVH. This procedure has steps to inspect above and through the CRDM shroud windows for evidence of leakage every refueling outage. The licensee also generates a model work order every refueling outage to inspect pressure-retaining components above the head. This outage, the work order provided instruction to inspect the upper and intermediate canopy seal welds because the BMV examination procedure covered the examination of the lower canopy seal welds in addition to the penetration nozzles and the head surface area.

12) Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPVH?

There were no indications of leakage found during this outage.

4OA6 Meetings, Including Exit

Exit Meeting

On January 10, 2008, the inspectors presented the inspection results to Mr. J. Pitesa and other members of licensee management, who acknowledged the findings. The inspectors confirmed that all proprietary information provided or examined during the inspection period had been returned.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

- 10 CFR 50 Appendix B, Criterion XVI requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, the licensee failed to identify and correct the misaligned 1A safety injection pump bearing oil cooler following the receipt and evaluation of industry operating experience detailing the same issue in 2004. While the issue was entered into the Component Health Report, no inspections of installed plant equipment or other actions were taken in response to the industry operating experience. The condition was discovered at Catawba after maintenance personnel conducting routine maintenance at McGuire identified four end bells improperly installed on September 4, 2007. Catawba corrected the end bell orientation immediately upon discovery and entered the condition into their corrective action program as PIP C-07-4662. The risk was determined to be of very low safety significance as the licensee demonstrated through their operability calculation that the safety injection pump would have been able to perform its safety function under worst case accident conditions.

ATTACHMENTS: (1) SUPPLEMENTAL INFORMATION
(2) STATUS OF GL 2004-02 COMMITMENTS FOR CATAWBA 2

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
E. Beadle, Emergency Planning Manager
W. Byers, Security Manager
J. Caldwell, Modification Engineering Manager
B. Cauthen, RN System Engineer
G. Cornwell, Project Manager
J. P. Downing, Manager, Steam Generator Maintenance
B. Ferguson, Mechanical, Civil Engineering Manager
J. Foster, Radiation Protection Manager
P. Gillespie, Operations Manager
E. Haack, Performance Testing Engineer
T. Hamilton, Safety Assurance Manager
G. Hamrick, Engineering Manager
R. Hart, Regulatory Compliance Manager
G. Hudson, QA/QC Team Leader
T. Jackson, Regulatory Compliance
L. Keller; Supervisor, Reactor and Electrical Systems
D. Llewellyn, Alloy 600 Program Director
S. Mays, BACC Program
J. McConnell, Shift Operations Manager
J. Morris, Catawba Site Vice President
K. Nicholson, Regulatory Compliance
J. Pitesa, Station Manager
M. Sawicki, Regulatory Compliance Engineer
E. Sherwood, CNS Work Control
C. Trezise, Reactor and Electrical Systems Manager
A. Young, Licensing Engineer

NRC
J. Moorman, III, Chief, Reactor Projects Branch 1

LIST OF ITEMS OPENED, CLOSED, AND REVIEWED

Opened and Closed

050000413,414/2007005-01	NCV	Failure to Perform Required ASME Code Section XI Leakage Testing (Section 1R08.1)
05000414/2007005-02	NCV	Failure to Develop a Lift Plan and Risk Management Actions for the Replacement of Piping Over a Safety-Related SSC (Section 1R13)

05000414/2007005-03	NCV	Inspections of the Unit 2 ECCS Containment Sump Installation Failed to Identify Deficiencies Prior to Declaring the Safety-Related Structure Operable (Section 1R17)
05000413,414/2007005-04	NCV	Failure to Promptly Identify and Correct a Significant Condition Adverse to Quality Affecting the Ability of Both CRAVS Chillers to Operate as Designed Following a SBO due to Inadequate Troubleshooting and Post-Maintenance Testing. (Section 1R19)

Closed

05000413/2007003-00	LER	Under-Voltage Condition Resulted in the Actuation of the Emergency Diesel Generators (Section 4OA3.1)
05000413/2007-002	LER	Technical Specification Violations Associated with Divider Barrier Integrity (Section 4OA3.2)
05000414/2007001-00	LER	Failure to Comply with Action Statement in Technical Specification 3.3.1 for Loss of a Channel of the Solid State Protection System (Section 4OA3.3)
05000413/2007004-00	LER	Control Area Chilled Water System Inoperable in Excess of Technical Specification Requirements due to Unanticipated Component Interactions (Section 4OA3.4)
2515/166	TI	Pressurized Water Reactor Containment Sump Blockage (NRC Generic Letter 2004-02) - Unit 2 (Section 4OA5.1)
2515/150	TI	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009)- Unit 2 (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather

PT/0/B/4700/038, Cold Weather Protection, Rev. 26
IP/0/B/3560/013; Calibration Procedure for DigiTrace 200N Heat Trace Controller; Rev. 0
IP/0/B/3560/008; Preventative Maintenance and Operational Check of Freeze Protection Heat Trace and Instrument Box Heaters (EHT/EIB) Systems (Fall PM) Rev. 50
IP/0/B/3560/009; Operational Check for Winter Months and Extreme Cold Weather Surveillance of Freeze Protection Heat Trace and Instrument Box Heaters (EHT/EIB) Systems, Rev. 11
IP/0/B/3560/011; Summer Preventive Maintenance and Operational Check Of Self Regulated and Constant Wattage Freeze Protection Heat Trace And MHIB Heaters (EHT/EIB) Systems, Rev. 16
PIP C-07-6856; Investigation into why the heating water converters were not heating up. Cold weather protection PT in progress
PIP C-06-8177; Freeze Protection circuit 1RC18 damaged during maintenance activities
PIP C-07-00480; Possible freeze protection issues with RW Cabinets at RN and RL RW sheds
PIP C-07-00633; Thermostats for ventilation heaters not set correctly
PIP C-07-00811; Cold weather curtains in exterior Doghouse not secured
PIP C-07-06633; Procedure OP/1/A/6450/004 Enclosure 4.9: Unable to completely drain water per procedure from the Fuel Pool Ventilation System
PIP C-07-06808; Breakers that control the Waste Solidification Building heaters found in the "off" position.
PIP C-07-04371; Freeze Protection circuits 1CF01 and 1CF03 found failed during Summer PM
PIP C-07-00124; Equipment Reliability concerns with Freeze Protection on Service Bldg and Aux Bldg roof.
PIP C-07-00078; Low voltage on Freeze protection circuits in WC pit
PIP C-06-08211; RES/MCE need to evaluate RC freeze protection prior to mod's CD100691 and CD200692 (new controllers and circuits for Unit 1 & 2 RC pit) are designed.
PIP C-06-05500; Freeze Protection Summer PM found 1MIHB0011 and 1MIHB0012 deleted
OAC Alarm Responses for points C1P0118 (Ambient Dry Bulb Temperature); C1P1821 (Ambient Wet Bulb Temperature),C2P0118 (Ambient Dry Bulb Temperature), and C2P1821 (Ambient Wet Bulb Temperature)
NSD 317; Freeze Protection Program, Rev. 3

Section 1R04: Equipment Alignment

PIP C-07-6945; Non-licensed operator placed protected equipment tape on 2B RN pump vs. 1B RN pump
Drawing CN 1609-1.0, Flow Diagram of DG Engine Cooling Water System, Rev. 15
Drawing CN 1609-2.0, Flow Diagram of DG Lube Oil System, Rev. 24
Drawing CN 1609-2.0, Flow Diagram of DG Lube Oil System, Rev. 22
Drawing CN 1609-4.0, Flow Diagram of DG Engine Starting Air System, Rev. 23
Drawing CN 1609-2.0, Flow Diagram of DG Engine Starting Air System, Rev. 22
Drawing CN 1609-3.0, Flow Diagram of DG Engine Fuel Oil System, Rev. 21
Drawing CN 1609-3.1, Flow Diagram of DG Engine Fuel Oil System, Rev. 17

Drawing CN 1609-5.0, Flow Diagram of DG Engine Air Intake and Exhaust System, Rev. 6
Drawing CN 1609-7.0, Flow Diagram of DG Room Sump Pump System, Rev. 10
OP/1/A/6350/002; Diesel Generator Operation, Rev. 138
OP/1/A/6550/001; Diesel Generator Fuel Oil System Operation, Rev. 62
OP/1/A/6550/002; Diesel Generator Lube Oil System Operation, Rev. 60
OMP 2-28; Diesel Generator Logbook for the 1A and 1B diesel generators
TS 3.8.1, AC Sources – Operating and TS 3.8.2; AC Sources – Shutdown\
Emergency Diesel Generator Health Report; 2007Q1, 2007Q2 and 2007Q3
125 VDC Diesel Auxiliary Power System Heath Report; 2007Q1, 2007Q2 and 2007Q3
PIP C-0700685; High temperature aftercooler water inlet annunciator came into alarm 10 minutes into the run
PIP C-07-1719; The 1A DG tripped during its operability PT and the computer indicated 1ETA-18 lockout.
PIP C-07-3411; Valve 1KD24 has excessive corrosion present due to a leak
PIP C-07-3610; DG 1B tripped on vibration during the 5 hour operability PT
PIP C-07-3634; During performance of OP/1/A/6350/002, DG 1B tripped at full load due to high vibration
PIP C-07-3635; Unexpected TSAIL entry C1-07-01665 for the 1B DG failure to achieve 3950 volts to 4370 volts following a diesel start. The actual voltage was 4400 volts.
PIP C-07-4475; This documents a station blackout signal event which lasted long enough to start all 4 diesel generators, but since it was less than 8.5 seconds, none of the sequencers actuated (no loads were shed)

Section 1R05: Fire Protection

Station Fire Impairment Log
Pre-Fire Plan for Fire Strategy Area RB-1; Unit 2 Reactor Building, Section 2.20
Pre-Fire Plan for Fire Strategy Area 4, Auxiliary Building 543 level, Rooms 200 - 248
Pre-Fire Plan for Fire Strategy Area 1, Auxiliary Building 522 level, Rooms 100 – 112
Pre-Fire Plan for Fire Strategy Area 3, Auxiliary Building 543 level, Rooms 250, 250A, 255 and 256 (Unit 1 CA Pump Room and Motor Driven CA Pump Pits)
Pre-Fire Plan for Fire Strategy Area 40, Auxiliary Building 543 level, Room 254 (Unit 1 CA Turbine Driven Pump Pit)
Pre-Fire Plan for Fire Strategy Area 11, Auxiliary Building 560 level, Rooms 200 - 248
Pre-Fire Plan for Fire Strategy Area AW, Standby Shutdown Facility, 594 foot Elevation
Pre-Fire Plan for Fire Strategy Area AX, Standby Shutdown Facility, 611 foot Elevation
Pre-Fire Plan for Fire Strategies D and E, Catawba Nuclear Station Turbine Building Unit 1, 568 foot elevation
Select Licensee Commitments Section 16.9-4; Fire Hose Stations
Select Licensee Commitments Section 16.9-5; Fire rated Assemblies
NSD 313, Control of Combustible and Flammable Material, Rev. 6
NSD 314; Hot Work Authorization, Rev. 6
PIP C-07-7058; Fire hose cabinet downstream of 1RFA-64 (outside of Unit 1 CA pump room) found to be in a poor state of repair by NRC Resident
PIP C-0707059; Fire hose cabinet outside of the Unit 2 CA pump room found to be in poor condition after notified of the condition of the Unit 1 hose cabinet

Section 1R07: Annual Heat Sink Performance

UFSAR Section 9.5.5; Diesel Generator Jacket Cooling Water System
CNS-1274.00-00-0016; License Renewal Basis Specification, Section 4.16.3; Diesel Generator Engine Cooling Water Heat Exchangers
DAP2000 Computer Application Version Tracking system

Section 1R08: Inservice Inspection Activities

NDE-600, Ultrasonic Examination of Similar Metal Welds in Ferritic and Austenitic Piping, Revision 17
NDE-35, Liquid Penetrant Examination, Revision 21
PT/2/A/4150/001 H, Inside Containment Boric Acid Check, Revision 14
MP/0/A/7650/040, Inspection, Evaluation and Cleanup of Boric Acid on Plant Materials, Revision 14
NSD 322, Boric Acid Corrosion Program
PIP C-07-05248, 2007 CNS Boric Acid Corrosion Program Assessment
SGMEP 105, Westinghouse Model D5 Specific Assessment of Degradation Mechanisms for Catawba Unit 2 EOC 15, Revision 6
Condition Monitoring and Operational Assessment for Catawba Unit 2 EOC 14
CNC 2201.01-00-0007, Evaluation of Foreign Objects in the Preheater of the Catawba Unit 2 Steam Generators, Revision 1
Relief Request 07-GO-001, Proposed Alternative to support application of full structural weld overlays on various pressurizer nozzle-to-safe end welds
Confirmatory Action Letter No. NRR-07-015, regarding Alloy 82/182 butt welds in the pressurizer
PIP C-07-05738 NRC ISI Inspector has questioned the Station's use of IWA-5244 Section (b) 2 for conducting the system pressure test for buried portions of the RN System
PIP C-07-05659 Crack-like indication was detected just above the top of the tubesheet in the 2B steam generator.
PIP C-07-05445 Document the inspection of the U2 NV Letdown line from the point were the pipe exits the regenerative heat room through the "B" accumulator room and the "B & C" fan room, to the wall of the "C" accumulator room
PIP C-07-05264 Surface indication found during augmented ISI MT exam
PIP C-07-05205 Preliminary findings from General Visual Inspection PT/2/A/4200/078 performed in the area of the Unit 2 ECCS sump on 9/21/07
PIP C-07-01970 Pipe cap on 2NB-503 has gone from an inactive leak to an active leak
PIP C-07-01978 Dried boron was found on the body to bonnet joint and also the stud and nut material on valve 2KF-19
PIP C-07-02546 Boron between Cap and Body of 2FW-53 cannot be thoroughly cleaned
PIP C-07-05536 Alloy 600 - Welding Services Incorporated (WSI) confirmed today (9/29/07) they have issues with the layout and punchmarks on PZR PORV nozzle weld overlay
RT Examination Report for Weld 2 NI 2492-NI.00-139-25
UT Examination Data Sheets for Surge Line Pressurizer Overlay NW-1-WBM-WOL, -DM, and -SS
UT Examination Reports UT-07-745 through -747 (welds 2SM59-01, -02, and -4A-A)

PT Examination Reports PT-07-478 through -480 (welds 2NC-52-6, -7, and -8)
Weld Process Control Record for Work Order: 01748154 (weld 2492-NI.00-139-25)
VT-3 examination reports for F01.020.033/2-R-ND-0323 and F01.021.091/2-R-NS-1208

Section 1R11: Licensed Operator Requalification

OP-CN-LOR-S-07; LOR Task Requirement Guide, Rev. 14
AP/1/A/5500/012; Loss of Charging or Letdown, Rev. 25
EP/1/A/5000/FR-H.1; Response to Loss of Secondary Heat Sink, Rev. 30

Section 1R12: Maintenance Effectiveness

PT/2/A/4350/002B, Diesel Generator 2B Operability Test, Rev. 89
Unit 2 Autolog entries associated with the 2B DG break-in and operability runs
PIP C-07-5829; Delays in performing break-in run for the 2B DG due to air leaks on the 3-way valve
PIP C-07-5949; Received alarm for loss of control power on the 2B DG
PIP C-07-6789; Unit 2 DRPI did not change when attempting to move shutdown banks C, D and E during RCCA movement testing
PIP C-07-6792; During performance of PT/2/A/4600/001 (RCCA movement test), the RPI Non-Urgent failure annunciator was received due to shutdown bank N9 rod indication problems
WO 01780921; Determine cause of the failure of shutdown banks C, D and E to move and repair
PT/2/A/4600/001, RCCA Movement Test, Rev. 30 (performed twice, once as a functional retest of the system following completion of repair activities)
Failure Investigation Process troubleshooting and repair plan for Unit 2 control rod shutdown banks C, D, and E
IP/0/A/3890/001; Controlling Procedure for Troubleshooting and Corrective Maintenance; Rev. 056
Unit 2 AutoLog entries associated with the shutdown bank movement issues
WO 01748147; Repair shutdown bank N9 Rod Data B failure
PIP C-07-01169; Rod N-9 DRPI indication failing
CD201320; Temporary design Change to install and subsequently remove Operator Aid Computer point data to exclude N-9 data from the Data B alarm logic
CD201264 Install Helicoil into 2D SG cold leg primary manway
WO 01726965; Repair #8 Stud hole on 2D SG cold leg primary manway
MP/0/A/7650/070; Helicoil Installation, Rev. 9
MP/0/A/7650/148; ASME Section XI Repairs or Replacements, Rev. 16
TM/0/A/7550/044; Westinghouse Procedure - Steam Generator Primary Manway Stud Hole Repair for Catawba Unit 2, Rev. 0
PIP C-06-02442; Steam Generator 2D cold leg primary manway has damaged threads in stud hole #8

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation

Risk Management Actions for 2B DG Battery Charger repairs conducted under WO 1782004 on 13 November, 2007
2DGCB Charger Repair Plan under Work Order 1782004-01
PIP C-07-6926; Performance of Immediate Determination of Operability for 2B DG Battery Charger due to spurious alarms
PIP C-07-6948; 2B DG Battery Charger placed Unit 2 in an unplanned ORAM Orange
SOER 91-01 Package for the Commissioning Testing of the Automatic Voltage Regulator Replacement Installed during Catawba Unit 2 2EOC15 Refueling Outage
WO 01118529, Post Modification Testing of the Unit 2 Automatic Voltage Regulator
Duke Energy Nuclear Lifting Program, Rev. 13
NSD 213; Risk Management Process, Rev. 6
NSD 403; Operational Risk Management (Modes 4, 5, 6, and No-Mode) per 10CFR50.65(a)(4), Rev. 16
Critical Activity Plan for Modification CD200411, Auxiliary Building RN Piping Replacement
Work Order 01723595, Unit 2 replacement of valve 2RN-838 and relocate valve 2RN229B
Duke Energy Nuclear Lifting Program Manual
PIP C-07-5440; Cutout of RN piping and valves was being done without a lift plan or other risk management actions on Unit 2
PIP C-07-5447; Error found in the oversight plan for the RN piping replacement
Catawba UFSAR Section 17.0; Quality Assurance Program
Critical Activity Plan; NC Fill and Vent using NCP’s to purge air from Steam Generator U-tubes, Rev. 1

Section 1R15: Operability Evaluations

Alden Labs testing report on ECCS throttle valve clogging from debris induced into the flow stream
WCAP 8110, Supplement 9, Ice Fallout from Seismic Testing of Fused Ice Basket, dated May 1974
Atomic Energy Commission letter to Westinghouse Electric Corporation providing an assessment of WCAP 8110, Supplement 9 dated November 21, 1974
PIP G-00-0438; Duke’s position regarding the applicability of WCAP-8110, Supplement 9, dated May 1974 needs to be documented
McGuire PIP M-02-2830; Update UFSAR to remove references to WCAP-8110, Supplement 9
Catawba UFSAR Section 6.6.20
PIP C-04-1209; NV pump 1A has a discharge head-to-casing leak that requires a formal evaluation when the ISI system pressure test is performed
PIP C-04-1168, Cover leak identified on the 2B NS pump
PIP M-07-5135; UFSAR ND and NS pump Net Positive Suction Head calculation discrepancy
Calculation CNC-1223.04-00-0104; Evaluation of Runout Limits on NV pumps, Rev. 0
Calculation CNC-1223.12-00-0057; Hydraulic Model of the Unit 1 Emergency Core Cooling System. Rev. 8
Calculation CNC-1223.04-00-0063; Acceptance Criteria Verification for PT/1(2)/A/4400/001, ECCS Flow Balance, Rev. 9

ODMI Assessment of the return of Unit 2 to service without having transformer 2ATD available
PIP C-07-5347; Operations requests an Immediate Determination of Operability concerning the inability to perform SR 3.8.1.8 on Unit 1 for B train power due to the failure of transformer 2ATD
PIP C-07-5160; Transformer 2ATD temperatures increased rapidly when the 6.9kV feeder breaker was closed
CNSD-0111-03; System Description for the 600 V Blackout Auxiliary Power System, Rev. 6
CNSD-01115-02; System Description for the 4.16kV Blackout Auxiliary Power System, Rev. 3
CNSD-0116-01; System Description for the 6.9kV Normal Auxiliary Power System, Rev. 6
NUREG-0954; Safety Evaluation Report related to the operation of Catawba Nuclear Station Unit 1 and 2, February 1983

Section 1R17: Permanent Plant Modifications

PIP C-06-8777; Unusual event occurred when the loop drain valves on the “C” NC loop inadvertently opened during plant heat-up on Unit 1
PIP C-07-2912; Unexpected entry into TSAIL for submarine hatch not being secured
PIP C-07-5682; New operator installed on 2FW-27A requiring engineering evaluation
PIP C-07-5945; 2FW-27A failed its required acceptable stoke time for “open to close” and “close to open”
PIP C-07-6100; 2FW-55B failed its required acceptable stoke time for “close to open” and “open to close”
PIP C-07-6102; New operator installed on 2FW-55B requiring engineering evaluation
CD201296; Modify Unit 2 reactor coolant system loop drain lines to preclude inadvertent loss of Reactor Coolant System inventory
CD201528; Add stop and modify arms of the Unit 2 submarine hatch between lower and upper containment
CD200863; Install body vent valves on 2FW-27A and 2FW-55B to eliminate to potential for pressure locking of the valves if required during a Mode 4 Loss of Coolant Accident (LOCA)
CD200490; ECCS Unit 2 containment recirculation sump strainer modification
Root Cause Directional Discussion / Interim Corrective Actions associated with the submarine hatches on both units being found unsecured during power operation (contained in PIP’s C-07-2911 and C-07-2912)
PIP C-07-6876; Unacceptable gap observed between top hat and plenum on east wing section FP-14
PIP C-07-6781; Working copy of TN/2/A/CD200490/02M being used in containment was found to be the wrong revision of the procedure
WO 01731978, Task 14; Re-inspect gaps on ECCS sump prior to entry into Mode 4
PT/2/A/4400/018; Unit 2 Containment Building Civil Structures Inspection, Rev. 003
TN/2/A/CD200490/02M; Installation of New Unit 2 Containment Recirculation Sump Strainer Trains A and B, Rev. 0 and Changes A and B
Videos of the internal inspections conducted on the ECCS sump structure
As built drawings CNM 2144.06-005.001 and CNM 2144.06-0033.001

Section 1R19: Post-Maintenance Testing

Complex Activity Plan for restoration of transformer 2ATD
LER 05000413/2007-004; Control Area Chilled Water System Inoperable in Excess of Technical Specification Requirements due to Unanticipated Component Interactions
Root Cause Failure Analysis Report; Train A YC Chiller Failure During ESF Testing, Rev. 0
Engineering Troubleshooting Process Guide Failure Investigation Process report for the YC Chiller B failing to start during the 2B LOCA ESF testing
AP/0/A/5500/039; Control Room High Temperature, Rev. 05
PIP C-07-6479; A YC chiller failed to start during A train ESF testing on Unit 2
PIP C-07-6848; Complete loading sequence for the B YC chiller not verified during the ESF testing
PIP C-07-6503; Unplanned TSAIL entry for B YC due to the B YC chiller failure to restart during the B train ESF testing
TSAIL reports for the A and B YC chillers covering the periods in which the replacement fuses were installed in the temperature circuitry for the chillers
Autolog entries for the period of 10/25/07 through 10/30/07
Work Order 01779183; 0YC Chiller A; I/R not starting during ESF testing
Station Modification CD201603; Remove redundant fuse on YC chiller 2CRA-C-1
Station Modification CD101604; Remove redundant fuse on YC chiller 1CRA-C-1

Section 1R20: Refueling and Outage Activities

2EOC-15-IRT Unit 2 Outage Risk Assessment
Site Directive 3.1.30, Unit Shutdown Configuration Control (Modes 4, 5, 6 or No Mode), Rev. 35
Nuclear System Directive, NSD-403, Shutdown Risk Management (Modes 4, 5, 6 and No Mode), per 10CFR50.65(a)(4); Rev. 16
NSD 500; Red Tags / Configuration Control Tags; Rev. 24
PT/2/A/4350/003, Electrical Power Source Alignment Verification, Rev. 45
OP/2/A/6200/005, Spent Fuel Cooling System, Rev. 64
PT/0/A/4150/037, Fuel / Component Movement Accounting, Rev. 9; Enclosure 13.3; Reload Transfer Sheet
PT/2/A/4200/002C, Containment Closure Verification (Part I); Rev. 64
PT/2/A/4200/002I, Containment Closure Verification (Part II); Rev. 36
PT/2/A/4200/002J, Containment Closure Verification Penetration Status Change; Rev. 13
OP/0/A/6100/014, Penetration Control for Modes 5 and 6; Rev.32
OP/2/A/6150/001, Filling and Venting the Reactor Coolant System, Enclosure 4.16, Reactor Coolant System Vacuum Refill Without Solid Operation; Rev. 75
OP/2/A/6150/006, Draining the Reactor Coolant System; Rev. 70; Enclosure 4.2, Decreasing the NC System Level and Enclosure 4.3, Increasing the NC System Level
OP/2/A/6550/006, Transferring Fuel with the Spent Fuel Manipulator Crane; Rev. 54
OP/2/A/6550/007, Reactor Building Manipulator Crane Operation; Rev. 34
OP/2/A/6550/008, Fuel Transfer System Operation; Rev. 10 & 11
MP/0/B/7150/012, Refueling Canal Cleanliness; Rev. 7
PT/2/A/4550/001B; Reactor Building and Fuel Transfer Refueling Component Test, Rev. 19

PT/2/A/4550/001C, Refueling Communications Test; Rev. 16
PT/2/A/4550/001D; Reactor Building Manipulator Crane Load test; Rev. 12
PT/2/A/4550/001E; Spent Fuel Building Manipulator Crane Load test; Rev. 7
PT/0/A/4550/003C, Core Verification; Rev. 9 - Superseded by PT/0/A4550/003 C; Post Refueling Core Verification, Rev. 0
PT/0/A/4150/022, Total Core Reloading; Rev. 39
PT/0/A/4150/037; Fuel / Component Movement Accountability, Rev. 10
PT/0/A/4200/002, Containment Cleanliness Inspection; Rev.29
SM/0/A/8510/008, Ice Condenser Foreign Material Exclusion Inspection; Rev. 3
PT/0/A/4150/019; 1/M Approach to Criticality; Rev.34
PT/0/A/4150/001J, Zero Power Physics Testing; Rev. 3
PT/0/A/4150/001, Controlling Procedure for Startup Physics Testing; Rev. 41
PT/0/A/4150/019B, NC System Dilution Following Refueling, Rev. 15
OP/0/A/6100/006; Reactivity Balance Calculation, Rev. 72
OP/2/A/6100/001, Controlling Procedure for Unit Startup; Rev. 144
OP/2/A/6100/003, Controlling Procedure for Unit Operations; Rev. 100
OP/2/B/6300/001, Turbine Generator Startup; Rev.74
OP-CN-JITT-ZPPT/Turbine; Just In Time Training Package; Initial Startup / Zero Power Physics Testing / Turbine On-Line; Rev. 7
PT/0/A/4150/001J, Zero Power Physics Testing Pre-Job Briefing Package
MP/2/A/7150/042; RX Vessel Head Removal & Replacement, Rev. 39
Catawba Unit 2 Spent Fuel Pool Assembly Location Map
CNEI-0400-149, Catawba 2 Cycle 16 Core Operating Limits Report; Rev. 0
Critical Activity Plan; NC Fill and Vent using NCP's to purge air from SG U-tubes, Rev. 1
PIP C-07-4838; Assessment of industry initiative of heavy load lifts
PIP C-07-4954; One train of containment sump recirculation was not available as required by Site Directive 3.1.30
PIP C-07-4990; Post transient assessment of the turbine trip on low condenser vacuum during the Unit 2 shutdown
PIP C-07-4991; Reactor Engineering's shutdown plan was low on the amount of boric acid estimated to be required for the shutdown
PIP C-06-2136; Bottom head inspections of the reactor vessel during the 2EOC14 outage in 2006
PIP C-07-6305; An anomaly was noted on the core barrel for the 2C hot leg during the upper internals inspection
PIP C-07-6308; Operations assessment of the cooldown from Mode 3 to Mode 5 for Unit 2 EOC15 refueling outage
PIP C-06-1882; Documentation of the Unit 2 2EOC14 Ice Condenser Walkdown
PIP C-07-5638; Documentation of the Unit 2 2EOC15 Ice Condenser Walkdown
PIP C-07-6849; Material found in upper containment during the performance of PT/0/A/4200/002 at the end of 2EOC15
PIP C-07-6852; Lower inlet door exceeded the acceptance criteria of 15.5 lbs while performing the "As-Left" initial opening force test
PIP C-07-5190; 2EOC15 Ice Basket Damage Assessment

PIP C-07-5237; The top strut of support 2-NC-1599 is missing the inner bolt and nuts of the 2 bolt clamp
PIP C-07-5196; Support 2-NV-1614 is missing the load pin between the strut and the 2 bolt clamp
PIP C-07-5376; Replacement rotating element in 2B NV pump has a higher horsepower requirement than the previous element and that in the 2A NV pump
MP/0/B/7650/145; Containment Polar Crane, Rev. 009
MP/2/A/7150/042, Reactor Vessel Head Removal and Replacement, Rev. 37, 38 and 39
MPM/0/A/7650/057, Polar Crane Operation and Upper Containment Load Paths, Rev. 20
Complex Activity Plan for the Unit 2 Reactor Vessel Head Removal and Replacement Within the Bounds of the Catawba Specific Head Drop Analysis
NRC Regulatory Issue Summary 2005-25, Supplement 1, Clarification of NRC Guidelines for Control of Heavy Loads
NUREG-0954; Catawba SER Supplement 4, Appendix F, Control of Heavy Loads at Nuclear Power Plants: Catawba Nuclear Station Units 1 and 2 (Phase II)
PIP C-97-2354; Present method of lifting the reactor vessel head during outages does not conform to the guidelines of NUREG-0612 and Generic Letter 81-07
PIP C-07-4838; Industry initiative on heavy load lifts
PIP C-07-7181; Enforcement Guidance Memorandum 07-006; Enforcement Discretion for Heavy Load Handling Activities
Memo from W. Parker (Duke Power Company) to H. Denton (NRC) dated September 24, 1981 on NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
Memo from W. Parker (Duke Power Company) to H. Denton (NRC) dated July 1, 1982 on NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
Memo from H. Tucker (Duke Power Company) to H. Denton (NRC) dated August 6, 1982 on NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
Memo from H. Tucker (Duke Power Company) to H. Denton (NRC) dated April 19, 1984 providing the results of the NUREG-0612 Phase I and Phase II technical evaluations
Memo from H. Tucker (Duke Power Company) to H. Denton (NRC) dated August 17, 1984 on NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
Catawba Nuclear Station Calculation CNS-1144.00-00-0010; Appendix B, Reactor Building Lifting Devices
Catawba Nuclear Station Calculation CNS-1144.03-14-0004; Reactor Building Vessel Head Drop and Other Heavy Load Drops on the Operating Floor

Section 1R22: Surveillance Testing

PIP C-07-6353; Procedure discrepancies identified in PT/2/A/4550/001 D; Reactor Building Manipulator Crane Load Test, during performance prior to core reload
91-01 Pre-Job Brief for the Containment Integrated Leak rate Test, PT/2/A/4200/001A, Rev. 2
PIP C-06-1882; Documentation of the Unit 2 2EOC14 Ice Condenser Walkdown
PIP C-06-3513; 2EOC14 Ice Condenser Outage Critique
PIP C-07-5738; Documentation of the Unit 2 2EOC15 Ice Condenser Walkdown
PIP C-07-6852; Lower inlet door exceeded the acceptance criteria of 15.5 lbs while performing the “As-Left” initial opening force test

MP/0/A/7150/139; Ice Condenser Walkdown and Inspection (completed copy), Rev. 002
PIP C-07-7445; 2A D/G Operability test has conflicting standby LD temperatures (NRC identified)
DocuTracks Request CNS-2007-005487 for PT/2/A/4150/001D (NC System Leakage Calculation) – The references to LCO action statements are incorrect and need to be updated to reflect the current TS amendment
DocuTracks Request CNS-2007-005488 for PT/1/A/4150/001D (NC System Leakage Calculation) – The references to LCO action statements are incorrect and need to be updated to reflect the current TS amendment

Section 1EP6: Drill Evaluation

Catawba Emergency Response Organization Drill Scenario Guide 07-01
Catawba Emergency Response Organization Drill Scenario Guide 07-02
RP/0/A/5000/020, TSC Activation Procedure, Rev. 23
Catawba Nuclear Site Critique Summary Report for Drill 07-01
Catawba Nuclear Site Critique Summary Report for Drill 07-02

Section 4OA1: Performance Indicator Verification

NSD 225, NRC Performance Indicators, Rev. 3
NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 4 and Rev. 5
LER 413/06-002, Safe shutdown potentially challenged by an external flooding event and inadequate design and configuration control
LER 413/06-003; Technical Specification violations associated with the hydrogen ignition system
LER 413/07-001; Safe shutdown capability potentially challenged by fire protection deficiencies attributed to design oversight
LER 413/07-002; Technical Specification violations associated with divider barrier integrity
LER 414/07-001; Failure to comply with action statement in Technical Specification 3.3.1 for the loss of a channel of solid state protection system
Consolidated Data Entry 3.0 MSPI Derivation Reports; Unavailability Index and Unreliability Index; September 2007 – reports for each MSPI listed under the Mitigating Systems cornerstone on Section 4OA.1
PT/2/A/4150/001D, NC System Leakage Calculation, Rev. 64
DocuTracks Request CNS-2007-005487 for PT/2/A/4150/001D (NC System Leakage Calculation) – The references to LCO action statements are incorrect and need to be updated to reflect the current TS amendment
DocuTracks Request CNS-2007-005488 for PT/1/A/4150/001D (NC System Leakage Calculation) – The references to LCO action statements are incorrect and need to be updated to reflect the current TS amendment
LER 05000413/2006-001; Loss of Offsite Power Event Resulted in a Reactor Trip of Both Catawba Units from 100% Power

Section 4OA2: Identification and Resolution of Problems

PIP C-06-3902; Unit 2 Cooling Tower overflowed and entered the 1A DG room
PIP C-06-7420; During the NRC flood inspection the week of 10/30/06, several issues were identified with the conduit seals that enter the Standby Shutdown Facility
WR 00199298; Inspect conduit seals in manholes CMH 2, 3, 18A, 18B and 21 on an 18-month frequency
WO 1013458; Increase the frequency of inspecting the monitored tank building trench hatch covers from annually to semi-annually
AR 00158155; Perform annual inspections of the cooling tower yard drains, WC pond yard drains and switchyard drains
AR 00158158; Conduct annual inspections of berms and curbs around the site
AR 00199697; Perform semi-annual inspections of the DG roof hatch seals
AR 00199700; Perform semi-annual inspections of the Conduit Manhole missile shield cover seals
AR 00159414; Inspect and clean the transformer yard conduit manhole drains every 18 months
AR 00208859; Inspect the conduit seals that enter the turbine buildings from the transformer yard conduit manholes
AR 00165873; Periodically inspect the Standby Shutdown Facility cable trench penetration seals

Section 4OA3: Event Follow-up

PIP C-07-2365; Unexpected TSAIL entry due to OTDT Channel 4 loss of power
PIP C-07-2484; Lessons Learned from the replacement of the power supply and channel 4 card in the Unit 2 B train SSPS cabinet
PIP C-07-3408; PORC Meeting to review the LER associated with the failure to comply with the action statement of TS 3.3.1 for a loss of a channel of SSPS
Root Cause Failure Analysis Report; Train A YC Chiller Failure During ESF Testing, Rev. 0
Engineering Troubleshooting Process Guide Failure Investigation Process report for the YC Chiller B failing to start during the 2B LOCA ESF testing
PIP C-07-6479; A YC chiller failed to start during A train ESF testing on Unit 2
PIP C-07-6848; Complete loading sequence for the B YC chiller not verified during the ESF testing
PIP C-07-6503; Unplanned TSAIL entry for B YC due to the B YC chiller failure to restart during the B train ESF testing
PIP C-07-5892; A sample contained from groundwater monitoring well #213 was found to contain tritium levels that triggered the communication protocol of the NEI initiative on ground water protection
PIP C-07-5968; SC DHEC request for drinking water samples from on-site wells
SC DHEC News Releases dated October 10, 2007 and November 2, 2007
PNO-II-07-012; Onsite Groundwater Tritium Contamination
PNO-II-07-012A; Update - Onsite Groundwater Tritium Contamination at the Catawba Nuclear Station Site

Event Notification Form #43703; NRC Notification of elevated tritium levels in a groundwater monitoring well within the Protected Area at Catawba, 10/09/07

Section 4OA5: Other Activities

[TI 2515-166]
Design Change Packages
CD200490, CMP U2 ECCS Replace Containment Recir Sump Straine

Corrective Actions
PIP C-07-06672, Limited Areas of Without Coatings related to the Unit 2 ECCS Sump Mod
PIP C-07-06781, Working Copy of TN/A/CD/200490/02M Not Revised

Plant Procedures
PT/0/A/4200/002, Containment Cleanliness Inspection, Rev. 027
PT/2/A/4400/018, Unit 2 Containment Building Civil Structures Inspection, Rev. 003

[TI 2515-150]
Procedures

54-PT-200-07, “Color Contrast Solvent Removable Liquid Penetrant Examination of Components,” Rev. 7
54-ISI-604-004, “Automated Ultrasonic Examination of Open Tube RPV Closure Head Penetrations,” Rev.4
54-ISI-603-003, “Automated Ultrasonic Examination of RPV Closure Head Penetrations Containing Thermal Sleeves,” Rev. 3
54-ISI-605-03, “Automated Ultrasonic Examination of RPV Closure Head Small Bore Penetrations,” Rev. 3
51-9045055-000, “RPV Head Penetration Inspection Plan & Coverage Assessment for Catawba Unit 2 and McGuire Unit 1."
MP/0/A/7150/042D, “Reactor Vessel Head Penetration Visual Inspection,” Rev. 3

Engineering Documents

Calculation No. CNC-1201.01-00-0022, “Determination of Interim Inspection Requirements for the Reactor Vessel Heads and RV Head Inspection Documentation,” Rev. 6
Dominion Engineering Calculation C-3023-00-02, “Catawba Unit 2 Upper Head CRDM Nozzle Welding Residual Stress Analysis,” Rev. 0

Corrective Action Documents

PIP C-07-05751

Work Orders

WO 01731046-01, “2NC Rx Head: RV Head CRDM Canopy Seal Welds - Visual

Other Records

EPRI Letter from Mr. Jack Spanner (Program Mgr.) to Ms. Rachel Doss (Duke Power Corp.) dated September 5, 2007
Personnel Certification Records for Areva NDE examiners
Areva UT Transducer Reports and/or Acceptance Test Report for UT inspection probes: 2928-07003 (Gimbald probe), S5003NL (blade probe), S5025NL (blade probe), 9269-07005 (vent line probe).
PT examination report for RPVH vent line

Section 4OA7: Licensee-Identified Violations

Inspection Report 05000369, 370/2007-009, Special Inspection Report
MP/0/A/7650/056, Heat Exchanger Corrective Maintenance, Rev. 030
Calculation CNC-1223.12-00-0074; Determination of Heat Removal Capability of NI Pump 1A Oil Cooler in Degraded Condition
PIP C-07-4662; Reportability determination of NI pump 1A oil cooler issue
TSAIL entries associated with the 1A NI pump to facilitate end bell oil cooler repairs
Work history for the bearing and speed changer oil coolers on the NI and NV pumps for Unit 1 and Unit 2
American Standard drawing 5-162-06-018-003, Heat Exchanger, Rev. 03
American Standard Heat Transfer Division Operating Instructions and Parts List for Type BCF, HCF and SSCF heat exchangers, dated 10/1/74
Component Health Report for Heat Exchangers covering the 1st trimester of 2004

LIST OF ACRONYMS

AP	-	Abnormal Operating Procedure
AR	-	Action Request
BACC	-	Boric Acid Corrosion Control
BMV	-	Bare Metal Visual
CA	-	Auxiliary Feedwater System
CAP	-	Corrective Action Program
CFR	-	Code of Federal Regulations
CMH	-	Conduit Manhole
CNS	-	Catawba Nuclear Station
CRDM	-	Control Rod Drive Mechanism
CRAVS	-	Control Room Area Ventilation System
DG	-	Diesel Generator
ECCS	-	Emergency Core Cooling System
ECT	-	Eddy Current Testing
EOC	-	End-of-Cycle
EPA	-	Environmental Protection Agency
EPRI	-	Electric Power Research Institute

ESF	-	Engineered Safety Feature
ID	-	Inside Diameter
ISI	-	Inservice Inspection
KD	-	Diesel Generator Jacket Water Cooling
KF	-	Spent Fuel Pool Cooling
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
MSPI	-	Mitigating System Performance Indicator
MTB	-	Monitored Tank Building
NCV	-	Non-Cited Violation
NDE	-	Non-Destructive Examination
NEI	-	Nuclear Energy Institute
NRC	-	Nuclear Regulatory Commission
NS	-	Containment Spray System
NSD	-	Nuclear System Directive
NUREG	-	Nuclear Regulations
NV	-	Chemical and Volume Control
OTDT	-	Over Temperature Delta Temperature
PI	-	Performance Indicator
PIP	-	Problem Investigation Process report
PT	-	Penetrant Test
PWSCC	-	Pure Water Stress Corrosion Cracking
RCCA	-	Rod Cluster Control Assembly
RCS	-	Reactor Coolant System
RN	-	Nuclear Service Water
RPVH	-	Reactor Pressure Vessel Head
RTP	-	Rated Thermal Power
SBO	-	Station Blackout
SCDHEC	-	South Carolina Department of Health and Environmental Control
SG	-	Steam Generator
SR	-	Surveillance Requirement
SSC	-	System, Structure and Component
SSPS	-	Solid State Protection System
TS	-	Technical Specification
TSAIL	-	Technical Specification Action Item Log
UFSAR	-	Updated Final Safety Analysis Report
UT	-	Ultrasonic Testing
WO	-	Work Order
YC	-	Controlled Area Chilled Water

ATTACHMENT 2

Catawba 2 GL 2004-02 Commitments Applicable to TI 2515/166

GL 2004-02 Request	Actions implemented	Status
GL 2004-02, 2(b) A general description of and implementation schedule for all corrective actions including any plant modifications that you identified while responding to this generic letter.	The corrective actions required by this Generic Letter will be completed on or before December 31, 2007 as follows: 1. A baseline evaluation has been performed for Catawba by Enercon Services, Inc. This evaluation was performed using the guidance of NEI 04-07. The evaluation is currently under review by Catawba and will be completed by June, 30, 2006 by Enercon Services, Inc. 2. A refined evaluation using the guidance of NEI 04-07 will be completed for Catawba by June 30, 2006. This evaluation will provide plant-specific refinements to the baseline evaluation that can be justified for Catawba. This evaluation is expected to provide additional head loss margin for the containment sump. 3. A downstream effects evaluation will be completed for Catawba by Enercon Services, Inc. This evaluation will be performed using the methodology provided by WCAP-16406-P, " Evaluation of Downstream Sump Debris Effects in Support of GSI 191." Any additional plant modifications or procedure changes associated with this evaluation will be completed by December 31, 2007.	1. The baseline evaluation for Catawba Nuclear Station has been reviewed and accepted by Catawba. **This commitment is closed.** 2. This evaluation was covered in Catawba Calculation CNC-1223.11-00-0037. The original scope of the refined analysis has been reviewed and accepted by Catawba. **This commitment is closed.** 3. The Downstream effects evaluation for erosion and blockage of components (pumps, valves, and orifices) is complete and demonstrated in Enercon report DUK008-PR-01, Rev. 0. Necessary plant modifications to address potential blockage of ECCS valves have been identified and will be completed by December 31, 2007. The documentation of the effectiveness of the bypass eliminators regarding fuel blockage is complete. Minor Design Change CD101006 for Unit 1, and CD201007 for Unit 2, have been initiated per the associated Engineering Change Request within the proposed corrective action following the normal modification practice. This is an engineering request to install smaller ECCS flow orifices in order to provide greater clearance on the ECCS throttle valves in order to comply with sump debris downstream effect evaluation. Unit 2 was completed during 2EOC15, and Unit 1 was unsuccessful during its previous outage, but will complete the modification during 1 EOC 17. **Therefore this commitment is on schedule to be completed by April 30, 2008.**

	4. Chemical effects will be evaluated to confirm that sufficient margin exists in the final sump design to account for any associated head loss. The evaluation will be completed by June 30, 2006. Any additional plant modifications or procedure changes associated with this evaluation will be completed by December 31, 2007. 5. Confirmatory walkdowns of containment using the guidance of NEI 02-01, "Condition Assessment Guidelines: Debris Sources Inside PWR Containments" (NEI 02-01) were completed for Catawba Unit 2 in the fall of 2004 and for Catawba Unit 1 in the Spring of 2005. 6. A confirmation of the conservatism of the 200 pound latent debris assumption used in the baseline analysis will be performed by latent debris surveys sampling during the Catawba Unit 2 Spring refueling outage in 2006. 7. The plant labeling process will be enhanced to require that any additional labels or signs placed inside containment are evaluated to ensure that the design basis for transportable debris is not invalidated. This corrective action will be completed by December 31, 2007.	4. The replacement strainers are being designed with additional margin in an effort to accommodate increased head loss due to chemical effects. Testing and analysis to address chemical effects are not complete. Testing for chemical effects started on June 2, 2006. Upon completion of testing , the results will be evaluated and further actions will be determined. Downstream chemical effects are still under investigation by the industry with the intent of addressing this issue by December 31, 2007. An Integrated Prototype Test (IPT) started October 23, 2007 in Huntsville, Alabama, and the testing is being conducted by Wyle Labs. **This is a new commitment date, and is on schedule to be closed April 30, 2008.** 5. The walkdowns of containment using the guidance of NEI 02-01 were completed in the fall of 2004 for Unit 2 and the Spring of 2005 for Unit 1. **This is a new commitment date, and is on schedule to be closed April 30, 2008.** 6. Latent debris sampling completed by Enercon Services, Inc. During the Catawba Unit 2 Spring 2006 refueling outage confirmed in the conservatism of the 200 pound latent debris assumption. **This commitment is closed.** 7. In lieu of a containment cleanout procedure, model work orders have been created for each unit to show containment cleanout as a regularly scheduled activity in the overall outage schedule. Model work Order 98775894 has been created for Unit One activity, and Model Work Order 98775902 has been created for Unit 2 activity. Nuclear Site Directive (NSD) 503, Rev. 6, revised the station directive to include requirements to

	8. Testing will be performed to confirm that the replacement strainer head loss is acceptable under design basis debris loaded conditions. This testing will be conducted prior to installation of the replacement strainers.	8. Head loss testing has been completed by Enercon Services, Inc. Test reports have been issued by Enercon and after review of these tebris testing reports, they have been found acceptably by Catawba. **This commitment is closed.**
	9. A modified containment sump strainer and supporting structure will be installed during 1EOC17 for Catawba Unit 1 and during 2EOC15 for Catawba Unit 2.	9. CD200490 is the modification package for the ECCS Unit 2 Containment Recirculation Sump Strainer, which will be completed at the conclusion of 2EOC15. **The installation of the containment sumps is on track to be completed as committed.**
	10. Replacement of the Microtherm insulation (currently installed on portions of the Reactor Vessel Heads) will be completed in the Fall of 2006 for Catawba Unit 1 and in the Fall of 2007 for Catawba Unit 2. The replacement of this insulation will reduce the postulated accident debris loading on the sump strainer.	10. Equivalent Change CE201028 was initiated to replace the Unit 2 R.V. Head Microtherm insulation with mirror insulation (with CE100933 initiate for Unit 1 R. V. Head Microtherm replacement). CE201028 was implemented by the work order task (01112604 01) associated with this Design Change to replace the Unit 2 R.V. Head Microtherm insulation with mirror insulation. **This commitment is closed.**
	11. Duke will evaluate the modification process to determine if additional controls are needed in order to maintain the validity of inputs to analyses performed in resolving GSI-191 concerns. This evaluation will be completed by June 30, 2006.	11. The subject evaluation has been competed and documented in the Duke corrective action program. Additional controls were deemed prudent. Revision 4, Engineering Directive Manual (EDM), Appendix K5 has been enacted on October 31, 2007 to capture the suggestions from this evaluation. **This commitment is closed.**

GL 2004-02, 2(f) A description of the existing or planned programmatic controls that will ensure that potential sources of debris introduced into containment (e.g., insulations, signs, coatings, and foreign materials) will be assessed for potential adverse effects on ECCS and CSS recirculation functions.	Catawba has several programmatic controls in place to ensure that potential sources of debris introduced into containment will be assessed for adverse effects on ECCS and Containment Spray System recirculation functions. These programmatic controls include requirements related to coatings, containment housekeeping, material condition and modifications. Some programmatic controls are described in more detail below.	Catawba Operations: 1. Perform the following inspections to ensure that containment drainage paths are unblocked: PT/0/A/4200/002 (Containment cleanliness Inspection) 2. PT/1/A/4600/016 (Surveillance Requirements for Unit Startup). This test includes an inspection of the refueling cavity drains. Each drain is verified visually by line of sight where possible. 3. PT/1(2)/A/4600/003B (Quarterly Surveillance Items). Quarterly visual inspection of refueling canal and Upper Containment compartment to verify there is no debris that could obstruct the refueling canal drains. Catawba Maintenance: 1. Verify the operability and freedom from debris of ice condenser drains. 2. SM/0/A/8150/004 (Inspection of Ice Consenser Floor Drains) and Procedure PT/1(2)/A/4400/018 has been developed to support the inspectio nof containment civil features including crane wall penetrations dedicated as sump recirculation flow paths, containment sump integrity for both screens and structure, and Incore Instrument Enclosure door and hatch for closure.

	Coatings Program As described in Duke's November 11, 1998 response to GL 98-04, "Potential for Degradation of ECCS and CSS after LOCA because of Construction and Protective Coating Deficiencies and Foreign Materials Inside Containment," Duke has established controls for the procurement, application, and maintenance of Service Level 1 protective coatings used inside containment. The requirements of 10 CFR 50 Appendix B are implemented through the specification of appropriate technical and quality requirements for the Service Level 1 coating program. For Service Level 1 coatings, Duke is committed to comply with Reg Guide 1.54 at Catawba. Per the GL 98-04 response, vendor supplied mechanical equipment (valves, pumps, hoists, tanks, etc.) that was procured prior to the issuance of Reg Guide 1.54 (or that are impractical to purchase with qualified coatings) all have coatings that cannot be certified to comply with the standards, and are thus defined as unqualified.	*Coatings Program* The comprehensive Duke Energy corporation Containment Coatings Assessment Program in effect at Catawba Nuclear Station is used to identify degraded qualified/acceptable coatings and determine the amount of debris that will result from these coatings. This program also ensures that qualifies/ acceptable coatings remain in compliance with plant licensing requirements for design-basis accident (DBA) performance. A primary containment coatings condition assessment is conducted during each refueling outage or any other extended outage. Visual inspections are conducted and documented by ANSI N45.2.6 Level II personnel and/or personnel who have demonstrated overall technical knowledge of coatings. The resultant data is reviewed by the site Coating Specialist and is used to facilitate proper planning and prioritization of coatings maintenance as needed to maintain the integrity of qualified/acceptable primary containment coating systems. The primary containment coating condition assessment protocol consists of a 100% visual inspection of all accessible coated areas by qualified personnel. The use of visual inspection by qualified personnel for containment coating assessment has been validated by the recently-issued EPRI Report 1014883 'Plant Support Engineering: Adhesion Testing of Nuclear Coating Service Level 1 Coatings."

	Containment Housekeeping/Material Condition Duke's August 7, 2003 response to Bulleting 2003-01, " Potential Impact of Debris Blockage on Emergency Sump Recirculation at PWRs," described planned actions regarding containment cleanliness. These actions have been implemented and involve containment cleaning and visual inspections. Extensive containment cleaning is performed during refueling outages using water spray, vacuuming, and hand wiping. In general, this is limited to the space in lower containment that would be submerged under large break LOCA conditions. Additionally, localized washdowns are performed as needed. Visual inspections are performed on the remaining areas of containment. Foreign material is removed as necessary. Material accountability logs are maintained in Modes 1 through 4 for items carried into and out of containment. These controls are implemented using administrative procedures.	*Containment Housekeeping/Material Condition* Site Directive 3.1.2 was revised to add detail to material accountability logs, which must be kept for items carried into and out of containment in Modes 1 through 4. In lieu of a containment cleanout procedure, model work orders have been created for each unit to show containment cleanout as a regularly scheduled activity in the overall outage schedule. Model Work Order 98775894 has been created for Unit One activity, and Model Work Order 98775902 has been created for Unit 2 activity.

	Modification Process Duke's modification process currently includes an administrative procedure that directs the design and implementation of engineering changes to the plant. This procedure directs that engineering changes be evaluated for system interactions. As part of this evaluation, there is direction to include consideration of any potential adverse effect with regard to debris sources and/or debris transport paths associated with the containment sump. While these existing controls provide assurance that modifications to the plant will be assessed for potential adverse effects on the containment sump, Duke plans to provide further evaluation to determine if additional controls are needed. Duke will identify any additional controls that may be needed in order to maintain the validity of inputs to analyses performed in resolving GSI-191 concerns. *Plant Labeling Process* The plant labeling process will be enhance to ensure that any additional labels or signs placed inside containment are evaluated to ensure that the design basis for transportable debris is not invalidated. This corrective action will be completed by December 31, 2007.	*Modifications Process* Revision 4, Engineering Directive Manual (EDM), Appendix K5 has been enacted October 31, 2007. *Plant Labeling Process* In response to the direction that "the plant labeling process will be enhanced to require that any additional labels or signs placed in containment are evaluated to ensure that the design basis for transportable debris is not invalidated", the following changes were made. NSD 503, STATION LABEL AND SIGN STANDARDS, Rev. 6, issued 09/18/06 incorporated changes in the Purpose (503.1) for the Label/Sign program to be designed to provide guidance to "Prevent Labels/Signs inside containment from being transported to the ECCS Containment Sump suction." In section 503.5.2 approved label/sign materials for inside containment are specified as Stainless Steel and Porcelain covered Stainless Steel which meet the transportable debris criteria. These changes have been adopted by all three Duke Energy nuclear sites.