U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/94006(DRP)

Docket No. 50-331 License No. DPR-49

Licensee: IES Utilities Incorporated
IE Towers, P. O. Box 351
Cedar Rapids, IA 52406

Facility Name: Duane Arnold Energy Center

Inspection At: Palo, Iowa

Inspection Conducted: February 8 through March 19, 1994

Inspector: J. Hopkins
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Approved: R. D. Lanksbury, Chief
Reactor Projects Section 3B

4/1/94
Date

Inspection Summary

Inspection on February 8 through March 19, 1994
(Report No. 50-331/94006(DRP))

Areas Inspected: Routine, unannounced inspection by the resident and region based inspectors of followup, licensee event reports followup, followup of events, operational safety, maintenance, surveillance, spent fuel pool modifications, regional requests, management meetings, and report review.

Results: An executive summary follows:

EXECUTIVE SUMMARY

Plant Operations

The plant operated up to full power during the period with minor down power operations due to surveillance testing. Pressure oscillations were identified on the "B" reactor recirculation pump number 2 seal after a routine down power transient. Pressure returned to normal, and there was no indication of increased drywell leakage (Section 5.c). The operations, maintenance, and engineering departments promptly evaluated the risk to the plant and took effective corrective actions when a previously unrecognized failure mode of the heat-tracing system was brought to their attention (Section 5.b). Good compliance with the foreign material exclusion requirements was noted during the work on the spent fuel pool (Section 8).

Maintenance/Surveillance

Performance of maintenance activities during the report period was very good. Most activities were well planned, had appropriate engineering and management involvement, and were performed in accordance with approved plant procedures. Examples included repairs to "B" control building chiller oil temperature control valve, the reactor core isolation cooling system turbine stop valve, and the high pressure core injection steam trap. However, poor planning was identified during the "B" standby diesel generator jacket water pump seal replacement and the proposed ice removal on the utility tower insulators for the 161Kv lines leading to the startup transformer (Section 6).

An unresolved item (URI) was identified for the failure of the standby filter unit (SFU) system to perform its safety function without the nonsafety-related hot water preheat system, and the failure of the technical specification testing to verify the proper operation of the SFU system (Section 7.a).

Engineering

The engineering department performed a good root cause evaluation during the troubleshooting of the "A" residual heat removal pump failed post-maintenance test (Section 7.b).

Plant Support

A URI was identified as a result of apparent lack of attention to detail by a nonlicensed operator resulted in a high radiation access door not being shut and locked (Section 4). During the spent fuel pool modification work, good planning, communications, oversight and teamwork were observed (Section 8).

DETAILS

1. Persons Contacted

*J. Franz, Vice President Nuclear
*D. Wilson, Plant Superintendent, Nuclear
*R. Anderson, Operations Supervisor
*P. Bessette, Supervisor, Regulatory Communications
*J. Bjorseth, Maintenance Superintendent
*L. Henderson, Manager, Emergency Planning
*J. Kinsey, Licensing Supervisor
*M. McDermott, Manager, Engineering
*K. Peveler, Manager, Corporate Quality Assurance
*S. Swails, Manager, Nuclear Training
J. Thorsteinson, Assistant Plant Superintendent, Operations Support
*G. Van Middlesworth, Assistant Plant Superintendent, Operations and Maintenance
*T. Wilkerson, Manager, Radiation Protection
*K. Young, Manager, Nuclear Licensing

In addition, the inspectors interviewed other licensee personnel including operations shift supervisors, control room operators, engineering personnel, and contractor personnel (representing the licensee).

*Denotes those present at the exit interview on March 18, 1994.

2. Followup (92701)

a. (Closed) Open Item 50-331/91019-01(DRP): Dual Function Containment Isolation Valves. (A dual function containment isolation valve performs a safety function to open or close to support safety system operation, and has a safety function to close to provide primary containment isolation.) This open item concerned containment isolation valves which would not remain closed, under certain conditions, when operated from the control room. Specifically, the core spray (CS) minimum flow bypass valves would not remain closed if the CS system flow was less than 300 gallons per minute (gpm); the high pressure core injection (HPCI) torus suction isolation valves would not remain closed on low level in the condensate storage tank (CST) or high level in the torus; and the reactor core isolation cooling (RCIC) torus suction isolation valves would not remain closed on low level in the CST. Additionally, the valves were not listed in technical specifications (TS) as power operated containment isolation valves. The primary containment isolation function of these valves was being reviewed by the Office of Nuclear Reactor Regulations (NRR) to determine if any generic implications existed. (See inspection report (IR) 331/91022 and open item 331/90009-03(DRP), closed in IR 331/92023, for related information.)

When these issues were first identified, the licensee performed a safety evaluation and concluded that the necessary compensatory measures were in place to ensure the valves were capable of performing their containment isolation function. The NRC's position, documented in a letter to the licensee, dated October 10, 1991, was that if any emergency core cooling system (ECCS) or containment isolation valve experienced a failure mode that did not allow the valve to fully function as intended, the requirements for primary containment isolation may no longer be met. Unless relief was granted, the limiting condition for operation (LCO) for primary containment isolation applied. In addition, even if the valve was stuck open, the malfunction degraded the ECCS function since the system could no longer be isolated.

In a letter dated December 11, 1991, the licensee committed to adopt the NRC's position concerning safety-related dual function containment isolation valves. In March 1992, amendment 181 was approved which deleted the lists of power operated containment isolation valves from TS. Administrative control procedure (ACP) 1410.7, "Guidelines for Inoperable Primary Containment Isolation System (PCIS)," issued in April 1992, identified PCIS valves and penetrations, denoted applicable TS requirements for inoperable PCIS valves, and provided specific guidance to the plant staff if an inoperable PCIS valve was identified.

In a letter to the NRC, dated December 7, 1993, the licensee withdrew their commitment to apply the TS LCO for any ECCS or containment isolation valve that experienced a failure that did not allow the valve to fully function as intended. The licensee's position was that the ECCS function of the valves (i.e. CS minimum flow bypass valves, HPCI and RCIC torus suction isolation valves) was more important than the containment isolation function. If a dual function containment isolation valve was determined to be inoperable, licensee management would contact the NRC to determine the safe position for the valve. The licensee's withdrawal of their commitment, and the NRC's position concerning safety-related dual function containment isolation valves was being reviewed and will be resolved by NRR (TAC number 88398). This open item is closed.

b. <u>(Closed) Unresolved Item 50-331/92013-01(DRP):</u> River Water Pump Motor Circuit Breaker Fire. This item was reviewed by the inspectors and determined to be a violation of 10 CFR Part 50, Appendix B. The review of the corrective actions for violation (50-331/92017-01(DRP)) is documented below. This unresolved item is closed.

c. <u>(Closed) Violation 50-331/92017-01(DRP):</u> River Water Pump Motor Circuit Breaker Fire. In early June 1992, the licensee replaced the electrical circuit breakers for the four river water supply (RWS) pumps with a new design. Each of the breakers was tested and declared operable prior to replacing the next breaker. On June 17, 1992, operators started the "D" RWS pump. The pump immediately tripped, and fire alarms actuated near the 1B20 load center. A fire from the "D" RWS breaker was extinguished within 8 minutes. An investigation into the cause of the fire identified that the clearance between the breaker primary disconnects and the stabs on the bus work was inadequate. All RWS breakers were effected by this condition. The licensee declared the RWS pumps inoperable until they were replaced with the original design circuit breakers.

The modification in early June 1992 replaced the existing circuit breakers, model K225, with model K800S breakers. Correspondence with the vendor led the licensee to believe that the new breakers were a like-for-like replacement. The K800S breakers were not verified by the licensee to ensure the breaker disconnects fit into the bus work stabs properly. A lack of thorough in-house review of the breaker interface design specifications was determined to have been the root cause of this event.

The licensee conducted an investigation and identified corrective actions to prevent recurrence. The inspectors reviewed the corrective actions and interviewed personnel involved with corrective action implementation. The corrective actions appeared adequate to prevent recurrence. This violation is closed.

No violations or deviations were identified in this area.

3. Licensee Event Reports (LER) Followup (92700) (90712)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective actions were accomplished, and corrective actions to prevent recurrence had been accomplished in accordance with technical specifications.

a. (Closed) LER 92-010 (331/92010-LL): River Water Pump Motor Circuit Breaker Fire. This item was reviewed by the inspectors and determined to be a violation of 10 CFR Part 50, Appendix B. The review of the corrective actions for the violation (50-331/92017-01(DRP)) is documented above. This LER is closed.

b. (Closed) LER 92-013 (331/92013-LL and 92013-01): Reduced Scram Setpoint Due to Induced Noise Signal Caused Automatic Reactor Scram. This event was previously discussed in Inspection Report 50-331/92017(DRP). The scram resulted in some complications that were addressed through the corrective actions. A review of the licensee's analysis and corrective actions was conducted, and no concerns were identified. The corrective actions appeared adequate to prevent recurrence. This LER is closed.

No violations or deviations were identified in this area.

4. Followup of Events (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements, and that corrective actions would prevent future recurrence. The specific events are as follows:

February 10, 1994 - Preheat coils on "B" Standby Filter Unit (SFU) failed. (See section 7 for details.)

February 27, 1994 - Locked high radiation area door found ajar.

Locked High Radiation Area (LHRA) Door Found Ajar.

On February 27, 1994, at approximately 5:00 p.m. (CST), with the plant at approximately 100 percent power, a LHRA door was found ajar. The door was closed and resting on the door jamb, but not latched and locked. The door provided access to the steam jet air ejector (SJAE) room in the turbine building basement. The SJAE room had been accessed several times earlier in the day to support surveillance and maintenance activities during a planned downpower evolution. The last known exit through the door was earlier in the day at approximately 5:00 a.m. by a nonlicensed auxiliary operator (AO). There was no security card reader for the door. The AO thought the door had properly shut when the SJAE room was exited. Earlier in the day, personnel who exited the SJAE room noted that the door had not properly latched when it closed. The door was properly closed by those personnel.

The licensee conducted an investigation of the event and determine that the root cause was personnel error due to lack of attention to detail. The investigation concluded that no other personnel entered the SJAE room after the AO exited at 5:00 a.m. The licensee's immediate corrective actions included repairing the door latch mechanism, verifying all LHRA doors were closed and locked, and providing training to plant personnel involved with the event. Additionally, operations personnel were no longer allowed to make high radiation area entries for routine rounds without health physics personnel present. The past practice had been that operators were allowed to enter high radiation areas unaccompanied due to the special training they received on the entry requirements and the use of radiation survey instruments. Requalification training on the entry requirements was being provided for operations personnel. This was the first time a LHRA door was found ajar since 1991. Failure to ensure a high radiation access door was shut and locked was considered an unresolved item (URI) pending further review by Region III radiation protection specialists (331/94006-01(DRSS)).

No violations or deviations were identified in this area. One URI was identified.

5. Operational Safety Verification (71707) (71710)

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during the inspection. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of the reactor building and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance. It was observed that the Plant Superintendent, Assistant Plant Superintendent of Operations, and the Operations Supervisor were well-informed of the overall status of the plant and that they made frequent visits to the control room. The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan. The inspectors observed plant housekeeping and cleanliness conditions and verified implementation of radiation protection controls.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, Title 10 of the *Code of Federal Regulations*, and administrative procedures.

a. Standby Diesel Generator (SBDG) Air Start Distributor Cam

On January 13, 1994, a 10 CFR Part 21 notification was made by Coltec Industries, formerly named Fairbanks Morse Diesel Engines, concerning a potential problem with the diesel engine air start distributor cam. The concern was that cams which were manufactured using an "arc marking" technique were susceptible to cracking. Based on Coltec's recommendation, the licensee visually inspected the cams (in situ) for both SBDGs and determined that the cams were stamped, vice arc marked. Additionally, no cracks were identified. The cams were also visually inspected for cracks during each refueling outage. No cracks had been identified. Based on additional information from Coltec Industries, the licensee planned to replace the cams during the next refueling outage, scheduled for early 1995. The inspectors reviewed the licensee's response to the 10 CFR Part 21 notification and had no concerns.

b. Cold Weather Protection (71714)

On February 12, 1994, a Region III plant identified a 2-foot long section of heat-traced piping adjacent to the condensate storage tank (CST) that was blocked. A fuse in the heat-trace circuit had blown with no alarms or indications of the failure, and the piping had frozen. A temperature monitoring device, immediately downstream of the blockage, had not reached the low temperature alarm setpoint. On February 15 the inspectors brought this event to the licensee's attention and requested that they review the adequacy of their cold weather protection programs to determine if the plant was susceptible to a similar failure. The licensee identified six heat-traced pipes from the CST for safety-related equipment which were susceptible to the failure mechanism. All other heat-traced piping on systems important to safety had alarms or other indications available to the operators to ensure that the heat-trace circuits were operating and providing the desired protection.

The licensee's immediate corrective action was to locally monitor the pipe's temperatures once each shift when outside air temperature was below 40 degrees fahrenheit (deg. F). All pipe temperatures were greater than 50 deg. F. The licensee planned to develop a permanent method of monitoring the temperatures or of positively determining that the heat-trace circuit was functioning properly. The operations, maintenance, and engineering departments promptly evaluated the risk to the plant and took effective corrective actions.

c. Pressure Oscillations on "B" Reactor Recirculation Pump Number 2 Seal

On February 27, 1994, reactor power was reduced to approximately 80 percent to support testing activities. The licensee determined that the "B" reactor recirculation pump number 2 seal pressure had increased to approximately 650 psig from the nominal 500 to 575 psig. Pressure indications on the number 1 seal and both of the "A" reactor recirculation pump seals were normal. There was no indication of increased drywell leakage. By March 8, number 2 seal pressure had returned to the normal band. A similar transient had been observed during the down power operation on January 18, 1994. Seal pressure had returned to normal within a few days. The seal package for the "B" reactor recirculation pump had been replaced during the refueling outage in September 1993. The inspectors will continue to monitor the performance of the pump seals and the licensee's planned corrective actions.

No violations or deviations were identified in this area.

6. Monthly Maintenance Observation (62703)

Station maintenance activities of safety-related systems and components listed below were observed and/or reviewed to scertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with technical specifications (TS).

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which might affect system performance.

Portions of the following maintenance activities were observed and/or reviewed:

- 4160 Vac circuit breaker inspection.

- 1V-SF-21 standby diesel generator (SBDG) room supply fan breaker inspection.

- 1P-44B fuel oil transfer pump breaker inspection.

- "B" control building chiller oil temperature control valve repair.

- Reactor core isolation cooling (RCIC) system turbine stop valve repair.

- "B" SBDG jacket water pump seal replacement.

- "B" emergency service water pump loss of control power.

- High pressure coolant injection (HPCI) steam trap repair.

Overall, the performance of maintenance activities during the report period was very good. Activities were well planned, had appropriate engineering and management involvement, and were performed in accordance with approved plant procedures. Examples included repairs to "B" control building chiller oil temperature control valve, the RCIC system turbine stop valve, and the HPCI steam trap. However, poor planning was identified during the "B" SBDG jacket water pump seal replacement and the proposed ice removal on the utility tower insulators for the 161Kv lines leading to the startup transformer (see below).

<u>Ice Buildup on Startup (S/U) Transformer</u>

On February 8, 1994, with the reactor at approximately 100 percent power, ice buildup was identified on the utility tower insulators for the 161Kv lines leading to the S/U transformer. The main transformer and the electrical distribution switchyard were inspected, and no ice buildup was identified. The S/U transformer, which was powered from the switchyard, was the normal power supply to the two essential buses. The licensee shifted the power supply for the essential buses from the S/U transformer to the standby transformer to minimize the risk of an electrical transient due to ice buildup. Plans were made to de-energize the S/U transformer and remove the ice on the tower insulators.

On February 9, during the pre-evolution brief, plant electrical technicians planned to use "buzz sticks" to verify the 161Kv lines were de-energized. (A "buzz stick" was an insulated device which was intended to make noise when placed near energized high voltage lines. (See IR 331/93015 for information concerning "buzz sticks".) The inspectors asked if "buzz sticks" were authorized for determining if a high voltage line was de-energized. The licensee stopped the maintenance activity to resolve the issue.

The licensee contacted the corporate Safety Department and determined that the prohibition against using "buzz sticks" had not been distributed on a corporate wide basis. The memo prohibiting their use was signed on February 4, 1994, and distributed on February 11. Additionally, the licensee contacted the corporate organization that normally maintained the high voltage distribution system and determined that the amount of ice buildup was not a hazard. The licensee continued to monitor the buildup to determine if a problem developed.

The inspectors were concerned that the licensee had not thoroughly planned the maintenance activity. Although the initial identification and immediate actions were pro-active, the lack of proper planning disrupted the work schedules of both the operations and maintenance departments. Additionally, the plan to use "buzz sticks" indicated that management expectations were not clearly communicated to all levels of the organizations. This example was not indicative of the licensee's routine performance.

Following completion of the activities related to the S/U transformer, the inspectors verified that the electrical distribution system had been returned to service properly.

No violations or deviations were identified in this area.

7. <u>Monthly Surveillance Observation (61726)</u>

The inspectors observed technical specification (TS) required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with TS and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed portions of the following test activities:

STP-42B044-SA - Low-Low Set System Functional Test and Pressure Switch Calibration.

STP-42E003-Q - Calibration and Functional Test of Containment Air Sampling System Instruments.

STP-45A002-Q - Low Pressure Coolant Injection (LPCI) System Quarterly Operability Test.

STP-47B008-M - Standby Gas Treatment and Standby Filter Unit Operation With Heaters On.

a. "B" Standby Filter Unit

On February 10, 1994, with the reactor at approximately 100 percent power, the "B" train of the standby filter unit (SFU) failed monthly surveillance test procedure (STP) 47B008, "Standby Gas Treatment and Standby Filter Unit Operation with Heaters On." The circuit breaker for the electric preheat coils tripped on high temperature several times during the STP. The "B" SFU fan continued to operate after the electric heaters tripped and continued to supply outside air at approximately minus 17 deg. F through the SFU and as a result the nonsafety-related hot water preheat coils froze and ruptured. The "B" SFU was declared inoperable and the 7 day TS LCO was entered. The "A" SFU had passed the STP on the previous day.

On February 14, during the troubleshooting, the licensee determined that the high temperature, "on contact," heating element trip setpoint (750 deg. F) for the electric heaters was too low to ensure the "A" SFU could preheat the cold outside air without the aid of the hot water preheating system. On February 14, at approximately 3:17 p.m., both trains of the SFU system were declared inoperable. The licensee notified the NRC in accordance 10 CFR 50.72 that the SFU system was not capable of performing its intended function and entered the 12 hour to Hot Shutdown LCO. The electric heater trip setpoint was reset to a higher temperature, and at approximately 6:14 p.m., on February 14 the "A" SFU was declared operable, thus allowing exiting of the 12 hour Hot Shutdown LCO. The hot water preheat coils were removed from the "B" SFU, the high efficiency particulate air (HEPA) filters and charcoal bed were replaced and tested, the high temperature trip for the electric heaters was reset at a higher temperature, post-maintenance testing was successfully completed, and the "B" SFU train was declared operable on February 15.

The SFU system was designed to ensure that in an emergency, the control room was maintained at a positive pressure and an adequate supply of filtered air was provided to the control room to allow continued plant operation. The preheating system was designed to remove moisture and preheat outside air, at temperatures down to minus 30 deg. F, to a minimum of 50 deg. F before the air entered the charcoal filter bed. The safety-related electric preheat coils and the nonsafety-related hot water preheat coils were physically in series in the SFU and had separate temperature control systems.

The "as found" setpoint for the "A" SFU electric heater temperature controller was found to be set at approximately 50 deg. F and the "B" SFU electric heater temperature controller was found to be set at approximately 88 deg. F, vice the design setpoint of 50 deg. F. Investigation by the licensee found that the electric heater controllers were not in the calibration program. The licensee subsequently incorporated them into the program with an annual frequency. The "as found" setpoint of the "A" SFU hot water control system was found to be approximately 10 deg. F below the nominal 55 deg. F setpoint and the "B" SFU hot water temperature control system "as found" setpoint was found approximately 30 deg. F below the nominal 55 deg. F setpoint, both due to instrument drift. The SFU hot water temperature control system was on a 6 year calibration cycle and had last been calibrated in January 1992. The hot water control system was recalibrated and returned to service and the licensee was performing an evaluation to determine whether or not to remove the hot water coils.

Since the setpoint of the hot water control system was greater than the electric temperature control system, the performance of the hot water control system masked the inadequate setpoints of the electric temperature control system and high temperature trip. The licensee concluded that the routine monthly TS required STP had not adequately tested the ability of the electric preheaters in the SFU to perform their safety function.

An engineering evaluation determined that with an electric temperature control system setting of 50 deg. F and a high temperature trip setpoint of 750 deg. F, the SFU would not have been able to preheat the outside air at temperatures less than 15 deg. F. Since the design bases for the SFU system was to remove moisture and preheat outside air at temperatures down to minus 30 deg. F, the SFU was not capable of performing its safety function without the nonsafety-related hot water preheating system.

The failure of the SFU system to perform its safety function without the nonsafety-related hot water preheat system, and the failure of the TS STP to verify the proper operation of the SFU system was considered an URI (331/94006-02(DRP)) pending review by Region III specialists. The inspectors will continue to monitor the performance of the SFUs and the licensee's corrective actions.

b. "A" RHR Post-Maintenance Operability Test.

On March 10, 1994, with the reactor at approximately 100 percent power, the "A" RHR pump failed STP 45A002-Q, "LPCI System Quarterly Operability Tests," due to low pump discharge pressure and was declared inoperable. The pump had been out of service for preplanned maintenance and calibration of the differential pressure instrument (PDIS 1971A) that controls minimum flow valve MO-2009. The pump's discharge pressure was 154 psig at 4800 gpm flow. The required discharge pressure was greater than 160 psig at 4800 gpm. The pump's discharge pressure gauge and the flow transmitter (FT 1971A) were checked for proper calibration and no concerns were identified. The STP was performed again and discharge pressure was 150 psig at 4800 gpm. The results of the February 1994 quarterly STP were 171 psig at 4800 gpm.

The engineering and maintenance departments evaluated the information and determined that air was trapped in the sensing lines of FT 1971A. The air was most probably introduced when PDIS 1971A was calibrated on March 9, 1994. Flow transmitter 1971A and PDIS 1971A shared a common flow element. The licensee reviewed the calibration procedure and determined that there was a potential for introducing air into FT 1971A when PDIS 1971A was refilled. Additionally, the lack of high point vents in the piping configuration for PDIS 1971A made it difficult to remove all of the entrapped air. The licensee "back filled" FT 1971A, and on March 11 reperformed the STP. The pump discharge pressure was 171 psig at 4880 gpm. The licensee planned to review and modify the calibration procedure for PDIS 1971A to prevent air intrusion. The engineering department performed a good root cause evaluation during the troubleshooting. The inspectors will continue to monitor the performance of the RHR system and the licensee's review of the calibration procedure for PDIS 1971A.

No violations or deviations were identified in this area. One URI was identified.

8. Spent Fuel Pool (SFP) Modifications and Activities.

During this inspection period, the licensee, in conjunction with contractors, was in the process of modifying the storage capacity of the SFP. The work in progress was to remove a number of structures and some existing fuel racks in order to replace them with additional high density fuel racks.

A regional inspector on site observed a sample of the activities which included over pool work, hydrolyzing (water jet decontamination and cleaning), removal of gun barrels (control rod storage racks) and a fuel channel rack, radiation surveys and records, packaging and securing of material for shipment to a waste repository, preparations for lifting an existing spent fuel rack, and the storage and condition of the new spent fuel racks. The inspector also attended daily briefings on this project, received an ALARA brief and training on foreign material exclusion for the refuel floor activities. In addition, he toured that portion of the facility with the project coordinator and interviewed supervisors and workers.

The inspector verified that heavy lift path exclusions were observed, that refuel floor access control was maintained, reviewed applicable procedures including the construction work package traveler, "Removal of Gun Barrels, Channel Rack", and associated contractor (Holtec) procedures.

The inspector observed that during the daily briefings, that there was good discussion and the meetings were attended by almost all personnel involved in the project. He noted that there was flexibility and consideration given to unexpected plan changes and interruptions, and that there were contingencies for other unexpected occurrences such as radiation levels in excess of that expected.

During the work and planning, it was also noted that there was good cooperation and team work between the construction (Holtec) workers and the licensee staff. The presence of the ALARA coordinator and QA representative were noted and that the licensee supervisor took an active role in the ongoing work. In addition, it was noted that all personnel involved worked well with the Health Physics staff on the project that resulted in low radiation exposures.

The inspector also observed that the requirements of the recently implemented foreign materials exclusion (FME) procedure "Refuel Floor Housekeeping Control" Number 1408.12, Revision 2, of March 4, 1994, were being followed by all personnel involved. This included observance of the FME exclusion boundary; tethering of loose items; exclusion of the use of tape; and control of personal items such as glasses, hard hats, and personal monitoring equipment. The inspector also verified that the refuel floor material accountability log was properly maintained.

No violations or deviations were identified in this area.

9. Regional Requests (92701)

Defective Westinghouse Puffer Tube Assemblies

During replacement of Westinghouse 4160 Vac circuit breakers, a Region III plant determined that the puffer tube assemblies were incorrectly configured and poorly constructed. A 10 CFR Part 21 notification was made by the Region III plant. The puffer tube was designed to supply a jet or puff of air through an insulated tube and nozzle to each of the three main contact assemblies, each time the circuit breaker was opened. The purpose of the jet of air was to direct the arc current upward into the arc chute where it would be interrupted. Failure of the puffer tube assembly could have prevented the circuit breaker from interrupting rated fault current. The licensee determined that Westinghouse puffer tube assemblies were not used in the plant or electrical distribution switchyard.

No violations or deviations were identified in this area.

10. Management Meetings (30702)

On March 2 - 4, 1994, Messrs. J. Martin, Regional Administrator; G. Grant, Director, Division of Reactor Safety (DRS); R. Lanksbury, Chief, Division of Reactor Projects, Section 3B; and M. Huber, DRS, were onsite and met with site and corporate management. During the visit, Mr. Martin toured the plant with the senior resident inspector.

On March 10, 1994, Mr. W. Axelson, Director, Division of Radiation Safety and Safeguards (DRSS), was onsite and met with members of the radiation protection, security, fire protection, and emergency planning organizations. During the visit, Mr. Axelson toured the plant.

On March 17 - 18, 1994, Mr. W. Snell, Chief, Radiological Programs Section 1, DRSS, was onsite and met with members of the radiation protection, quality assurance, and emergency planning organizations. During the visit, Mr. Snell toured the plant.

11. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's monthly operating report for February 1994. The inspectors confirmed that the information provided met the requirements of TS 6.11.1.C and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during the inspection are discussed in Sections 4 and 7.a.

13. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Section 1) on March 18, 1994, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspectors also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspectors. The licensee did not identify any such documents or processes as proprietary. The licensee acknowledged the findings of the inspection.