APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-285/94-03

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: January 2 through February 12, 1994

Inspectors: R. Mullikin, Senior Resident Inspector
R. Azua, Resident Inspector

Approved: William B. Jones for
William D. Johnson, Chief, Project Branch A — 3/29/94
Division of Reactor Projects — Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of onsite events, operational safety verification, maintenance and surveillance observations, followup on Augmented Inspection Team, followup on corrective actions for violations, followup on previously identified inspection findings, and followup on licensee event reports.

Results:

- The operators appropriately responded to plant transients and alarms which resulted from equipment and component failures. Good command and control was observed after a plant trip by the senior licensed operator. Prompt operator actions mitigated the effect an accidental fire sprinkler head discharge had on equipment in the turbine building (Sections 2 and 3.2.1).

- The radiological protection and security programs were properly implemented (Sections 3.3 and 3.4).

- Plant housekeeping was excellent (Section 3.3).

- Maintenance personnel demonstrated an excellent knowledge of their responsibilities. Good performance was noted (Section 4).

- Three examples were identified where plant personnel failed to demonstrate adequate attention to detail for procedural compliance. These examples were:

  An escorted visiting maintenance individual was not adequately controlled and stepped on a safety-related valve (Section 4.4);

  A chemistry technician failed to follow a surveillance test procedure (Section 5.1); and

  An engineer failed to promptly report a damaged safety-related valve to operations (Section 8.2).

Summary of Inspection Findings:

- Violation 285/9403-01 was opened (three examples) (Sections 4.4, 5.1 and 8.2).

- Inspection Followup Item 285/9403-02 was opened (Section 3.2.2).

- Violation 285/9203-01 was closed (Section 7.1).

- Violation 285/9209-01 was closed (Section 7.2).

- Inspection Followup Item 285/9203-02 was closed (Section 8.1).

- Unresolved Item 285/9326-04 was closed (Section 8.2).

- Licensee Event Report 92-024 was closed (Section 9).

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the Fort Calhoun Station was operating at 100 percent power. On January 7, 1994, reactor power was reduced to 60 percent to locate and repair a main condenser tube leak. On January 9, during power ascension, two out of three heater drain pumps tripped because of high vibration and an electrical overload condition. Reactor power was subsequently reduced from 86 percent to 47.5 percent to replace the heater drain tank dump valve controller due to a failure of the valve to close during the transient. On January 10, power was increased and maintained at 90 percent until a second heater drain pump could be repaired and put into service. On January 13, the plant reached 100 percent power.

On February 11, a reactor trip occurred because of an engineered safety feature logic supervisory relay failure. The relay was replaced and criticality achieved on February 12. A special inspection was initiated to review the single failure vulnerability of the existing engineered safety feature performance capability. The results of this special inspection are documented in NRC Inspection Report 50-285/94-08. At the end of the inspection period, the plant was in power ascension.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Loss of Two Heater Drain Pumps

On January 9, 1994, during a routine tour, the turbine building operator noticed that Heater Drain Pump FW-5B was vibrating sufficiently to cause the 4160-volt power supply cable to sway. The turbine building operator notified the control room and the pump was removed from service. The plant was in power ascension and at 86 percent power after a reduction to 60 percent power to repair a condenser tube leak. At the time of the discovery, two of the three heater drain pumps, FW-5A and FW-5B, were in operation. The licensee started Pump FW-5C after shutting down Pump FW-5B. Within 5 minutes sparks were observed coming from the Pump FW-5C motor housing and the motor tripped on instantaneous overcurrent.

The loss of two heater drain pumps resulted in an increase in heater drain tank level. Heater drain tank Level Control Valve LCV-1198 opened and dumped condensate water directly to the condenser. However, the valve would not fully close. The controller for Valve LCV-1198 was found to be defective and was replaced on January 10. Reactor power was reduced to 47.5 percent in order to perform this repair.

The licensee, after repairing Valve LCV-1198, increased reactor power to 90 percent. The inspectors discussed with the licensee any compensatory measures which had been developed in the event that the third heater drain pump were to trip. It was determined that a loss of the third heater drain tank pump would not cause a turbine trip nor an unnecessary challenge to safety systems. This postulated event was found to have been adequately addressed in the licensee's abnormal procedures.

2.2 Power Excursion Above Licensed Power Limit Because of an Inadvertent Reactor Coolant System Dilution

On January 19, the inspector, while reviewing the control room log, noted that a power increase above the license limit had occurred on January 18. Reactor power had increased to approximately 100.5 percent. The inspector verified that the licensee had satisfied their Technical Specification Limiting Condition for Operation by reducing power within the specified time limit. This event was included as the subject of a special inspection. The results of this inspection are documented in NRC Inspection Report 50-285/94-06, Section 2.

2.3 Reactor Trip

On February 11, at 3:40 a.m., a reactor trip occurred because of an inadvertent containment high pressure signal (CPHS). The Channel "B" CPHS actuation logic lockout relay (86B/CPHS) tripped causing a Train B safety injection actuation, containment isolation actuation, ventilation isolation actuation, and steam generator isolation signals. The main steam isolation closures resulted in a turbine trip/subsequent reactor trip. The reactor tripped before any of the reactor protection system setpoints were reached. A CPHS actuation should only occur if containment pressure reaches 5.0 psig. Actual containment pressure at the time of the trip was approximately 0.6 psig. A notification of unusual event was declared at 4 a.m. (CST).

The inspectors were in the main control room following the event and reviewed the licensee's assessment of the plant response. It was found that all safety equipment operated as designed. With the main feedwater system isolated, an automatic start of the electric auxiliary feedwater pump (FW-6) and turbine driven auxiliary feedwater pump (FW-10) occurred. In addition, with the main steam isolation valves closed, the main steam code safety valves lifted. These actuations were expected for this event. Primary system decay heat removal was maintained through the two main steam safety valves that have pneumatic controllers.

The inspectors observed good command and control by the shift supervisor. The licensed senior operator was effective in establishing the licensed operation priorities to recover from the event. Good use of the emergency operating procedures and abnormal operating procedures was noted. An emergency temporary modification was initiated to lift a lead on the relay to reset the actuation signal. The notification of unusual event was subsequently downgraded at 7:46 a.m.

The licensee's investigation into the event revealed that Relay 86B/CPHS had shorted, thus causing the CPHS. The licensee was planning to send the relay offsite for independent evaluation of the cause of the failure. This relay had been installed since initial operation of the plant.

The inspectors were in the control room and observed the installation and postmaintenance testing of the new relay. The testing was performed using Procedure OP-ST-ESF-0010, "Channel "B" Safety Injection, Containment Spray and Recirculation Actuation Signal Test." No problems were noted during these activities.

2.4 Conclusions

The operators appropriately responded to the heater drain pump trips and the safeguards actuation. Good command in the control room was observed after the trip.

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 for proper communication of plant status from one shift to the other. Discussion with operators indicated that they were aware of plant and equipment status and reasons for lit annunciators. The inspectors observed that Technical Specification limiting conditions for operation were properly documented and tracked. The inspectors noted that operators were declaring equipment inoperable during surveillance testing. Control room traffic was observed to be effectively limited to personnel requiring access to conduct work related activities.

3.2 Plant Tours

3.2.1 Broken Sprinkler Nozzle

While touring the turbine building basement on January 12, 1994, the inspector encountered a large amount of water on the basement floor. The water appeared to have originated from a fire protection sprinkler nozzle that was located directly overhead. A nonlicensed operator in the area explained that maintenance personnel involved in removing a heater drain pump motor from the turbine building basement to the truck bay, inadvertently struck the sprinkler head. The sudden deluge of water caused control room alarms. The alarms alerted the control room operators, who were also informed by maintenance personnel as to the cause of the problem in accordance with plant administrative procedures. Two nonlicensed operators were dispatched to investigate. The nonlicensed operators, upon determining that no fire existed, proceeded to isolate the affected nozzle using Procedure OI-FP-01, "Fire Protection System Water System." The inspector accompanied the operator while he verified that all the appropriate valves, as identified in the procedure, had been closed. The operators coordinated their efforts, maintaining contact with each other and the control room via radio communications. The inspector noted that the operator checked to see if any equipment in the vicinity had been adversely affected by the event and none was noted. Finally, the fire protection system engineer was contacted to verify that appropriate compensatory measures had been initiated for the unplanned impairment.

3.2.2 Auxiliary Steam Leak in Emergency Diesel Generator 1 Room

On January 31, the inspector noted the presence of a small auxiliary steam leak in the Emergency Diesel Generator (EDG) 1 Room. The inspector observed that the leak had been identified by the licensee due to a deficiency tag attached to a conduit. The leak appeared to be a pinhole leak at a 1-inch piping elbow and was located approximately 12 feet above the floor. The condensed steam was dripping into a pail that had been placed on the floor. The inspector noted that the pail was emptied before the pail overflowed. Although the steam leak presented a housekeeping problem, the inspector was concerned with the electrical cable inside of a conduit that the steam was impenging against. The inspector notified the licensee as to this concern.

The licensee identified that the conduit contained a security cable. The cognizant system engineer determined that the cable provided alarm functions and that any degradation of the cable by the steam would only result in a trouble alarm. The inspector reviewed the priority given to correct the steam leak. It was determined that the work request had been properly prioritized and was scheduled to be worked.

The inspector noted that this was the second pinhole auxiliary steam line leak in this room within the last 3 months. Both leaks were at 1-inch piping elbows. This 1-inch line was observed to come off of a larger auxiliary steam line header located in the same area. Previously, the licensee had modified the boundry between the EDG rooms to prevent a common mode failure in the event an auxiliary steam line break had occurred in one of the two EDG rooms. However, the inspector was concerned that erosion/corrosion conditions, which apparently resulted in the 1-inch line elbow steam leak, may also exist in the steam header and could still adversely affect operation of an EDG.

This concern was discussed with the cognizant system engineer. He stated that there was no evidence to indicate an erosion/corrosion problem in the large auxiliary steam lines in the room, as indicated by the maintenance history on this line. However, these lines were not included in the licensee's erosion/corrosion program. At the end of the inspection, the licensee was reviewing their erosion/corrosion monitoring program to assess the need to include the auxiliary steam line. The inspectors will followup on the licensee's evaluation of the need in include the auxiliary steam line as Inspection Followup Item 285/9403-02.

3.2.3 Equipment Tagout

On January 31, EDG 1 was declared inoperable to perform both corrective and preventive maintenance. The inspector walked down the equipment tagout sheets for the maintenance activity and verified that the components were in their designated positions and that the clearance tags were appropriately hung.

The inspector verified that the licensee met the Technical Specification requirements for an inoperable EDG. In addition, the inspector verified that the EDG 2 supporting systems were appropriately aligned by using the checklist in Operating Instruction OI-DG-2, "Diesel Generator No. 2 (EDG 2) Normal Operation."

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 radiologically controlled area. Contaminated areas and high radiation areas were properly posted, and restricted high radiation areas were found to be locked, as required. The housekeeping in the controlled areas was maintained at an excellent level.

3.4 Security Program Observations

Security personnel were observed to perform their duties in a professional manner. Security personnel were found to perform thorough inspections of personnel who failed to clear the detection equipment. 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 responsibilities were knowledgeable of the escort requirements and appropriately maintained control of their assigned personnel.

3.5 Visit to the Local Public Document Room (LPDR)

On January 10, the inspector visited the LPDR located in the W. Dale Clark library in downtown Omaha, Nebraska. The purpose of the visit was to familiarize the inspector with the content and status of this room.

The inspector found that the majority of documents regarding the Fort Calhoun Station, were in the form of microfiche located in a locked room on the same floor. Reference books located on the shelves provided ample information for identifying documents of choice, and clear guidance on how to retrieve this information. The inspector reviewed the information and found it to be complete.

3.6 Conclusions

Operator actions were very good following an accidental fire sprinkler head discharge. The presence of small auxiliary steam leaks in an EDG room raised concerns on the condition of the piping. The LPDR was informative and complete. Plant housekeeping was excellent.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 TRINUKE Vacuum/Filtration Unit AC-20 Filter Replacement

On January 11, 1994, the inspector observed the licensee replace the filter cartridges for TRINUKE Vacuum/Filtration Unit AC-20 located in the spent fuel pool. This maintenance activity was governed by Maintenance Work Order (MWO) 933807. The inspector reviewed the MWO and found it to be general in nature, placing emphasis on the skill of the craft. The MWO provided sufficient information to identify the equipment to be worked on, and the type of work that was to be performed. The MWO had been reviewed and approved by the licensee, as noted by the appropriate signatures.

Prior to the initiation of this maintenance activity, the licensee held a briefing with the personnel involved. The briefing included the details of the maintenance activity; the radiation work permit that was to be used, including good radiation work practices and precautions with regard to handling highly contaminated equipment (i.e., used filter cartridges); and the removal and storage of the used filter cartridges. Maintenance personnel interviewed by the inspector were found to be knowledgeable of their responsibilities.

The inspector observed that the licensee utilized very good as-low-as-reasonably-achievable (ALARA) practices. Radiation protection personnel oversight was also very good. The health physics technician monitored the maintenance personnel efforts closely, keeping them appraised of dose rates in the area, and aiding them with the removal and storage of the used filter package. The health physics technician also prepared a laydown area in the eventuality that if the maintenance personnel were not able to remove the filter package under water, an area would be available for the TRINUKE filtration unit to be placed on the side of the spent fuel pool. The radiation work permit, which the maintenance personnel were working under, provided appropriate protective measures had this been necessary.

The maintenance activity was completed in a timely manner and with the filter in the pool, thus minimizing personnel exposure. The personnel involved were observed to perform their duties in a professional manner. The inspector reviewed the maintenance history for the TRINUKE Vacuum/Filtration Unit AC-20. No adverse trend was noted.

4.2 Cleaning and Flushing Containment Spray Pump Seal Water Cooler

On January 11, the inspector observed a preventive maintenance activity that flushed the component cooling water side of the Containment Spray Pump SI-3C's seal water cooler. This work was performed using Maintenance Procedure MP-AC-FLUSH, "Cleaning and Flushing of Coolers Supplied by the CCW System."

In preparation for this effort, redundant equipment was determined to be operable. In addition, the inspector verified that all the proper equipment had been tagged out prior to the licensee initiating the work. The licensee entered the appropriate Technical Specification limiting condition for operation as indicated by the control room log.

While preparing for this maintenance activity, maintenance personnel observed very good radiation work practices including prestaging equipment, minimizing their time in higher dose areas, and staying in low dose areas while waiting for the flushing effort to be completed. Upon completion of the flushing effort, the system engineer inspected the flush water for any signs of debris or sand, and none were noted. Maintenance equipment was promptly removed and stored, with maintenance personnel adhering to excellent housekeeping practices. The system valve alignment was returned to normal and the pump was declared operable following a successful postmaintenance test. The inspector verified that all valves, altered for this activity, had been returned to their normal operating condition.

4.3 Heater Drain Pump C Motor Installation

On January 12, the inspector observed portions of the licensee's efforts in receiving and installing Heater Drain Pump C Motor FW-5C-M. The motor had recently experienced high vibration and, as a result, had been removed and sent to the vendor for inspection and repairs. The licensee's efforts were covered by MWO 940079 and Maintenance Procedure MM-RR-FW-0020, "Inspection and Repair of Heater Drain Pumps."

The inspector reviewed the maintenance work order and the associated procedure, and verified that its guidance did not conflict with the information provided in the vendor's instruction manual. Proper steps were taken by the licensee to negate those portions of Procedure MM-RR-FW-0020, which did not apply to this effort. The inspector reviewed Danger Tag Verification Sheet 94-0036 to verify that all the appropriate tagouts had been addressed. Finally, the postmaintenance test equipment (i.e., vibration monitors and meggering equipment) were found to have been properly calibrated.

Maintenance personnel were found to observe very good personnel safety practices. Those that were to be operating crane equipment were verified as having the appropriate training and qualification. Procedural compliance was noted throughout this effort and those maintenance personnel questioned displayed excellent knowledge of their responsibility. No problems were experienced during the installation of the pump motor.

Following completion of the maintenance activity, postmaintenance tests were performed on the pump and motor. The results of the tests were within the acceptance criteria set forth in the maintenance work order. The inspectors concluded that the work activity was well performed.

4.4 Furmanite Activities on Main Steam System

On January 20, the inspector observed licensee contract personnel seal two steam leaks located at Swagelok fittings on the 1/2-inch warmup lines for the Turbine Driven Auxiliary Feedwater Pump FW-10 steam supply piping. These leaks were sealed with the use of Furmanite sealing compound and the two activities were covered under MWOs 940002 and 940003, and Temporary Modifications 94-001 and 94-002, respectively.

The inspector reviewed the maintenance work orders, the temporary modifications, and the Furmanite (contractors) Procedure QA-4-N-93520, "Furmanite American Engineering Procedure." The maintenance work orders were general in nature, but specific instructions prohibiting peening on the Furmanite enclosures or the piping was noted. The inspector also verified that the maintenance work orders provided adequate postmaintenance testing requirements, not only for determining that the leaks had been sealed, but to identify that the sealant had no impinging effect on the steam flow through the piping. Furmanite Procedure QA-4-N-93520 was noted to have been reviewed and approved by the licensee prior to the performance of this activity.

Prior to beginning the maintenance activity the inspector verified that the equipment that had been prestaged met the procedure requirements. The work area was found to be accessible without having to build scaffolding. These items included the Furmanite sealant compound, sealant enclosure boxes, sealant injection shutoff valves, and a pressure gauge. In addition, the inspector checked the certification and calibration documents associated with each item. No discrepancies were noted.

During the maintenance activity, good procedure compliance by the contract personnel was noted. Quality control personnel were observed to monitor the effort and perform verification checks during the appropriate quality control hold points designated in the procedure. The inspector questioned the contract personnel with regard to the activity that they were performing and found that they were knowledgable of their responsibilities. However, a concern that a component in the area may have been damaged as a result of improper personnel action was noted when one of the contract personnel stepped on the actuator and handwheel for the main steam isolation valve Bypass Valve HCV-1042C, while trying to reach one of the steam leaks. The inspector identified this to the licensee quality control personnel who in turn contacted the control room. An operator was dispatched to check the valve and identified that the valve position had not been altered. The licensee further evaluated that no damage had occurred to the valve. The licensee issued Corrective Action Report 94-023 to address this occurrence.

cable trays. Although the contract employee was being escorted, and as a result did not undergo the licensee's general employee training program, it is the escort's responsibility to ensure that his charge is aware of licensee management expectations and plant procedural requirements. This event is of concern because the failure by the licensee to adequately control contract personnel demonstrated a lack of attention to detail which could have resulted in the inadvertent operation of, or damage to, safety related equipment. The failure to fully implement the requirements of Standing Order SO-M-100 is considered to be a violation of NRC requirements (285/9403-01).

Following completion of the maintenance activity, the postmaintenance tests described in the maintenance work orders were performed. The results of the tests indicated that the steam leaks had been sealed and that the maintenance effort had no adverse effect on the steam flow through the 1/2-inch warm up line.

4.5 EDG 1 Governor Replacement

On January 31, the inspector observed the installation of a new governor on EDG 1 by the licensee. The work was performed using MWO 930855. The governor was replaced in an efficient manner and the inspector verified that all control settings were in accordance with the vendor specifications.

After this and other maintenance activities were completed, the EDG was started to demonstrate operability using Surveillance Test OP-ST-DG-0001, "Diesel Generator 1 Checks." The test was successful until operators attempted to stop the EDG, but were unable to do so either from the control room or locally. An operator then proceeded to manually move the control lever for the fuel injectors to the off position. This was successful in stopping the EDG but resulted in breaking the control rod linkage assembly.

The licensee did not have a spare linkage in stock. The linkage was approximately 6 inches in length and was connected to the governor shaft in the middle and to the fuel rack control arms at each end. A replacement part was located at the vendor, and the part was received and installed on February 2. The damaged control linkage was removed for examination as to the cause of the failure. The licensee performed a visual inspection of the linkage and control arm for EDG 2 to ensure that a common mode failure mechanism did not exist. The inspector also performed a visual inspection and no visible flaws were detected.

Troubleshooting activities were conducted concurrently to determine the reason for the inability to shutdown the EDG. The licensee determined that the shutdown solenoid, which was a part of the newly installed governor, had a diode suppression circuit in the supply line which the previous governor did not have. Since the field connections to the solenoid were reversed from what was required, the licensee initiated Temporary Modification No. 94-006 to reverse the two field wires at a locally mounted junction box. This modification was approved and installed on February 1. Postmodification testing revealed no problems with the operability of the EDG and it was declared operable on February 2. The inspector reviewed the temporary modification package and found a good technical evaluation and 10 CFR 50.59 applicability screening. No unreviewed safety questions were identified. The inspector verified that the temporary modification package was in the control room, control room drawings were marked with the temporary modification number, and that document control had a copy of the marked up drawings. The licensee was performing a review to determine the cause of the reversed wiring. No information was available on the cause of the broken linkage or the reversed wiring at the end of the inspection period.

4.6 Conclusions

Throughout this inspection period, maintenance personnel demonstrated the required knowledge of their responsibilities. Prebriefings held prior to each maintenance activity were very informative and provided an excellent forum for questions. Maintenance personnel were found to adhere to ALARA practices. Good communication between maintenance personnel and other crafts was noted. One instance of lack of attention to detail in the stepping on a valve resulted in a violation of plant procedures.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 Auxiliary Building Exhaust Stack Sampling and Analysis

On February 8, 1994, the inspector observed the performance of Surveillance Test CH-ST-VA-0001, "Auxiliary Building Exhaust Stack Sampling and Analysis." Other procedures associated with this test were Chemistry Sampling Procedure CH-SMP-RE-0013, "Auxiliary Building Exhaust Stack Sampling Particulate and Iodine," and Chemistry Sampling Procedure CH-SMP-RE-0012, "Auxiliary Building Exhaust Stack Sampling Radioactive Gases." The purpose of these surveillance tests are to sample and analyze the auxiliary building exhaust stack for alpha, radioactive gases, iodine, and particulates with half-lives greater than 8 days.

The inspector reviewed the procedure and found that it satisfied, in part, the requirements of the Fort Calhoun Station off-site dose calculation manual. The procedures had been reviewed and approved as noted by the appropriate signatures.

The test was broken into two parts. The first part, covered by Procedure CH-SMP-RE-0012, provided instructions for taking a gaseous sample from Auxiliary Building Exhaust Stack Radiation Monitor RM-062. During the performance of this effort procedural compliance was noted. Near the end of this effort, Section 6.2.6 of the procedure called for closing the downstream isolation valve on the sample container to allow it to pressurize slightly before shutting the inlet isolation valve. The inspector noted that when the chemistry technician performed this function, he appeared to close both valves almost simultaneously. When questioned by the inspector, the technician stated that due to the size of the pump and the the sample container, it did not take very long for the sample container to pressurize slightly. He also added that if the container was pressurized too much, it would explode, and that it did not take very much pressure for this to occur. The technician also added that on previous occasions, this had happened during different tests with the same sample containers. The inspector questioned the technician with regard for the need to pressurize the sample container. He stated that the increased pressure increased the density of the sample and, thus, provided for more accurate results.

The second part of the test was covered by Procedure CH-SMP-RE-0013. This procedure addressed the replacement of the iodine cartridge and filter in Auxiliary Building Exhaust Stack Radiation Monitor RM-060. Following the removal of the used iodine cartridge and filter, the technician placed both the filter and the cartridge in the same storage bag. This was not in accordance with Sections 6.1.4 and 6.1.5 of the procedure which identified that both were to be stored in separate bags. The failure to store the filter and cartridge in separate bags represents a second example of a violation for a failure to follow procedures (285/9403-01).

Good communication between the chemistry technician and the control room was noted. Analysis of the material obtained during this surveillance effort did not identify any anomalous readings.

5.2 Conclusions

Inattention to detail by a technician resulted in the procedural guidance not being strictly followed during performance of a surveillance test. The licensee's actions to resolve concerns with obtaining the gaseous sample did not adequately address the potential personnel safety hazard and a possible contamination that could occur if the sample container were to overpressurize and explode. Good communication between chemistry personnel and operations personnel was noted.

6. AUGMENTED INSPECTION TEAM FOLLOWUP (92701)

During November 19-22, 1993, an NRC Augmented Inspection Team conducted an onsite inspection to review the circumstances concerning the uncontrolled movement of control element assemblies (CEAs). The results of this inspection are documented in NRC Inspection Report 50-285/93-25. This report documents the corrective actions that the licensee committed to complete to resolve the concern with the uncontrolled CEA movement. The following is a review and/or status of these corrective actions.

6.1 Corrective Action:

Troubleshoot, identify, and eliminate all grounds in the rod control, core mimic, and rod block systems and remove the hardwired connection between the 120-VAC and 28-VDC power supplies.

Inspector Followup: The licensee had performed troubleshooting during the inspection period, identified and repaired the grounds that caused the anomalies, and removed the hardwired connection.

6.2 Corrective Action:

Install a permanent ground detection system on the rod control and core mimic systems.

Inspector Followup: The licensee installed, under Modification MR-FC-93-021, a permanent ground detection system on the control rod drive system. This detection system consisted of lights which detected the presence of grounds by differences in illumination. The licensee also installed voltmeters on the positive and negative leads to detect the presence of ground by differences in voltage readings. The inspector verified that this system was installed and monitored as a part of the turbine building operator checklist.

6.3 Corrective Action:

Perform comprehensive testing of the rod control, core mimic, and rod block systems.

Inspector Followup: The licensee had, prior to startup, performed all required surveillances associated with the rod control system. All tests were completed satisfactorily. The inspector observed the plant startup and no rod control problems were encountered.

6.4 Corrective Action:

Have the Nuclear Safety Review Group (NSRG) conduct an independent review of the troubleshooting and testing activities.

Inspector Followup: The inspector reviewed the summary provided by the NSRG of the review of troubleshooting and ground detection testing. The NSRG concluded that the licensee's activities in these areas were adequate.

6.5 Corrective Action:

Have a shutdown safety advisor (SSA) conduct an independent assessment to confirm the adequacy of operator and instrumentation and control technician actions during the CEA withdrawal event of November 13, 1993.

Inspector Followup: The SSA was a position created for the refueling outage and consisted of three individuals with senior reactor operator training. In a memorandum dated November 19, 1993, an SSA provided the results of an independent evaluation of the event. The SSA concluded that the event did not jeopardize shutdown safety but made recommendations as to procedure revisions. These recommendations were reviewed by the licensee and included, if warranted, in the licensee's corrective actions.

6.6 <u>Corrective Action</u>:

Review all other ungrounded power supply systems to ensure these systems are provided with ground detection systems.

Inspector Followup: The licensee provided the results of the review of other ungrounded systems. It was found that ground detection systems were installed on all ungrounded systems.

6.7 <u>Corrective Action</u>:

Conduct a formal safety assessment to confirm that the event was bounded by the safety analysis and that the present design meets the current licensing basis. This included an evaluation by Combustion Engineering of the safety and operational significance of any malfunctions resulting from multiple grounds, including low resistance and high resistance grounds. It also included an assessment of the effect of multiple smart grounds that could result in bypassing redundant rod block contacts.

Inspector Followup: This action was reviewed by the inspection team during the inspection period and was found to be acceptable.

6.8 <u>Corrective Action</u>:

Conduct a review of 1993 refueling outage modifications and maintenance for possible linkage to this event. This review was to include work related to the multiple grounds and the moisture intrusion into the connector.

Inspector Followup: The licensee reviewed all 1993 refueling outage activities and concluded that no activities could be identified that would have introduced the ground or was a source of the moisture.

6.9 <u>Corrective Action</u>:

Perform an initial update of the Nuclear Network that will include the details surrounding these events and the root causes of the events.

Inspector Followup: The licensee provided an industry network notification on November 17, 1993, and updated as required.

6.10 <u>Corrective Action</u>:

Review plant records to determine if any similar occurrences of uncontrolled rod motion had occurred.

Inspector Followup: The licensee documented in a memorandum dated November 22, 1993, that there had been two additional inadvertent rod movement (1986 and 1989) occurrences. The licensee concluded that these were not caused by grounds.

6.11 Corrective Action:

Complete a root cause analysis to identify root cause for the November 13, 1993, event and identify corrective actions to preclude similar events.

Inspector Followup: The licensee's root cause analysis concluded that the cause of the event was a lack of a ground detection system for the power supply to the rod control drive system and core mimic display. Included in this analysis were several recommendations which were incorporated in the licensee's corrective actions.

6.12 Corrective Action:

Reinforce to all operations personnel that all instrumentation indications will be considered valid unless it is proven that the instrument indication is invalid. In addition, all operating shifts will receive training regarding the events, the revised procedures, and the new ground detection system prior to assuming their watch duties.

Inspector Followup: Operations personnel were briefed on the event and the new ground detection system. The inspector attended one of these crew briefings during a shift turnover. Training on new procedure changes is ongoing and occurs as procedures are revised. The licensee has an ongoing commitment to include lessons learned from this event in future formal training classes. This is scheduled for completion by May 1, 1994.

6.13 Corrective Action:

The annunciator response procedure (ARP-CB-4/A8) for the continuous rod motion alarm will be revised. This revision will ensure that CEA positions are verified using all available indications after the rod mode selector switch is placed in the OFF position.

Inspector Followup: The inspector verified that Annunciator Response Procedure ARP-CB-4/A8, "Annunciator Response Procedure A8 Control Room Annunciator A8," was revised to satisfy this commitment.

6.14 Corrective Action:

Revise Surveillance Procedure IC-ST-CEA-0002, "Functional Test of SCEAPIS Rod Block Actuations," by adding a precaution to ensure that containment integrity is established whenever more than one CEA is to be moved.

Inspector Followup: The inspector verified that Surveillance Procedure IC-ST-CEA-0002 had been revised to add the appropriate precautions.

6.15 Corrective Action:

A calculation will be completed that will demonstrate the sensitivity of the newly installed ground detection system on the rod control and the core mimic systems.

Inspector Followup: The NRC reviewed the licensee's Calculation FC06172, "Rod Drive Control Ground Detection Relay Set Point Determination," Revision B. The calculation indicated that the ground fault detectors will detect ground faults when the rod drive contactors are not energized. Since the rod drive contactors are deenergized with the plant operating at power, the NRC concluded that the ground fault detectors will be effective for detecting of these types of ground faults.

The issue that the calculation (and design) of the ground fault detectors would not detect ground while the rod drive contactors were energized was also reviewed. As the result of this condition, it could be postulated that, with a rod drive contactor energized (which means that CEA motion is in progress), a ground fault developing under this condition could potentially connect the rod drive contactor to a power supply without energizing the ground fault relay. As the ground fault relay is not energized in this condition, a ground fault alarm would not annunciate. Such a fault could bypass the rod control circuit, thereby preventing the contactor from dropping out and providing for continuous CEA motion.

The licensee was made aware of this potential but considered their ground detection system design to be adequate for the detection of ground faults that could result in uncontrolled CEA movement.

6.16 Corrective Action:

A signoff and inspection criteria will be considered for the procedure used for disconnecting and reconnecting control element drive mechanism (CEDM) cable connectors.

Inspector Followup: This action is currently under review with a scheduled completion date of June 1, 1994.

6.17 Corrective Action:

Procedure OP-2A, "Plant Startup," will be revised to require a reactor trip if a reactivity anomaly which results in an increasing count rate or reactor power level is observed.

Inspector Followup: The inspector verified that Procedure OP-2A was revised to require either CEA insertion or a reactor trip for a reactivity anomaly.

6.18 Corrective Action:

Standing Order SO-0-1, "Conduct of Operations," will be revised to add a statement to the annunciator response section emphasizing that all alarms are to be treated as valid unless proven otherwise and that alarms directly associated with safety functions must be fully understood prior to continuing with other plant activities.

Inspector Followup: The inspector verified that Standing Order SO-0-1 was revised to include the above requirement.

6.19 Corrective Action:

Lessons learned from this event will be included in future training classes. This will include additional training on CEA position indication as part of the biennial licensed operator requalification training program. This training will also encompass any new procedural changes that have been made as a result of these events.

Inspector Followup: The inspector reviewed the student performance printout for training given to operators on this event. This training was given during November and December 1993. In addition, the licensee revised operator Lesson Plan 7-12-26 to provide training on this event during license requalification classes.

6.20 Corrective Action:

The performance of maintenance and testing activities affecting safety functions and requiring a high level of attention during an outage will be evaluated to determine the feasibility of restricting the performance of these activities to between 2:30 a.m. and 6 a.m. These activities could include testing of CEAs, shutdown cooling evolutions, and monitoring of reactor coolant system level during filling or draining operations. These activities are more likely to be completed successfully when fewer distractions are present in the control room. Another consideration that will be examined will be to place administrative restrictions on the number of activities or personnel in the control room at any one time.

Inspector Followup: The licensee has two commitment documents covering these actions. The one for scheduling of maintenance and testing activities was scheduled for completion of evaluation by March 15, 1994. The one for controlling control room activities or personnel was scheduled for completion of evaluation by April 1, 1994.

6.21 Corrective Action:

Evaluate what improvements can be made to protect the CEDM cable connectors against water intrusion.

Inspector Followup: The licensee evaluation of this action is scheduled for completion by June 1, 1994.

6.22 Conclusions:

The corrective actions completed by the licensee satisfy the commitments made in these areas. The corrective actions not completed were verified to be included in the licensee's commitment tracking program. No further followup is required.

7 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS AND A DEVIATION (92702)

7.1 (Closed) Severity Level IV Violation 285/9203-01: Failure to Control Foreign Material from Entering the Refueling Cavity and Spent Fuel Pool

This violation resulted from the inspector's observations during the beginning of the 1992 refueling outage that foreign materials were not being properly logged and accounted for in the designated foreign material exclusion area. In addition, a foreign material exclusion coordinator had not been designated.

The licensee stated that, unlike previous outages, an honor system for the control of foreign materials was utilized. Thus, no foreign material coordinator was designated. However, after the findings presented by the inspector, the licensee concluded that this system was not working properly. Thus, the licensee reinstituted the use of foreign material coordinators. The inspectors observed that after that time, the use of foreign material was properly controlled. In addition, the inspectors routinely observed the control of foreign materials during the 1993 refueling outage. Appropriate control of foreign materials was noted.

7.2 (Closed) Severity Level IV Violation 285/9209-01: Inadequate Procedure to Assure Proper Electrical Lineup

This event occurred during a refueling outage when shutdown cooling was secured after three 480-VAC electrical busses were lost during the performance of a surveillance test. The licensee was performing flow testing on two high pressure safety injection pumps while the plant was in an abnormal electrical configuration. Due to maintenance being performed, the three 480-VAC busses were tied together and being supplied through one transformer. The supply breaker tripped on thermal overload and power was lost to all three busses. This resulted in a loss of power to the shutdown cooling flow control valve controller and shutdown cooling flow indication. Since the shutdown cooling flow control valve failed open the control room operators were concerned of a possible runout condition on the operating safety injection pump. Thus, they secured shutdown cooling until the situation could be assessed and corrected. Within 7 minutes the operators had restored shutdown cooling.

The licensee concluded that the event resulted from the surveillance procedure not reflecting design limitations with plant electrical systems in an abnormal alignment. In addition, the outage organization was not effective in controlling the scheduling of surveillance tests. The licensee has revised the control of surveillance activities during outages by requiring all surveillance test scheduling to be performed by the outage group.

The licensee included the event into the operator training program and provided training to existing licensed operators. The inspector reviewed the training documentation to verify that these actions had been performed.

The licensee reviewed and revised 40 surveillance tests to ensure that the shift supervisor consults Operating Instruction OI-EE-2B, "480 Volt Hot Bus Transfer," if the 480-VAC buses are not in their normal alignment. The inspector verified that the 40 procedures had been revised to include the appropriate requirement.

8 FOLLOWUP (92701)

8.1 (Closed) Inspection Followup Item (IFI) 285/9203-02: Erroneous Alarm Setpoint for Spent Fuel Pool Heat Exchanger

This item concerned the finding that the alarm response and calibration procedures listed the alarm setpoint for the component cooling water side of the spent fuel pool heat exchanger as 200°F where the actual operating temperature was approximately 100°F. The inspector documented in NRC Inspection Report 50-285/92-03, that the alarm was nonsafety-related and that other control rooms alarms would alert operators of insufficient spent fuel pool cooling.

The inspector verified that the subject alarm response and calibration procedures had been revised to incorporate the correct temperature.

8.2 (Closed) Unresolved Item 285/9326-04: Reporting of Damaged Raw Water Valve

This unresolved item concerned the failure by a licensee individual to promptly report to operations personnel a safety-related valve (HCV-2881B) with a broken handwheel stem. Valve HCV-2881B was the raw water outlet isolation valve on Component Cooling Water Heat Exchanger AC-1B. The system engineer discovered the deficiency on December 16, 1994, but operations was not informed until the inspector discovered the broken stem on December 17. The failure to notify operations on December 16 delayed the operability evaluation required by Procedure NOD-QP-31, "Operability and Reportability Determinations." Valve HCV-2881B was determined to be operable on December 17.

The licensee has established procedures and instructions that provide guidance to licensee personnel on reporting deficient conditions. The General Employee Training Manual, "Station Orientation," is the manual that all site personnel, except visitors, are tested on. This clearly stated that all personnel have the responsibility to report safety-related concerns or problems to the appropriate individuals. However, this was a recent revision to the manual and previously the requirement was to identify and report quality or safety-related problems in a person's own work area. Training on the new more detailed requirements has not yet been conducted for all plant personnel.

Standing Order SO-M-100, "Conduct of Maintenance," Section 6.3.1, instructed maintenance personnel to report deficient conditions to the shift supervisor. Standing Order SO-G-18, "Operational Nonconformance Reports," Section 1.3.3, required all plant personnel to notify the shift technical advisor or the shift supervisor immediately when operational nonconformances are discovered to ensure that the actions necessary to maintain the plant in a safe condition are taken as required by the Technical Specifications. Operation nonconformances are defined, in part, as a nonconforming condition found in any operable system, structure, or component. The engineer initiated a maintenance work request which would have repaired the valve but would not have guaranteed that a timely operability determination be made. The failure to immediately report the damaged valve to the shift supervisor or the shift technical advisor is considered to be a third example of a failure to follow procedures and is considered to be a violation (285/9403-01).

9 ONSITE REVIEW OF LICENSEE EVENT REPORTS (92700)

<u>(Closed) Licensee Event Report 92-024: Failure to Comply with Linear Heat Rate Technical Specifications During Alarm Inoperability</u>

This report described an event in which the licensee, following a review of Technical Specification 2.10.4(1)(b), identified four separate occasions in which conditions specified in the Technical Specification were not satisfied when the plant computer incore detector alarms were inoperable. Specifically, the Technical Specification required that power be reduced to the limits of the core operating limits report, unless measured peak linear heat rate prior to the incore detector alarm outage was not greater than 90 percent of the allowable peak linear heat rate.

The event was not determined to be significant with respect to plant safety. Linear heat rate is used to provide information on core performance and fuel management and does not provide any automatic protective function. Data for these events indicated that the peak linear heat rate, before and after alarm inoperability, did not exceed the Technical Specification allowable peak linear heat rate.

The root cause of these events was considered to be a lack of an adequate procedure for covering the monitoring of key reactor physics parameters. No documentation was available to the reactor engineer on whether or not uncertainties/allowances were to be applied to the peak linear heat rate obtained from the CECOR computer program. A contributing factor was the lack of a training program for the reactor engineer and the shift technical advisors on the operation and application of the CECOR computer program.

The licensee's corrective actions were as follows:

- Developed a Technical Specification interpretation to define the appropriate application of uncertainties/allowances to peak linear heat rate when operating under Technical Specification 2.10.4(1)(b)(i).

- Procedure OI-ERTCS-2, "Core Monitoring Systems," was developed for the online computer code to include operation, alarm response and functional inputs to the program. In addition, the procedure also included the monitoring of key reactor physics parameters.

- Checklist FC-1213, "Checklist for CECOR Performance," was revised to include a statement to notify the shift supervisor if peak linear heat rate is greater than 90 percent of the Technical Specification limit.

- Training was provided to the reactor engineer and the shift technical advisors on the operations of the CECOR computer program, and on the material developed above.

The inspectors reviewed documentation for the completion of the corrective actions taken by the licensee. Based on the review performed by the inspectors, the licensee had taken appropriate actions to preclude repetition of this event.

ATTACHMENT 1

1 PERSONS CONTACTED

Licensee Personnel

*R. Andrews, Division Manager, Nuclear Services
*C. Brunnert, Supervisor, Operations Quality Assurance
*G. Cavanaugh, Licensing Engineer
*J. Chase, Manager, Fort Calhoun Station
G. Cook, Supervisor, Station Licensing
H. Faulhaber, Supervisor, Maintenance
*M. Frans, Supervisor, Systems Engineering
*J. Gasper, Manager, Training
*W. Gates, Vice President, Nuclear
*R. Jaworski, Manager, Station Engineering
*W. Jones, Senior Vice President
*B. Kindred, Senior Nuclear Security Supervisor
*L. Kusek, Manager, Nuclear Safety Review Group
W. Orr, Manager, Quality Assurance and Quality Control
*T. Patterson, Division Manager, Nuclear Operations
*R. Phelps, Acting Division Manager, Production Engineering
F. Smith, Supervisor, Chemistry
*R. Short, Manager, Nuclear Licensing and Industry Affairs
*J. Skiles, Acting Manager, Design Engineering
J. Tills, Assistant Plant Manager, Operations
*D. Trausch, Acting Manager, Training

*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 February 16, 1994. During this meeting, the inspector 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 inspector.