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

Report Nos.: 50-413/91-03 and 50-414/91-03

Licensee: Duke Power Company
P.O. Box 1007
Charlotte, N.C. 28201-1007

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: January 6, 1991 - February 2, 1991

Inspector: for W. T. Orders, Senior Resident Inspector — 2/21/91 Date Signed

for P. C. Hopkins, Resident Inspector — 2/21/91 Date Signed

for J. Zeiler, Resident Inspector — 2/21/91 Date Signed

Approved by: for George A. Belisle, Chief, Reactor Projects Section 3A, Division of Reactor Projects — 2/21/91 Date Signed

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of review of plant operations; ESF system walkdown; followup of events; surveillance observations; maintenance observations; and, licensee event reports.

Results: Three violations were identified:

The first violation involved three examples of failure to follow procedures or inadequate procedures, resulting in an inadvertent feedwater isolation (Paragraph 4.0), an inadvertent Auxiliary Feedwater auto-start (Paragraph 5.0), and a missed fire watch (Paragraph 10.0).

The second violation involved the failure to ensure that the personnel access hatch between upper and lower compartments of Unit 1 containment was operable while operating in Modes 3 and 4 (Paragraph 6.0).

The third violation involved an operational mode change (from Mode 2 to Mode 1) while in the Technical Specification Action Statement for an inoperable train of the Residual Heat Removal System (Paragraph 7.0).

One Non-Cited Violation (NCV) was identified involving an individual entering a high radiation area without an alarming, radiation monitoring device (Paragraph 9.0).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

B. Caldwell, Station Services Superintendent
*R. Casler, Operations Superintendent
T. Crawford, Integrated Scheduling Superintendent
R. Ferguson, Shift Operations Manager
J. Forbes, Technical Services Superintendent
R. Glover, Performance Manager
*J. Hampton, Station Manager
T. Harrall, Design Engineering
L. Hartzell, Compliance Manager
R. Jones, Maintenance Engineering Services Manager
*V. King, Compliance
F. Mack, Project Services Manager
*W. McCollum, Maintenance Superintendent

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

NRC Resident Inspectors

*W. Orders
*P. Hopkins
*J. Zeiler

*Attended Exit Interview

2. Plant Status

a. Unit 1 Summary

Unit 1 began the report period operating in Mode 4, Hot Standby, after shutting down in order to trouble-shoot an intermittent electrical ground indication on the main generator. The cause of the ground was determined to be the buildup of copper deposits in the generator excitation system's rectifier cooling tubes. Repairs to the generator were completed on January 7. Details of the generator ground problem are discussed in Paragraph 12.c. During this forced outage, a visual inspection of the ice condenser basket U-bolts was performed due to a U-bolt problem previously identified at Duke's McGuire Nuclear Station. Details pertaining to the Ice Condenser U-bolt problem are delineated in Paragraph 12.d. Upon completion of the ice condenser work, the Unit returned to Mode 1, 100 percent

power, on January 13. On January 30, a turbine runback to 65 percent power occurred due to an erroneous indicated 1A main feedwater pump trip signal. The pump had not actually tripped, but the logic indicated a tripped condition due to the failure of two oil pressure switches on the pump. While repairing these switches, reactor power had to be reduced to below 50 percent due to exceeding the Quadrant Power Tilt Ratio (QPTR) during the previous 24 hour period. After clearing the condition, the Unit was returned to full power operation on February 1 and completed the report period at that plateau.

b. Unit 2 Summary

Unit 2 began the report period operating in Mode 3 after shutting down on January 5 for similar ice condenser U-bolt inspections as Unit 1. The results and details of the U-bolt inspections are discussed in Paragraph 12.d. After completing this activity, the unit returned to Mode 1, 99 percent power on January 10, and remained at virtually full power the remainder of the report period.

3. Plant Operations Review and ESF System Walkdown (71707 and 71710)

The inspectors reviewed plant operations throughout the report period to verify conformance with regulatory requirements, Technical Specifications, and administrative controls. Control Room logs, the Technical Specification Action Item Logs, and the Removal and Restoration Log were routinely reviewed. Shift turnovers were observed to verify that they were conducted in accordance with approved procedures. The complement of licensed personnel on each shift inspected, met or exceeded the requirements of Technical Specifications. Further, daily plant status meetings were routinely attended.

Plant tours were performed on a routine basis. The areas toured included but were not limited to the following:

Turbine Buildings
Auxiliary Building
Units 1 and 2 Diesel Generator Rooms
Units 1 and 2 Vital Switchgear Rooms
Units 1 and 2 Vital Battery Rooms
Standby Shutdown Facility

During the plant tours, the inspectors verified by observation and interviews that measures taken to assure physical protection of the facility met current requirements. Areas inspected included the security organization, the establishment and maintenance of gates, doors, and isolation zones in the proper conditions, and that access control and badging were proper and procedures followed.

In addition, the areas toured were observed for fire prevention and protection activities and radiological control practices. The inspectors also reviewed Problem Investigation Reports (PIRs) to determine if the licensee was appropriately documenting problems and implementing corrective actions.

During this report period, the inspectors conducted a detailed walkdown of accessible portions of both trains of the Unit 2 Safety Injection (NI) System. Portions of the as-built configuration were reviewed against the current plant NI system drawings. Selected NI system equipment and components were examined to ensure that there were no conditions which might degrade the system's performance. Selected piping supports and restraints were observed for deficiencies. Using the licensee's NI System lineup procedure, OP/1/A/6200/04, the inspectors verified that main system flowpath valves were in their proper positions. This activity was accomplished by using the control room board indication as well as local observation. Valves were verified to be installed correctly, and did not exhibit signs of packing leakage, bent stems, or improper labeling. Selected instrumentation was examined to ensure proper installation, functioning, and that local process parameters were consistent with expected values and control room indication. In addition, general housekeeping conditions were examined to ensure that the required levels of cleanliness were being observed.

No violations or deviations were identified.

4. Inadvertent Feedwater Isolation

Event Summary:

On the morning of January 8, 1991, Unit 2 was in Mode 3, having been shut down to allow the aforementioned ice condenser inspection. At approximately 2:07 a.m. the unit experienced a feedwater isolation and an auxiliary feedwater (CA) auto start signal when the level in the A steam generator was allowed to exceed the high level setpoint. The operator reset the CA auto start signal and initiated the process of recovery returning the unit to pre-event conditions by 3:00 a.m.

Background:

The CA System assures sufficient feedwater to supply the Steam Generators for decay heat removal in the event of loss of normal feedwater. On the receipt of a "loss of both CF pumps" signal, the CA System is designed to automatically start both motor driven CA pumps, open the associated flow control valves to supply flow to the S/Gs, and isolate the Steam Generator Blowdown System (BB) and the Nuclear Sampling (NM) System valves associated with the four Steam Generators. The CA system can also be used to supply feedwater to the S/Gs during normal shutdown conditions when CF has been removed from service. Such was the case on January 8. The CA System does not have automatic Steam Generator level control.

As described above, an interlock is provided to isolate feedwater to a S/G if an acceptable level is exceeded. This interlock is to prevent overfill. The interlock (P-14 signal) provides a feedwater isolation signal which trips both CF pumps, closes associated CF valves and indirectly starts both motor driven CA pumps due to tripping of both CF pumps.

Event Details:

On the morning of January 8, 1991, Unit 2 was in Mode 3, Hot Standby, having been shut down on January 5 to allow an inspection of the ice condenser U-Bolts. Details of the U-Bolt inspection are delineated elsewhere in this report. The feedwater system had been manually isolated to allow feedwater flow venturi cleaning. Both Motor Driven Auxiliary Feedwater (CA) pumps were running, providing water to the Steam Generators (S/Gs). At approximately 2:00 a.m., a level deviation alarm was received on the 2A S/G. At that time, level in the 2A S/G was approximately 67 percent whereas the levels in S/Gs B, C, and D were between 58 and 61 percent. The Nuclear Control Operator (NCO) responded by reducing CA flow to that generator. According to the operator, the level in the S/G appeared to decrease. At approximately 2:05 a.m., the NCO again adjusted the flow to S/G 2A. At this time, the level in the S/G was approximately 74 percent. Feedwater isolation occurs at 78 percent. At 2:07 a.m., a feedwater isolation occurred due to a high level in S/G 2A. The 2B Main Feedwater (CF) pump, which had been operating in recirculation mode, tripped. (2A CF pump was already tripped.) A CA System auto start signal was initiated due to the loss of both CF pumps. This signal would normally start both motor driven CA pumps but they were already operating. The signal did however, cause the CA flow control valves to go full open. The NCO reset the CA auto start signal and initiated the process of recovery from the event. By 3:00 a.m., the unit had, for the most part, been returned to pre-event conditions.

Conclusion:

During the licensee's investigation into this event, it was found that during the period spanning from 2:00 a.m. until the feedwater isolation occurred, the NCO was apparently distracted from his duties by a maintenance person who entered the control room to vacuum, and an operator who needed assistance with a tagout. Notwithstanding the distractions, the primary responsibility of a licensed operator at the controls is the safe operation of his/her assigned unit.

Operations Management Procedure (OMP) 1-8, Authority and Responsibility of Licensed Reactor Operators and Licensed Senior Reactor Operators, Section 7.0, Authority and Responsibility of Licensed Reactor Operators, Part 7.2.B requires that the Operator at the Controls (OATC) shall:

a) be knowledgeable of the unit status at all times;

b) ensure that the unit is safely operated in compliance with TSs and operating procedures; and,

c) ensure that control room instrumentation is routinely surveyed and information from this survey is evaluated to assure safe unit operation.

Contrary to those requirements, on the morning of January 8, 1991, the Unit 2 OATC was not knowledgeable of the unit status, in that for a period of approximately 10 minutes after receiving a Steam Generator Level Deviation alarm and noting a high steam generator level in generator 2A, he did not adequately monitor the indicated level instrumentation for that generator to effectively evaluate available information in order to assure that the unit was operated safely, in compliance operating procedures.

This resulted in a feedwater isolation and ESF actuation when level in that generator reached the P-14 setpoint of 78 percent.

This is considered to be a violation of Technical Specification 6.8.1 for failing to follow procedure OMP 1-8 and is one of three examples which collectively constitute Violation 413, 414/91-03-01: Failure to Follow Procedures or Inadequate Procedures.

One violation was identified.

5. Inadvertent Actuation of the Auxiliary Feedwater System

Event Summary:

On January 8, 1991, with Unit 2 in Mode 3, an inadvertent CA auto-start occurred on Train A of the CA System while Instrument and Electrical (IAE) personnel were correcting a wiring problem in the ATWS Mitigation System Actuation Circuitry (AMSAC). The CA auto-start signal was generated when a jumper was placed across terminals causing the AMSAC logic to react as if both Main Feedwater Pumps (MFWPs) had been tripped. After the actuation, Operations successfully terminated the event and returned the plant to normal Mode 3 conditions.

Background:

The purpose of the AMSAC circuitry design is to initiate CA and a main turbine trip during conditions indicative of an Anticipated Transient Without Scram (ATWS) event. The ATWS condition that this system guards against is a loss of feedwater capability along with a failure to trip the

turbine. The AMSAC system is independent from the existing reactor trip system, therefore, upon detection of a loss of feedwater capability, a separate, independent turbine trip signal and a separate, independent CA auto-start signal is generated. At Catawba, inputs to the AMSAC circuitry originate from pressure switches which monitor hydraulic control oil pressure to the MFWPs turbine stop valves and limit switches which monitor the position of the MFWPs turbine control valves. A CA auto-start signal is generated upon detection of low control oil pressure to the stop valves or minimum feedwater control valve position.

Event Details:

On December 17, 1990, while investigating an electrical ground problem in both channels of the non-safety 125 VDC power supplies, one of which powers the AMSAC circuitry, IAE discovered a wiring discrepancy in the AMSAC circuitry. When AMSAC was originally installed in May 1989, two wires which were to have been deleted by the modification were not removed. This error connected the circuitry to the wrong location in the as-designed Channel A 125 VDC power supply and cross-connected the circuitry to the Channel B 125 VDC power supply.

On January 4, 1991, Maintenance Engineering Services (MES) personnel initiated Work Request No. 3848MES and developed a work plan to be used by IAE technicians to correct the wiring problems. It was determined that both MFWPs would have to be tripped and control power for both pumps de-energized prior to the removal of the wires. On January 5, 1991, Unit 2 was brought off-line to perform ice basket inspections in the Ice Condenser. On January 7, 1991, MES revised the original work plan due to problems in placing both MFWPs in a tripped condition with the plant in Mode 3. The revised plan allowed the A MFWP to be tripped and the B MFWP to be reset. On January 8, 1991, when IAE personnel placed the first jumper in accordance with the revised work plan instructions, the A Train CA auto-start signal was initiated. It was later determined that the revised work plan had prescribed the incorrect placement of jumpers.

Safety Significance:

The Unit 2 AMSAC circuitry was installed on May 18, 1989, via a station modification (NSM). The wires found in the circuitry should have been removed by personnel installing the modification. The NSM implementation procedure directed personnel installing the modification to rewire the circuitry per "red marked" drawings of the modified circuitry. Since the AMSAC addition was considered a non-safety related NSM, the implementation procedure did not contain steps that specified terminal to terminal changes nor the documentation of wires lifted and reterminated.

Due to similar NSM problems and problems with NSM Post-Modification Testing, the NSM program has changed significantly since the implementation of the AMSAC modification. Non-safety related NSMs now contain steps that specify terminal to terminal changes as well as documentation of leads lifted and reterminated. The licensee has, therefore, taken

corrective action which should preclude future similar wiring installation errors.

The licensee performed an operability evaluation to determine if the AMSAC system would have performed its intended function with the wiring errors. It was determined that although the circuitry was not being powered from its intended power supply location, the system would have performed its intended function.

Conclusion:

Technical Specification 6.8.1 requires in part that written procedures shall be established covering the activities referenced in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. In accordance with Regulatory Guide 1.33, maintenance activities shall be accomplished using procedures or documented instructions which are appropriate to the circumstances. Implicit in this requirement is the stipulation that the procedures be adequate for the tasks being performed.

Since the wiring repairs on the AMSAC circuitry were being performed by written instructions provided by MES, these instructions are considered as part of the maintenance procedure used to perform the repair activity. The inspectors concluded that the instructions, i.e., maintenance procedure used to perform this activity was inadequate and is therefore considered a violation of the above requirements. This violation is one of three examples which collectively constitute Violation 413, 414/91-03-01: Failure to Follow Procedures or Inadequate Procedures.

One violation was identified.

6. Inoperable Access Hatch Between Upper and Lower Compartments of Unit 1 Containment

Event Summary:

On January 10, the inspectors conducted a routine inspection of the Unit 1 containment. The unit was in Mode 3 being returned to power following a forced maintenance outage which began on January 4. During the containment inspection, the inspectors found the emergency personnel hatch in the divider barrier between upper and lower containment compartments closed but not secured. In this configuration, this hatch was not performing its intended function as part of the divider barrier designed to assure diversion of steam through the ice condenser bays in the event of a LOCA.

Event Details:

The licensee's investigation determined that the hatch apparently became inoperable sometime after the start of the maintenance outage on January 4. It is hypothesized that personnel walking on the hatch caused the hatch's latch to become disengaged. It should also be noted that although the latch handwheel was provided with a tamper seal, it was attached such that the hatch could be opened without breaking the seal.

Following this discovery, the licensee inspected the emergency hatch in Unit 2 and verified that it was properly closed and secured. The following additional actions were initiated: the lock latches are to be adjusted to assure that all four latch pins will properly engage; a match line is to be painted on the handwheel and hatch to indicate the fully closed position of the handwheel; procedures will be revised to indicate that the tamper seal will be installed between the hatch handwheel spoke and hatch hinge; and, a "DO NOT STEP" sign will be installed on top of the hatch door. These actions should prevent future occurrences.

Safety Significance:

The licensee design organization has evaluated this event and determined that the unsecured hatch would not result in exceeding the FSAR design compression rate for the upper containment in the event of the Design Basis Accident. The FSAR design calculations for Mode 1 indicate that with this hatch open, the upper containment pressure would peak at 7.82 psig which is considerably less than the design peak pressure of 15 psig. Furthermore, the hatch is only considered to have been opened during Modes 3 and 4 where the available energy in the steam and coolant systems was much less.

Conclusion:

TS Section 3.6.5.5 requires this hatch to be operable and closed when the Unit is in Modes 1 through 4. When a personnel access door/hatch is inoperable or open, except for personnel transit, the action statement for TS 3.6.5.5 requires the door/hatch to be restored to operable status or its closed position within 1-hour or the plant is to be placed in at least hot standby within the next 6 hours and in cold shutdown within the following 30 hours. The emergency personnel hatch is assumed to have been inoperable since the beginning of the maintenance outage on January 4. The failure to maintain this hatch closed and operable during modes 3 and 4 is identified as Violation 413/91-03-02: Inoperable Personnel Access Hatch Between Upper and Lower Containment Compartments.

One violation was identified.

7. Mode Change While In a Technical Specification Action Statement

Event Summary:

At approximately 1:19 a.m. on January 13, 1991, Unit 1 was taken from Mode 2 to Mode 1 with Train A of the Residual Heat Removal (ND) System inoperable, a violation of the requirements of Technical Specification 3.0.4.

Background:

The Emergency Core Cooling System (ECCS) provides emergency cooling to the Reactor core in the event of a break in either the Reactor Coolant (NC) or Main Steam (SM) Systems. Several systems work in conjunction to provide ECCS functions, including the NI, ND, Refueling Water (FW), and Chemical and Volume Control (NV) Systems. ECCS alignment changes over time after initiation, with different phases characterized by the water source and flow path utilized. The immediate, automatic response following actuation is referred to as the injection phase. During the injection phase, borated water is supplied from the FWST to the NC system cold legs. For the injection phase, the NV, NI, and ND pumps provide high, intermediate, and low pressure pumping capability, respectively. When the FWST supply is depleted, the containment sump provides the water supply for what is referred to as the recirculation phase.

The ND system consists of two heat exchangers, two pumps, and associated piping, valves, and instrumentation necessary for operational control. During normal plant operation, the system is aligned to inject borated water from the FWST upon receipt of a Safety Injection signal. Each ND pump has a suction line from the FWST header, containing a check valve (FW-28 on Train A or FW-56 on Train B). FW-28 and FW-56 are designed to prevent backflow to the FWST.

PT/1/A/4200/53A, is performed quarterly to ensure the freedom of movement of 1FW-28. This test can be performed in virtually any mode, but it must be recognized that the respective train of ND becomes inoperable when the suction valve is closed.

Event Details:

On the evening of January 12, 1991, Unit 1 was in Mode 2, Startup, at approximately 3 percent reactor power. Operations began the shift awaiting the repair of the Control Room Ventilation Chill Water (YC) System Train B chiller prior to increasing power for entry into Mode 1.

Early in the shift, a meeting was held to discuss the return to service of the YC Train B chiller and the performance of PT/1/A/4200/53A. It was decided that a Non-Licensed Operator (NLO), assigned the Auxiliary Building rounds, would perform the Periodic Test (PT) after completion of

his rounds. Entry into Mode 1 would occur after the YC Train B chiller was returned to service, which was expected to occur early in the shift. Although this meeting involved the Shift Supervisor (SS), Unit 1 Supervisor (US), and the Control Room Senior Reactor Operator (CRSRO), the consequences of rendering ND train A inoperable when performing PT/1/A/4200/53A was not recognized or discussed. (To perform the test, the suction valve to the A ND pump, FW-27A, must be closed, an act which renders the ND pump inoperable.)

At approximately 12:20 a.m., the NLO notified the US and the Control Room Operators (CROs) that he was proceeding to the ND Pump Room to perform the PT.

At approximately 12:55 a.m., the Train B YC chiller was returned to service, clearing the way for mode change. The SS requested that final pre-mode change preparations be made for entry into Mode 1. Reactor power at this time was approximately 4 percent. After completion of these pre-mode change preparations, the SS authorized entry into Mode 1 and the OATC began the power increase. Soon after he began, the OATC received a telephone call from the NLO, who requested that the OATC close 1FW-27A. In addition, the NLO read a caution statement in the procedure to the OATC. The caution statement warns that with 1FW-27A closed, starting ND Pump 1A will cause the system to operate with no available suction supply. The CROs briefly discussed the implication of closing 1FW-27A but failed to recognize the impact on ND Pump 1A operability and the in-progress mode change. At approximately 1:15 a.m., the OATC closed 1FW-27A. The 1.47 Bypass Panel alarmed indicating trouble on ND Train A. The OATC was expecting the alarm since he had just closed 1FW-27A and immediately acknowledged it. At this time, he had no operability concern because he believed that 1FW-27A received an auto-open signal.

The SS, who was standing behind the main control board, had observed the OATC's actions, and questioned him about the evolution. The SS was unaware that the PT had begun. The OATC told the SS that he had closed 1FW-27. The SS questioned the OATC about operability of the ND Pump 1A. The OATC told the SS that he thought 1FW-27A received an auto-open signal. There was a brief discussion about 1FW-27A having an auto-open signal, but no one was sure. The SS then questioned the OATC about the power level and was told that power was approximately 4.8 percent. The SS then discussed the options of opening 1FW-27A or inserting the control rods to stop the power increase. It was decided not to open 1FW-27A at that time due to the possibility of flooding the ND pump room. (As part of the test, ND suction header vents and drains are opened. If 1FW-27A is opened with the vents and/or drains open, there is a direct flowpath from the FWST to the ND pump room floor.) It was also decided to not insert the control rods due to possibility of not being able to stop the power increase, briefly entering Mode 1 and then returning back into Mode 2.

At approximately 1:19 a.m., the OATC reported that power was greater than 5 percent indicating that the unit had entered Mode 1.

At approximately 1:22 a.m., the OATC reopened 1FW-27A, returning the ND System to its normal alignment for plant operation. The valve had been closed for approximately 7 minutes, 3 minutes of which was in Mode 1.

Subsequently, the SS reviewed the PT and investigated the function of 1FW-27A. It was confirmed that 1FW-27A did not receive an auto-open signal and that a mode change in violation of Technical Specification 3.0.4 had been made.

Safety Significance:

In as much as train B of ND was fully operable during this event, there was minimal associated safety significance.

Conclusions:

Technical Specification 3.5.2 states that for Modes 1, 2 and 3, two independent ECCS subsystems shall be operable with each subsystem including an operable ND pump and an operable flow path capable of taking suction from the FWST on a Safety Injection signal and automatically transferring suction to the containment sump during the recirculation phase of operation.

Action Statement a. of 3.5.2 states that with one ECCS subsystem inoperable, the inoperable subsystem must be restored to operable status within 72 hours or the unit must be placed in at least HOT STANDBY within the next 6 hours and Hot Shutdown within the following 6 hours.

Technical Specification 3.0.4 requires that entry into an operational mode or other specified condition shall not be made when the conditions for the Limiting Condition for Operation are not met and the associated Action Statement requires a shutdown if they are not met within a specified time interval.

Contrary to the above requirements, Unit 1 was taken from Mode 2 to Mode 1 with the 1A ND pump inoperable. This is considered a violation of the requirements of Technical Specification 3.0.4 and is documented as Violation 413/91-03-03: Failure to Comply with the Requirements of Technical Specification 3.0.4.

One violation was identified.

8. Inoperable Starting Air (VG) System for Diesel Generator 2B

On January 14, 1991 at approximately 4:00 a.m., operations personnel removed Diesel Generator (D/G) Starting Air (VG) System compressor 2B2 from service for routine preventive maintenance activities. Each D/G is supplied with two independent VG trains each comprised of a compressor, air receiver, associated valves, etc. At that time, a temporary cross

connection hose was installed between the two VG system air receiver tanks in preparation for cross connecting the two receivers if necessary to facilitate repressurizing the 2B2 receiver from 2B1. The cross connection valves between the receiver tanks were not opened at this time. At 6:00 a.m., D/G 2B trouble alarm was received in the control room and an operator was dispatched to investigate. The operator found the pressure in receiver tank 2B2 had decreased to 150 psig. D/G 2B was declared inoperable at 6:10 a.m. When the operator attempted to equalize the pressure in the two tanks by opening the cross connection valves it was noted that one of the fittings had a missing gasket. Another cross connect hose was obtained from the other unit and was installed at about 6:20 a.m. By this time, the pressure in tank 2B1 was 245 psig and 145 psig in tank 2B2. After the cross connection was completed, the 2B1 compressor repressurized both the B1 and B2 receivers, returning the D/G to operable status. Both air receiver tanks are required to be operable at a pressure above 210 psig in order for the D/G to be operable. At some time between 4:00 a.m. and 6:00 a.m., D/G 2B became inoperable. The inspectors verified that once the operators became aware that the diesel was inoperable, the appropriate action statements of the Technical Specifications were promptly implemented.

During this review the inspectors noted that a previously identified concern, involving the fact that the low air pressure alarm for the air receiver tanks is set at 160 psig which is considerably lower than the minimum required design pressure of 210 psig, had not been corrected.

The inspectors were informed that a modification is currently in design to provide another low air pressure alarm which will be set at 220 psig. This should alert the operators of low tank pressure prior to the tank pressure decreasing below that pressure required to support operability. It should be noted that this is but the latest of a series of problems associated with VG, its attendant valves and air drying hardware, which in the aggregate is cause for concern relative to the reliability of the system, and in turn, for the operability of the D/Gs.

No violations or deviations were identified.

9. Failure To Issue Radiation Monitoring Device For Entry Into High Radiation Area

The inspectors were informed of an event which occurred on January 23, 1991, involving an individual entering two posted high radiation areas without an alarming, radiation monitoring device (dosimeter) or being accompanied by a Radiation Protection (RP) technician. Prior to entering Unit 2 Auxiliary Building Rooms 109 and 425, the individual discussed with RP technicians his intentions of entering the room. A technician issued keys to the individual, but then became engaged in another problem. A second technician was then asked to help the individual. The second technician recalled asking the individual if he had everything he needed and the individual indicated that he had. Based on the individual's response, the technician thought that an alarming dosimeter had already

been issued. Without the proper dosimetry, the individual proceeded to enter Rooms 109 and 425 and, upon exiting Room 425, realized that he did not have an alarming dosimeter. He immediately returned to the RP Office and reported the incident.

It was later determined by the licensee that the highest general area dose rate that the individual had been near was only 20 millirem per hour.

The licensee initiated PIR No. 2-C91-44 on January 24, 1991, to investigate the problems associated with this incident. The RP staff indicated that as part of their corrective actions, they were reviewing various means of insuring that high radiation room keys are not issued without proper radiation monitoring devices.

Technical Specification 6.12.1 requires that any individual permitted to enter a high radiation area be provided with a radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received or be accompanied by an RP technician with such a device.

This issue is identified as a licensee identified violation of the requirements of Technical Specifications 6.12.1. After review of the circumstances relative to this issue, it was determined that this violation will not be cited in that the criteria specified in Section V.G.1 of the NRC Enforcement Policy were satisfied. This is documented as Non-Cited Violation (NCV) 414/91-03-04: Failure to Wear Alarming Dosimeter into a High Radiation Area.

One NCV was identified.

10. Failure to Investigate Fire Protection Panel Alarm

Event Details:

On January 25, 1991, the control room received a D/G 1B CO_2 trouble alarm. By 9:15 p.m., the system had been declared inoperable, a fire watch established, and a high priority work request written to investigate the problem. On the morning of January 26, an IAE work request planner investigating the problem reset the alarm locally from the D/G room and the alarm remained cleared, indicating that the problem no longer existed. He determined that further investigation could not proceed until the alarm came in again. After discussions between the IAE Work planner and and the Shift Supervisor, the Shift Supervisor determined that the system was operable, and the fire watch was discontinued at 9:20 a.m. Appropriate documentation indicating that the fire watch had been removed was left at the Fire Protection Console Operator's (FPCOs) desk. The FPCO is an operations person, normally the non-licensed operator (NLO) responsible for outside rounds. The FPCO is assigned the ultimate responsibility for

assuring that appropriate fire watch activities are performed to ensure compliance with the fire protection/detection requirements. The status of the D/G CO_2 system was apparently not conveyed to the NCOs. Therefore, at approximately 4:00 p.m., when the alarm was again received in the control room, the NCO acknowledging the alarm determined that no further action was necessary. This was based on his assumption that a fire watch was still in progress and that IAE personnel were working on the system. At approximately 6:30 p.m., during shift turnover, the FPCO noticed that the alarm was back in, but failed to investigate whether the CO_2 system was impaired and if a fire watch was necessary. On January 27, at approximately 9:20 a.m., a fire watch was re-established after the Shift Supervisor learned from the FPCO that the alarm was in. Two shift turnovers had occurred between the time the alarm had first come in and when a fire watch was established.

Safety Significance:

After investigation of the D/G CO_2 alarm problem, the licensee determined that the problem had not caused the impairment of the system and it would have functioned properly had an actuation signal been generated.

Evaluation:

After an initial review of the circumstances surrounding this incident, the inspectors determined that communication problems between operations personnel led to this incident. When the system was declared operable and the fire watch discontinued on the morning of January 26, the NCO was not apprised of the status of the system. Subsequently, when the alarm was received later that afternoon, the NCO assumed that the system was still inoperable and that a fire watch was still in progress. Based on this he did not alert the FPCO as required by the annunciator response for the Fire Protection Panel.

Even though the FPCO was not informed, when the D/G CO_2 trouble alarm came in at approximately 4:00 p.m. on January 26, he became aware of the alarm later during routine monitoring of the FPC for shift turnover. Appropriate action was then not performed by he or the oncoming shift FPCO to investigate the problem in order to determine if the system was impaired and if a fire watch was required.

The inspectors reviewed Station Directive 2.12.7, Fire Detection and Protection, which delineates the requirements and responsibilities of plant personnel to ensure that fire detection and protection requirements are met. The FPCO has been assigned the ultimate responsibility to ensure that these requirements are met. Among the FPCO's duties is the monitoring of alarms on the Fire Protection Console (FPC) which is located in the control room and the verifi[illegible] of fire detection and protection system impairments to ensure that [illegible]ate fire watch activities are performed.

The FPCO's failure to take appropriate action upon knowledge of an alarm condition is considered a violation of Station Directive 2.12.7 and is one of three violations which collectively constitute Violation 413, 414/91-03-01: Failure to Follow Procedures or Inadequate Procedures.

One violation was identified.

11. Surveillance Observation (61726)

a. General

During the inspection period, the inspectors verified plant operations were in compliance with various Technical Specification requirements. Typical of these requirements were confirmation of compliance with the Technical Specifications for reactivity control systems, reactor coolant systems, safety injection systems, emergency safeguards systems, emergency power systems, containment, and other important plant support systems. The inspectors verified that: surveillance testing was performed in accordance with approved written procedures; test instrumentation was calibrated; limiting conditions for operation were met; appropriate removal and restoration of the affected equipment was accomplished; test results met acceptance criteria and were reviewed by personnel other than the individual directing the test; and, any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

b. Surveillance Activities Reviewed

The inspectors witnessed or reviewed the following surveillances:

PT/0/A/4250/11	RL Temperature and Discharge Flow Determination
OP/0/A/6450/11	Control Room Area Ventilation/Chilled Water System
PT/1/A/4250/02C	Turbine Control Valve Movement
OP/1/A/6100/03	Controlling Procedure for Power Increase
PT/1/A/4450/10B	D/G CO_2 Weekly Test
PT/1/A/4200/31	SV Valves Inservice Test
OP/1/A/6450/17	Containment Air Release and Additional System
OP/1/A/6450/18	Auxiliary Feedwater Pump Pits CO_2 System
PT/2/A/4150/01D	NC System Leakage Calculation
OP/2/A/6350/02	D/G Operation Procedure
IP/2/A/3162/01	Control Room Area Ventilation System Safety Related Instrumentation

PT/2/A/4150/13E	Calorimetric Reactor Coolant Flow Measurement
PT/2/A/4150/13D	Venturi Fouling Corrections
PT/2/A/4450/16	VQ System Cumulative Purge Time
PT/2/A/4200/20	FW Valve Inservice Test
PT/2/A/4200/13E	CA Valve Inservice Test
PT/2/A/4200/53A	Partial Stroke Test 2FW-28
PT/2/B/4250/04B	Feed Pump Stop Valve Movement Test
PT/2/A/4150/01D	NC System Leakage Calculation
PT/2/A/4200/13C	Nuclear Service Water Valves Inservice Test
PT/2/B/4250/02A	Main Turbine Weekly Trip Test
PT/2/A/4400/03G	Component Cooling Water System Valve Verification
PT/2/A/4450/03A	Annulus Ventilation System Train A Operability Verification
PT/2/A/4600/02A	Mode 1 Periodic Surveillance Items

No violations or deviations were identified.

12. Maintenance Observations (62703)

a. General

Station maintenance activities of selected systems and components were observed/reviewed to ensure that they were conducted in accordance with the applicable requirements. The inspectors verified licensee conformance to the requirements in the following areas of inspection: activities were accomplished using approved procedures, and functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities performed were accomplished by qualified personnel; and materials used were properly certified. Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

b. Maintenance Activities Reviewed

The inspectors witnessed or reviewed the following maintenance activities:

00960	SWR	Addition of Oil to YC Compressor Sump to Proper Level
04338	SWR	Perform Calibration on 2VCLP 5380 (2CR-AHVI Cooling Control)
04339	SWR	Perform Calibration on 2VCLP 5480, (2CRA-AHVI Cooling Control)
004221	SWR	Unit 2 Steam Generator Narrow Range Level Monthly ACOT

c. Unit 1 Main Generator Electrical Ground

On December 17, 1990, with Unit 1 in Mode 1, 100 percent power, an alarm was received in the control room indicating the detection of an electrical ground on the Main Generator. Onsite Transmission Department personnel reset the ground detection relay and the ground cleared. The ground detection relay, collector rings, and generator excitation system (Alterex) were inspected to ensure proper functioning. No problems were found.

On December 20, the ground was again picked up and was also successfully reset by Transmission personnel. Between December 31, 1990 and January 1, 1991 the ground detection relay picked up and was reset approximately thirteen times. On January 2, the relay was inspected and it was discovered that even though the relay was reset there was a ground current that could be detected. Based on confirmation of an actual ground current and recommendations from Transmission and a General Electric (GE) representative, Unit 1 was shutdown on January 4.

Immediately after tripping the Unit off-line, Transmission tested the generator rotor and determined that a ground was not evident. After extensive testing on the Alterex, the ground was determined to be in the Alterex power rectifier banks. GE Technical Information Letter (TIL) 1027-3, dated October 31, 1988 identified that rectifier cooling water tubes, which are part of the Generator Cooling Water System (KG), could have copper deposits built up in them creating a path to ground. The tubes were removed and examined and it was confirmed by meggar testing and chemical analysis that copper deposits had formed in the tubes and were creating an electrical ground leakage path. All Unit 1 tubes were removed, cleaned, meggar tested, and re-installed. Additional testing after the Unit returned to 100 percent power operation on January 15 confirmed that the ground had been found and corrected.

The licensee initiated PIR No. 1-C91-11 on January 2, 1991 to document the generator ground problem and to ensure that further evaluation was conducted in order to determine what needs to be done to prevent recurrence. As part of this effort, the Chemistry Department plans to evaluate the efficiency of the KG demineralizers. As discussed in the GE TIL 1027-3, a direct relationship exists between the severity of copper deposits and the quality of the deionizer resins used in the KG demineralizers. In addition, Transmission plans to increase inspection and maintenance of the rectifier cooling water tubes to prevent future copper buildup problems.

d. Ice Condenser U-Bolt Inspection

During the cycle 7 refueling/maintenance activities at McGuire Unit 2, a number of ice basket hold-down U-bolt assemblies were found cracked or broken. The design at Catawba is similar. Based upon this similarity, Catawba personnel reviewed applicable procedures, materials information and maintenance practices to determine if Catawba had similar problems. The evaluation concluded that the Ice Condenser System (ICS) for both Catawba Units were operable.

This conclusion was based, in the main, on the following:

(1) no broken or missing U-bolts had been found on Catawba Units 1 and 2 following 100 percent visual inspection;

(2) wrench tightening had been performed on 33-50 percent of all U-bolts with no failures observed; and,

(3) required Technical Specification surveillance activities associated with the ice basket had been performed and had not resulted in any broken bolts.

Subsequent to issuance of that operability evaluation, another visual inspection was conducted following an unplanned Unit 1 shutdown on January 1, 1991. At that time, three U-Bolts were found to be broken and one was missing. After finding unexpected problems on Unit 1, the licensee shut down Unit 2 for a similar inspection. No problems were found.

Following the visual inspections and subsequent torque (proof) testing, it was concluded that the ICSs for both Units were operable. This operability determination is predicated upon the following:

(1) no broken or missing U-bolts identified on Unit 2;

(2) three broken and one missing U-bolts visually identified in Unit 1; and,

(3) assessment of Ice Condenser Operability from Westinghouse, dated November 11, 1990.

The current operability evaluation is valid until the next refueling outage for each unit. The licensee is currently evaluating possible options for a permanent solution to the problem.

No violations or deviations were identified.

13. Review of Licensee Event Reports (92700)

The below listed Licensee Event Reports (LERs) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, verification of compliance with Technical Specifications and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied and the relative safety significance of each event. Based on this review the following LERs were closed:

413/89-09	Incomplete Technical Specification Associated With Incore Instrumentation Room Purge System
413/89-20	Abnormal Degradation of Steel Containment Vessels Due To Corrosion By Standing Water In the Annulus Areas.

No violations or deviations were identified.

14. Exit Interview

The inspection scope and findings were summarized on February 7, 1991, 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	Description and Reference
VIO 413, 414/91-03-01	Failure to Follow Procedures or Inadequate Procedures (Paragraphs 4.0, 5.0 and 10.0).
VIO 413/91-03-02	Inoperable Personnel Access Hatch Between Upper and Lower Unit 1 Containment Compartments (Paragraph 6.0).
VIO 413/91-03-03	Failure to Comply with the Requirements of Technical Specification 3.0.4 (Paragraph 7.0).
NCV 414/91-03-04	Failure to Wear Alarming Dosimeter into High Radiation Area (Paragraph 9.0).