APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-285/93-26

Operating License: DPR-40

Licensee: Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 399, Hwy. 75 - North of Fort Calhoun
Fort Calhoun, Nebraska

Facility Name: Fort Calhoun Station

Inspection At: Blair, Nebraska

Inspection Conducted: November 21, 1993, through January 1, 1994

Inspectors: R. Mullikin, Senior Resident Inspector
R. Azua, Resident Inspector
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Accompanying
Personnel: S. Bloom, Project Manager, Nuclear Reactor Regulation

Approved: Thomas F. Stetka 1/26/94
Thomas F. Stetka, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Areas Inspected: Routine, unannounced inspection of onsite followup of events, operational safety verification, safety system walkdown, maintenance and surveillance observations, and followup of licensee event reports.

Results:

- A failure by engineering personnel to provide an adequate postmaintenance test for an electrohydraulic control (EHC) system modification resulted in a plant trip and was considered to be a violation (Section 2.1).

- A deficient surveillance test procedure caused both auxiliary feedwater pumps to be inoperable, at the same time, during a portion of the surveillance test (Section 2.2).

- Failure by an operator to place both trains of control room ventilation in recirculation mode resulted in one train switching over to the

filtered air makeup mode following a ventilation isolation actuation signal (Section 2.3).

- The licensee appropriately controlled housekeeping activities (Section 3.2).
- Maintenance personnel were found to be knowledgeable of their responsibilities (Section 4).
- Maintenance activity prebriefings were found to be excellent (Section 4).
- The control element assembly troubleshooting activity which occurred with the reactor in power operations was well coordinated (Section 4.3).
- System engineer knowledge of the surveillance trend for raw water pumps was very good (Section 5.1).

Summary of Inspection Findings:

- Violation 285/9326-01 was opened (Section 2.1).
- Unresolved Item 285/9326-02 was opened (Section 2.2).
- Unresolved Item 285/9326-03 was opened (Section 2.3).
- Unresolved Item 285/9326-04 was opened (Section 3.2.2).
- Unresolved Item 285/9326-05 was opened (Section 6.1).
- Licensee Event Report 92-013 was closed (Section 7).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the Fort Calhoun Station was in its 14th refueling outage. An Augmented Inspection Team was onsite at the beginning of the inspection period to investigate the uncontrolled rod withdrawal event that occurred on November 13, 1993. A Confirmatory Action Letter was issued on November 19, stating that the licensee would not proceed beyond Mode 3 (Hot Shutdown) until meeting with the NRC staff to review the results of the licensee's efforts to identify and correct the condition that caused this event. On November 22, the Augmented Inspection Team held a public exit meeting. Following this meeting, the NRC staff granted the licensee permission for startup. The Augmented Inspection Team findings are documented in NRC Inspection Report 50-285/93-25.

The Fort Calhoun Station achieved criticality on November 24. Mode 1 (Power Operation) was reached on November 25. On December 6, a main turbine trip occurred from 100 percent power because of an erroneous low EHC system fluid pressure signal. The main turbine trip resulted in an automatic reactor trip. Mode 1 was again reached on December 7. At the end of this inspection period, the plant was operating at 100 percent power.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Main Turbine/Reactor Trip Resulting From EHC System Problem

2.1.1 Description of Event

On December 6 a main turbine trip occurred while the reactor was at 100 percent power. The main turbine trip initiated an automatic reactor trip. At the time the plant trip occurred, the licensee was performing a scheduled monthly rotation of the two EHC pumps. EHC Pump EHC-3B was in operation at the time. As provided for in Operating Instruction OI-ST-10, "Turbine Generator Tests," the auxiliary operator pressed the test push button for Pump EHC-3A and the pump started as expected. Within approximately 5 to 10 seconds after Pump EHC-3A started, the main turbine tripped on low EHC pressure. This was the first time that a pump rotation was performed after the EHC pressure switch location had been moved during the refueling outage.

2.1.2 Troubleshooting and Immediate Corrective Actions

The licensee initiated troubleshooting activities to investigate the cause of the low EHC pressure. Pressure recording test equipment was installed at the EHC pressure switch location and the operating instruction was again performed. The licensee noted that, each time the test push button was depressed, an EHC system pressure decrease of 250 to 625 psig from 1600 psig was recorded. The main turbine trip EHC low pressure trip setpoint was set at

1100 psig. The licensee also measured the EHC system pressure at the main header and no pressure decrease was observed.

The licensee concluded that the cause of the sensed low EHC pressure was the configuration of the EHC pressure trip switches. During the latest refueling outage, a total of six pressure switches were moved away from the EHC pumps to reduce switch vibration. The design change resulted in increasing the sensing line length from approximately 3 feet to 22 feet. The six switches were connected to the main EHC system header via a common 1/4-inch fitting. The licensee determined that the increase in sensing line length resulted in the pressure drop. A design change was subsequently implemented to relocate the pressure switches such that pressure sensing was off the main EHC header.

2.1.3 Background

Prior to the 1993 refueling outage (Refueling Outage 14), the licensee initiated Engineering Change Notice ECN 93-162 to replace the pressure switches on the EHC system with a different model. The previously installed switches had been noted to drift out of calibration frequently. The new switches were installed during a planned mini-outage in April 1993. After installing the new pressure switches on the EHC pump skid, the licensee noted during calibration that erratic switch operation was occurring due to vibration from the EHC pumps. These switches were found to be more sensitive to vibration than the original switches.

The licensee decided to reinstall the original pressure switches. The new pressure switches were again scheduled to be installed during Refueling Outage 14 when a design change to move the EHC pumps away from the skid was implemented. The licensee concluded that the originally installed switches could be relied on until the EHC system design modifications were implemented. However, the licensee cancelled the EHC pump relocations and decided to mount the pressure switches on dampening devices. The licensee subsequently determined that the dampening devices would not be adequate to ensure the pressure switches were properly supported. A design change was then implemented to move the pressure switches away from the hydraulic power unit skid and relocate them on a nearby wall. This work activity was authorized by Construction Work Orders CWO 93-234 and CWO 93-235 and was completed during Refueling Outage 14 on November 12, 1993.

The inspectors reviewed the work order documentation. Construction Work Order CWO 93-234 was the controlling document for the electrical installation portion of Engineering Change Notice 93-162, Revision 2. The work order did not specify an operability test. Construction Work Order CWO 93-235 was the controlling document for the mechanical portion of the work. Again, no postmodification operability test was specified in the work order. However, the system engineer, during final review of the work order, specified that pump testing, per Operating Instruction OI-ST-10, should be performed. This test was successfully completed but not performed with the EHC system appropriately configured for plant operation. Normally, this test would be performed at power and the low EHC pressure trip enabled. However, the system

engineer did not specify that the trip function be reset since it was felt that a sufficient postmodification test would be to verify the automatic start feature of the pumps.

2.1.4 Inspectors Review of Event

The licensee's engineering organization failed to properly consider all the effects the proposed facility change would have. The facility change was reviewed by engineering management, the system engineer, and an assistant plant manager. The engineering change notice specified that leak testing be performed after the installation of the modification. The system engineer specified the postmodification testing to be performed in the construction work order. However, the postmodification test was not adequate to functionally test the modification and did not receive the detailed review that it would have if specified in the engineering change notice. Even though the modification was to a nonsafety-related system, the failure of this system could, and did, present an unnecessary challenge to plant safety systems, as evidenced by the reactor trip.

The inspectors reviewed Quality Procedure PED-QP-2, "Configuration Change Control," which established the Production Engineering Department's responsibilities and requirements for preparing, reviewing, approving, and processing engineering change notices. The procedure required that specific aspects of construction or installation important to the correct functioning of the facility engineering change notice shall be listed by Design Engineering Nuclear in the engineering change notice. Specific testing requirements to ensure proper installation, function, or overall system performance or operational characteristics shall also be specified, including all acceptance criteria values where appropriate. Engineering Change Notice ECN 93-162, Revision 2, was written and approved without proper testing specified to ensure acceptable operation of the modification. The failure to implement the requirements of Procedure PED-QP-2 is a violation of NRC requirements (285/9326-01).

2.2 Auxiliary Feedwater (AFW) Pumps Operability

On December 9, the licensee performed Surveillance Test Procedure SE-ST-AFW-3005, Revision 6, "Auxiliary Feedwater Pump FW-6 and Check Valve Test." During the conduct of the surveillance test, the system status was changed, which rendered both the motor-driven and steam-driven AFW pumps inoperable. The system status changes were conducted in accordance with the surveillance procedure.

The licensee subsequently identified, after the surveillance test had been completed and the system returned to service, that Technical Specification (TS) 2.5 had been met and that TS 2.0.1, which required that, with both AFW pumps unavailable the unit be placed in HOT SHUTDOWN within 6 hours, was not exceeded. The licensee's emergency implementing procedures specified that a Notification of Unusual Event be declared for the plant required shutdown. The Notification of Unusual Event was reported but not

declared, since the condition which constituted the declaration no longer existed. The licensee made a 1-hour report to the NRC Operations Duty Officer as required by 10 CFR 50.72(b)(1).

The inspectors reviewed the surveillance procedure, operator actions, and licensee response to the event. It was found that the surveillance procedure had recently been revised to provide clarification on the operability status of AFW Pump FW-10, during the performance of the test. This was the first time this new revision (Revision 6) of the procedure had been used since the procedure changes were incorporated. This surveillance test was divided into two parts. The first part was established to test AFW Pump FW-10 Discharge Check Valve FW-174 for backleakage. The second was designed, in part, to perform a flow test on AFW Pump FW-6.

During the first portion of the test, AFW Pump FW-10, Suction Valve FW-349, a locked-open manual valve, was closed and the control switch for the AFW pump turbine's Steam Supply Stop Valve YCV-1045 was taken from the AUTO position and placed in the CLOSE position. The procedure stated that this rendered AFW Pump FW-10 inoperable. The licensee entered TS 2.5 as required for the one AFW pump being inoperable. The action statement associated with this TS allowed the licensee to continue power operation, with one AFW pump inoperable, for a period of up to 24 hours. At the completion of this portion of the test, the procedure required Valve FW-349 to be reopened.

The operators noted that the procedure did not provide instructions for placing the control switch for Valve YCV-1045 back to the AUTO position. The operators discussed the need to place the steam supply stop valve for AFW Pump FW-10 back to the AUTO position prior to performing the second half of the surveillance test. The operators concluded that it would be acceptable to continue the surveillance test provided contingency actions for manually initiating the AFW system were established. The second half of the surveillance test addressed the flow capacity of AFW Pump FW-6. For this portion of the test, an alternate flow path was established from the pump to the emergency feedwater storage tank to allow a pump flow of 200 gpm.

During the performance of the test, the shift supervisor questioned the acceptability of having AFW Pump FW-10 inoperable while AFW Pump FW-6 was being tested with flow diverted to the emergency feedwater storage tank. Following a review of TS 2.5, and after discussions with the licensed senior operator (LSO), it was determined that a problem may exist, both with the valve alignment and taking credit for operator action. At this time it was determined that the surveillance test should be stopped and the AFW system returned to service until this concern was resolved. However, by the time this determination was made, the test of AFW Pump FW-6 had been completed and the operators were in the process of returning the AFW system to its' normal standby lineup. The shift supervisor initiated Incident Report 930387 to document the procedural deficiency which allowed for both feedwater pumps to be inoperable.

The licensee subsequently determined that both AFW Pumps FW-6 and FW-10 had been inoperable concurrently for approximately 20 minutes. The shift supervisor discussed this event with a licensing representative who had been present in the control room. This individual identified that Nuclear Operations Division Quality Procedure NOD-QP-31, "Operability and Reportability Determinations," specified that credit for operator action could only have been taken if the surveillance procedure had provided specific instructions to that effect. In addition, a dedicated operator would have had to have been assigned and trained to carry out those specific instructions. These actions had not been developed for this surveillance activity.

The inspectors reviewed the guidance provided in Procedure NOD-QP-31. It was determined that the operations staff had not been informed of the specific operator actions and limitations required during maintenance activities and surveillance testing to consider the equipment operable. The inspectors concluded that the licensee had not effectively communicated the requirements for determining equipment operability.

Upon identification of this event, the licensee took the following immediate corrective actions:

- Operations crews were briefed, prior to coming on shift, about the specifics of this event.
- An operations memo providing temporary guidance to operators was issued, regarding equipment operability during surveillance testing.
- The plant review committee was briefed on this event.
- A root cause analysis was initiated.
- The 10 CFR 50.59 preparer and reviewer of the safety analysis for the Surveillance Test Procedure SE-ST-AFW-3005 change were disqualified, based on the inadequate safety analysis that concluded that the procedure changes did not have a safety impact. The scope of the work activities for these individuals were reviewed for the previous 2 years.

The inspectors reviewed the adequacy of the procedure change activity and were concerned with the 10 CFR 50.59 and procedural change reviews performed by licensee personnel. It was noted that the procedure change had been reviewed by a Plant Review Committee subcommittee which consisted of an inservice inspection engineer, an operator, and the cognizant system engineer prior to the procedure change being presented to the qualified reviewer. In addition, it appeared that operator command and control weaknesses occurred due to the failure of the operators to stop the test when it was realized that both AFW trains could be rendered inoperable.

The inspectors determined that further review of this event is required to fully understand the determine the effectiveness of control room command and control. This is considered to be an unresolved item (285/9326-02).

2.3 Mispositioning of Control Room Dampers

On December 30, both trains of the toxic gas monitors became inoperable because the recorder trace paper ran out. With both trains of toxic gas monitors inoperable, TS 2.22 required that the control room ventilation system be placed in the recirculation mode. Upon receipt of the alarms indicating the monitors were inoperable, the LSO placed the Train A control room ventilation system into the recirculation mode. However, this same action was not taken for the Train B control room ventilation system. The LSO noted that Train B Air Conditioning Unit VA-46B was danger-tagged out of service for replacement. The LSO erroneously judged that, with the air conditioning unit out of service, there was no need to take the Train B associated dampers to the recirculation position.

The licensee later performed Surveillance Test OP-ST-ESF-0023, Revision 11, "S2-2 Automatic Load Sequencer Test." As a preplanned part of this testing, a ventilation isolation actuation signal was generated. The ventilation isolation actuation signal logic was designed to cause the control room ventilation to default to the filtered air makeup mode of operation if the recirculation mode was not selected. Because the Train B ventilation system was not in the recirculation mode, the Train B ventilation system defaulted to the filtered air makeup mode, which brought in outside air into the control room. The Train A ventilation fan exhaust duct, which is common with Train B ventilation system duct work downstream of the Train B fan, provided the motive force. The associated control room annunciators alerted the operators to this abnormal condition. The licensee subsequently determined that the Train B ventilation system had performed as required and that TS 2.22, for placing the Train B ventilation system in the recirculation mode, had not been met. The licensee's evaluation concluded that outside filtered air was brought into the control room for approximately 6 minutes with the toxic gas monitors inoperable. The operators promptly initiated Incident Report 9304122 to document this event.

The inspectors noted that two conditions had contributed to this event. The first was that the operators' were not fully cognizant of the individual ventilation system component response to an initiation signal. The second was that the clearance order tag, which had been hung on the Train B Air Conditioning Unit VA-46B control switch, to indicate that it was out of service, was covering the Train B ventilation system control switch and made it appear that it also had been taken out of service.

The inspectors determined that further review of this event is required to determine the reasons for the actions by operations personnel. This is considered to be an unresolved item (285/9326-03).

2.4 Inoperable Diesel Driven Fire Pump

On December 22, Diesel Driven Fire Pump FP-1B failed its monthly surveillance test due to a failure to start. The pump impeller was found to be mechanically bound which had caused the diesel engine starter motor to fail. The licensee subsequently determined that the pump failure had occurred when one of the impeller blades of the vertical three-stage pump came in contact with the pump body. The pump was located in a 30-foot deep well in Cell C of the intake structure, situated adjacent to the Missouri River. Other equipment located in this intake structure included the motor driven fire water pump and a safety-related raw water pump.

The inspectors discussed the pump failure with the cognizant system engineer. The system engineer identified that the failure had resulted when the third stage impeller came in contact with the pump wear ring. The cause for this occurrence was improper tightening of the nut on the collet, which holds the impeller in place. Operation of the pump caused the nut to back off, thus loosening the collet and allowing the impeller to drop along its vertical shift onto the pump wear ring. This caused the pump to bind. The licensee identified that they had recently replaced the pump during the last refueling outage with a new one, and that this appeared to be an error by the pump vendor. The pump internals were inspected, no significant damage was noted, and the pump was reassembled. Postmaintenance tests did not identify any further problems.

During the licensee's inspection of the fire pump, it was identified that some buildup of sand on the ledge upon which the fire pump sits in the intake structure had occurred due to reduced Missouri River flow in the winter months. The licensee was concerned that too much sand build up could affect future pump performance. The system engineering supervisor identified that an engineering change notice was being developed to install a sparging system to wash sand buildup away from each of the four raw water pumps which operate in the same environment. As the result of finding sand on the fire pump ledge, the licensee decided to evaluate the engineering change notice to determine if the system could be expanded to include the two fire pumps.

In the interim, the system engineering supervisor indicated that the fire pumps would be jogged biweekly in addition to the monthly performance test to further assure reliability. Additionally, the frequency of rotating raw water pumps was increased from every 24 hours to every 12 hours.

2.5 Conclusions

Inadequate reviews by engineering personnel resulted in an inadequate surveillance test and the failure to specify an adequate postmaintenance test following a plant modification. The turbine/reactor trip, which resulted from a modification to the electrohydraulic control system, is an example of a reduced sense of concern with regard to the impact that nonsafety-related maintenance activities may have on challenges to safety systems. Inattention

to detail by operators resulted in improper operation of the control room ventilation system. Licensee response to plant events was found to be prompt and effective.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Routine Control Room Observations

The inspectors observed activities throughout this inspection period to verify that proper control room staffing and control room professionalism were maintained. Shift turnover meetings were conducted in a manner that provided effective continuity of plant status from one shift to the other. Discussions with operators indicated that they were aware of plant and equipment status and reasons for lit annunciators. The inspectors observed that TS limiting conditions for operation were properly documented and tracked. Plant management was observed in the control room on a daily basis. Control room traffic was observed to be effectively limited to personnel requiring access to conduct work-related activities.

On November 24 the inspectors observed a portion of the plant startup from the refueling outage. There were no observed anomalies in the rod control system during rod withdrawal. Control room traffic was properly controlled. The briefing given to operators was thorough, with emphasis on the corrective actions developed as a result of the uncontrolled rod withdrawal event.

3.2 Plant Tours

The inspectors routinely toured various areas of the plant to assess the general area conditions. The inspectors verified that accessible emergency core cooling system and other safety-related valves and switches were correctly positioned.

The inspectors conducted a review of the containment building prior to the reactor criticality following the refueling outage. Housekeeping activities were found to be excellent and the licensee's close out inspection had been effectively performed. All outage equipment was noted to have been removed, and no debris or trash was identified. Safety-related piping and valves not accessible during plant operation were observed. Installed snubbers and supports were intact and valves were properly positioned. Required locked valves were properly secured. The containment building sumps were inspected and screens were found to be intact and the sumps were free of debris. Finally, all fire extinguishers that had been staged in the containment building during the outage had been moved back to their normal location in the auxiliary building corridor leading to the containment personnel access lock.

3.2.1 Tour With Turbine Building Operator

On November 24, the inspectors observed the turbine building operator logkeeping activities associated with the recently installed control rod drive

ground detection system. The operator had been appropriately trained and properly conducted the activity. No grounds were detected.

3.2.2 Raw Water Valve Broken Stem

On December 17, the inspectors observed that Raw Water Valve HCV-2881B had a broken handwheel stem. Valve HCV-2881B is a fail open air actuated butterfly valve located on the outlet of Component Cooling Water Heat Exchanger AC-1B. The valve is located near a grating that must be reached by ladder and is not a normal passageway. The stem was sheared off where the stem entered the valve actuator body. The inspectors observed that the valve appeared to be in the full open fail-safe position. The licensee was promptly notified of this condition and a deficiency tag was initiated by plant personnel. Incident Report 930406 was also initiated to review the event.

Plant management informed the inspectors that the broken valve stem had not been reported. It was later identified that this condition had been identified by the system engineer the previous day and documented in a maintenance work request. However, the inspectors determined that the condition had not been reported to the shift supervisor.

The licensee subsequently performed an operability determination which indicated that the valve was operable based on it being in its fail-safe position. In addition, a surveillance test was performed on the valve, which demonstrated that it was operable. An inspection of the remaining seven similar valves on all four safety-related heat exchangers was conducted and no damage was noted.

On December 22, the licensee performed an additional evaluation to determine whether the remaining stem could work its way into the valve and prevent it from opening. The licensee concluded that the stem could not move into the valve. The licensee was evaluating the cause for the valve stem failure at the end of the inspection period.

The inspectors will review the adequacy of the licensee's corrective action process to ensure that potentially degraded equipment is appropriately evaluated for operability concerns as an unresolved item (285/9326-04).

On December 27 the system engineer observed, during an inspection of Valve HCV-2881B, that three of the four cap screws that held the spring barrel to the valve housing had sheared off. This condition did not affect the ASME pressure boundary; however, it could have hindered the air operator's performance. An inspection of the other seven valves did not identify any similar conditions. The system engineer did observe that all four raw water outlet valves were vibrating to varying degrees, with Valve HCV-2881B having the most vibration. The four inlet valves were not observed to be vibrating. Operations personnel were notified of the equipment deficiency at this time. The licensee declared Heat Exchanger AC-1B inoperable and removed the actuator from Valve HCV-2881B for inspection. The TS require only three of the four component cooling water heat exchangers to be operable. The licensee has

implemented administrative controls to maintain the valves in their fail safe position until the cause for the valve component failures has been identified.

3.3 Radiological Protection Program Observations

The inspectors verified that selected activities of the licensee's radiological protection program were properly implemented. Health physics personnel were observed routinely touring the controlled areas. Contaminated areas and high radiation areas were properly posted, and restricted high radiation areas were found to be locked, as required.

Health physics personnel coverage of maintenance and surveillance activities, in contaminated areas, was found to be very good. This was specifically noted during the safety injection pump recirculation line check valve tests and during Charging Pump CH-1A maintenance activities. Health physics personnel periodically measured exposure rates near the equipment that was being worked on and, also, identified low dose areas where personnel performing the test could stand to minimize their exposure rate.

3.4 Security Program Observations

Security personnel performed their duties in a professional manner. Security personnel were found to perform thorough inspections of personnel who failed to clear the detection equipment. The inspectors observed security personnel perform package and vehicle searches. Vehicles were properly controlled or escorted within the protected area. Designated vehicles parked and unattended within the protected area were found to be locked and the keys removed. The inspectors routinely toured the protected area perimeter and found it maintained at an excellent level. Proper compensatory measures were taken when a security barrier was inoperable. Plant personnel assigned escort responsibility were knowledgeable of the escort requirements and appropriately maintained control of their assigned personnel.

3.5 Conclusions

Housekeeping throughout the plant, including areas inside containment, was found to be excellent. Review of the results of the licensee's evaluation, regarding the Raw Water System Valve HCV-2881B stem and cap screw failures, will be tracked as an unresolved item. Failure of a system engineer to promptly notify the control room, following identification of a damaged raw water system valve, was contrary to general employee training guidance. Plant personnel safety practices were found to be good. Health physics personnel coverage during maintenance and surveillance activities was found to be very good.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 Auto Start Pressure Switch PS-5098 Replacement

On December 15, the inspectors observed the maintenance activity that replaced the Hydraulic Fluid Pump EHC-3B-12 auto start Pressure Switch PS-5098. This switch replacement was necessary because the switch operation, which starts the EHC pump on low pressure, had become intermittent. This work activity was authorized by Maintenance Work Order 933809, Surveillance Test Procedure OI-ST-10, "Turbine Generator Tests," and Calibration Procedure IC-CP-01-5098, "Calibration of Turbine Hydraulic Pump EHC-3B Auto Start Pressure Switch, PS-5098." The inspectors verified that the maintenance work order and procedures had been reviewed and approved as noted by the appropriate signatures. The inspectors also verified that the work instruction and procedures were technically accurate and within the skill of the craft.

The maintenance activity prebrief was found to be excellent. Emphasis was placed on the potential impact this maintenance activity could have on plant operation in that a main turbine/reactor trip could occur on low electrohydraulic control system pressure. Instrumentation and controls personnel were cautioned on the proper work sequence for disconnecting the pressure switch.

The inspectors noted that plant personnel had prestaged the equipment required for performance of this activity. Instrumentation required for the performance of this maintenance activity was determined to be appropriately calibrated. The instrumentation and controls technicians were interviewed by the inspectors. All were found to be knowledgeable of their responsibilities. The system engineer responsible for this system was present to provide oversight and support of the maintenance activity. Double verification by the technicians was noted when identifying leads that were to be lifted. In addition, when the hydraulic fluid line leading to the pressure switch was isolated by closing the respective isolation valve, this too was independently verified. Leads were properly taped to prevent inadvertent contact. As leads were lifted, this action was logged on the "Lifted/Landed Lead Log." Following removal of the defective pressure switch, the technicians verified that the new and old switches were physically comparable.

Following the installation of the new pressure switch, care was taken to slowly refill the hydraulic fluid line leading to the pressure switch. This was done to avoid causing an inadvertent pressure drop in the system. No problems were noted. Once this effort was completed, the leads were landed using the same double verification process. This was appropriately logged.

The pressure trip setpoint calibration effort, which was performed with the use of Procedure IC-CP-01-5098, was independently verified by the lead technician who took readings at the electrohydraulic control cabinet (this

action was not required by the procedure). The results obtained by the technicians calibrating the pressure switch and the lead technician were in agreement.

Postmaintenance testing was performed in accordance with the procedural requirements. The switch operated as expected. The technicians promptly cleaned up the work area prior to leaving it, observing good housekeeping practices.

4.2 Inspection of Emergency Diesel Generator (EDG) 2 Cylinder Liners

On December 21, the inspectors observed the licensee perform an inspection of EDG 2 cylinder liners. The inspection was performed using Maintenance Work Order 933922. The work order was initiated based on a concern identified in a 10 CFR Part 21 notification. The notification identified a potential cracking problem with the laser hardened cylinder liner (Electro-Motive Division Model 645 diesel engine Part Number 9318833). The suspect cylinder liners were manufactured in 1984.

The licensee determined that, although they had the Model 645 diesel engine, only one cylinder liner had been replaced since initial construction. The replaced cylinder liner (Number 5 Cylinder) was inspected and the part number (8415993) did not match the suspect liner. In addition, the licensee inspected the remaining cylinder liners and verified that no suspect liners were installed. The licensee has initiated a work item to inspect the EDG 1 liners during the next monthly surveillance.

4.3 Troubleshooting of Control Element Assembly (CEA) 16 Drive

On December 17, the licensee performed Surveillance Test Procedure OP-ST-CEA-0003, "Control Element Assembly (CEA) Partial Movement Check," with the reactor in power operation. During the test, CEA 16 was inserted to 120 inches but could not be subsequently withdrawn. The rod was then driven in to 117 inches to ensure the exercise limit switch was cleared, but the rod still could not be withdrawn. Abnormal Operating Procedure AOP-02, "CEA and Control System Malfunctions," was appropriately entered.

A licensed operator checked to ensure all switch contacts were clean. He moved the manual rod control lever from side to side and the CEA was then able to be withdrawn. The licensee initiated Incident Report 930407. In addition, Maintenance Work Order 933988 was issued on December 23 to troubleshoot the manual raise/lower circuit for CEA 16. The inspectors observed electrical maintenance personnel perform portions of the troubleshooting. Electrical maintenance determined that the raise/lower switch contacts had high resistance. In consultation with the system engineer, who also observed the troubleshooting, it was determined that the switch needed replacement. The appropriate parts were procured, issued, and installed on December 29.

As part of the operability verification for the replaced switch, the licensee performed Procedure OP-ST-CEA-0003. All control element assemblies operated as designed, with the exception of CEA 16, which again could not be withdrawn when inserted to 120 inches. Troubleshooting activities revealed that the mechanical interlock which prevented simultaneous actuation of the CEA withdrawal and insertion relays was binding. The interlock was replaced and no further problems were noted.

The inspectors noted that electrical maintenance personnel were provided with detailed work packages from maintenance planning. It was evident that electrical maintenance personnel understood the components and circuitry they were troubleshooting. System engineering provided strong support for both operations and maintenance. Communications between operations and electrical maintenance were effectively implemented.

4.4 Fire Pump Rebuilding

The inspectors observed the rebuilding of Diesel Driven Fire Pump FP-1B following the failure described in Section 2.4. The inspectors observed portions of the pump reassembly which was authorized by Maintenance Work Order 933968. The pump removal, refurbishment, and replacement instructions were supplemented by Procedure MM-RR-FP-0003, Revision 1, "Fire Pump Rebuilding." The work instructions were found to be appropriate. The inspectors discussed the task with two maintenance technicians. The inspectors found the technicians to be knowledgeable of the procedural requirements and familiar with rebuilding the three stage pump. The inspectors verified that the rigging slings utilized by the craft had current inspections.

Considering the magnitude of the pump rebuild job and concurrent repair of traveling screens, the material condition of the intake structure was very good. Equipment, tools, and component parts were properly staged and identified.

4.5 Conclusions

Personnel involved in maintenance activities were found to be knowledgeable of their responsibilities. Strong communication between maintenance and operations personnel was noted. Maintenance activity prebriefings were excellent. System engineer presence during maintenance activities to provide oversight and support was noted. Licensee response to the 10 CFR Part 21 notification regarding the EDG cylinder liners was prompt and proactive.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 Raw Water Pump AC-10B

The inspectors reviewed the licensee's actions to return Raw Water Pump AC-10B to an operable status. On December 14, during a review of the control room operations log, the inspectors noted that a log entry identified that the pump had failed its inservice test. However, the same entry also declared the pump to be operable.

Surveillance Test Procedure OP-ST-RW-3011, "Raw Water Pump Quarterly Inservice Test," provided the inservice test criteria for Class 1, 2 and 3 pumps. The inspectors reviewed surveillance test results for the last 2 years for Pump AC-10B. The surveillance test packages had been appropriately reviewed and approved. The inspectors noted that, during previous surveillance tests, when the pump performance degraded to the Low Alert Range for flow (i.e., requiring increased surveillances if pump performance remains in this area), the pump vane height was adjusted and the pump retested with satisfactory results.

The cause of the pump performance degradation was determined to be decreased impeller vane height, as a result of erosion caused by the quality of river water. The results of the most recent surveillance test conducted prior to December 14 indicated that the pump entered the Low Alert Range again. This time the licensee was unable to adjust the pump vane height because excessive wear had occurred. As a result of the pump entering the Alert range, the inservice testing frequency was increased from four times a year to once every month.

On December 14, the surveillance test results indicated that the pump performance had degraded such that the surveillance test acceptance criteria could no longer be met. The licensee appropriately declared the pump inoperable. Because the licensee has experienced wear of the raw water pumps previously, engineering evaluations had been performed to assess pump operability based on Missouri River temperature. These evaluations were performed using the most conservative high river water temperature of 85°F. These calculations provide a basis for determining if the pumps can perform their required safety design function. Based on these calculations, the results of the surveillance test indicated that the pump could still perform its safety design function. Subsequently, Pump AC-10B was declared operable, as provided by the licensee's Inservice Inspection Program Plan. The inspectors verified that the critical condition specified in the engineering evaluation was valid (river temperature was at 40°F). The inspectors also reviewed Engineering Analysis EA-FC-91-028, "Raw Water Pump Minimum Operability Limit," for Raw Water Pump AC-10B. No discrepancies were noted.

The inspectors reviewed the raw water pump's performance with the system engineer. The system engineer indicated that no other actions had been planned for Pump AC-10B at this time. This was because the pump was nearing the end of its operating cycle (2 years) and was scheduled to be replaced

during the first quarter of 1994. It was also identified that the performance of the raw water pumps had improved over the past several years because of improvements in coating materials used on pump internals. The inspectors noted that the system engineer's knowledge of pump performance and trending was very good.

5.2 Conclusions

Surveillance procedures had been properly reviewed and approved. System engineer knowledge of the raw water pumps, and of their performance trends, was very good. Licensee application of the inservice inspection program plan to the raw water pumps was found to be good.

6 ENGINEERED SAFETY FEATURES WALKDOWN (71710)

6.1 Raw Water System - Normal Operation

The inspectors walked down the accessible portions of the raw water system to verify the system valve and switch alignment using Operating Instruction OI-RW-1, "Raw Water System - Normal Alignment," Checklist OI-RW-1-CL-A. Drawing 11405-M-100, "Raw Water Flow Diagram," was also used in the verification process. The inspectors found that all the valves were in the correct position. The physical appearance of the equipment was very good. The inspectors observed that an unlabeled manual valve was recently installed downstream of Valve SW-236, which is on the backup seal water supply line to Raw Water Pump AC-10A. This valve was not identified on the valve lineup checklist. In addition, the inspectors noted the following discrepancies with the checklist:

- Valves HCV-2898C and IA-HCV-2898C-B were duplicated on the checklist.
- Valve RW-213 was listed as located in Room 18 (Component Cooling Water Heat Exchangers C and D room) but was physically located in Room 4 (auxiliary building basement).

It was subsequently identified to the inspectors that the unlabelled valve had been recently installed in the Raw Water Pump AC-10A seal water injection line as a part of Modification ECN 92-468 and LWO 93-0248. This modification provided for the installation of a throttle valve on each of the four raw water pump seal water injection lines. The inspector noted that the valve had been placed into service prior to revising the applicable operating instructions and drawings. It was found that the valve had been tested in accordance with the postmodification test requirements; however, system status controls had not been implemented. Final modification system acceptance had also not been completed. The inspectors will review the licensee's design modification program which permitted equipment to be placed into service without establishing appropriate system status controls as an unresolved item (285/9326-05).

6.2 EDGs - Normal Operation

The inspectors walked down the starting air, fuel oil, lube oil, and jacket water cooling systems for both EDGs. All valves and switches were in the correct positions. In addition, the physical appearance of the equipment was excellent.

6.3 Conclusions

The valve lineups for the raw water system and the EDGs were appropriately established to provide for system operation.

7 ONSITE REVIEW OF LICENSEE EVENT REPORTS (92700)

(Closed) Licensee Event Report 92/013: Inadvertent Isolation of Radiation Monitors During Containment Purge

This licensee event report addressed an event in which three ventilation isolation valves were inadvertently closed during a containment purge. The event occurred when the leads were accidentally lifted during work in a control room panel. The licensee concluded that the root cause was the susceptibility of the spade wire lugs installed during original construction to inadvertent loosening and loss of connection.

The corrective actions taken, as a result of this event, were to:

- Revise the maintenance procedure to incorporate requirements for terminating wires in accordance with appropriate engineering standards.
- Incorporate a requirement that, for a close-out inspection of control room panel maintenance activities, the condition of panel wiring complies with procedural requirements.
- A discussion of this event and the associated root cause analysis was discussed with maintenance electricians and instrumentation and control personnel to increase sensitivity to the possibility of inadvertently lifting spade wire lugs.

Following a review of the licensee's actions, the inspectors concurred with the licensee's conclusions that this was not an indication of a programmatic problem. The licensee's corrective actions were determined to be appropriate.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

*R. Andrews, Division Manager, Nuclear Services
*J. Chase, Manager, Fort Calhoun Station
*G. Cook, Supervisor, Station Licensing
*M. Frans, Supervisor, Systems Engineering
*J. Gasper, Manager, Training
*W. Gates, Vice President, Nuclear
*R. Jaworski, Manager, Station Engineering
*L. Kusek, Manager, Nuclear Safety Review Group
*W. Orr, Manager, Quality Assurance and Quality Control
*T. Patterson, Division Manager, Nuclear Operations
*R. Phelps, Manager, Design Engineering
*R. Short, Manager, Nuclear Licensing and Industry Affairs

*Denotes personnel that attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on January 5, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee agreed with the inspection findings presented at the meeting. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.