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

Report Nos.: 50-413/96-03 and 50-414/96-03

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

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

Facility Name: Catawba Nuclear Station Units 1 and 2

Inspection Conducted: February 8 - 13, 1996

Inspectors: H. O. Christensen, Team Leader — 3/11/96 Date Signed
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Approved by: Albert F. Gibson, Director — 3/12/96 Date Signed
Division of Reactor Safety

SUMMARY

Scope:

This was a special reactive team inspection to evaluate and determine the cause of the February 6, 1996, Loss of Off-site Power at Catawba Unit 2. Additionally, operator performance during the event, maintenance practices and abnormal occurrences were evaluated.

Results:

The Loss of Off-site Power on Catawba Unit 2 was caused by the failure of two separate 22 kV potential transformer resistor bushings. The apparent cause was a combination of a degraded resistor and moisture in the potential transformer resistor bushing isolated phase bus panels. The event occurred due to two separate faults. The first fault occurred on February 5, 1996, and appeared to be intermittent on the "B" train phase "Z" resistor bushing (weakening the bushing). The second fault occurred on February 6, 1996 on the "A" train phase "X" resistor bushing and likely caused the second initiation of the first fault, (paragraphs 2.2, 4.0 and 5.0).

The equipment taken out of service prior to the event was evaluated by the licensee for PRA risk considerations and the risk was determined to be acceptable. This decision appears appropriate. During the event, the 2B emergency diesel generator was out of service for battery charger maintenance, (paragraph 2.1).

The operators performed adequately during the event and appropriately implemented the emergency procedures. During the event a safety injection occurred as designed and was a result of the cooldown caused by steaming the Steam Generators (S/G) and feeding the S/Gs with auxiliary feedwater. The operators terminated the safety injection appropriately, (paragraph 3.0).

During the event the licensee decided not to perform the required surveillance on the 2A emergency diesel generator. The surveillance required starting and fully loading the emergency diesel generator. This decision was made to prevent challenging the electrical lineup that was established with the Unit 1 cross connect. This decision appears appropriate for the circumstance. However this action was considered a 10 CFR 50.54(x) action and should have been reported. This was identified as a non-cited violation, (paragraph 2.4).

The apparent "D" S/G temperature anomaly was determined to represent actual plant conditions during the event. T-Cold indicated a higher temperature than T-Hot. The T-Cold and T-Hot instrumentation operated correctly, (paragraph 7.5).

The licensee determined that the simulator functions differently than the plant. The digital rod position indication system and reactor water makeup pumps lost power during the event while the simulator indicates that the equipment has power and functions. This difference provided negative training to the operating crews, (paragraph 3.3).

The licensee's Failure Investigation Process Team and the Significant Event Investigation Team were effective in evaluating the event and determining root cause, (paragraph 8.0).

Event recorder data provided adequate information to determine that the 22 kV electrical system was deteriorating the day before the event. If the licensee had reviewed the data in a timely manner, the loss of off-site power event might have been prevented. The licensee failed to follow procedures for responding to event recorder alarms. This was identified as a violation, (paragraph 4.0).

Past maintenance activities in the transformer yard were not effective in detecting or preventing the resistor bushing failures, (paragraph 6.1).

REPORT DETAILS

1. PERSONS CONTACTED

Licensee Employees

*A. Bhatnagar, Operations Superintendent
*J. Forbes, Engineering Manager
*W. McCollum, Catawba Site Vice President
*T. McConnell, Station Support Division Manager
*G. Peterson, Station Manager
*Z. Taylor, Regulatory Compliance Manager
*M. Tuckman, Senior Vice President

*Attended exit interview.

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

NRC Employees

*P. Balmain, Acting Senior Resident Inspector, RII
*R. Baldwin, Acting Resident Inspector, RII
*F. Burrows, Electrical Engineer, NRR
*H. Christensen, Chief, Maintenance Branch, RII
*G. MacDonald, Reactor Inspector, RII
*R. Martin, Project Manager, NRR
*M. Miller, Reactor Inspector, RII

Acronyms and abbreviations used throughout this report are listed in the last paragraph.

2. LOSS OF OFFSITE POWER EVENT (71707)

2.1 Event Summary

A Loss of Off-site Power occurred at Catawba Unit 2 on February 6, 1996. A detailed sequence of events is provided in Attachment A.

Unit 1 and Unit 2 were at 100 percent power. The "2B" EDG and the "2B" service water pump were out of service for maintenance. At 12:30 p.m., a ground fault on the "A" train and "B" train 22kV isolated phase bus system occurred. Approximately 40 seconds later a reactor trip was generated due to underfrequency on the Reactor Coolant Pump busses. The "2A" EDG started and energized the "A" train (2ETA) essential bus; the "B" train was not energized due to the "2B" EDG being out of service. S/G pressure initially peaked due to the reactor trip and then began to decrease. The operators closed the main steam isolation valves due to decreasing S/G pressure (AFW and steam line drain effects). S/G pressure continued to decrease and the plant received an automatic Safety Injection (SI) signal based upon low pressure on the "A" S/G. An Unusual Event was declared at 12:43 p.m. Approximately 37 minutes after the reactor trip the operators terminated the Safety Injection. The

pressurizer went water solid due to continued charging. This caused the pressurizer PORV to open a number of times. The PRT rupture disc ruptured on high pressure, which caused an increase in containment pressure. Approximately 1 hour following the reactor trip letdown was re-established and approximately 3 hours (3:23 p.m.) following the reactor trip the "2B" EDG was placed in service on essential bus 2ETB. At 5:00 p.m., boration was commenced for cold shutdown conditions. Approximately 6 hours following the reactor trip 2ETB was being supplied by Unit 1 and "2B" EDG was secured. At 8:00 p.m., (approximately 7 hours) 2ETA was being supplied from Unit 1 and "2A" EDG was secured. On February 7, at 5:00 p.m., Mode 5 was reached. On February 8, 1996 at 1:20 a.m., the "2B" main power was restored to the non-safety busses, and the essential busses were being supplied by the Unit 1 cross-ties. The Unusual Event was terminated at 2:15 a.m.

2.2 Electrical Sequence of Events

Post-event review indicated that, on February 5, 1996, intermittent faults occurred on Unit 2 "Z" phase of the "B" train 22 kV isolated phase bus system. These faults were too short in duration for protective relays to time out and were indicated by an undervoltage alarm on Bus "B", generator neutral overcurrent, and "X" phase overvoltage on Bus "A" and Bus "B". Oscillograph traces displayed waveform distortions such as current and voltage spikes on the "X" and "Z" phases.

On February 6, 1996, at 12:30 p.m., a ground fault occurred on the "X" phase of Bus "A". This was followed by an overvoltage condition on "Z" phase and created a solid ground condition. The "X" phase-to-ground coupled with the "Z" phase-to-ground resulted in a phase-to-phase fault current of 254,000 amperes.

Unit 2 22 kV Bus "A" and Bus "B" transformer differential relays picked up on high instantaneous current leading to lockout signals for both busses. This was followed by opening of breakers for the switchyard, 6.9 kV buses, and main generator which resulted in the loss of offsite power to Unit 2. Undervoltage signals on the two 4.16 kV essential busses then generated start signals for the two corresponding EDG's. The one operable EDG started and was connected to its associated bus carrying shutdown loads.

The "B" EDG was restored to service roughly 3 hours into the event and powered its associated bus until offsite power was made available to the bus from Unit 1 approximately 2.5 hours later. An additional feed of offsite power from Unit 1 was established, to power the redundant 4.16 kV essential bus, and allow securing the corresponding EDG 7.5 hours from the start of the event. Additional recovery operations for the two main sources of offsite power through the main step-up transformers took place in subsequent days.

2.3 Safety Injection

The inspector reviewed the licensee's analysis of the steamline pressure and the safety injection transient to determine if the Safety Injection was required.

The inspector determined that at approximately 5 minutes after the reactor trip, the operators closed the MSIVs when S/G pressure decreased from approximately 825 to 800 psig. During the event the "B" motor driven (MD) auxiliary feedwater (AFW) pump was not available (2ETB was de-energized), the AFW system went into the flow optimization mode to protect the only MD pump available. The flow was optimized to the "A" S/G from the "A" MD AFW pump at ~490 gpm with no flow provided to the "B" S/G from the "A" MD AFW pump. The Turbine Driven (TD) AFW pump then supplied the "B" and "C" S/Gs (~550 gpm total). The increased auxiliary feedwater flow to the "A" S/G caused the steam to quench resulting in a continued decrease in "A" S/G pressure (MSIVs already closed). The decrease in steam pressure ultimately caused a Low steamline pressure (setpoint 775 psig) to occur on the "A" steamline. The inspector verified the event using the alarm typer data.

The Inspector concluded that based upon the auxiliary feedwater system response and subsequent operator action of closing the main steam line isolation valves and the actuation of auxiliary feedwater to the steam generators the low pressure safety injection operated as expected.

2.4 EDG Surveillance

The inspector reviewed the licensee's actions for not conducting EDG surveillances during the event of February 6, 1996. The inspector also reviewed Technical Specification 3/4.8.1.1., AC Sources, and 10 CFR 50.54.(x) and 10 CFR 50.72 to determine if the actions were appropriate.

On February 6, 1996, the "2A" EDG was supplying the 2ETA 4.16 kV emergency bus with the 2ETB bus being supplied by the "2B" EDG. When Unit 1 power supply was cross connected through SATA and SATB to Unit 2's 4.16 kV essential power busses ETA/ETB respectively, both "2A" and "2B" EDGs were placed in standby readiness (8:55 p.m.). The licensee was required to perform surveillance 4.8.1.1.2a.4. and 4.8.1.1.2a.5 in order to demonstrate Operability of the "2A" diesel generator by 8:30 a.m. on February 7, 1996. The surveillance required loading of the "2A" EDG on the 2ETA bus to determine operability.

The licensee decided that this surveillance was not required because it met the intent of action statement "d" of Technical Specification 3.8.1.1 since the "2A" EDG was running prior to the Unit 1 to Unit 2 cross connect. Additionally, the licensee did not want to challenge the cross connected power source and wanted to maintain stable plant conditions. The inspector determined that once the licensee exited action statement "d", the licensee should have entered action statement "a" which required the Operability determination of the EDG. Since this

requirement TS was not performed, the licensee should have implemented 10 CFR 50.54(x) and made a 50.72 report stating they did not meet the requirement of Technical Specification 3.8.1.1. 10 CFR 50.54(x) allows the licensee to depart from technical specifications in an emergency when the action is needed to protect the public health and safety and no action with technical specifications that can provide adequate or equivalent protection is immediately apparent. The action shall be approved by a licensed senior operator and reported to the NRC Operations Center via a 10 CFR 50.72 report. It was noted that an SRO approved the action.

The inspector concluded that the licensee made the correct decision in not testing the EDG in this condition and the NRC (ENS communications) was aware of the EDG not being tested. However, the licensee should have made a formal 10 CFR 50.54(x) determination and subsequently report this decision to the NRC. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. (NCV 96-03-01)

2.5 Technical Specification 3.0.3

The inspector reviewed the licensee actions for exiting Technical Specification 3.0.3 to determine if the action was appropriate.

The inspector determined that immediately following the reactor trip, the plant entered Technical Specification 3.0.3 since Technical Specification 3.8.1.1 could not be met due to two inoperable offsite sources and one inoperable EDG. Approximately 9 hours later Technical Specification 3.0.3 was exited when offsite power was restored to the 4.16 kV essential busses via two alternate feeds from Unit 1 with one operable EDG and thereby meeting Technical Specification (TS) 3.8.1.1.c.

The inspector determined that there were four sources of offsite power available to each unit. Each one is physically independent, has adequate capacity, and can be used. The licensee takes a very conservative approach and considers these sources to be operable only when they are connected to the 4.16 kV essential busses. TS 3.8.1.1.c requires two operable sources of offsite power and one operable EDG for the plant to be in modes 1 through 4. The licensee met this requirement when the two alternate offsite sources from Unit 1 (two of the four sources) were connected to the Unit 2 emergency busses with one operable EDG.

The inspector concluded that when the two alternate off-site sources were connected to the plant with one operable EDG, the licensee could exit from TS 3.0.3 and that the actions of the licensee were proper.

3.0 OPERATOR ACTIONS AND PROCEDURES (71707)

3.1 Operator Performance

a. Scope

The operator's performance during the event was evaluated including the effectiveness of the emergency operating procedures. The inspector observed control room actions during the event, and observed SEIT team interviews of the operating crew. Additionally, the inspector reviewed the emergency operating procedures, event recorder data and operator logs.

b. Findings

The inspector evaluated the performance of the licensed operators during the event. The inspectors determined that during the LOOP the operators entered E-0, Reactor Trip or Safety Injection. The reactor tripped on Underfrequency on the Reactor Coolant Pumps. Upon entering E-0, DRPI indication was not available. Step 2 of E-0 required the operators to verify reactor trip. This was accomplished using three indications, a). all rod bottom lights - LIT, b). all reactor trip break and bypass breakers -OPEN and c). I/R amps - DECREASING. During the performance of this step all rod bottom lights were dark. The entire DRPI panel lost power and was dark. The operators entered the Response Not Obtained (RNO) column of the procedure based on the lack of rod bottom light indication. The control room operators took the appropriate actions in that they manually tripped the reactor. Additional requirements of the RNO for Step 2 was if the reactor will NOT trip to monitor the Critical Safety Function Status Trees and to enter EP-FR-S.1, Response to Nuclear Power Generation/ATWS. At this point the operators did not exit E-0 to enter FR-S.1 due to indications of the reactor being tripped. The inspector reviewed the basis document for the use of E-0 and determined that the operators during the performance of Step 2 RNO appropriately continued in E-0 and should not have exited to FR-S.1. The basis document for Step 2 required the operators to make a decision to determine if the reactor had tripped. The operating crew contacted a Reactor Engineer (RE) and asked the RE if there was a way to determine rod position based upon alternate indications. The RE ran a General Program 76 and determined that the rods were on the bottom; however, the RE recommended that two independent indications of rod position should be used to verify rod position and recommended the crew borate the reactor. The crew noted that NV-236B, Emergency borate valve was de-energized and the crew was unable to open the valve from the control room due to lack of power. During the event, normal make up to the VCT started. It

was at this time the operators noted that the reactor makeup water pumps did not start upon this automatic make-up signal. The operators also noted the "A" train boric acid pump started and that make up through the blender to the VCT was injecting boron. The RWMST pumps were not powered during the event therefore only boric acid was injected into the VCT. The inspectors noted that E-0 does not provide guidance to the operators concerning the necessity to emergency borate if rods are not on the bottom. The operators traversed through E-0, at Step 5, Verify if S/I injection is actuated: the conditions of the plant at that time did not warrant an SI. The SI RNO required the operator to enter ES-0.1, Reactor Trip Response. The operators correctly transitioned to the ES-0.1. The operators closed the MSIVs based upon RNO of Step 4 of ES-0.1 (Verify all 6.9 kV busses - Energized). The closure of the MSIVs occurred at approximately 5 minutes after the initiating event. The inspectors reviewed this and determined that it was consistent with the time it took to go through the procedures with the inoperable equipment. At Step 7 the operators were unable to establish rod position and entered the RNO to establish emergency boration. The inspectors determined that the RNO at Step 7 does not provide the operators contingency actions if valve NV-236B (Boric Acid to NV Pumps Suction) does not open. It was at this point that the plant experienced a Safety Injection due to low steam line pressure (775 psig) from two of the "A" loop channels. The operators correctly returned to E-0 and commenced the diagnostic portion of the procedure again.

The inspector observed that, ES-0.1, Reactor Trip Response, does not provide contingency actions to address if valve NV-236B does not open from the control room. Additionally, during the performance of AP/2/A/5500/07, Loss of Normal Power, Case II, Loss of All Power to an Essential Train, the inspectors observed during the performance of Step 16 b that the RNO was entered due to offsite power not being available. The RNO requires the operators to perform Enclosure 3 (Restoration of Offsite Power). The performance of Enclosure 3 slowed the operators down in the progression of the procedure and did not provide them useable guidance to combat the loss of power. The inspectors reviewed the corresponding Unit 1 procedure AP/1/A/5500/07 and determined that the procedure did not contain the same problem. The licensee revised the Unit 2 procedure to address this deficiency.

c. Conclusion

The inspector concluded that the Operators acted appropriately and in accordance with procedural guidelines. Additionally, the weaknesses with the Unit 2 procedures were corrected.

3.2 Operator Performance Upon Securing Safety Injection.

a. Scope

The inspector reviewed the operating logs, event recorder data and emergency procedures to determine if the safety injection termination criteria had been met and if the operators could have terminated the safety injection prior to water solid condition.

b. Findings

The inspector evaluated the equipment available during the event. The inspector determined that the recovery was complicated with the loss of power to two charging valves and one letdown valve. The control room operators could not have prevented the pressurizer from going into a solid condition and subsequent filling and rupture of the pressurizer relief tank. The control of valve NV-309, NV-295 and NV-148 required manual local manipulation with coordination from the control room with the use of a phone talker relaying information to the valve operators and the balance of plant operator (RO). This was a complicated evolution to coordinate between the four operators (one in the control room and three in the field).

When SI was terminated at 1:07 p.m. with the closure of valve NI-009A safety injection flow dropped from approximately 130 gpm to 0 gpm. Charging flow increased from approximately 50 gpm to approximately 160 gpm. It was during the recovery of charging and letdown that charging flow continued to inject at approximately 160 gpm for about 10-12 minutes.

c. Conclusion

The inspector evaluated the recovery from SI termination and determined that SI termination criteria was met and that the operators could not have prevented the water solid condition due to the complicated restoration procedure requiring local operations. The operator actions were appropriate.

3.3 Simulator Deficiencies

a. Scope

The inspector observed a portion of a LOOP simulator exercise to compare the simulator event to the actual February 6, 1996 event.

b. Findings

The inspectors determined that the simulator does not model the plant as designed and does not simulate plant responses precisely during the loss of off-site power. During the LOOP on February 6,

1996 Digital Rod Position Indication and Reactor Water Make Up Pumps lost power. The simulator indicated that power was still available to these components.

This difference was of concern because the training department is relied upon to provide operating crews realistic plant conditions for training in order to become familiar with expected plant responses. This averts unexpected performance, doubts and possible traps which operators may encounter during operational events. To address these issues the licensee provided a night order to operations to inform the crews of the simulator differences, and plans to fix the simulator differences in the future.

c. Conclusion

The inspectors concluded that the simulator differences provided negative training which may have led them to doubt equipment availability.

4.0 ROOT CAUSE DETERMINATION (37550)

a. Scope

The licensee established a Failure Investigation Process (FIP) team and an independent Significant Event Investigation Team (SEIT) to determine the cause of the event and establish corrective actions. The inspectors reviewed the licensee activities related to the event root cause investigation. The corrective actions are described in paragraph 6.0. The inspectors reviewed event recorder data, event oscillographs, resistor bushing failure data, and examined the failed resistor bushings. FIP team and SEIT team documentation was reviewed. The inspectors discussed the event sequence with FIP and SEIT team personnel. The failed resistor bushings were analyzed by the Duke Power Metallurgical Lab and were sent to a contractor for failure evaluation.

b. Findings

The FIP and SEIT teams did a satisfactory job of determining the causes of the event. The root cause analysis was broad and considered a wide range of potential contributors. A thorough and systematic approach was taken in evaluating and eliminating possible fault contributors. The evaluation effort included FIP team, SEIT team, metallurgical lab, and an outside consulting firm. The electrical transient analysis was satisfactory. All equipment functioned as designed except for one protective relay (Unit 2A 22 kV Undervoltage relay) which was replaced. The diagnosis of the fault was made more difficult because one oscillograph had failed and the event recorder and oscillograph data was not well correlated.

The cause of the event was determined most likely to be failure of two separate 22 kV isophase bus duct potential transformer resistor bushings. This conclusion is supported by the physical evidence. The root cause of the resistor bushings failures has not been conclusively determined. Arcing in the resistor bushings and moisture contamination on the resistor bushing has been determined as the most likely root causes. This conclusion is somewhat speculative and the exact root cause for the failures may never be conclusively determined. The event occurred due to 2 separate common mode failures. The first fault occurred on Monday February 5, 1996, and appeared to be an intermittent fault which weakened the 22 kV 2B train Z phase resistor bushing. The second fault occurred on Tuesday February 6, 1996, on the 22 kV 2A train X phase resistor bushing and likely caused a second initiation of the first fault.

Moisture in the isolated phase bus contributed to the event. The failure of the heaters in the 22 kV 2A potential transformer compartments could have contributed to the failures.

The resistor bushing design has not shown good reliability. Failures have been identified by the vendor. Testing failures have occurred at Catawba and failures have occurred at McGuire, Zion and San Onofre. Zion and San Onofre have or will replace their bushings. Some of the previous testing failures also had moisture contribution. There have been moisture related deficiencies with the isolated phase bus system before at Catawba.

Event recorder alarms occurred indicating the first intermittent failures which were not acted upon. These precursor alarms if acted upon could possibly have prevented the LOOP on Tuesday February 6, 1996. Additionally, the event recorder alarms do not have any alarm response procedures to provide guidance to the operators. Modification Exempt Change CE-3595 relocated the events recorder and eliminated the events recorder annunciator as a nuisance alarm on Unit 2. The event recorder data was not acted upon. Engineering personnel were not notified of the electrical fault alarms. The method of handling event recorder alarms was not consistent with Operations Management Procedure 1-8 section 7.2.B.9. At the time of the event, the event recorder data was not routinely reviewed prior to filing the printouts. Some of the datapoints on the event recorder can provide a function other than post event diagnostic evaluation.

c. Conclusion

The inspector determined that the LOOP was caused by the failure of the potential transformer resistor bushings. The failure to take action on the event recorder alarms of February 5, 1996, was a violation for failure to follow the Operations Management Procedure 1-8, and an inadequate alarm response procedure. (Violation 50-414/96-03-02).

5.0 TRANSFORMER YARD DESIGN (37550)

5.1 Common Mode Failure

a. Scope

The inspector reviewed FSAR Charter 8, the SER, and GDC-17 to determine if the potential transformer resistor bushing failure was a single failure or common mode failure.

b. Findings

The licensee concluded that a single failure did not cause the loss of both train "A" and train "B" electrical power from the main step-up transformers and that GDC-17 conformance was not compromised. The licensee supported the position on the single failure by stating that the first failure (B train Z phase) was a pre-existing intermittent single failure and that a second failure (A train X phase) was not precipitated by the intermittent "Z" phase fault. The licensee stated that the first fault was due most-likely to arcing inside the resistor bushing on the "Z" phase creating an ionized gas which was believed to have leaked from the bushing and, in the presence of moisture and contamination, led to intermittent arcing to ground. The licensee also attributed the second fault to a similar problem in the "X" phase resistor bushing. Both faults occurring at the same time then degraded simultaneously due to overvoltage interaction creating a phase-to-phase fault which then led to the event.

The inspector basically agreed with the licensee's conclusion that the event was caused by a common mode failure (arcing in the resistor bushings with moisture and contamination in area of bushings) but believes moisture and contamination are most likely to be the main contributors.

The inspector also agreed that the plant appears to be designed in accordance with the plant's FSAR and as stated in the SER and that the plant's conformance to GDC-17 was not compromised. GDC-17 states that:

> Electric power from the transmission network to the on-site electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all on-site alternating current power supplies and the other offsite electric power circuit, to assure that the specified acceptable fuel design limits and design

conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

c. Conclusion

The inspector concluded that the plant meets the requirements of GDC-17 by having two immediately available, physically independent sources of offsite power through the main step-up transformers and two additional physically independent offsite sources with delayed access from Catawba Unit 1 through shared 6.9 kV to 4.16 kV transformers as described in the plant's FSAR. The failures of "A" and "B" train potential transformer resistor bushings were most likely from common causes of a degraded resistor with moisture and/or contamination in the area of the bushing. The failures resulted in the loss of the two immediate access sources but did not compromise the two delayed access sources which were subsequently utilized to recover the plant.

5.2 Electrical Transient Analysis

a. Scope

The inspector evaluated the licensee's electrical transient analysis, discussed the analysis with the selected FIP and SEIT team members and reviewed event recorder data.

b. Findings

The licensee's electrical analysis for this event determined that the initial, short-duration ground fault of approximately 11 amperes picked up the appropriate relays but the fault duration was not long enough for the relays to time out. When the second ground fault occurred, the increase in voltages on the buses further degraded the transient into a solid 254,000 ampere phase-to-phase fault. The licensee's analysis was supported by printouts from the events recorder which lists the alarms received from individual electrical protective relays and by traces from the oscillograph for voltages and currents. Also visual examinations were performed on the associated equipment in the transformer yard and the failed resistor bushings were sent to the licensee's metallurgical laboratory for analysis. The inspector considered this to be a very thorough and adequate approach toward development of an electrical transient analysis for the event.

During the day before the event and during the event itself, oscillograph traces were initiated for only one of the two trains and one undervoltage relay on Bus B was inoperable. These limitations did have an impact on the analysis but this was believed to be minimal. Instead of identifying the exact root

cause of the event, two possible causes (resistor degradation and moisture/contamination) have been listed because of these limitations.

c. Conclusion

The inspector concluded that the electrical transient analysis was satisfactory to assess the cause of the loss of off-site power event.

6.0 MAINTENANCE (62703)

6.1 22kV Isolated Phase Bus System (2EPA)

a. Scope

Using Inspection Procedure 62703, Maintenance Observation, as guidance, the inspectors observed corrective maintenance activities to the damaged equipment to verify work activities were performed in a satisfactory manner. The preventive and corrective maintenance procedures were reviewed to determine their adequacy. Work orders were examined to ensure appropriate post maintenance testing was specified and completed. Modification packages were reviewed to ensure their completeness. Additionally, the maintenance history was reviewed to determine if any adverse trends existed or could be recognized.

b. Findings

The inspector determined that preventive and corrective maintenance for the 22kV Isolated Phase Bus (IPB) System were performed by the licensee's off-site service group, "Electric Systems Support" (ESS). The 22kV IPB System was not classified as a safety-related system and was treated accordingly. ESS provided the maintenance service for all switchyards, transmission lines, and high voltage systems at both nuclear and non-nuclear sites. The maintenance procedures used by ESS were general in nature and depended on the "skill of the craft" for proper implementation. The three procedures used by ESS to repair and test the 22kV IPB System were as follows:

IP/0/A/3890/0 - Controlling Procedure For Trouble Shooting And Corrective Maintenance

IP/0/B/4974/02 - Isolated And Non-Segregated Phase Bus Inspection And Maintenance

SI/0/A/2400/001 - Doble Testing

Work Orders W/O 96011362, "Repair B Train Isolated Phase Bus" and W/O 96011363 " Repair A Train Isolated Phase Bus" initiated the corrective action for repairs and testing. The inspector observed

that the corrective work and testing was performed in a satisfactory manner. The licensee implemented modifications to replace all the existing resistor bushings with a new design. The old design bushing contained an internal resistor. The new design has a separate external resistor. Additionally, to prevent moisture buildup, the licensee removed (jumpered) the thermostats for the potential transformer/bushing panel heaters. The modification ensured that the heaters remained energized.

The inspector reviewed the 22kV IPB System work order (WO) maintenance history for the period of 1991 to the present time. This history was provided by the licensee from a computer file and identified as "Work Order Search" dated February 8, 1996. The WOs addressed both preventive and corrective maintenance. The WOs included all the equipment in the 22kV IPB System such as transformers, cooling fans, air filters, breakers, inspections, and PMs. There were 160 corrective maintenance work orders and 114 preventive maintenance (PM) work orders. In addition, the problems associated with the resistor bushings from 1987 to present were reviewed.

1987 - Unit 2 "A" Train resistor bushing had to be replaced.

1990 - Unit 2 "A" Train resistor bushing had t be replaced

1993 - Unit 1 "B" Train resistor bushing had to be replaced.

1995 - Unit 1 "B" Train resistor had significant moisture build up.

1995 - Unit 2 "B" Train indicated a ground on "X" phase as the result of a dirty bushing. This was identified during a PM.

The inspector reviewed the SEIT findings and noted that the SEIT identified that the heater PM frequency for Units 1 and 2 had been extended over time. The PM frequency was changed from monthly to quarterly and then to yearly.

On-site, the maintenance department had one person assigned as a "Job Sponsor" and System Engineering had one engineer assigned. The primary function of the "Job Sponsor" was to coordinate and provide administrative and interfacing activities between the site and ESS for scheduling and supporting maintenance. The system engineer performed the function of tracking system design issues. There was on-site oversight in both maintenance and engineering; however, there was no sense of "ownership." The scheduled maintenance and engineering activities were tracked, but the overall system was not evaluated and trended to determine if the right problems were being addressed.

c. Conclusion

The inspector concluded that the corrective maintenance, testing, and modifications to repair the isolated phase busses were implemented in a satisfactory manner. The PM program was not effective in maintaining the isolated phase bus system and a contributor was the lack of clear system responsibility. Additionally, ESS performed adequate maintenance as a service group, but also did not have ownership of the system.

7.0 EQUIPMENT ISSUES (62703)

7.1 Loss of Digital Rod Position Indication (DRPI)

a. Scope

During the Loss of Off Site Power (LOOP) event, the DRPI system de-energized. The inspectors reviewed Problem Investigation Process (PIP) Report 0-C96-0305; FSAR Section 1.8.1.28.1.1, Accident Monitoring Instrumentation; Regulatory Guide 1.97; and drawings CN-2705-02.04, CN-2704-06.01, CN-2704-06.01-01, and CN-2782-02.03 to determine if the system functioned correctly.

b. Findings

The inspector determined that the DRPI system operated as designed and as-built. The training "simulator" model of a LOOP event had the DRPI system energized which was not consistent with the actual plant operation during this LOOP event. There were no requirements in the FSAR or RG 1.97 that required the power supply to be safety-related or have battery back up. The DRPI indicator is classified as a RG 1.97, Category 3, Type B Variable instrument. A Type B Variable provides information to indicate whether a safety function is being accomplished. A Category 3 instrument does not require Class 1E power or battery back up power. The DRPI system was in compliance with the licensing basis and regulatory requirements. The licensee stated the simulator was changed February 8, 1996, to model the as-built operation of the DRPI on LOOP.

c. Conclusion

The inspector concluded that the DRPI system functioned as designed and as specified in the FSAR.

7.2 The Reactor Makeup Water Pumps (RWMSTP)

a. Scope

During the LOOP event, the reactor makeup water pumps could not be started. The pump start circuits and associated interlocks from relays were not powered by Class 1E power with battery back up.

The inspectors reviewed PIP Report 0-C96-0337, drawing CN-2705-02.04, and FSAR 9.3.4.2. to identify the problem and verify appropriate corrective action was implemented.

b. Finding

The FSAR states the RWMSTPs are non-safety related equipment and are not required to mitigate the consequences of an accident. During training "simulator" scenarios involving LOOP events, the RWMSTPs remained available since they were considered powered from "Blackout" motor control centers. However, the pump start circuit interlock was modified per modification NSM CN-20017 to allow operation during a blackout condition. The pumps operated as designed, but the design was in error of what was intended. The licensee has initiated appropriate corrective action by 1) issuing "Operations Information Notice" making the operation staff aware of the actual operation of the RWMSTPs, and 2) developing minor modification packages that would provide blackout (battery backed) power to allow operation of the pumps.

c. Conclusion

The inspector concluded that appropriate corrective action was implemented and that the RWMSTPs functioned as designed.

7.3 Emergency Diesel Generator (EDG) Readiness - 2B Battery Charger (BC)

a. Scope

Prior to the LOOP event, the 2B EDG/BC was out of service and in a 72 hour Technical Specifications action statement. This was due to a failed internal AC capacitor which had placed the battery charger out of service. When the LOOP event occurred, the "2B" EDG could not start due to it being in the maintenance mode. The "2A" EDG started and provided power as required. The inspectors reviewed PIP Report 2-C96-0313, FSAR Chapter 8, Technical Specifications (TS) 3.8.1.1, and work order 96011113 to identify the problem and verify appropriate corrective action was implemented.

b. Finding

The inspectors determined that the failed AC input capacitor caused the EDG/BC to be out of service at the time of the LOOP event. The failure of the AC capacitor was not normal for this type of component. The inspector did not identify a preventive maintenance (PM) activity that the PM program would have required the replacement of the AC capacitor. The PM program does have the replacement requirements for the DC capacitors. DC capacitors are the type that normally fail after a period of time. The

maintenance staff under the direction of the system engineer repaired the EDG/BC and made it available within three hours of the LOOP event. The 2B EDG/BC was repaired, operability tested as required by TS, and returned to service in a satisfactory manner.

c. Conclusion

The inspector concluded that the 2B EDG non-availability was caused by the failure of an AC capacitor in the battery charger and the licensee's actions to restore the battery charger was satisfactory.

7.4 Containment Radiation Monitors EMF 38/39/40

a. Scope

During the LOOP event, EMF 38/39/40 radiation monitor experienced a loss of electrical power and would not operate after the power was restored. The inspectors reviewed FSAR 1.8.1.28, RG 1.97, PIP Report 2-C96-0311, and work order 96006267 to identify the problem and verify appropriate corrective action was implemented.

b. Finding

EMF 38/39/40 would not operate after electrical power was restored. The pump motor would not start due to a failed overload relay in the start circuit. The motor starter overload relays were replaced and EMF 38/39/40 was returned to service. EMF 38/39/40 are not RG 1.97 instruments (radiation monitor) and are not required for accident monitoring.

c. Conclusion

The inspector determined that except for the failed overload relay in the motor starter, the instruments operated as designed. The radiation monitors were correctly repaired.

7.5 Reactor Coolant Loop D "T-Hot" - "T-Cold" Temperature Anomaly

a. Scope

During the LOOP event, T-Cold was observed indicating a slightly higher temperature than T-Hot in the "D" loop. The inspectors reviewed FSAR 4.4.3, 7.2.2.3.2, 7.4.1, and Chapter 5; Westinghouse's memorandum "NC Loop D Behavior During Natural Circulation Cooldown"; and the licensee's "Loop D, T-Hot & T-Cold Wide Range Temperature Indication" memorandum dated February 8, 1996. In addition, discussions were conducted with System Engineering. These actions were taken to determine if the temperature anomaly was an actual plant condition.

b. Finding

At the time of the LOOP event, the conditions for reactor coolant Loop "D", the auxiliary feedwater (AFW) pumps line up to the steam generators (S/G), and S/G "D" main steam line power operated relief valve (PORV) were as follows:

Train "A" motor driven AFW Pump "A" was aligned to S/Gs "A" and "B".

Turbine driven AFW pump was aligned to S/Gs "B" and "C".

Train "B" motor driven AFW Pump "B" was aligned to S/Gs "C" and "D".

"2B" EDG was out of service and inoperable due to the battery charger being in a 72 hour TS action statement. [See discussion in 7.3]

Maintenance was in progress for Loop "D" PORV. This caused the PORV to be isolated and unavailable which prevented steaming of S/G "D" until the maintenance was completed.

At the start of the LOOP event, S/G "D" did not have AFW and the PORV was unavailable to allow steaming. At this time the level in S/G "D" decreased to a low level of 24 percent. In addition, when AFW flow and the PORV were unavailable, cooling and natural circulation flow of the reactor coolant in Loop "D" was limited. The temperature in both T-Hot and T-Cold legs of Loop "D" gradually approached each other. When AFW was restored significant cooling was provided, S/G level was restored, and the S/G pressure decreased. By the time the PORV was initially operated, the natural circulation driving force provided by the AFW was again diminishing which limited the flow through the S/G U-tubes. Operation of the PORV reduced the pressure in the S/G further reducing natural circulation of reactor coolant flow. When AFW was re-initiated and because of the piping configuration in the T-Cold leg, delayed effects of a sluggish reactor coolant flow through S/G "D" caused the T-Hot leg to cool faster than T-Cold. Physically, the T-Hot resistance temperature detector (RTD) is closer to the S/G than the T-Cold RTD. The T-Cold RTD is closer to the reactor vessel due to an intermediate leg between the S/G and the reactor coolant pump. This resulted in T-Hot cooling faster than T-Cold and T-Cold's temperature being slightly higher. Eventual steaming of S/G "D" with the use of the PORV restored natural recirculation and T-Hot temperature gradually increased above T-Cold. During this time period the licensee's instrument technicians measured both narrow and wide range resistance temperature detectors (RTD) in Loop "D" to verify the temperatures observed were correct.

c. Conclusion

The inspector concluded that the phenomenon of T-Cold temporarily exceeding T-Hot after the LOOP event when there was no AFW to the S/G "D" and the PORV was not available depicted the actual occurrence.

7.6 Overpressurization of Letdown Line

a. Scope

During the Unit 2 LOOP event, a suspected water hammer of letdown lines downstream of containment occurred during repressurization of letdown. The inspector reviewed the licensee's operability evaluation and work order which documented the letdown line inspection. The inspector performed an independent walkdown to determine if there was any evidence of system damage due to the potential water hammer. The inspectors reviewed PIP Report 2-C96-0341, FSAR Section 9.3.4, Drawings CN-2554-1.0, CN-2554-1.6, Work Order 96012030 01, and the plant letdown transient flow, temperature, and pressure data to determine if the problem was identified and appropriate corrective action taken.

b. Findings

The letdown system was not damaged by water hammer. During the Unit 2 LOOP event, a Phase A containment isolation signal occurred which closed containment isolation valves 2NV-10A, 2NV-11A, 2NV-13A, and 2NV-15B isolating letdown flow. Valve 2NV-15B did not close due to the loss of train B power during the event. Components performed as designed. After letdown was isolated the letdown lines downstream of the letdown orifices gradually dropped down to Volume Control Tank pressure from approximately 350 psig which is the normal letdown line segment pressure. Due to valve 2NV-849 not having power during a blackout, the operators had to repressurize letdown manually. At approximately 1:57 p.m., on February 6, 1996, when the letdown system was manually returned to service, a pressure transient occurred. The pressure transient caused relief valve 2NV14 to lift which relieved the pressure increase. The transient data shows no letdown pressure greater than 350 psig. Relief Valve 2NV14 is set for 600 psig. The letdown piping downstream of the letdown orifices has design pressure and temperature values of 615 psia and 400°F respectively. The pressure spike which occurred and lifted relief valve 2NV14 was not seen in the transient data and therefore lasted less than 8 seconds which was the time interval of the pressure transient data. The relief valve lifted only once and relieved the pressure pulse.

The walkdown was performed per procedure MP/0/A/7650/95 change 0 entitled Post Transient Piping and Hanger Inspection. Review of the licensee's work order showed that there was no evidence of

letdown line damage. This was confirmed by the inspector independent letdown line walkdown. The licensee's PIP concluded that there was no evidence that shows that an actual transient occurred on the letdown pipe. The licensee has assigned corrective action to Mechanical Systems Group to pursue the feasibility of providing blackout power to NV849.

c. Conclusion

The inspector concluded that the letdown line was not damaged and was acceptable for plant restart. The resolution of this startup issue was satisfactory.

7.7 Power Operated Relief Valve 2NC-34 Cycling

a. Scope

During the Unit 2 LOOP event, 2NC-34 Power Operated Relief Valve (PORV) operated 74 times to control reactor coolant pressure on anticipatory pressure rate signal. The plant transient data showed that 2NC-34 opened approximately 43 times on steam and 31 times on water. The valve operated as expected on all strokes. Due to the frequent valve cycles and the valve damage to the Salem Copes Vulcan PORV reported in NRC IN 94-55, the licensee performed an operability evaluation for PORV 2NC-34. The inspectors reviewed FSAR Sections 5.2.2 and 5.4.13 , NRC IN 94-55, TS 3.4.4, DBD CNS-1553.NC-00-0001, revision 2, PIP Report 0-G94-0330, PIP Report 0-C96-306, PORV stroke time testing data, drawings CNM-1205.10-0002.001, CNM 1205.10-0280.001, and the licensee's PORV assessment. The inspector also discussed the valve maintenance history and experience with the McGuire PORVs which experienced cycling during a LOOP at McGuire Unit 2 in 1993. The licensee cycled 2NC-34 after the event and measured the valve stroke time. The inspector reviewed the licensee activities and documents related to 2NC-34 to determine if the valve incurred damage due to repeated cycling and if the valve would continue to perform its safety function.

b. Findings

Based on review of the licensee's evaluation, the stroke time data after the Unit 2 LOOP event and visual external inspection of the valve performed by the inspector, PORV 2NC-34 was not damaged due to cycling. IN 94-55 documented cracking on the disc-stem of the Salem PORV. The Catawba PORV was supplied by Control Components Inc. while the Salem PORV was a Copes Vulcan valve. The Catawba valve utilized a one piece stem-disc construction with a drag-stack cage which reduces the pressure drop across the stem-disc. The Salem PORV was a two piece pinned stem-disc with all pressure drop across the disc and seat. The Catawba PORV operator was a

piston type with air to open and close and utilized a spring for fail closure. The Catawba PORV design was not susceptible to the problems noted with the Copes Vulcan PORV in IN 94-55.

There were no manufacturer limits on maintenance frequency based on time or cycles for the CCI PORVs. Maintenance frequency was based on experience. PORV 2NC-34 was refurbished with new disc stack, disc, and seat ring internals in January, 1992. All three Unit 2 PORVs were repacked during the 1995 refueling outage. The CCI design PORV has a documented extensive successful full pressure and flow test history. Duke Power Company personnel at McGuire station were contacted and reported no problems with the Unit 2 PORVs which experienced cycling during a 1993 LOOP event.

During the event PORV 2NC-34 operated as expected with no noted leakage. Subsequent to the cycling during the event, PORV 2NC-34 was cycled and the stroke time met the TS requirements. The inspector examined 2NC-34 and noted no external damage or evidence of air or packing leakage. The licensee has issued work request 96006334 to inspect the valve at the next refueling outage (2EOC8).

c. Conclusion

The inspector concluded that the licensee's evaluation of PORV 2NC-34 cycling was satisfactory and that the valve was not damaged. The resolution of this startup issue was satisfactory.

7.8 AFW Sump Pump Check Valve Leakage

a. Scope

During the Unit 2 LOOP event the TDAFW pump and TDAFW sump pump "2A" were operating. A portion of the TDAFW pump discharge flow was directed through the TDAFW pump lube oil cooler as cooling water and then to the steam turbine driven AFW pump 2 sump. The TDAFW pump pit sump was pumped to the turbine building sump. Backleakage through check valves 2WL894, 2WL836, and 2WL834 allowed the TDAFW sump pump discharge to fill Floor Drain Sump C which overflowed onto the AFW Pump Room floor to a level of several inches. This area was separated from the AFW pump pits by a concrete curb which was approximately 15 inches high. If leakage had continued to the point where water overflowed this curb it could eventually threaten operability of the TDAFW pump. The inspectors reviewed FSAR Sections 10.4.9, 11.2.2.7.3 and 11.2.2.2.5.7, Liquid Radwaste System DBD CNS-1565.WL-00-0001 revision 4, DBD CNS-1592.CA-00-0001 revision 7, Duke Power Company Catawba Nuclear Station IPE Submittal Report dated September 1992, June 29,1993, modification cancellation memorandum, Alarm Response Procedures for Panel 2AD-5, drawing CN-2565-2.2, revision 21, PIP Report 2-C96-0223, PIP Report 2-C96-0271, and work orders 9601208301, 9601039501, 9601138701. The inspectors reviewed

licensee activities related to the AFW Pump Room check valve leakage to determine if the problem was identified and corrective action adequate.

b. Findings

The operators immediate action was to close manual valves 2WL835 and 2WL836 to stop the leakage. Temporary portable sump pumps were used to remove the water from the AFW Pump Room. No water overflowed the AFW Pump Room curb into the AFW pump pits. PIP 2-C96-0271 was initiated to document the condition and work orders were generated to repair the leaking check valves. The licensee determined that it would take greater than 24 hours for the backleakage flow to overflow the AFW Pump Room curb into the AFW Pump pits. This would provide ample time for corrective action prior to the TDAFW Pump becoming threatened by flooding.

Check valve 2WL894 was included in the ASME Section XI IWV valve testing program however it was classified as a category C passive valve. This valve was normally closed and was required to remain closed to accomplish its safety function. This valve did not require an IWV test. Check valves 2WL836 and 2WL834 were not included in the ASME Section XI IWV program. None of the three check valves were periodically tested for backleakage.

The licensee repaired all three leaking check valves. The check valves were determined to have leaked due to debris/FME problems. PIP 2-C96-0223 documented check valve leakage of 2WL832 which was the CAPT #2 Sump Pump 2B discharge check valve. PIP 2-C96-0271 documented the maintenance history of these check valves which showed a significant amount of corrective maintenance for backleakage on 1,2-WL-834 and 1,2-WL-836 due to debris found in the valves. This appears to be a design deficiency which does not adequately protect the valves from FME/debris and a potential problem with FME control in the AFW Pump Room and AFW Pump Pits. There was no periodic backleakage testing performed on any of these three check valves.

The inspector noted that the Catawba PRA refers to an eductor which was added to Unit 1 by modification CN-11122 in April 10, 1990, to draw water from the TDAFW pump pit sump. The PRA indicated that without any flow from the TDAFW sump pumps the TDAFW pump pit would flood in approximately 3 hours. The PRA did not take credit for the eductor. The Catawba IPE Submittal Report Section 6.3 indicates that the eductor modification could not remove the required flow and the modification was not made on Unit 2. The inspector verified that TDAFW pit sump pumps were powered from emergency AC power and one pump received backup power from the SSF. The eductor modifications were CN-11122 for Unit 1 and CN-205 for Unit 2. Unit 1 modification was installed April 10, 1990, but failed the acceptance test. Unit 2

modification was never installed. Modification cancellation letter was written June 29, 1993, and the modification was cancelled on September 22, 1993.

The inspector reviewed the system and determined that the leakage could be isolated by manual valves and adequate time was available to take corrective action prior to the TDAFW pump becoming flooded. Annunciator H/1, H/2, and H/3 on panel 2AD-5 provided AFW pump sump level Hi Hi alarms for the AFW Pump 2A, AFW Pump 2B, and the CAPT pit sumps respectively. Alarm response procedures required immediate actions to dispatch an operator to investigate the alarm. The inspector noted that there was no annunciator for the AFW Pump Room Floor Drain Sump C level. This level was an OAC computer point which was not considered to be a vital computer point and did not have an alarm response procedure.

c. Conclusion

The inspector reviewed the licensee's PIPs and determined that the problem was adequately identified. The work orders were reviewed and the inspector verified that the PMT adequately verified that the check valves were repaired and were functionally tested. The resolution of this startup issue was adequate for restart.

7.9 Service Water Pump Low Flow Operation

a. Scope

During the Unit 2 LOOP event, the service water (RN) pumps started on the SI signal as designed. Two of the pumps operated at reduced flow conditions. The RN pumps are rated for 8600 gpm continuous and 4000 gpm for 2 hours or less in 10 hours. The licensee performed an operability evaluation and tested the RN pumps which had operated under low flow conditions. The inspector reviewed FSAR Section 9.2.1, DBD CNS-1574.RN-00-0001 revision 7, PIP 0-C96-0275, and the test result data from the ASME Section XI IWP pump testing.

b. Findings

The pumps were not damaged by operation on reduced flow. RN Pump 2A operated for 7 hours and 15 minutes below 8600 gpm and RN pump 1B operated for 2 hours and 15 minutes below 8600 gpm. During the period of reduced flow operation for these two pumps the flow was estimated to be approximately 8000 gpm. The pump vendor and the pump maintenance contractor evaluated the low flow operation and concluded that it would not have damaged the pump. The test data showed that RN pump 2A and 1B still operated in the acceptable range for flow, differential pressure and vibration. The test data was compared to previous test results and the data showed

very little change from past performance. The performance change in flow and differential pressure for RN pump 1B was 0.2% and 0.5% respectively and 0.3% and 0.8% for RN pump 2A.

c. Conclusion

The inspector concluded that RN pump operation at reduced flow conditions did not affect the pump performance and the pumps were acceptable for restart. The licensee's evaluation and the resolution of this startup issue was satisfactory.

7.10 Containment Pressurization

a. Scope

On February 7, 1996, at 10:33 a.m., the licensee conducted a containment purge using the Containment Air Release and Addition System. The purge was to reduce containment pressure caused by instrument air system leakage.

The inspectors reviewed FSAR Section 3.8.2.3, 6.2.1 and 9.3.1.2.1, TS 3.6.1.9, PIP 1-C95-0643, containment venting trending records, and work orders for instrument air leakage repairs during the U2EOC-7 outage. The licensee activities and documentation for this issue was reviewed to determine if the problem was identified and corrective action adequate.

b. Findings

The inspector determined that the containment pressurization rate had been increasing on Unit 2 prior to the recent Unit 2 refueling outage. The frequency of containment venting also had been increasing. TS 3.6.1.9 allows the venting of containment via the Containment Air Release and Addition System for up to 3000 hours per year and requires that the cumulative releases be determined every 7 days. The licensee monitored the containment venting via procedure PT/1/A/4450/16, VQ System Cumulative Purge Time. Trending identified the increased venting frequency and PIP 1-C95-0643, VQ Releases Approaching TS Limit Because of Air Leakage in Reactor Building, was initiated. The TS containment pressure limits were -0.1 to 0.3 psig and containment design pressure was 15 psig. The containment venting data showed that Unit 2 was venting once per 12 hours and that the cumulative release time was determined and trended. The licensee met all TS requirements. A survey performed by the licensee of similar plants showed that of the 10 plants surveyed, all 10 vented containment approximately every 24 - 48 hours. During the U2EOC7 outage the licensee located and repaired air leakage inside Unit 2 containment. Leakage was determined to be from regulators and fittings on the instrument air system. These efforts reduced the leakage by approximately 40%. The same effort is planned for the upcoming Unit 1 outage. The inspectors reviewed 15 work orders completed

on Unit 2 during the outage and noted that 14 were repair or replacement of leaking instrument air regulators. Containment venting trend data (from 11-12/1995) showed that the Unit 1 cumulative release was 2647 hours and Unit 2 was 2538 hours. Before the U2EOC7 outage the Unit 2 venting rate was 63 hours per week and after the outage the unit 2 venting rate was 30 hours per week. Unit 1 was 55 hours per week. The containment isolation system isolated the instrument air system on a containment phase A signal.

c. Conclusion

The inspector determined that the licensee's evaluation of this issue was satisfactory.

8.0 SIGNIFICANT EVENT INVESTIGATION TEAM (SEIT) (40500)

a. Scope

Using Inspection Procedure 40500, Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems, as guidance the inspector reviewed the SEIT implementing procedure, Nuclear System Directive 216; the SEIT Charter; the sequence of events; root cause evaluation; and the SEIT management debrief notes. Additionally, the inspector conducted discussion with selected SEIT members, attended several SEIT working group debrief meetings and attended the SEIT management debrief conducted on February 12, 1996.

b. Findings

The inspector found that the SEIT was promptly activated on February 6, 1996, by the Catawba Site Vice President. Directive 216, recommended that the SEIT be activated for a loss of offsite power event. The team consisted of a team leader and nine members. The majority of the team members (9 of 10) were independent (non-Catawba employees), and appeared to be well qualified.

The inspector determined that the SEIT Charter was detailed and comprehensive. The Charter was very similar to Charters developed for NRC Augmented Inspection Teams. Examples of the items pursued were: develop and validate a sequence of events; evaluate the significance of the event with regard to radiological consequences; identify procedural usage/adequacy issues; identify human factor and training deficiencies; evaluate operator actions, determine equipment malfunctions and Root Cause; and evaluate management actions prior to and during and following the event.

The inspector observed several SEIT working group debrief meetings. These meeting were detailed, challenging, and showed a questioning attitude by the members. Each member participated in

the discussions and offered insights and suggestions for further follow-up and evaluation. Additionally, the inspector observed portions of the operator interviews. The interviews were informative and provided a better understanding of the event. The inspector noted that a few of the questions asked were leading and did not allow for a full discussion of the issues.

As noted in section 4.0 of this report, the inspector considered the SEIT root cause evaluation satisfactory.

The inspector observed the SEIT management debrief. The debrief was detailed and provided the plant management with a better understanding of the event. The SEIT addressed the various areas of its Charter. Examples of the items addressed were: sequence of events; root cause analysis of electrical system failure; strengths identified (i.e., operators staged to man SSF if needed); issues/concerns identified (i.e., steam line depressurization rate was faster than expected); and review of station restart list.

c. Conclusion

The inspector concluded that the SEIT was effective in evaluating the loss of off-site power event.

8.1 Review of UFSAR Commitments

While performing the inspections which are discussed in this report the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

9.0 EXIT INTERVIEW

The inspection scope and findings were summarized on February 13, 1996, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
96-03-01	NCV	Failure to report not performing a EDG surveillance in accordance with 10 CFR 50.54(x), paragraph 2.4.
96-03-02	VIO	Failure to follow procedure for event recorder alarms. paragraph 4.0.

10.0 ACRONYMS AND ABBREVIATIONS

AC	-	Alternating Current
AFW	-	Auxiliary Feedwater
CFR	-	Code of Federal Regulation
DRPI	-	Digital Rod Position Indication
EDG	-	Emergency Diesel Generator
EDG/BC	-	Emergency Diesel Generator Battery Charger
ESS	-	Electric Systems Support
ETA	-	Essential Transformer 'A'
ETB	-	Essential Transformer 'B'
FIP	-	Failure Investigation Process
FSAR	-	Final Safety Analysis Report
GDC	-	General Design Criteria
gpm	-	gallons per minute
IPB	-	Isolated Phase Bus
kV	-	Kilovolt
LOOP	-	Loss of Offsite Power
MD	-	Motor Driven
MSIV	-	Main Steam Isolator Valves
PM	-	Preventive Maintenance
PORV	-	Power Operated Relief Valves
PRT	-	Pressurizer Relief Tank
RE	-	Reactor Engineer
RNO	-	Response Not Obtained
RTD	-	Resistor Temperature Detector
RWMSTP	-	Reactor Water Make-up Storage Tank Pump
SATA	-	Station Auxiliary Transform 'A'
SATB	-	Station Auxiliary Transform 'B'
SER	-	Safety Evaluation Report
SEIT	-	Significant Event Investigation Team
S/G	-	Steam Generator
SI	-	Safety Injection
T-Cold	-	Reactor Coolant Temperature Cold Loop
TD	-	Turbine Driven
TDAFW	-	Turbine Driven Auxiliary Feedwater
T-Hot	-	Reactor Coolant Temperature Hot Loop
TS	-	Technical Specifications
VCT	-	Volume Control Tank
W/O	-	Work Order

Attachment A

SEQUENCE OF EVENTS

CATAWBA UNIT 2 REACTOR TRIP - 2/6/96

TIME	EVENT DESCRIPTION
02/05/96	Intermittent grounds occur on Z phase of B Zone 22 kV system. (event precursor)
02/06/96	
08:25	NLO reports that the DGBC AC input breaker tripped open.
08:31	D/G 2B declared inoperable.
08:51	PT/2/A/4350/02C, Available Power Source Operability Check performed due to D/G B inoperability. TD AFW pump is operable.
12:30:08.040	Generator neutral overcurrent alarm (indicating ground 22 kV system Zone A).
12:30:08.042	22 kV BUS B undervoltage alarm (Bus A relay was failed and did not alarm).
12:30:08.052	22 kV bus A and B overvoltage relay actuation.
12:30:08.066	Generator neutral overvoltage relay actuation (single ground fault with ground current limited by generator neutral transformer).
12:30:08.076	Second ground fault 22 kV Zone B phase Z, 22kV bus B overvoltage relay actuation.
12:30:08.080	Phase to Phase fault from Zone A X phase to Zone B Z phase with no current limiting. (Fault current estimate 254,000 amps RMS)
12:30:08.088	Zone A and B transformer differential relays detect phase to phase fault.
12:30:08.098	Bus B differential relays activate a Zone B lockout. (Signals to open switchyard, 6.9 kV bus, and generator breakers)
12:30:08.108	Bus A differential relays activate a Zone A lockout. (Signals to open switchyard, 6.9 kV bus, and generator breakers)
12:30:08.218	Generator breakers open to clear fault
12:30:49.234	Switchyard Breakers Open

TIME	EVENT DESCRIPTION
12:30:49.260	ETA Undervoltage on 2 of 3 phases
12:30:49.264	ETB Undervoltage on 2 of 3 phases
12:30:49.283	6.9kV incoming feeder breakers opened
12:30:49.284	Blackout Logic Initiated Train B
12:30:49.298	Blackout Logic Initiated Train A
12:30:49.482	Automatic Reactor Trip due to Underfrequency on 2/4 Reactor Coolant pump buses.
12:30:49.552	Reactor Trip Switchgear RTA Breaker Tripped
12:30:49.562	Reactor Trip Switchgear RTB Breaker Tripped
~12:30:49.5	Operators Enter E-0, Reactor Trip or Safety Injection DRPI indication blank.
~12:30:49.5	Entry into T.S. 3.0.3 due to offsite and on-site power sources. Unable to meet T.S. 3.8.1.1, A.C. Sources
12:30:49.570	Turbine trip on Reactor Trip
12:30:49.824	CF Pump A Trip (CF Turb/Pump A/B Lo Oil Press Trip)
12:30:49.950	CF Pump B Trip (CF Turb/Pump A/B Lo Oil Press Trip)
12:30:57.466	Blackout Logic Actuated B, (CA pump autostart signal) (2B EDG in the maintenance mode)
12:30:57.594	Blackout Logic Actuated A, 2A Diesel Generator Start sequence. (CA pump autostart signal)
12:30:58.716	2A EDG breaker closes on to 2 ETA
~12:31:05	S/G pressure peak at ~ 1134 psig. S/G A atmospheric relief valve (SV 19) opens. [Note: this is not an accurate time, the alarm typer printed this info out at 12:31:10, the time was extracted from the Steam line press for evaluation graph).
~12:33:25	Main Feedwater Isolation (Rx trip with low Tave (564° F)
Unknown	Operators Entered ES-0.1, Reactor Trip Response
~12:35:47	Manual Main Steam Isolation by Crew due to decreasing S/G pressure. Isolation completed between ~825 and 800 psig.
12:38:17.500	Safety Injection signal, S/G A Ch 4 Lo Stm Press SI, (775 psig)
12:38:28.384	Safety Injection signal, S/G A Ch 2 Lo Stm Press SI, (775 psig)

TIME	EVENT DESCRIPTION
12:38:28.386	Steam Line Lo Press loop A SI, Reactor Trip signal. [logic 2/3 Detectors, 1/4 loops]
12:38:28.436	D/G B LOCA logic sequencer actuated
12:38:28.448	D/G A LOCA logic sequencer actuated
~12:38	Operators Re-enter E-0, Reactor Trip or Safety Injection
12:38:48.504	Steam Line Lo Press loop C SI, Reactor Trip signal. [logic 2/3 Detectors, 1/4 loops]
~12:43	NOUE declared
~12:47	PZR Pressure reached PZR PORV setpoint (~2270 psig). NC 34 began to open and close periodically to decrease pressure. (The licensee calculated the PORV opened [full stroke] 74 times. The team calculated the NC 34 PORV came off its closed seat approximately 110 times.
~12:56	Operators Transition to E-1, Loss of Reactor or Secondary Coolant.
13:00:49	Train A and B Phase A reset
13:00:49.590	Sequencer A Reset Actuated
~13:02	Operators Transition to ES-1.1, SI Termination
~13:07	S/G "D" loop Th starts reading lower than loop Tc indication.
13:07:51	Safety Injection Terminated, NV-009, NI BIT Disch Isolation, Charging Pump 2A in operation supplying NC pump seal injection.
~13:10	Pressurizer water solid.
~13:11	Secured NI pump 2A and ND pump 2A.
~13:14	Operations Start actions to re-establish letdown.
13:18	Operations throttles (NV) charging flow.
~13:20	PRT rupture disk blown. Containment pressure increase. (Time not validated)
~13:25	Operatcrs use S/G PORVs to initiate Natural Circulation

TIME	EVENT DESCRIPTION
13:30	OSC operational
13:39	TSC operational
13:29	Operations Crew determine that Offsite Power is NOT an option. Main transformer is not available. Decision made to cross connect power from Unit 1.
13:32	Natural Circulation Established
~13:59	RO/BOP coordinate through CRSRO the lineup of Letdown. Letdown restored. Possible water hammer on the letdown line occurred during manual local restoration of letdown.
~14:02	Containment Pressure at 0.9 psig and increasing.
14:16	Started Load Shedding of 2TB, with the Use of AP-07, Case II Loss of Normal Power, Loss of all power to an essential train.
14:18	Operator directed to start feeding the "D" Steam Generator at > 50 gpm but < 100 gpm with the TD CA pump.
14:25	RO starts feeding the "D" S/G.
~15:23	2 "B" D/G placed in service
15:23:50	ETA and ETB Powered from the A & B DGs
15:30	Operators use AP-07, Case II Step 10d to restore letdown, local manual control of valves with control room.
15:38	Ops is aligning SATB to Unit 1 except for one Breaker. (Not validated, TSC logs)
15:51	FIP (Failure Investigation Process) Chartered (TSC Logs)
16:41	Leak in Penetration Room Reported to the Control Room.
16:45	Report to control room of leak in penetration room from CA turbine.
16:51	Letdown is placed in automatic operation.
~17:00	Commenced Boration through NV-236B (emergency borate valve) to increase NCS (RCS) boron concentration for adequate shutdown margin.
17:15	SS makes preparations to rack in the B MDCA (auxiliary feed water pump) pump breaker.
17:23	Operators enter FR-I-1, Respond to High Pressurizer Level.
17:51	Completed adding 3000 gallons boron through NV-236B.

TIME	EVENT DESCRIPTION
17:59	TD AFW pump is secured, 2 B MD AFW pump is running. (TSC Logs)
18:00	Restored Offsite power to 2 ETB via Unit 1 through SATB.
18:10	Secured the 2B DG.
20:00	Aligned Power to 2 ETA from Unit 1 through SATA.
20:55	Both Unit 2 D/Gs shutdown and placed in standby.
21:17	Exited T.S. 3.0.3 for A.C. power sources, 2B D/G remains in a 72 hour LCO action statement. (TSC logs)
21:18	Entered ES-0.2, Natural Circulation Cooldown.
21:25	Commenced RCS cooldown to 350°F.
22:21	Cooling Down at 50°F/hr.
22:54	Decision was made to NOT perform the required DG surveillance item of running the 2A DG fully loaded. This is due to the electrical alignment of ETA to Unit 1.
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01:37	Cooldown at 35°F/hr.
04:45	Unit 2 entered Mode 4.
05:37	Removed 2A NI pump from standby readiness.
06:00	Operations questions operability of 2NV-135 (cross connect between charging and the residual heat removal system). Control board only had indication of valve demand. (This valve is necessary to pressurize the RHR system to go into RHR Cooling (ND).
06:29	PZR PORV LTOP ACOT's completed.
07:35	VQ release authorized. (VQ, containment purge)
09:05	ND (RHR) was placed in service on Train A. Train B was pressurized and ready for operation.
09:10	Initiated Cooldown to 140°F.
09:39	Placed PZR PORVs NC-34A and NC-32B in low-pressure mode.

TIME	EVENT DESCRIPTION
10:33	Containment Purge started.
~10:41:27	Operator Aid Computer receives a yellow path in Heat sink. Operators enter FR-H.3 due to high level in "B" S/G. The SRO directs the BOP to secure both MD AFW pumps.
~11:00	T-Hot reads > T-Cold
11:10	FR-H.3 exited.
11:35	Unit Status: Unit 1 100%, Unit 2 Mode 4, 283°F, 351 psig containment pressure 0.82 psig.
11:39	Cooldown rate at ~15°F/hr.
13:55	Unit Status: Unit 1 100%, Unit 2 Mode 4, 261 °F, 350 psig, containment pressure 0.73 psig.
17:02	Unit 2 entered Mode 5.
17:42	Safety Review Group reports when power is restored to Unit 2 6900 bus, EAL may be exited.
17:54	VQ release secured. (containment purge)
18:20	ND (RHR) pump 2A is placed in service.
22:35	Natural Circulation procedure exited.
23:14	Ice condenser teams will be dispatched for blocking the ice condenser lower inlet doors.
23:30	Unit Status: Unit 1 100%, Unit 2 both trains of ND (RHR) are in service at 160°F, and 75 psig with a bubble in the Pressurizer
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01:19	2B Main Power Restored to 6.9 kV buses. 2TA, 2TB and 2TD are being energized from Unit 2 feeds. 2TC not re-powered from Unit 2 feeds due to backfeed TSM for NF (Ice Condenser freezer unit) supplies.
01:43	2RDA, RDB power restored, DRPI indication restored.
06:25	Cooldown completed.

TIME	EVENT DESCRIPTION
09:43	Energized 2TC from 2T2B
16:00	Secured NV PZR spray and established ND aux PZR spray per procedure for Unit Cooldown.
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14:28	PRT rupture disk replaced.
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03:27	2A Main power returned to service.