U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-413, 50-414
License Nos:	NPF-35, NPF-52
Report Nos.:	50-413/96-20, 50-414/96-20
Licensee:	Duke Power Company
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	422 South Church Street Charlotte, NC 28242
Dates:	December 1, 1996 - January 11, 1997
Inspectors:	R. J. Freudenberger, Senior Resident Inspector P. A. Balmain, Resident Inspector R. L. Franovich, Resident Inspector R. S. Baldwin, Chief Examiner, DRS (Section 01.2)
Approved by:	C. A. Casto, Chief Reactor Projects Branch 1 Division of Reactor Projects

ENCLOSURE

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 & 2
NRC Inspection Report 50-413/96-20, 50-414/96-20

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by a regional reactor safety inspector.

Operations

- Control room operators identified a cold leg accumulator discharge promptly and took appropriate immediate action to terminate it. (Section O1.1)

- The inspector concluded that the control room was run in a professional and organized manner; plant management aggressively analyzed reactor coolant system leakage data on Unit 1 and proactively decided to shutdown Unit 1 to find and repair a leak; and the Reactor Operator and Unit Supervisor Log books were a source of limited information concerning unit status. (Section O1.2)

- The Plant Operations Review Committee meeting review and discussion of approaches to restore a failed Unit 1 solid state protection system relay to an operable status were substantive and focused on safety. The shutdown that was subsequently initiated because of the failed relay was well controlled. (Section O1.3)

- The decision to shutdown Unit 2 as a result of the cumulative effect of the existing operator work arounds demonstrated site management's commitment to operational safety. (Section E1.1)

Maintenance

- The licensee's decision to initiate a plant shutdown before reaching the maximum unidentified leakage limit allowed by Technical Specifications was responsive to resolving the adverse condition promptly. Efforts to ensure that carbon steel equipment was protected from boric acid corrosion were appropriate. Corrective maintenance on the 1D reactor coolant pump number 1 seal leakoff line was completed without any personnel contamination events. (Section M1.1)

- The licensee identified mispositioned nitrogen backup supply valves associated with two steam generator power operated relief valves at the end of the inspection period. This issue is characterized as an unresolved item pending completion of the licensee's investigation. (Section M1.2)

Engineering

- An engineering evaluation that supported maintaining the residual heat removal discharge header pressurized at approximately 600 psig was sensitive to the potential for void formation resulting from system depressurization. Nonetheless, the evaluation did not consider the effects of maintaining the header pressurized on all modes of operation of the system. (Section E1.1)

- The Failure Investigation Process associated with a failed residual heat removal pump performance test was initiated in a timely manner, which facilitated early identification of the cause of the degraded pump performance and timely actions to restore operability. (Section E1.1)

- The licensee identified an auxiliary feedwater system design deficiency involving inadequate train separation of the assured suction source. This issue is characterized as an unresolved item pending completion of the licensee's investigation. (Section E1.2)

- The licensee's actions in identifying and repairing a Unit 2 Component Cooling Water system weld leak were appropriate. The licensee's efforts in developing a repair technique that preserved the cracked portion of the weld were innovative and allowed for detailed metallurgical examination and root cause analysis of the failure. (Section E2.1)

Plant Support

- The licensee displayed appropriate sensitivity to the potential for tampering following the mispositioning of several nitrogen supply valves associated with two Unit 2 the steam generator power operated relief valves. (Section S1.1)

Report Details

Summary of Plant Status

Unit 1 began the period operating at 100% power. On December 5, a power reduction to 2% power commenced to permit a lower containment inspection to identify the source of increasing reactor coolant system (RCS) leakage. The unit was shutdown later that day when the source of leakage was identified as a failed weld on a reactor coolant pump seal leakoff line. Repairs were completed on December 7, with the unit in Mode 4. On December 9, the unit was taken critical. The unit reached 100% power on December 10, and operated at this level until December 30, when a Technical Specification (TS) required shutdown to mode 3 was completed following a solid state protection system relay failure. The unit was taken critical on December 31, reached 100% power on January 1, and operated at this level for the remainder of the inspection period.

Unit 2 began the period operating at 100% power. On December 14, a power reduction and shutdown commenced because of residual heat removal pump operability concerns associated with gas entrainment. The unit reached Mode 5 on December 17. The unit was taken critical on December 21, reached 100% power on December 23, and operated at this level for the remainder of the inspection period.

Review of UFSAR Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 Cold Leg Accumulator Discharge during Unit 2 Shutdown

a. Inspection Scope (71707)

During the shutdown to Mode 5 on December 16, an inadvertent emergenc core cooling system (ECCS) discharge into the RCS occurred. The inspector discussed the event with licensee personnel, reviewed Problem Investigation Process (PIP) report 2-C96-3285, and reviewed station procedures.

b. Observations and Findings

On December 14, the licensee initiated a Unit 2 shutdown to Mode 4 to attempt to improve check valve seating in the safety injection system that was resulting in accumulator leakage into and pressurization of the residual heat removal (RHR) system (see Section E1.1 of this inspection report). While in Mode 4 the licensee discovered a weld leak on

component cooling water piping associated with the reactor coolant pumps (see Section E2.1 of this inspection report). The unit was shutdown to Mode 5 so repairs to the weld leak could be made.

During the shutdown to Mode 5 on December 16, an inadvertent emergency core cooling system (ECCS) discharge into the RCS occurred. When RCS pressure reached the cold leg accumulator (CLA) discharge setpoint of 600 psig, all four CLAs injected into the RCS cold legs. The CLA discharge isolation valves should have been closed to prevent this, but they were open. Control room operators promptly determined that the CLA discharge isolation valves were open and increased RCS pressure to 610 psig to terminate the discharge. Subsequently, the CLA discharge isolation valves were closed and deenergized.

The licensee initiated a root cause investigation to determine why the CLA discharge isolation valves were in the wrong position (open), establishing the injection flowpath. The licensee had originally planned to shutdown to Mode 4, perform pressure boundary check valve testing to reseat valves suspected of leaking, and return to full power operation. The pressure boundary check valve testing required the CLA discharge isolation valves to be closed. The component cooling water system weld leak repair required the RCS to be depressurized and cooled down so that the reactor coolant pumps could be secured. The cooldown and depressurization to Mode 5 was initiated during the pressure boundary check valve testing (when the CLA discharge isolation valves were closed). In procedure OP/2/A/6100/02, Controlling Procedure for Unit Shutdown, approved November 25, 1996, step 2.31 required that the discharge valves be closed. Since the CLA discharge isolation valves were in the closed position for the pressure boundary check valve testing which was in progress, this procedure step was signed. However, in accordance with Enclosure 13.33 of PT/2/A/4200/01N, Reactor Coolant System Pressure Boundary Valve Leak Rate Test, the CLA discharge isolation valves were reopened following the test. As a result, the valves were open when RCS pressure reached the injection pressure of the CLAs.

The licensee is documenting the event in a Licensee Event Report (LER); corrective actions will be evaluated when the LER has been submitted to the NRC.

c. <u>Conclusions</u>

The inspector concluded that the control room operators identified the CLA discharge promptly and took appropriate immediate action to terminate it. Further NRC evaluation of the event and the resulting corrective actions will be conducted during the associated LER review.

O1.2 Control Room Observations

a. Inspection Scope (71707)

During the period of December 2-5, 1996, the inspector used guidance in Inspection Procedure 71707 to observe and evaluate control room operations and plant conditions. Areas observed included shift turnovers, crew communications, operator performance/interaction during surveillances, operator knowledge, and operations log books.

b. Observations and Findings

The inspector conducted observations on two crews in the Unit 1 and Unit 2 control rooms throughout the week. The inspector observed control room access, communications, operator behavior during surveillances and maintenance, and reviewed reactor operator logs.

The inspector observed a quiet and professionally run control room, noting that control room access was limited by the Control Room Supervisor. The control room was devoid of extraneous personnel causing disruption or distractions for the control room operators. The inspector also observed that the crew generally used the three-way communications delineated in OMP 1-1, Administration of Operations Management Procedures and OMP 2-16, Control Room Conduct. Annunciators that alarmed were read aloud by one reactor operator and the other reactor operator and control room supervisor would simultaneously repeat back the annunciator that was announced. During surveillances the control board operators were attentive to alarms and parameters that required monitoring. The inspector questioned various Reactor Operators (ROs) concerning the status of annunciators that were in alarm. In all cases, the operators were able to explain the reasons for the annunciators being in alarm.

The inspector evaluated RO knowledge concerning the status of the unidentified leakage on Unit 1. All operators questioned were knowledgeable concerning the status of this leakage. All operators queried knew what parameters required trending and the status of those trends. The operators were knowledgeable concerning the necessary contingency actions if the leakage had increased.

The inspector attended all special meetings concerning the increased unidentified leakage on Unit 1 in which various disciplines were represented. A concerted and conscientious effort to categorize and determine the source of the leak was observed. The inspector noted an open forum for discussion using a systematic approach in order to pin point the problem area. Additionally, the inspector observed the 6:30 a.m. and 8:30 a.m. plan of the day meetings each morning during the week. During these meetings, the inspector observed a good working

relationship between the different groups represented. These meetings demonstrated the licensee's commitment to maintaining an open dialogue between departments.

The inspector reviewed the operating log books of the RO and Unit Supervisors. While these logs contained information required by OMP 2-17, Control Room and Unit Supervisor Logbooks, they did not necessarily contain all pertinent information concerning shift operations. The logs did not contain, for example, the removal of and the return to service of a power range instrument for calibration. This information was available from the Technical Specification Action Item Log, but was not reflected in the Unit's RO or Supervisor logs.

The inspector also noted that a number of alarmed control board annunciators were unanticipated, but were not logged as was expected by operations management. "A DFCS Trouble" alarm (1AD-4, C-5) was received December 4, at approximately 4:00 p.m. and was not logged in the Unit 1 log book. Additionally, the inspector noted that annunciator "Accum Tank 'D' HI/LO Level" alarm (2AD-9, D-4) was in alarm and was not logged in the Unit 2 log book. Annunciator "Comparator P/R Channel Deviation" (2AD-2, B-3) went into alarm a number of times during day shift December 4, 1996. The log entry in the Unit 2 log book stated that this alarm came in 5 times during the shift. The entry did not describe the frequency at which the alarm was received.

During a plant walkthrough, the inspector noted that the locking devices on locked valve actuators 1NV-391, 1NV-393, and 1NV-389 would not have prevented the actuator from being inadvertently moved to the open position from the locked closed position. The Control Room Supervisor was notified on December 4, 1996, of these apparent valve locking device discrepancies. The inspector observed on December 5, 1996, that two of the three locking devices were repositioned in such a manner that the actuator would not move from the locked closed position; however, it appeared to the inspector that the locking device on valve 1NV-391 would not have prevented the actuator from moving from the closed to the open position. The Operations Shift Manager was notified of this problem and that the handwheel on valve 2NV-276 had a valve number written in marker instead of an appropriate valve identification label.

c. <u>Conclusions</u>

The inspector concluded that the control rooms were run in a professional and organized manner. The Control Room Supervisors limited extraneous noise and distractions for the board operators, thereby enabling them to maintain their attention to the units. The inspector found that the operators assigned to Unit 1 were knowledgeable concerning the status of the unidentified leakage on the unit and were aware of contingency actions necessary if the leakage increased.

Plant management aggressively analyzed plant leakage data on Unit 1 and established an integrated corrective action plan to determine the source of the leak and to correct it. The licensee's decision to shutdown Unit 1 to find and repair the leak was considered proactive. Additionally, the OSM was responsive in correcting identified locking device deficiencies.

Reactor Operator and Unit Supervisor log books contained entries required by OMP 2-17, but were a limited source of information concerning unit status. It was difficult to obtain complete information on unit status because of the location and limited amount of information provided in each log. The licensee has plans to assess log keeping practices. Pending further review, this item will be tracked as Inspector Followup Item (IFI) 50-413,414/96-20-03, Log Keeping Practices.

O1.3 Unit 1 Shutdown - Solid State Protection System (SSPS) Latching Relay Failure

a. Inspection Scope (37551,40500)

On December 30, at 12:30 p.m., the latching function of the Unit 1 SSPS K616 latching relay failed two consecutive times during a normally scheduled TS quarterly slave relay surveillance test. Consequently, the unit entered a 12-hour TS action statement (6 hours to repair plus 6 hours to be in Mode 3) and was shutdown on December 31, by 12:30 a.m. The relay replacement was completed and the TS action for further cooldown was exited by 1:00 a.m. The inspector reviewed the licensee's actions to restore the relay to an operable status, including licensee management discussions and a Plant Operations Review Committee (PORC) meeting. The inspector monitored the unit shutdown and observed portions of the relay replacement and testing activities.

b. Observations and Findings

The K616 relay is a normally deenergized relay located in the train A SSPS and is part of the actuation logic for the steam line isolation Engineered Safeguards Feature (ESF) function. When a steam line isolation signal is received, the K616 relay changes state to send close signals to all four Main Steam Isolation Valves (MSIVs) and all four steam generator Power Operated Relief Valves (PORVs). During testing on December 30, the relay changed state but failed to remain latched. Initial troubleshooting revealed that the failure to latch was due to the slave relay not moving far enough to allow the latch to engage. The licensee then performed the surveillance test approximately 10 consecutive times and the K616 relay and latching function performed as required each attempt without any additional failures.

The inspector observed a special PORC meeting that the licensee convened to review the acceptability of available approaches for restoring the

relay to an operable status and exiting the shutdown action statement. Because of a concern to prevent inadvertent actuation of the relay during replacement activities, the maintenance was not able to be performed within the TS action time and a unit shutdown was performed.

c. Conclusions

The licensee's PORC meeting review and discussion of approaches to restore a failed Unit 1 solid state protection system relay to an operable status were substantive and focused on safety. The shutdown that was subsequently initiated because of the failed relay was well controlled.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Reactor Coolant Pump 1D Number 1 Seal Leakoff Line Leakage

a. Inspection Scope (62707)

On December 5, a Unit 1 shutdown was initiated to investigate the source of an unidentified RCS leak of approximately 0.5 gpm (1.0 gpm is the maximum limit allowed by TS). A cracked weld in the 1D reactor coolant pump (RCP) number 1 seal leakoff line was subsequently identified to be the source of the leak. The inspector observed wetted equipment and components inside containment; reviewed procedures for inspecting and evaluating boric acid spills on carbon steel components; observed portions of the licensee's boric acid inspection and evaluation activities; and reviewed related PIP report 1-C96-3210.

b. Observations and Findings

On November 28, the licensee detected a slight increase in drainage to the Unit 1 Ventilation Unit Condensate Drain Tank. Within several days they also observed an increasing trend in containment temperature. The licensee sampled the Ventilation Unit Condensate Drain Tank and determined that low level isotopes were present. Increases in other parameters, such as RCS unidentified leakage rate and the containment floor and equipment sump filling and pumping, indicated that an RCS leak potentially existed. Subsequent confirmatory troubleshooting and containment entries revealed indications of primary system leakage.

Although RCS unidentified leakage did not approach the maximum limit imposed by TS, the licensee initiated a unit shutdown on December 5. A containment entry was made on December 6, and the licensee determined that the source of the leak was a cracked weld in a spool piece in the 1D RCP number 1 seal leakoff line. The cracked weld was identified on the down stream side of the spool piece flange in the leakoff line. Although the affected section of piping was qualified for RCS

temperature and pressure, it was considered part of the chemical and volume control system and designated as Class B piping. Therefore, the leakage was not characterized as RCS pressure boundary leakage. The spool piece was removed and replaced with a newly fabricated spool piece. The old flange was shipped for failure evaluation. A dye penetrant test was performed on the number 1 seal leakoff lines of the other three RCPs; no crack indications were identified. During a Unit 2 shutdown from December 16-20, 1996, the Unit 2 RCPs were also evaluated for similar cracks in the number 1 seal leakoff lines; none were identified. Only the 1D RCP number 1 seal leakoff line features a spool piece configuration; all other Unit 1 and 2 RCP leakoff lines are comprised of a continuous stretch of piping.

The inspector observed inspection and evaluation activities associated with potential boric acid corrosion of carbon steel equipment. The licensee implemented Procedure PT/1/A/4150/01H, Inside Containment Boric Acid Check, approved October 10, 1990, to inspect plant equipment exposed to leakage from the cracked flange and evaluate the potential for corrosion. No vulnerable components were identified, and wetted areas were cleaned prior to unit restart.

Visual and stereovisual examinations revealed that the weld failure was caused by mechanical fatigue. The licensee proposed in PIP 1-C96-3210 a long-term corrective action to implement a minor modification to change the 1D RCP seal leakoff line configuration from a spool piece to a section made from butt welds that can be installed only one way. Two advantages of this modification are a lower stress intensity factor and joint soundness.

c. Conclusions

The inspector concluded that the licensee's decision to initiate a plant shutdown before the maximum unidentified leakage limit allowed by TS was reached was responsive to resolving the adverse condition promptly. Efforts to ensure that carbon steel equipment was protected from boric acid corrosion were appropriate. Corrective maintenance of the RCP number 1 seal leakoff line was completed without any personnel contamination events.

M1.2 Unit 2 Steam Generator PORV Nitrogen Backup Supplies Found Isolated

a. Inspection Scope (61726,71707)

On January 3, during nitrogen bottle replacement, the licensee identified that both nitrogen backup supply isolation valves for the Unit 2D steam generator (SG) PORV (2SV-1) were closed instead of in the required open position. Immediately following identification of the mispositioned valves the licensee checked the positions of all remaining SG PORV nitrogen valves on both units and found another instance where both nitrogen isolation valves were closed on the Unit 2B SG PORV (2SV-

13). The inspector discussed the issue with plant personnel, reviewed the associated PIP and the initial results of the licensee's investigation.

b. Observations and Findings

Licensee maintenance personnel performed the nitrogen bottle change out on 2SV-1 in response to a low nitrogen pressure alarm and recognized the mispositioned valves. The licensee's subsequent investigation determined that the nitrogen supply isolation valves for the two SG PORVs (2SV-1 and 2SV-13) were last manipulated on December 22, during surveillance testing (SG PORV D/P Stroke Tests). It is believed that they had been left closed from this time until January 3. The purpose of the nitrogen backup supply as stated in the TS bases is to ensure that the SG PORVs will be available to mitigate the consequences of a steam generator tube rupture accident concurrent with loss of offsite power. TS 3.7.1.6, Steam Generator Power Operated Relief Valves, does not allow the safety-related nitrogen gas supply for two SG PORVs to be isolated for more than seven days.

At the close of the inspection period the licensee had not completed their investigation of this mispositioning event. Preliminary results of the investigation indicated that the surveillance procedure was not adequate because a single verification step and signoff requirement were provided for a multiple action sequence involving reopening three valves located in separate locations in the steam valve rooms where testing was conducted.

c. Conclusions

This issue is characterized as Unresolved Item 50-414/96-20-01: Mispositioned Nitrogen Backup Supply Valves Result in Degrading The Function of SG PORVs, pending the licensee's completion of the root cause investigation and evaluation of the event.

M1.3 Control Rod Drop Testing (61726)

The inspector reviewed test results associated with Control Rod Drop Testing performed in accordance with NRC Bulletin 96-01, Control Rod Insertion Problems. The testing was performed on December 21, following a Unit 2 shutdown which lasted greater than 72 hours. The test results indicated that all rod times were well within the criteria established by TS 3.1.3.4, Rod Drop Time.

III. Engineering

E1 Conduct of Engineering

E1.1 Unit 2 Residual Heat Removal System Nitrogen Entrainment

a. Inspection Scope (37551)

On December 11, the 2B residual heat removal (RHR) pump failed its quarterly performance test. Inadequate flow and differential pressure across the pump was attributed to nitrogen entrainment in the system fluid that had migrated past check valves from the Cold Leg Accumulators. The inspector reviewed the circumstances that led to the condition, identification and resolution of the problem, and planned corrective actions.

b. Observations and Findings

Following the failure of the 2B RHR pump to pass its quarterly performance test on December 11, the licensee initiated a Failure Investigation Process (FIP) team to evaluate potential causes of the failure. The team considered gas in the pump, motor problems, pump problems, and instrumentation problems. Based on the symptoms observed by test personnel, the FIP team determined that gas in the pump was most likely. Further evaluation revealed that nitrogen had migrated past check valves from Cold Leg Accumulators.

The licensee had documented the following observations in PIPs C96-2634, C96-3095, and C96-3250. Since late September 1996, the RHR discharge header had been pressurized to approximately 600 psig and the frequency of makeup to the 'C' and 'D' Cold Leg Accumulators had increased. Based on the conditions observed, it was apparent that an RCS pressure boundary check valve was allowing backleakage from the Cold Leg Accumulators to migrate into the RHR system. An operability evaluation demonstrated that the backleakage was within TS limits. The licensee left the discharge header pressurized to keep the nitrogen in solution and prevent the creation of voids in the system. On November 15, the licensee identified a small leak on the 'B' RHR heat exchanger flange. The leakage was within the acceptance criteria for total emergency core cooling system (ECCS) leakage outside containment. Under these conditions the RHR system became saturated with nitrogen at approximately 600 psig as nitrogen migrated over a period of time from the Cold Leg Accumulators.

When the quarterly performance test was initiated on December 11, the discharge header was depressurized to establish test conditions with the 2B RHR pump running in recirculation. When the system was depressurized, nitrogen came out of solution, apparently at the recirculation mini-flow valve. As a result of the piping configuration, the majority of the gas stripped out of solution in this manner could

have migrated to the RCS loop suction lines. RHR system venting results substantiated that nitrogen gas accumulated there. Some gas bubbles were carried to the pump suction, adversely affecting the pump's performance.

To remove the nitrogen-saturated water from the recirculation loop, the licensee developed a procedure that established conditions to run the pump in recirculation and open pump discharge drains to feed and bleed water from the Fueling Water Storage Tank into the recirculation loop. Following a feed and bleed in this manner, the pump's performance returned to normal. An operability determination demonstrated that the pump was operable but degraded. To maintain system operability, compensatory actions were established to: (1) regularly vent the suction and discharge high points (prior to exceeding 400 psig); (2) increase the performance test frequency to weekly; and (3) perform the feed and bleed evolution following the test. The 2B RHR pump was declared operable before the TS action time expired.

Increased operator burden was created by the work arounds to vent the system regularly and perform additional tests. In addition, other work arounds had been put in place to compensate for an auxiliary feedwater assured suction source design deficiency (see section E1.2 of this report). To minimize operator burden, the licensee shut Unit 2 down to reseat the RCS pressure boundary check valves. This was accomplished using the pressure boundary valve test header, which is limited to use in Mode 4 or below by the plant's TS. An additional corrective action planned by the licensee was to evaluate ECCS system operations that might disturb the differential pressure across RCS pressure boundary check valves, such as Cold Leg Accumulator makeups and safety injection pump and valve testing.

c. Conclusions

The engineering evaluation that supported maintaining the RHR discharge header pressurized at approximately 600 psig was sensitive to the potential for void formation resulting from system depressurization. Nonetheless, the evaluation did not consider the effects of maintaining the header pressurized in all modes of system operation.

The FIP was initiated in a timely manner, which facilitated early identification of the cause of the degraded pump performance and timely actions to restore operability.

The decision to shutdown the unit as a result of the cumulative effect of the existing operator work arounds demonstrated site management's commitment to operational safety.

E1.2 Auxiliary Feedwater System Design Deficiency for Train Separation

a. Inspection Scope (37551,90712)

On December 11, 1996, the licensee identified a design deficiency during a design review of assured makeup supply to the auxiliary feedwater (AFW) system. The design review was conducted in support of a modification to reduce the ice condenser ice weight limit in TS. The inspector discussed the issue with plant personnel, reviewed associated station PIPs, evaluated proposed corrective actions, and observed portions of modifications implemented to correct the problem.

b. Observations and Findings

During a design review, the licensee determined that the flow of nuclear service water (the assured supply) to the AFW pumps was inadequate under certain accident scenarios. Specifically, with all three AFW pumps running with high flow demand and loss of the preferred suction sources, a single failure of one of the two assured makeup source valves would cause the remaining train of the assured source to attempt to supply all three auxiliary feedwater pumps, resulting in inadequate net positive suction head to all three pumps and render them inoperable.

The design deficiency involved the absence of check valves in locations that would ensure separation between the 'A' and 'B' trains of the assured source suction to the auxiliary feedwater system. Check valves were located upstream of a common header to the AFW pumps, where train separation could not be achieved.

The licensee promptly informed the NRC of the design deficiency. The root cause was suspected to be an initial design oversight. The design deficiency is being documented in Licensee Event Report 50-413,414/96-12.

A modification was implemented to install check valves in appropriate locations of the AFW system. The modification for Unit 2 was completed during a forced shutdown (to correct a nitrogen entrainment condition in the 2B RHR pump and discharge piping) from December 16 to December 20, 1996; the modification for Unit 1 was completed on January 9, . 97.

c. Conclusions

This issue is characterized as Unresolved Item 50-413,414/96-20-02: AFW System Design Deficiency Involving Inadequate Train Separation and a Single Failure Vulnerability, pending further review following the licensee's completion and submittal of the associated Licensee Event Report.

E2 Engineering Support of Facilities and Equipment

E2.1 Component Cooling Water (CCW) System Weld Leak

a. Inspection Scope (62707,37551)

The inspector reviewed evaluation and repair activities associated with a Unit 2 CCW system weld leak that was identified by the licensee during a containment walkdown on December 15.

b. Observations and Findings

The weld leak was located in the Unit 2 containment on the reactor building non-essential return header portion of the CCW system. This system services heat exchangers for the reactor coolant pump motor bearing coolers, thermal barrier, excess letdown, and reactor coolant drain tank. The licensee performed a ultrasonic examination of the weld and determined that the leak resulted from a crack that was approximately 3 inches long. The licensee performed an ASME code repair of the leaking weld (WO 96100337-01). The repair consisted of performing a circular cut in the piping around the cracked area to preserve it for analysis, removing the cutout, and welding a branch connection around the cutout area. Metallurgical analysis performed on the section that was removed determined that the crack resulted from nitrate induced intergranular stress corrosion cracking.

The inspector reviewed associated PIP 2-C96-3274. As part of corrective actions for the leak, the licensee performed walkdowns of all CCW system piping in the Unit 2 auxiliary building and accessible Unit 1 CCW system piping. No additional leaks were identified during the walkdowns. The licensee is also evaluating implementing a monthly walkdown of CCW system piping.

c. Conclusions

The licensee's actions in identifying and repairing a Unit 2 CCW system weld leak were appropriate. The licensee's efforts in developing a repair technique that preserved the cracked portion of the weld were innovative and allowed for detailed metallurgical examination and root cause analysis of the failure.

IV. Plant Support

S1 Conduct of Security and Safeguards Activities

S1.1 Response to Valve Mispositionings

a. Inspection Scope (71750)

The inspector reviewed the licensee's response to the potential for intentional mispositioning or tampering with the Unit 2 SG PORV nitrogen backup supply valves discussed in Section M1.2 of this report.

b. Observations and Findings

Following identification of the mispositioned nitrogen valves associated with two SG PORVs located in different plant areas, the operations shift crew involved management and implemented several precautionary actions to deal with a potentially deliberate tampering event. These actions included verifying the proper positioning all SG PORV nitrogen valves, verifying that important components located in the areas adjacent to the nitrogen valves were not tampered with (i.e., main steam safety valves and AFW steam supply valves), and securing access to the areas.

c. Conclusions

The licensee displayed appropriate sensitivity to the potential for tampering following the mispositioning of several nitrogen supply valves associated with two Unit 2 steam generator PORVs.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 15, 1997. The licensee acknowledged the findings presented. No proprietary information was identified.

Partial List of Persons Contacted

Licensee

Bhatnager, A., Operations Superintendent
Coy, S., Radiation Protection Manager
Forbes, J., Engineering Manager
Harrall, T., IAE Maintenance Superintendent
Kelly, C., Maintenance Manager
Kimball, D., Safety Review Group Manager
Kitlan, M., Regulatory Compliance Manager
McCollum, W., Catawba Site Vice-President
Peterson, G., Station Manager
Propst, R., Chemistry Manager
Rogers, D., Mechanical Maintenance Manager
Tower, D., Compliance Engineer

Inspection Procedures Used

IP 37551: Onsite Engineering
IP 61726: Surveillance Observation
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 40500: Controls to Identify and Resolve Deficiencies
IP 90712: LER Review

Items Opened, Closed and Discussed

Opened

URI 50-414/96-20-01	URI	Mispositioned Nitrogen Backup Supply Valves Result in Degrading The Function of SG PORVs (Section M1.2)
50-413,414/96-20-02	URI	AFW System Design Deficiency Involving Inadequate Train Separation and a Single Failure Vulnerability (Section E1.2)
50-413,414/96-20-03	IFI	Log Keeping Practices (Section 01.2)

List of Acronyms Used

AFW	-	Auxiliary Feedwater System
ASME	-	American Society of Mechanical Engineers
CFR	-	Code of Federal Regulations
CLA	-	Cold Leg Accumulator
DFCS	-	Digital Feedwater Control System
DPC	-	Duke Power Company
ECCS	-	Emergency Core Cooling System
ESF	-	Engineered Safeguards Feature
FSAR	-	Final Safety Analysis Report
IP	-	Inspection Procedure
LER	-	Licensee Event Report
OMP	-	Operations Management Procedure
OP	-	Operating Procedure
OSM	-	Operations Shift Manager
PIP	-	Problem Investigation Process
PORC	-	Plant Operations Review Committee
PORV	-	Power Operated Relief Valve
PT	-	Performance Test (Procedure)
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RO	-	Reactor Operator
SG	-	Steam Generator
SSPS	-	Solid State Protection System
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VIO	-	Violation
WO	-	Work Order