APPENDIX E

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/94-09
50-499/94-09

Operating License: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company (HL&P)
P.O. Box 1700
Houston, Texas 77251

Facility Name: South Texas Project Electric Generating Station (STP), Units 1 and 2

Inspection At: Matagorda County, Texas

Inspection Conducted: January 30 through March 12, 1994

Inspectors: D. P. Loveless, Senior Resident Inspector
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Approved: W D Johnson 4/22/94
W. D. Johnson, Chief, Project Branch A Date

Inspection Summary

Areas Inspected: Routine, augmented, unannounced inspection of plant status, onsite followup of events, operational safety verification, maintenance and surveillance observations, Technical Specification requirements verification, sustained control room and plant observation, and followup on operational readiness assessment team findings.

Results:

- A reactor operator failed to properly respond to a turbine trip annunciator while the reactor was at power (Section 2.2).

- Reactor operators responded to the reactor trip from power in an excellent manner (Section 2.3).

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- Licensee management made a conservative decision to repair a primary-to-secondary leak that was less than Technical Specification allowable limits (Section 2.4).

- Reactor operators, inappropriately performing surveillance activities in the wrong solid state protection system logic cabinet, caused a safety injection actuation and the loss of decay heat removal while the reactor was in midloop operations (Section 2.5).

- Overall, control room operations in Unit 2 improved throughout the inspection period (Section 3.1).

- The inspector verified that certain engineered safety features systems were in the appropriate standby alignments in Unit 1 (Section 3.3).

- The attention to detail of reactor plant operators was considered to be poor based on the number of plant deficiencies identified by the inspectors (Section 3.5).

- Licensee engineers' coverage of a contractor performed leak sealant repair was considered to be excellent (Section 4.3).

- A violation was identified for the failure of administrative controls to prevent scaffolding from being constructed within the minimum distance from large bore piping (Section 4.6).

- Increased first line supervision and improved self-verification techniques were observed in the field (Section 4.10).

- Turbine-driven auxiliary feedwater pump testing was completed satisfactorily. Restart Issue 1, "Turbine-Driven Auxiliary Feedwater Pump Reliability and Test Methodology," was considered resolved (Section 5.2).

- One violation was identified for the failure to properly review procedural changes (Section 5.9).

- Feedwater isolation bypass valve testing was completed satisfactorily. Restart Issue 14, "Adequacy of the Licensee's Resolution of the Reliability and Operability of the Feedwater Isolation Bypass Valves," was considered resolved (Section 5.14).

- The inspector's questions helped identify calculational errors in postaccident boron concentration uncertainties (Section 6.1).

- Thirty-four Technical Specification requirements were independently verified to be met (Section 6.2).

- Use of formal communications techniques was observed to be inconsistent in the control room during surveillance testing (Section 7.1).

- Operators did not always attempt to determine the cause and corrective action for problems initiating plant annunciators. Operators cleared unnecessary control panel alarms only after being questioned by the inspectors (Section 7.7).

- The licensee identified a failure to correctly test the local manual shunt trip on the reactor bypass breakers in accordance with Technical Specifications. This was a noncited violation (Section 7.9).

- The licensee determined that the reactor trip breakers and some solid state protection circuits had not been tested on a staggered test basis in accordance with Technical Specifications. This was a noncited violation (Section 7.9).

- Overall, licensed operator performance in the control room was found to be good. However, some weaknesses and inconsistencies were noted in the areas of: control room professionalism, communications, self assessment and corrective actions, self-verifications, and procedural controls (Section 7.16).

Summary of Inspection Findings:

- Violation 498/94009-01 was opened (Section 4.6).

- Violation 498/94009-02 was opened (Section 5.9).

- Deficiency 93-202-D1 remained open (Section 8.1).

- Deficiency 93-202-D4 remained open (Section 8.2).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1 Plant Status

At the beginning of this inspection period, the Unit 1 reactor was in Mode 5, with preparations underway to enter hot shutdown (Mode 4). On February 6, 1994, at 5:33 a.m. the reactor operators increased the reactor coolant system temperature to greater than 200°F and entered Mode 4. On February 8, at 6 p.m. the reactor coolant temperature was increased to greater than 350°F entering Mode 3, and on February 10, the reactor coolant system was stabilized at normal operating temperature and pressure.

On January 29, the licensee issued a letter stating their intent to restart Unit 1 and requested an opportunity to brief the NRC on their readiness to operate the plant safely. On February 14, a public meeting was held between HL&P and the NRC to discuss the completion of the Confirmatory Action Letter issues and the restart action plan status. On February 15, the Regional Administrator authorized the restart of Unit 1.

On February 17, reactor operators administratively entered Mode 2 and began withdrawing the movable rod cluster control assemblies. At 12:27 a.m., on February 18, the reactor was taken critical.

Following initial testing and placing secondary plant systems in service, reactor operators increased reactor power to greater than 5 percent on February 22 at 12:39 a.m., entering Mode 1. On February 25 at 5 p.m., having completed main turbine-generator testing, reactor operators closed the main generator output breaker ending the forced maintenance outage.

On February 28, the Normal Feedwater Regulating Valve 1D failed closed. Following an unsuccessful attempt to open the valve, reactor operators manually tripped the reactor from 28 percent power at 10:13 p.m.

During the recovery from the reactor trip, chemical analysis of the secondary water in Steam Generator 1C indicated a primary-to-secondary leak of approximately 160 gallons per day. On March 1 at 5 p.m., plant management decided to cool down the reactor and repair the leak. Mode 4 was entered on March 3 and Mode 5 on March 4.

On March 5, reactor operators drained the reactor coolant system to midloop, and opened the primary manways on Steam Generator 1C. A steam generator tube plug was found to be leaking. Replacement of the plug and additional testing and inspection of the steam generator was completed on March 10.

On March 10, operator performance errors and a lack of management oversight resulted in an inadvertent safety injection signal and a brief loss of residual heat removal flow while in Mode 5. This event is the subject of a special inspection and the results are documented in NRC Inspection Report 50-498/94-12; 50-49/94-12.

At the end of this inspection period, Unit 1 was in cold shutdown with preparations underway to return the unit to power and continue the power ascension plan.

1.2 Unit 2 Plant Status

Throughout this inspection period, the Unit 2 reactor was shut down and defueled. At the end of the inspection period, Unit 2 was in Day 278 of the refueling outage.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Failure of Safety-Related Damper Backup Batteries

On February 1, during corrective maintenance activities on Train C of the control room heating, ventilation, and air conditio[illegible] system, maintenance technicians identified that the Control Room Make[illegible]r 1-HE-FCV-9586 batteries had failed. Upon further investigation[illegible]ee personnel determined that the batteries for the dampers in all three trains of control room ventilation had failed.

The inspectors reviewed the vendor manual and determined that the batteries provided a backup power supply to cause these electrohydraulic dampers to fail closed on loss of all ac power. During a design basis accident, the standby diesel generator of one train was assumed to fail. Subsequently, the associated station battery would be depleted. For this train, the backup battery should cause the makeup damper to close. If the battery has failed, the damper will not close, and flow from the other two trains will be directed through the open damper and backward through the idled fan. This potential degradation of the control room ventilation system caused by a single failure was reported to the NRC by the control room operators.

Licensee personnel obtained batteries from another plant with a similar design and returned the dampers to an operable status. Licensee engineers performed calculations and determined that, with two operable trains of control room makeup, the system would continue to perform its intended safety function with a makeup damper failed open.

During a generic review, licensee engineers determined that makeup dampers in the fuel handling building ventilation system also contained backup batteries that had failed. The engineering evaluation of the effect of the failure or postulated accident conditions concluded that, although offsite doses would be increased, no operator action would be necessary to maintain offsite doses below regulatory limits. Additionally, engineering personnel plan to review all equipment qualification design change notices to ensure that appropriate items were identified in preventive maintenance tasks.

Based on extensive licensee corrective action, and the low safety significance of this event, this failure to fully meet Technical Specification requirements involving preventive maintenance program implementation will not be cited because licensee personnel satisfied the criteria in Paragraph VII.B.2 of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice."

2.2 Failures of Standby Diesel Generators

On February 3, 1994, Standby Diesel Generator 11 was started in accordance with Plant Surveillance Procedure OPSP03-DG-0001, Revision 0, "Standby Diesel 11(21) Operability Test." The diesel speed increased to approximately 600 rpm; however, the generator did not develop voltage or frequency. The licensee declared Standby Diesel Generator 11 inoperable and documented the failure on Station Problem Report 94-0250.

On March 1, Standby Diesel Generator 21 started in the normal run mode for no apparent reason. Licensed operators placed the diesel in cooldown mode as part of an orderly shutdown. The diesel immediately restarted in normal mode and the generator locked out on ground faults. Operators placed the diesel in pull-to-lock and declared the machine inoperable.

Also on March 1, during an 18-month surveillance inspection of Standby Diesel Generator 22, mechanics discovered that the piston skirt on Cylinder 4R was broken. Several large pieces of the skirt were removed from the oil sump. Technicians also noted that the cylinder liner indicated heavy signs of heat and scoring. Service Request 209772 was written to repair or replace the piston and liner. Station Problem Report 94-0551 was written to investigate the cause of the problem and develop generic corrective actions, as necessary.

Further review of the Standby Diesel Generator 11 failure will be conducted following receipt of the associated licensee event report. Additional inspection of the failures of Standby Diesel Generators 21 and 22 is documented in NRC Inspection Report 50-498/94-13; 50-499/94-13.

2.3 Operator Response to Turbine First Out Annunciator

On February 25, 1994, with the plant in Mode 1 and the main generator output breaker open, the inspector observed a portion of Plant Surveillance Procedure OPSP03-SP-0007B, Revision 3, "SSPS Actuation Train B Master Relay Test." While the operators were performing the procedure, an unexpected reactor trip/turbine trip first out annunciator illuminated and surprised the reactor operator. The inspector observed that the operator did not proceed to the turbine control board to verify that the turbine had tripped. Instead, the operator questioned the shift supervisor about any ongoing testing. The inspector determined that the operator should have believed the indications instead of assuming that testing was taking place. Furthermore, the reactor operator had difficulty distinguishing between a turbine or a reactor first out annunciator. The shift supervisor provided assistance and dispositioned the turbine first out annunciator as being attributed to the master relay test.

The operator had been aware that the test was in progress, but failed to associate that the test produced the alarm because he had not attended the surveillance test pretest briefing. The briefing was designed to heighten operator awareness of expected alarms as a result of the test.

A caution statement in the procedure, which noted that a reactor trip may occur while performing the test, was placed after the action step which generated the first out annunciator. The individual performing the procedure used the caution note to notify the control room of expected alarms. The caution note was incorrectly sequenced following the last procedure revision. Proper sequencing of notes and procedure steps would contribute to smoother procedure performance.

The operator stated that he had not verified the turbine trip at the turbine control board because the first out annunciator bistable was not flashing. A flashing bistable was indicative of an actual turbine trip. The operator stated that the bistable was illuminated solid and, therefore, an actual trip had not occurred. The inspector concluded that the operator relied on the annunciator to determine actual equipment conditions rather than verifying plant conditions using more direct indications.

2.4 Manual Reactor Trip (Unit 1)

On February 28, at 10:13 p.m., Unit 1 reactor was manually tripped from 28 percent power. The reason for the trip was a rapidly decreasing water level in Steam Generator 1D. The licensed reactor operator noticed that Normal Feedwater Regulating Valve 1D had closed. He attempted to reopen the valve by placing the controller in manual. When this effort failed, the unit supervisor directed a manual trip of the reactor prior to receiving an automatic trip on low steam generator water level.

The operators entered the emergency operating procedures expeditiously and performed the required actions in a superior manner. Because of the low decay heat in the reactor core and the high initial rate of auxiliary feedwater flow, the reactor temperature decreased to less than normal no-load temperature of 567°F. The operators were able to recover pressurizer level and stop the cooldown prior to reaching the temperature at which emergency boration would have been required. Reactor operators responded to the trip in an excellent manner. At the end of this inspection period, licensee engineers were still reviewing plant data as part of the routine posttrip review.

2.5 Identification of a Primary-to-Secondary Leak

On March 1, Blowdown Radiation Monitor RT-8043 on Steam Generator 1C alarmed following the reactor trip on February 28. This alarm indicated a primary-to-secondary water leak. Reactor operators responded by isolating blowdown from the affected steam generator. Chemistry technicians quantified the leak at approximately 160 gallons per day.

Licensee management decided to cool down the reactor and repair the leak. This was considered a conservative action because Technical Specification 3.4.6.2 allowed continued operation with up to 500 gallons per day through any one steam generator.

In Mode 5, mechanical maintenance personnel removed the steam generator primary manways. Licensee personnel identified the leak from a mechanical plug on the cold leg side of the steam generator bowl. The leaking plug was made of Inconel 690 and had been installed by Westinghouse to replace an Inconel 600 plug which had been installed before initial plant operation. The leaking plug was one of several which were used to replace Inconel 600 plugs, but the leaking plug (in Steam Generator C, Row 42, Column 101) had been installed using a manual process. All other plugs had been installed using an automated process. The licensee and its contractor determined that the manual method used on this plug was deficient. The leaking plug was drilled out and a replacement plug was welded in place. Subsequent leak testing indicated that the replacement plug did not leak.

2.6 Safety Injection and Loss of Shutdown Cooling

On March 10, 1994, while the plant was in midloop operations, licensed operators were performing Plant Surveillance Procedure OPSP03-SP-0005S, "SSPS Logic Train S Functional Test." The operators inadvertently began performing the test in Protection System Logic Cabinet R. Prior to the performance of Step 5.18, the operators questioned a procedural note that required the memories check of the logic cabinet to be conducted in the Train S logic cabinet.

The operators stopped work, informed the shift supervisor that the procedure was in error, and required them to perform testing in both logic cabinets at the same time. The shift supervisor reviewed the procedure, determined that it was adequate, and told the operators to complete the test.

Upon returning to the instrument cabinets, the operators determined that they had been working in the wrong logic cabinet. They decided jointly to back out of Logic Cabinet R using Section 5.20, "Restoration and Documentation." During this recovery, a full safety injection signal was received.

The control room operators responded to the event appropriately. All equipment functioned as expected with the exception of Essential Chiller 11C that tripped on low oil pressure. As designed, the residual heat removal system pumps were stripped from the safety busses. This resulted in the loss of decay heat removal from the reactor. The pumps were restarted within 5 minutes.

The circumstances surrounding the safety injection and loss of the residual heat removal system with the reactor in midloop operations were addressed in NRC Inspection Report 50-498/94-12; 50-499/94-12.

2.7 Conclusions

The licensee's response to plant events was considered good. However, reactor operators failed to properly respond to a turbine first out annunciator and performed testing in the wrong logic cabinet, causing a loss of delay heat removal while the reactor was in midloop operations. In contrast, the reactor operators' response to a reactor trip was considered excellent, and licensee management made a conservative decision to repair the primary-to-secondary leak before returning Unit 1 to power operations.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with license and regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. The following paragraphs provide details of specific inspector observations during this inspection period.

3.1 Control Room Observations

Throughout this inspection period, daily tours of the Unit 2 control room were performed. Shift turnovers were of good quality and included a complete review of control panel status. An improvement was noted in that control room communications were clear and concise. Inspection observations in the Unit 1 control room are discussed in Section 7 of this inspection report.

3.2 Plant Tours

During this inspection period, the inspectors toured various areas of the plant. The overall condition of the plant was found to be good. However, inspectors routinely identified minor plant deficiencies that had not been documented in station service requests. The licensee appeared to adhere to good housekeeping practices, but some instances were noted of exceptions to this general rule.

3.2.1 Tour of the Mechanical Auxiliary and Fuel Handling Building

On February 26, the inspector toured the Unit 1 mechanical auxiliary building 41 foot level and lower level with the shift supervisor. The inspector noted that Charging Pump 1A had oil on the floor at the pump end. The source could not be specifically identified nor was the volume enough to cause immediate concern. In the essential cooling water pipe chase, one of the sump pumps was removed and laying on the floor. Water was leaking from the pipe from which the pump was disconnected. The water was splashing on the removed pump and the running pump. The shift supervisor immediately notified maintenance and directed them to cover the pumps to protect them from the water. In general, the areas appeared to be clean and uncluttered. Very few contaminated areas remain on these levels.

On February 27, the inspector toured the Unit 1 mechanical auxiliary and fuel handling building and observed the condition of safety-related equipment located in these areas. Plant condition and housekeeping were good. However the inspectors noted that a bucket filled with some maintenance tools was left against a wall on the 40 foot elevation. No apparent work appeared to be in progress in the vicinity. Radiological boundaries were appropriately erected and posted. The inspector did not identify any leaking components.

3.2.2 Tours of Standby Diesel Generator Rooms and Isolation Valve Cubicles

While touring the standby diesel generator rooms and isolation valve cubicles, the inspector noted that, the emergency lighting did not appear to be directed at any specific area. The lighting did not appear to either help personnel egress from an area or help plant personnel locate important equipment during emergency conditions. The areas in question included the bottom of the stairwell leading to Emergency Diesel Generator 11 and the area above Auxiliary Feedwater Pump 14. The inspector notified the licensee of these findings.

During tours of Unit 1, the inspector found that the housekeeping and area cleanliness was acceptable. During these tours, the inspector noted several items that appeared to require repair. The inspector informed the shift supervisor of these items, who evaluated the concerns. The following conditions resulted in new service requests being issued.

- Service Request 305642 Main Steam Safety Valve 7420D drip pan full of water.
- Service Request 305890 Main Steam Safety Valve 7420A drip pan full of water.
- Service Request 201951 Emergency light hanging by its electrical cord without support.

In general, housekeeping in these areas was good; however, several instances of poor housekeeping practices were noted. A bag full of clean rags and empty squeeze bottles was located in one of the standby diesel generator rooms. In the auxiliary feedwater pump rooms, a discarded bulb from an emergency light box and some of the remains of packaging for the replacement bulb were located in the area above Auxiliary Feedwater Pump 14.

3.2.3 Tour of the Turbine Generator Building

On February 16, the inspector toured the Unit 1 turbine generator building. General appearance was very good. Areas of work activities were being kept as clean and uncluttered as reasonably possible, considering the activities in progress. Turbine building operations personnel were alert and active. The inspector noted that the long path recirculation line in the overhead of the ground floor level exhibited considerable movement. One of the hangers was observed to be rubbing against an adjacent pipe. The problem was discussed with a reactor plant operator, and a station problem report was written.

3.2.4 Tour of the Reactor Containment Buildings

On January 31, the inspector performed a walkdown of the Unit 1 reactor containment building, including inside the bioshield and the residual heat removal pump room and valve room. Material condition in the areas toured was notable. An exception was in the residual heat removal pump room and valve room in which work was in progress and final clean-up had not been performed.

On February 11, during a tour of the Unit 2 reactor containment building, the inspector observed an uncoupled run of Reactor Coolant Pump 2A. The run was performed to allow electrical maintenance personnel to test the electrical portion of the pump's lubricating oil system. A prejob briefing was conducted by the unit supervisor. All persons involved in the operation were attentive and knowledgeable. The pump start and run were uneventful. The operators performed self-verification during the evolution.

3.3 Safety System Flowpath Alignment

3.3.1 Emergency Core Cooling System Walkdown

On February 20, 1994, the inspector performed system walkdowns of the Unit 1 high head safety injection, low lead safety injection, and containment spray systems. The inspector verified that operators maintained the major flow path valves in the proper standby alignment. The inspector verified that the valve alignment properly reflected the alignment identified in the system piping and instrumentation diagrams. The inspector noted that the major flow path motor-operated valves had power available and were aligned properly, as indicated by main control board indicating lamps. The inspector verified that the main control board alignment agreed with that specified in Plant Operating Procedures 0POP02-SI-0002, Revision 0, "Safety Injection Systems Initial Lineup," and 0POP02-CS-0001, Revision 0, "Containment Spray Standby Lineup."

3.3.2 Chemical and Volume Control System Normal Letdown Walkdown

On February 21, the inspector verified the flowpath alignment of the Unit 1 normal letdown from the chemical and volume control system by observing the indications on the Main Control Panel CP004. The inspector verified that the instrumentation and controls were in their required position as delineated in Plant Operating Procedure 0POP02-CV-0004, Revision 1, "Chemical and Volume Control System Subsystem." The inspector verified that the applicable alarm annunciators were not illuminated.

3.3.3 Auxiliary Feedwater System Walkdown

On February 22, the inspector walked down accessible portions of the Unit 1 auxiliary feedwater system. The purpose of this effort was to verify that the system was properly aligned for Mode 1 operations. The inspector verified that the actual valve positions were in accordance with the requirements delineated in Plant Operating Procedure OPOP02-AF-0001, Revision 1, "Auxiliary Feedwater." No errors were noted. In addition, the inspector verified valve identification labels against Piping and Instrumentation Drawing 5S19F00024, Revision 30, "Auxiliary Feedwater."

3.4 Equipment Clearance Order Followup

The inspector reviewed the following Unit 1 equipment clearance orders:

- 1-94-40507 Spent Fuel Pool Cooling Pump 1A
- 1-94-40601 Essential Cooling Water Strainer A
- 1-94-40343 Containment Normal Purge
- 1-94-40555 Restoration of South Condenser Waterbox 11. Additionally, the inspector observed a partial release of this clearance order.

The inspectors verified that personnel had placed the correct tag on the correct component, that the component was in the required configuration, and that the equipment clearance order provided appropriate personnel and equipment protection.

3.5 Reactor Plant Operator Observations

On February 20, 1994, the inspector accompanied a reactor plant operator during his rounds of the mechanical auxiliary and fuel handling buildings. The inspector noticed several hoses and ladders that were not properly stored and a missing label. The inspector noted an apparent discrepancy in some component cooling water flow instruments. The instrument scales stated that the measurement was in units of pressure differential. However, the placard stated that the instruments read in gallons per minute.

The inspector found that the Plant Surveillance Procedure OPSP03-ZQ-0028, Revision 7, "Operator Logs," mechanical and electrical auxiliary building log sheet required the operator to measure the essential chiller compressor discharge pressure to the nearest tenth; however, the gauge resolution could only be read to the nearest whole number. After questioning operations support personnel about the adequacy of the table, they determined that they would correct the procedure by rounding the maximum expected compressor discharge pressures to the nearest whole number. The operations support personnel implemented changes to the similarly affected Plant Operating Procedure OPOP02-CH-0001, Revision 5, "Essential Chilled Water System."

In addition, the inspector toured the facility with reactor plant operators. The inspector observed as they performed their tours of the turbine generator building, mechanical auxiliary building, and standby diesel generator building. The inspector also observed while the operators completed their logs. The inspector reviewed the logs and no errors were noted. The inspector questioned the operators and found that they were very knowledgeable of their responsibilities and of the plant.

Throughout the inspection period, inspectors routinely identified a number of minor plant deficiencies that had not been documented on service requests, housekeeping problems, and instrument deficiencies. Some of these findings were documented in Sections 3.2.1, 3.2.2, 3.2.3, 3.5, 4.6, and 7.12 of this inspection report. The inspectors determined that the level and the number of these deficiencies may be indicative of a lack of attention to detail by reactor plant operators. Licensee management concurred that reactor plant operators continued to need increased supervision to improve their ability to identify plant deficiencies.

3.6 Conclusions

Communications were improved in the Unit 2 control room. Shift turnovers were of good quality and included a complete review of control panel status. Inspectors routinely identified plant deficiencies that had not been previously identified. This indicated a lack of questioning attitude by the reactor plant operators. Engineered safety system flow path alignments were verified, and material condition was considered good. Four equipment clearance orders were appropriately implemented.

4 MONTHLY MAINTENANCE OBSERVATIONS (62703)

The station maintenance activities addressed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC Regulations. The inspector verified that the activities were conducted in accordance with approved work instructions and procedures, the test equipment was within the current calibration cycles, and housekeeping was being conducted in an acceptable manner. Activities witnessed included work in progress, postmaintenance test runs, and field walkdown of the completed activities. Additionally, the work packages were reviewed and individuals involved with the work were interviewed. All observations made were referred to the licensee for appropriate action.

4.1 Startup Feedwater Pump Seal Replacement (Unit 1)

On February 7, 1994, Station Problem Report 94-0294 was written because of excessive leakage from the Startup Feedwater Pump 11 shaft seal. The inboard mechanical seal was leaking at about 10 to 20 gpm through the leak off drain line. The pump was stopped and the feedwater suction and discharge valves were closed. Service Request FW-1-208538 was issued to investigate and repair the leak.

On February 8, the inboard bearing housing was removed. The cap screws required to retain the mechanical seal were found in the bottom of the seal housing. An investigation of the event was initiated. It appeared that the cap screws had not been installed when the seal was replaced by contract personnel. Since that time, licensee management has performed corrective action to improve control over contract workers.

The pump, bearings, and lubricating oil system were flushed and inspected. There was no indication of degradation other than the inboard mechanical seal. The seal was replaced and the startup feedwater pump was returned to service on February 11. The mechanics and engineers involved exhibited good work practices. A review of the work package indicated a very detailed summary of the work performed. This indicated a heightened awareness of planners to the need for attention to detail.

4.2 Repair of Qualified Display Processing System Card

On February 15, the inspector observed the instrument technicians troubleshooting the Qualified Display Processing System APC-D2 Diagnostic Circuit. The investigation was performed in accordance with Service Request AM-305636. The effort was coordinated with the control room operators because Circuit Card APC-D2 could have affected the operability of Auxiliary Feedwater Pump 14 in addition to Steam Generator 1D Atmospheric Steam Relief Valve 1D. The first line supervision was present during troubleshooting. The investigation was conducted professionally and technicians were very knowledgeable. The problem with Circuit Card APC-D2 appeared to be that the read-only memory was missing information. The investigation revealed that Auxiliary Feedwater Pump 14 was not affected by the diagnostic circuit problem in Circuit Card APC-D2. The problem only affected Atmospheric Steam Relief Valve 1D.

On February 16, technicians replaced the memory data on the read-only memory card. The evolution was performed in accordance with Plant Maintenance Procedure OPMP07-AM-0042, "QDPS APC-D2 Removal From Service." This procedure required the technicians to trip several bistables that receive inputs from the qualified data processing system. This required entering the associated actions for Technical Specifications 3.3.1, 3.3.2, 3.3.3.6, and 3.7.16 Limiting Conditions for Operation. The crew was briefed on which alarms and actuations were expected during the evolution. The briefing was very concise and complete. The actual tripping of the bistables was conducted by two instrument technicians. One technician tripped the bistable, and the other provided dual verification.

Both technicians exhibited self-verification techniques while tripping the bistables. A third independent verifier also checked the bistables' state. A first line supervisor provided oversight during the entire process. The read-only memory card was replaced and calibrated in place, and the system was returned to service. Actions taken were deliberate and conservative. The Technical Specification action statements were exited in a timely fashion.

4.3 Furmanite Repair of Residual Heat Removal Valve RH-60C

On February 17, the inspector observed licensee contract personnel disassemble, clean, and inspect a leak sealant enclosure that encompassed the valve seal leak-off line located on Residual Heat Removal Suction Isolation Valve 1-RH-MOV0060C. This effort was being performed to repair a leak identified from the previously installed enclosure.

The inspector reviewed the service request and the associated procedure for this work. Procedural guidance for this effort was general in nature, but specific instructions prohibiting peening on the enclosure or the valve were noted. The inspector spoke with the contract personnel and found them to be knowledgeable of their responsibilities. This activity was determined to be within the skill of the craft.

The prejob briefing, held by the system engineer responsible for the residual heat removal system, was detailed in nature. A health physics technician was present to discuss the details of the radiation work permit. Using a survey map of the area, the health physics technician described the low dose areas where observers should be situated to minimize personnel exposure.

During the maintenance activity, procedural compliance by the contract personnel was noted. Health physics personnel monitored the effort, keeping all personnel in the area informed of the dose ratings and directing personnel to move to low dose waiting areas whenever work activity was delayed. Very good radiation work practices were demonstrated by all personnel during this effort. Licensee coverage of this effort was found to be excellent.

4.4 Condenser Tube Leak

On February 19, Service Request 201308 was initiated to repair a tube leak in the South Condenser Waterbox 11. On February 20, the inspector observed plant engineering personnel perform a final inspection of the condenser internals after repairs were made to the leaking tube. Mechanical maintenance personnel installed manways and tightened fasteners in accordance with the work instructions. Work was performed with the approved Work Authorization 94005233. The inspector observed operators partially release Equipment Clearance Order 1-94-40555. The inspector noted that the cleanliness of the area was good. Workers performed the evolution satisfactorily.

Initial chemistry results, caused by the tube leaking, placed the plant in Action Level 3 according to Plant General Procedure OPGP03-ZO-0012, Revision 7, "Plant Chemistry Specifications." Action Level 3 required a plant shutdown within 4 hours to avoid ingress and eliminate further concentration of harmful impurities. This action was designed to correct a condition that may have resulted in steam generator corrosion.

However, the steam generator blowdown cation conductivity specifications were never exceeded. After south Condenser Waterbox 11 was isolated, the condenser cation conductivity dropped. Procedure OPGP03-ZO-0012 allowed the plant manager to waive action levels based on a chemistry deviation report stating the technical basis for such a waiver. The plant manager determined that Action Level 3 could be waived based on the results of the total cation conductivity and the efforts to repair the leak. Reactor power was reduced from 3.5 percent to 1.5 percent power to reduce steam generator feedwater flow rates. This action reduced the effects of poor condenser water chemistry on steam generator chemistry. Lowering of reactor power was performed in accordance with Procedure OPOP03-ZG-0006, Revision 1, "Plant Shutdown from 100% to Hot Standby."

Operators responded to the condenser tube leak appropriately, and good support was given by all organizations involved.

4.5 <u>Seat Repair on Governor Valve for Feedwater Pump Turbine 11</u>

On February 23, the inspector observed mechanical maintenance personnel perform welding on Turbine Low Pressure Governor Valve 1-ES-196. The purpose of this repair was to seal weld a leak path that was identified in the valve. The leak path allowed sufficient steam leakage past the valve seat to cause the feedwater pump turbine to overspeed when it was uncoupled from the pump. This effort was performed under Service Request MS-309156.

The inspector reviewed the service request and the other documents in the work package and verified that they had been reviewed and approved as noted by the appropriate signatures. In addition, the inspector reviewed the welding qualifications for the contract personnel who were scheduled to perform the welding. The inspector verified that the contractors met HL&P's requirements for welding on nonsafety-related equipment.

The technicians replaced the seat insert from the valve. This required shrinking the metal seat insert by immersing it in liquid nitrogen. The inspector noted that proper industrial safety equipment was utilized for this effort, minimizing the personnel hazards of working with the liquid nitrogen. Following the shrinking effort, technicians placed the insert in the valve and prepared it for welding.

The technicians used shielded metal arc welding to seal weld the insert. The inspector noted that the spotter for the welding activity did not wear ultraviolet eye protection while welding activities were ongoing. The inspector raised this concern to the industrial safety representative. He stated that the site safety manual did not require personnel to wear ultraviolet protection; it allowed the spotter to look away from the arc. The inspector stated that in the confined space in which the welder and spotter were located, it would be difficult to avoid the reflective glare. The industrial safety representative agreed that, under those circumstances, some form of eye protection should have been provided to the spotter and that he would review the policy on this matter.

Overall, worker performance during this effort was found to be good. Licensee management oversight of this effort was noted.

4.6 Essential Cooling Water (ECW) Traveling Water Screen 1A Coupling Replacement

On February 23, the inspector observed two mechanics replace the ECW Traveling Water Screen 1A drive motor coupling in accordance with Service Request 1-EW-311804. Preventive Maintenance Procedure MM-1-EW-93001008 was utilized for performing the detailed work steps necessary to replace the coupling; Plant Maintenance Procedure OPMP04-ZG-0002, Revision 9, "Coupling Alignment," governed the alignment of the coupling; and Postmaintenance Test Matrix Item 3.21 dictated the requirements for conducting the postmaintenance test.

The inspector verified that the mechanics used calibrated equipment, that the mechanics had proper approval prior to beginning the work activity, that the new flexible coupling had material traceability, and that the operators properly removed the equipment from service. From discussions with the mechanics, the inspector found that the individuals were knowledgeable of the work scope and were familiar with the work instructions.

While verifying the equipment clearance order tag on the traveling screen motor breaker, the inspector reviewed the condition of scaffolding erected to allow mechanics to perform preventive maintenance on ECW Strainer 1A. Personnel erected the scaffolding under a scaffold permit for Preventive Maintenance Task MM-1-EW-86011663. Maintenance planners had determined that the scaffold could be erected as a Standard Seismic II/I scaffold as defined in Plant General Procedure OPGP03-ZM-0028, Revision 3, "Erection and Use of Temporary Scaffolding," Step 2.15. The inspector noticed that a scaffold cross member rested on the ECW Pump 1A discharge pipe upstream of ECW Strainer 1A. In addition, the inspector questioned whether the scaffolding would interfere with the manual operation of Discharge Strainer Emergency Backflush Isolation Valve 1-EW-277 and Lubricating Water Filter Inlet Isolation Valve 1-EW-117. Operations personnel performed an evaluation that demonstrated, in situations that required closing Valve 1-EW-117, the ECW pump would be secured and lubricating oil cooling was not required. In situations that required backwashing the strainer by opening Valve 1-EW-277, operations personnel demonstrated that they had sufficient time to move any interferences and begin a manual backwash. A maintenance supervisor initiated Station Problem Report 940481, moved the scaffolding away from the valves, and lifted the scaffold cross member off the safety-related pipe.

The inspectors reviewed Procedure OPGP03-ZM-0028, Step 4.2.6, which specifies that the minimum clearance between scaffolding members and instrument tubing, small bore piping, conduits less than 4 inches in diameter, and equipment shall be in accordance with Item C of Drawing 3A01-0-5-10003, Sheet 1, "Seismic Separations Control Drawings, Units 1 and 2." This drawing identifies that scaffolding members shall be considered as Group 0 and safety-related piping shall be considered as Group 3. This drawing specifies that the minimum separation between Groups 3 and 0 to be 2 inches when constructing a scaffolding. The inspectors determined that the licensee had not met the minimum seismic separation requirement as identified in Item C of Drawing 3A01-0-5-10003, Sheet 1, for the scaffolding and ECW discharge pipe. This is identified as Violation 498/94009-01.

The inspectors noted that management had not clearly established the minimum clearance requirement in Procedure OPGP03-2M-0028. The procedure specified that the clearance was applicable to small bore piping while the drawing was applicable to all safety-related piping. Although this may have contributed to this incident, the inspectors found a lack of awareness by personnel responsible for constructing and inspecting the scaffolding. This was also evident in the apparent interference that existed between the scaffolding and ECW valves.

The inspector discussed with licensee management the implications of this problem and a previous interaction between scaffolding and safety-related equipment as documented in NRC Inspection Report 50-498/93-55; 50-499/93-55. During this discussion, licensee personnel informed the inspector that they would develop training to enhance awareness of scaffold builders regarding minimum separation criteria when constructing scaffolds. Licensee personnel stated they would review the adequacy of an 8-hour training course for scaffold builders. In addition, engineering personnel informed the inspector that a 0-inch clearance would not affect operability, but did confirm that the intent of Item C of Drawing 3A01-0-S-10003, Sheet 1, was to assure that personnel meet the listed requirements to construct scaffold with at least 2 inches of clearance from large bore piping. In addition, during the course of the inspection, the inspector identified that Valve Actuator 1-EW-0027 was leaking oil. A service request was written to repair the leak.

4.7 Repair of a Feedwater Isolation Valve Hydraulic Skid

On February 27, Main Feedwater Isolation Valve 1A began to drift closed, resulting in dual position indication on the main control board. The operator noted the dual indication, informed the supervisor, and dispatched an operator to verify the valve position. The isolation valve was found to be approximately 90 percent open. Further investigation revealed that hydraulic pressure was less than 1800 pounds and noises from the hydraulic skid indicated that air binding was present in the system.

Reactor power was reduced to 8 percent and an operator was stationed at the feedwater isolation valve to notify the control room operators if the valve continued to drift close. Initial attempts to vent air from the system were ineffective. The system engineer was called to the site to direct the investigation. Upon arrival, the engineer performed a vent of the hydraulic skid in accordance with Service Request 1-FW-305885. He determined that Air Motor A was defective. Once the defective pump was isolated and Air Motor B was properly vented, hydraulic pressure returned to normal and the valve returned to full open.

Service Request 1-FW-305885 was replanned to replace Air Motor A. The motor was replaced, vented, and returned to service on February 28. Troubleshooting and venting of the hydraulic skid was considered to be skill-of-the-craft and procedural guidance had not been developed. The system engineer exhibited superior knowledge of the system and components. The work package along with the vendor manual provided good detail for replacement of Air Motor A.

4.8 Essential Cooling Water Piping Flange Replacement (Unit 2)

On March 2 and 3, the inspector observed portions of the welding activities associated with a 6-inch flange replacement on the essential cooling water supply to Standby Diesel Generator 22. Licensee personnel replaced the original carbon steel flange with a bronze-aluminum flange in accordance with Service Request 2-EW-212840, to repair microbiologically induced corrosion on the pipe.

The fit-up for the weld was within the acceptance criteria (3/32 inch) noted in Service Request 2-EW-212840 and verified by a quality control inspector. The technicians built a barrier to exclude foreign material from entering the pipe, controlled the issuance of welding rods, and had a dedicated fire watch during the welding activities. The completed weld appeared to be sound. The technicians performed postmaintenance tests, including dye-penetrant tests, on the inside and outside of the pipe, and a visual inspection was scheduled to follow system pressurization. The scope of the postmaintenance tests was appropriate for the work performed.

4.9 Replacement of High Head Safety Injection Pump Motor 2C

On March 4, 1994, the inspector observed electrical maintenance technicians perform work activities associated with the replacement of the Unit 2 High Head Safety Injection Pump 2C motor. The operators had identified excessive vibration of the pump motor during previous testing. The replacement of the motor was requested as corrective maintenance via Service Request 204798. The work was authorized properly by Work Authorization 94005453, and the motor had been taken out of service in accordance with an equipment clearance order.

The inspector reviewed the work instructions and determined that they were adequate for the work activity. The inspector observed the technicians torque the motor mounting bolts and install the motor case grounds. The work was performed appropriately and in accordance with Plant Maintenance Procedures OPMP05-SI-0001, Revision 2, "High Head Safety Injection Pump Motor Inspection," and OPMP02-ZG-0004, Revision 4, "Bolted Joint Procedure." The inspector verified that the tools met the calibration requirements. The inspector noted that the work was performed in accordance with adequate radiological controls and good industrial safety controls.

The electrical maintenance supervisor and a quality assurance inspector were present at the work site.

4.10 Conclusions

Maintenance practices observed during this inspection period supported continued plant operations. Equipment was properly removed and returned to service and postmaintenance testing indicated that the equipment had been properly repaired and would continue to perform its intended safety function. Increased first line supervision and improved self-verification techniques were observed in the field. In one case, craftsmen identified that the shaft seal capscrews had not been replaced during previous maintenance on Startup Feedwater Pump 11. Licensee engineers' coverage of a contractor leak sealant repair was considered to be excellent. One violation was identified for the failure to control the installation of scaffolding around safety-related equipment. Plant procedures failed to ensure that scaffold builders established the correct clearance between large bore piping and a scaffold cross member.

5 BIMONTHLY SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were being performed in accordance with the licensee's approved programs and the Technical Specifications.

5.1 Routine Surveillance Observations Deemed Commendable

The inspectors observed the following test performances and ensured that: personnel received approval to start from the shift supervisor, personnel used calibrated test equipment, test coordinators performed a pretest brief emphasizing important precautions and describing the major duties of each participant, and test coordinators provided test performers with a copy of the test for their review prior to performing the test.

Further, the inspectors verified that: personnel performing the surveillance complied with the procedures, personnel performed activities in accordance with management expectations, qualified personnel provided oversight and properly supervised trainees, the procedure assured personnel properly returned the system to service, personnel accurately recorded test data that met acceptance criteria, personnel knew the test purpose and scope, and the procedure verified the Technical Specifications for which it was developed. The inspectors observed the following surveillances performed on the associated dates:

2/11 OPSP10-DM-0001, "Rod Drop Time Measurement,"

2/16 1PSP03-AF-0007, Revision 8 uxiliary Feedwater Pump 14 Inservice Test,"

2/16 OPSP10-RC-0002, Revision 1, "Core Exit Thermocouple/Resistance Temperature Detection Cross Calibration,"

2/18	1PSP03-AF-0003, Revision 9, "Auxiliary Feedwater Pump 13 Inservice Test,"
2/19	1PSP03-CC-0009, Revision 3, "Component Cooling Water Train 1C Valve Operability,"
	OPSP03-CC-0011, Revision 0 "Component Cooling Water Valve Checklist,"
	1PSP03-AF-0007, Revision 8, "Auxiliary Feedwater Pump 14 Inservice Test,"
2/19	OPSP03-HC-0001, Revision 0, "Reactor Containment Fan Cooler Operability,"
2/22	1PSP03-AF-0007, Revision 8, "Auxiliary Feedwater Pump 14 Inservice Test,"
2/23	OPSP03-DG-0001, Revision 0, "Standby Diesel 11(21) Operability Test,"
	1PSP03-SB-0001, Revision 5, "Steam Generator Blowdown System Valve Operability Test,"
	OPSP03-EA-0002, Revision 0, "ESF Power Availability,"
	OPSP03-RC-0006, Revision 2, "Reactor Coolant Inventory,"
2/24	OPSP03-SP-0006R, Revision 2, "Train R Reactor Trip Breaker TADOT,"
	OPSP03-SP-0005R, Revision 3, "SSPS Logic Train R Functional Test,"
2/25	OPOP07-TM-0003, Revision 1, "Main Turbine Emergency Trip System Test," and
2/26	OPEP07-DB-0002, Revision 2, "Technical Support Center Diesel Generator Performance Test."

5.2 Turbine Driven Auxiliary Feedwater Pump Testing

As documented in NRC Inspection Report 50-498/93-31; 50-499/93-31, the turbine-driven auxiliary feedwater pump reliability and testing methodology was determined to be an issue requiring resolution prior to the restart of Unit 1. In NRC Inspection Report 50-498/93-38; 50-499/93-38, the inspector concluded that the actions taken by licensee personnel to resolve material deficiencies associated with the turbine-driven auxiliary feedwater pump and to improve the testing methodology were adequate to ensure operability following restart. Based on the results of that inspection, it was determined that sufficient improvements had been accomplished to support unit restart, pending satisfactory completion of the augmented testing program.

On February 9, 1994, the inspector observed testing of Auxiliary Feedwater Pump 14. The licensee performed Section 8.4, "Turbine Run: Manual Roll-up," of Plant Engineering Procedure 0PEP07-AF-0013, "Auxiliary Feedwater Pump 14 Special Post Maintenance Test." A pretest briefing for the personnel involved was performed. The pump was started satisfactorily in accordance with Plant Operating Procedure 0POP02-AF-0001, Revision 1, "Auxiliary Feedwater," Section 14. The reactor plant operator was turning the governor screw to increase the speed of the turbine to 3600 RPM. Once the turbine reached 3476 RPM, the subsequent turns on the turbine speed adjustment had no effect on turbine speed. The discharge pressure was at an acceptable pressure and steam header pressure was at 250 psig.

A decision was made to electronically trip the pump from the control room in accordance with Plant Engineering Procedure 0PEP07-AF-0013 to resolve the discrepancy of the turbine not reaching 3600 RPM. The mechanical overspeed trip linkage did not disengage. The test was officially suspended, and efforts were put forth to resolve the problem. Operators performed the procedure in a step-by-step manner. The inspector noted good communication from the pretest briefing until the test suspension.

On February 10, the inspector observed a pretest brief conducted on Steps 8.8 - 8.10 of Procedures 0PEP07-AF-0013, "Auxiliary Feedwater Pump 14(24) Special Post Maintenance Test," and 1PSP03-AF-0007, "Auxiliary Feedwater Pump 14(24) Inservice Test." The tests were performed concurrently. The briefing was thorough and individuals involved were informed of their specific test functions.

The pump turbine started satisfactorily with no overspeed trip. Two minor problems were encountered. The local turbine speed indication was erratic and the maximum turbine speed attainable was 3593 vs 3600 RPM as required. The local tachometer was found to have a defective sensor probe which was replaced. The mechanical stop was set too low, which prevented the turbine from reaching 3600 RPM. The mechanical stop was reset for succeeding runs. Neither problem recurred during the remainder of the testing.

On February 10, the inspector observed the pretest briefing for Auxiliary Feedwater Pump 14 testing. The test was being started when a reactor operator discovered a testing tag on the turbine Trip and Throttle Valve AF-MOV-0514. The equipment clearance order for this valve had been issued to the motor-operated valve technicians and had not been released. The motor-operated valve technicians had discovered some discrepancies during a postmaintenance inspection in the valve and were unable to perform the work because of a "stop work" that was ordered as a result of problems in Unit 2.

The test manager was not aware of the equipment clearance order on Valve AF-MOV-0514. The shift supervisor was not aware of the equipment clearance order on the valve or of the stop work that was in effect. The auxiliary feedwater pump test was suspended until the problems were resolved. The inspector noted poor communications between the motor-operated valve technicians, operations, and plant engineering.

On February 12, the final postmaintenance testing of Auxiliary Feedwater Pump 14 was observed. The system engineer conducted a pretest briefing. Step 8.14 of Procedure OPEP07-AF-0013 was conducted to verify that the turbine did not trip on overspeed following a cold start after a 24-hour cooldown. The pump test was successful, concluding the special test requirements.

The inspectors concluded that testing of the auxiliary feedwater pump had been completed in accordance with the licensee's augmented test program. Additionally, inservice testing of the pump was observed as documented in Section 5.6 of this inspection report. Therefore, Restart Issue 1, "Turbine-Driven Auxiliary Feedwater Pump Reliability and Testing Methodology," was considered resolved.

5.3 Motor-Driven Auxiliary Feedwater Pump Inservice Test

On February 18, the inspector observed operators perform testing of Auxiliary Feedwater Pump 13 in accordance with Plant Surveillance Procedure 1PSP03-AF-0003, Revision 9, "Auxiliary Feedwater Pump 13 Inservice Test." During this test, the inspector questioned the validity of the pump reference values that dated back to 1988. The inspector determined that the system engineer had performed reference value measurement tests in January 1994 for the three motor-driven auxiliary feedwater pumps. The system engineer performed the reference value tests following installation of permanent flow and suction pressure gauges in accordance with Plant Modification 88269. The system engineer had determined that the deviation between the new and previous reference values for suction pressure and differential pressure did not exceed the accuracy limits specified in the ASME Code, Section XI. Consequently, the system engineer decided to continue use of the previous reference values. Because the values remained within the accuracy of the instruments, the system engineer determined that a new set of reference values was not required. The inspector agreed with the system engineer's conclusions.

5.4 Component Cooling Water System Valve Operability Test

On February 19, the inspector observed operators perform valve operability testing for Component Cooling Water Train 1C valves in accordance with Procedure 1PSP03-CC-0009, Revision 3, "Component Cooling Water Train 1C Valve Operability." The reactor operator provided detailed instruction to a hot license candidate during performance of the test. The reactor operator provided qualitative guidance, such as, the type of valve control circuitry and the relative stroke times of the valves. The inspector found the procedure to be well written with appropriate precautions and notes. Prior to restoring valves which required removal of power, the operators demonstrated a good practice by verifying the valve indicated the proper position prior to opening the breaker. Upon questioning why the operators performed the activity in this manner, the operators stated that the procedure required the verification. The inspector found no requirement to verify the valve position. Upon further questioning, the operators determined that a different procedure contained the requirement. Also, a procedure writer identified that the Component Cooling Water Train 1C procedure differed from the other two trains. The procedure writer initiated a change to the restoration checklist that assured proper valve and breaker position. Therefore, operators would perform a conservative valve position verification based on procedural requirements as well as good operating practices.

5.5 Reactor Containment Fan Cooler Operability

On February 19, the inspector observed portions of the performance of Plant Surveillance Procedure OPSP03-HC-0001, Revision 0, "Reactor Containment Fan Coolers Operability." This surveillance was performed by a senior reactor operator license candidate under the direct supervision of a licensed senior reactor operator. The surveillance was properly authorized and was performed in accordance with the current approved procedure.

The procedure demonstrated the operability of the fan coolers as required by Technical Specifications. During the surveillance, if the component cooling water pump for the train to be tested was not running, the procedure required the operator to start that pump in accordance with Plant Operating Procedure OPOP02-CC-0001, "Component Cooling Water." The senior reactor operator candidate performed Section 10.0 of Procedure OPOP02-CC-0001, Revision 3, to start Component Cooling Water Pump 1C.

At one point, the procedure required the operators to, "verify the following for the CCW train to be secured: associated train residual heat removal (RHR) pump is secured, associated train RHR heat exchanger has no reactor coolant system flow, and associated RHR heat exchanger has no low pressure letdown flow." The candidate was standing at Control Panel CP0002, in front of the controls for Component Cooling Water Pump 1C. The inspector observed him glance over at Control Panel CP0001 and sign off the applicable steps in the procedure. Panel CP0001 contained the residual heat removal system controls and was located approximately 10 feet away from Panel CP0002. The inspector questioned his method of verification, and the unit supervisor stated that the plant was in Mode 2 and that all residual heat removal pumps were secured in accordance with Technical Specifications.

The inspector questioned the unit supervisor's response and the candidates' adequacy in verifying that the residual heat removal pumps were secured, as directed by the procedure. Both the unit supervisor and shift supervisor agreed that the verification of steps in procedure by the candidate were less than adequate and did not meet managements' expectations for utilizing the self-verification program. This was noted by the inspector as less than adequate supervision of the license candidates.

5.6 Auxiliary Feedwater Pump 14 Inservice Test

On February 19 and again on February 22, the inspector observed an increased frequency operability test of Auxiliary Feedwater Pump 14 in accordance with Procedure 1PSP03-AF-0007. The inspector found that the system engineer conducted thorough pretest briefings, the reactor plant operators used calibrated instruments, and the operators verified that the steam drain line valve alignments were correct. The inspector found the procedure to be well written and easy to follow. The operators conducted accurate, detailed communications during conduct of the testing.

5.7 Standby Diesel Generator 11 Operability Test

On February 23, the inspector observed a licensed operator conduct the semiannual fast load test of Standby Diesel Generator 11 in accordance with Procedure 0PSP03-DG-0001, Revision 9, "Standby Diesel 11 Operability Test." The operator performed the test well, with one exception. For this activity, self-verification of control board manipulations in accordance with licensee management's expectations was critical; however, the reactor operator consistently did not perform the reconfirmation step by referring to the procedure a second time. The inspector understood from discussions with senior operators that starting and loading the diesel quickly was important. However, for such a critical activity, following proper self-verification techniques in accordance with management expectations was considered to be important. The operator performed other aspects of the test properly.

5.8 Main Turbine Emergency Trip System Test

On February 25, the inspector observed a licensed operator perform main turbine emergency trip circuit testing in accordance with Procedure 0POP07-TM-0003, Revision 1, "Main Turbine Emergency Trip System Test." The inspector noticed that the test performer did not perform self-verification techniques in accordance with licensee management expectations and the written program. In addition, the inspector found that repeat-back communications of annunciator response did not occur during the test. The shift supervisor and the operations manager, stated that the crew would receive new directions for performing repeat-back communications and acknowledgements of alarm windows to ensure improvement in the crews' performance and more consistency among all crews.

5.9 Solid State Protection System Actuation Train B Slave Relay Test

On February 25, the inspector observed the reactor operators perform a portion of Plant Surveillance Procedure 0PSP03-SP-0009B, Revision 1, "SSPS Actuation Train B Slave Relay Test." Section 5.5 of the procedure provided instructions for testing slave relays associated with safety injection valves. The safety injection valves included the Accumulator 1B isolation valve, the safety injection pump recirculation valve, and the suction header isolation valve from the containment sump.

Licensee personnel had previously discovered that the required staggered testing of the relays associated with the automatic repositioning of safety injection pump suction header isolation and recirculation valves had been missed as documented in Section 7.9 of this inspection report. The inspector determined that satisfactory completion of applicable steps to Section 5.5 of the procedure would have fulfilled the missed Technical Specification surveillance test.

The licensed operators did not want to adversely impact the safety injection accumulator operation by cycling the accumulator isolation valve while the plant was in Mode 1. Therefore, night shift orders were drafted and issued on February 24 specifying that the shift not perform procedure Steps 5.5.4 - 5.5.16 while performing Section 5.5 to prevent cycling of the accumulator isolation valve. The reactor operators implemented the night order directives and did not perform Steps 5.5.4 - 5.5.16. These steps were marked as not applicable in the test procedure. During the test, neither the safety injection recirculation nor the suction header isolation valves automatically repositioned during performance of the test as expected and required. The inspector reviewed Plant General Procedure OPGP03-ZA-0010, "Performing and Verifying Station Activities." Section 4.3.21 stated that, "Procedure steps with signoff blanks or step checkoffs which are not performed shall be marked 'NA'." Step 4.3.21.2 required the performer to document the basis for not performing the step and that the basis should include an evaluation that not performing the step or steps would not affect the desired result of the specified task. The performer noted that testing the accumulator isolation valve was not required, but did not determine that the desired result of the test would not be affected. Subsequently, a review of the test identified that the performance of Step 5.5.8 was required to verify that the valves would automatically reposition upon receipt of a safety injection signal.

The inspector determined that the requirements of Procedure OPGP03-ZA-0010 were insufficient to ensure that the requirements of Technical Specification 6.5.3.1.a were met when a change to the intent of Procedure OPSP03-SP-0009B was performed by documenting procedural steps as not applicable. Consequently, the operators obtained a clean copy of the procedure, deviated from the night order instructions, and reperformed selected portions of the procedure to preclude cycling of the accumulator isolation valve and to test the desired slave relays. The slave relays were successfully tested.

The critical steps to test the desired slave relays were omitted by the night order recommendations because of an inadequate technical review performed by the technical assistant operations manager and the operations manager. The omission of these critical steps, and licensed operators marking the steps as not applicable, changed the intent of the procedure to test the slave relays.

Technical Specification 6.5.3.1.a requires that intent changes to procedures be reviewed and approved by the individual authorized to approve the original procedure. The authorized individual was the engineering programs manager in this case. The failure to properly review and approve this procedure change was a violation of Technical Specification 6.5.3.1 (498/94009-02).

5.10 Technical Support Center Diesel Generator Operability Test

On February 26, the inspector observed licensee personnel perform functional testing of the technical support center diesel generator in accordance with Procedure OPEP07-DB-0002, Revision 2, "Technical Support Center Diesel Generator Performance Test." Because of previous problems with the control circuitry for the dead bus transfer, the licensee prestaged the personnel as part of a contingency plan to address some of the more common problems such as loss of the Proteus computer, overheating of the diesel engine, and tripping of the 480 VAC feeder breaker.

The test coordinator explained each aspect of the contingency plan and discussed the test sequence in detail. The inspector noted that personnel demonstrated accurate communications and that the test personnel documented all discrepancies, such as defective indicating lamps, a compressor bank tripping unexpectedly, and a service request documenting an out-of-service component.

5.11 Observation of Battery Capacity Tests

On March 2, 1994, the inspector observed portions of the quarterly and weekly surveillance test on the Channel 1 battery. The electricians utilized Plant Surveillance Procedures OPSP06-DJ-0001, "125 Volt Class 1E Battery 7 Day Surveillance Test," and OPSP06-DG-002, "125 Volt Class 1E Battery Quarterly Surveillance Test," to perform this surveillance.

Measuring and test equipment used was in calibration and none of the battery cells were degraded. The electrolyte level in each cell was above the plates and between the high and low level marks on the battery. Each battery met the specific gravity and voltage criteria specified in the procedure.

The inspector found some debris around the battery racks. After identification, these items were removed. There was also some minor battery rack rust observed by the electricians and the inspector. The electricians initiated Service Request 180265 to remove the rust accumulations.

5.12 Solid-State Protection System Steam Pressure Loop Calibration (Unit 2)

On March 8, the inspector observed portions of the performance of Plant Surveillance Procedure OPSP05-MS-0516-2, Revision 1, "Steam Pressure Loop 1 Set 3 Calibration (P-0516)." The surveillance procedure was written to comply with Technical Specification calibration and surveillance requirements. Administrative approvals were properly obtained and documented prior to performance of the procedure. All test instrumentation was verified to be in current calibration.

During the calibrations, failed circuit cards were identified on Instruments PY-516C and PY-516B. Both cards were replaced and calibrated in accordance with the procedure. The data sheets reflected a discrepancy between the as-found and as-left data because of the circuit card change. However, the techricians annotated the data package to highlight the reason for the discrepancy.

The calibration package received the proper postcalibration reviews and the results met the Technical Specification requirements. The instrument cabinets were returned to the proper alignment for plant conditions following the calibration.

5.13 125 Volt Vital Battery Service Surveillance Test (Unit 2)

On March 9, the inspector observed electrical maintenance personnel perform portions of a battery capacity surveillance test on Unit 2, Class 1E, Station Batteries E2B11. The surveillance was performed in accordance with Plant Surveillance Procedure OPSP06-DJ-0004, Revision 1, "125 Volt Class 1E Battery Service Surveillance Test." The inspector verified that this test met the requirements of Technical Specification 4.8.2.1.d.

The inspector observed personnel obtain an equipment clearance order and work start approval. The inspector verified that the Equipment Clearance Order 37394 was accepted appropriately and that proper work authorization was given. The inspector observed personnel set up the test equipment in accordance with the procedure. Electrical maintenance personnel utilized the vendor manual for connecting the load unit. Plant General Procedure OPGP03-ZM-0021, "Control of Configuration Changes," was used for disconnecting the power leads from the batteries being tested and connecting the load cables from the resistance load bank. The inspector verified that the removal and installation of cables was performed properly.

Electrical maintenance personnel wore protective clothing around the batteries and fire breach permits were obtained for the doors that were opened to allow power cables to pass through. The inspector noted that the fire breach permits were not required by the procedure, but electrical maintenance personnel were aware of the need for the permits. The surveillance test was performed satisfactorily and the results were within the acceptable values. The inspector noted good work practices during the test.

5.14 Feedwater Isolation Bypass Valve Testing

As documented in NRC Inspection Report 50-498/93-31; 50-499/93-31, the adequacy of the licensee's resolution of the reliability and operability of the feedwater isolation bypass valves was determined to be an issue requiring resolution prior to the restart of Unit 1. In NRC Inspection Report 50-498/94-06; 50-499/94-06, the inspector concluded that the actions taken by licensee personnel were sufficient to support unit restart, pending satisfactory completion of operational leak checks with the system at normal operating temperature and pressure.

On February 14, 1994, the inspector observed portions of the postmodification testing of Feedwater Isolation Bypass Valve FV-7145A. The licensee performed this test in accordance with approved test instructions (FW-212110-D). The inspector reviewed the test package and concluded that the test could be performed as written. Some of the steps required skill-of-the-craft, for example, venting of control air from the top of the actuator. The inspector verified by interviewing the instrumentation and control technicians that they were knowledgeable of the tasks at hand. Feedwater Isolation Bypass Valve FV-7145A remained closed, no valve motion was observed with a reverse change in pressure of 1156 psid.

The inspector reviewed the test results for all four steam generator feedwater isolation bypass valves and verified that they were acceptable. The inspector concluded that testing of the feedwater isolation bypass valves had been completed in accordance with the licensee's testing program. Therefore, Restart Issue 14, "Adequacy of the Licensee's Resolution of the Reliability and Operability of the Feedwater Isolation Bypass Valves," was considered resolved.

5.15 Conclusions

In general, the plant surveillance testing implemented Technical Specifications surveillance requirements and was performed in a controlled manner. Operators performing a component cooling water system valve operability test demonstrated good operating practices and provided feedback to ensure that these practices were captured in a future revision of the surveillance procedure.

Qualified licensed personnel demonstrated an appropriate level of oversight of trainees performing surveillance activities. However, the inspectors identified on several occasions that trainees, as well as licensed operators, did not perform the complete sequence for self-checking in accordance with licensee management's expectations. The use of formal communication techniques was inconsistent in the control room. On several occasions, annunciators in alarm were not communicated to other control room personnel. Even though operators performed a successful technical support center diesel generator surveillance, the inspector found the large number of minor equipment problems to be significant.

One violation was identified because operators marked procedural steps as not applicable, changing the intent of the procedure, and failed to have proper procedural review performed.

6 TECHNICAL SPECIFICATION REQUIREMENTS VERIFICATION (71715)

6.1 Specific Verification Performed

Throughout the inspection period, the inspectors verified that plant systems, components, programs, and observations met the requirements of Technical

Specifications applicable for the mode of reactor operations. The following items were reviewed:

Technical Specification 3.1.1.1 specifies the minimum shutdown margin required for operational modes. On February 25, the inspector utilized operator logs under Plant Surveillance Procedure OSP03-ZQ-0028 to confirm that the rod insertion limit was logged every 8 hours and that digital rod position indication verified actual rod position.

Technical Specification 3.1.1.4 specifies the minimum required temperature for criticality. The reactor coolant system's lowest operating loop temperature (T_{avg}) was identified as being greater than or equal to 561°F, with K_{eff} greater than or equal to 1 on February 20. The inspector verified this temperature by monitoring the qualified display processing system, and the four analog meters located on the control board. Finally, the inspector reviewed the control room log and verified that for previous dates the log entries for T_{avg} were within the Technical Specification requirements.

Technical Specification 3.1.2.6 specifies the minimum required borated water sources required for plant operations. On February 25, the inspector verified that Procedure OPSP03-ZQ-0028, "Control Room Logsheet," required operators to record boric acid tank levels and temperatures and to record refueling water storage tank levels. The inspector verified that the Control Room Logsheet listed the Technical Specifications required minimum values as acceptance criteria. The inspector determined the current values met the Technical Specifications minimums. From review of the control room logbook and discussions with chemistry personnel, the inspector determined that the boron concentration over the last 3 weeks for the boric acid tanks met Technical Specification requirements.

Technical Specification 3.1.3.1 requires that all full-length shutdown and control rods be operable and within 12 steps of their group step counter demand position. On February 26, 1994, the inspector verified that the reactor operators had performed the required control room shift rounds to meet the Technical Specification requirements by review of the control room logsheet. The inspector confirmed the control room logsheet properly assured the Technical Specifications requirements were met. The inspector independently verified that all full-length shutdown and control rods agreed within $\pm$12 steps of their group step counter demand position. The inspector determined that the operators had verified within the last 31 days that all shutdown and control rods could be moved at least 10 steps in any direction. The inspector confirmed that operators completed Plant Surveillance Procedure OPSP03-RS-0001, Revision 0, "Monthly Control Rod Operability."

Technical Specification 3.1.3.2 specifies that the digital rod position indication system and the demand position indication system shall be operable. On February 20, the inspector witnessed the surveillance, which is performed every 12 hours and which entails verifying that both system indications agree within 12 steps. The inspector also verified that previous tests had been performed within the 12-hour time limit. Also, on February 26, 1994, the inspector verified that the reactor operators had performed the required control room shift rounds to meet the Technical Specification requirements by review of the control room logsheet. The inspector confirmed the control room logsheet properly assured the Technical Specifications requirements were met. The inspector independently verified that the digital rod position indicators and group step counters agreed within ±12 steps.

Technical Specification 3.1.3.5 requires that all shutdown rods be fully withdrawn while the reactor is critical. On February 20, the inspector verified that all shutdown rods had been withdrawn, prior to the licensee entering Mode 2, by monitoring the digital rod position indication. The inspector verified the same prior to the licensee entering Mode 1 and also identified that the licensee had verified their full-out position within every 12 hours. Again, on February 26, the inspector verified that the control rod heights met the rod insertion limits as specified in the core operating limits report.

Technical Specification 3.1.3.6 specifies the minimum control bank insertion for critical reactor operations. On February 18, the inspector verified that the control banks were within rod insertion limits specified in the core operating limits report. The inspector verified the rod insertion limits by observing the bank position on both the digital rod position indication and the rod bank demand position.

Technical Specification 3.2.5 specifies that certain departure from nucleate boiling related parameters shall be maintained within limits. On February 27, the inspector verified that the control board indicators for pressurizer pressure, average water temperature, and reactor coolant system flow were indicating above the minimum Technical Specification limits.

Technical Specification 3.4.1.1 specifies that the reactor coolant loops shall be operable. On February 20, the inspector verified loop operability by monitoring reactor coolant loop flows and temperatures on both the control board instrumentation and the emergency response facility data acquisition and display system. In addition, the inspector verified that none of the reactor trip bistables associated with loop temperatures and flows had been actuated. Finally, the inspector identified that the licensee verified loop operability within the 12-hour requirement.

Technical Specification 3.4.2.2 specifies that all pressurizer code safety valves shall be operable. On February 21, the inspector verified operability of the pressurizer code safety valves as specified in Technical Specification 3.4.2.2. The inspector observed the alarm annunciator windows being dark. The inspector verified that the surveillance was performed satisfactorily within the required frequency by the licensee's surveillance data base.

Technical Specification 3.4.3 specifies the minimum volume of water and groups of heaters required for pressurizer operability. On February 21, the inspector verified operability of the pressurizer. The inspector verified that the volume of water was less than 1816 cubic feet by viewing Level Indicator LI-0465 on the main control panel. The inspector verified that safety-related power was available to all heater groups by reviewing surveillance records of power availability.

Technical Specification 3.4.4 specifies the operability requirements for both power-operated relief valves and associated block valves. On February 21, the inspector verified that the power-operated relief valves were closed by the indicating lights on the control board and that the block valves were open, also by the indicating lights on the control board. Also, the inspector verified that the cold overpressure mitigation system signals had been blocked. The high discharge temperature alarm was illuminated on the annunciator panel. The system engineer and operators had verified no evidence of excessive seat leakage existed and determined that the condition was acceptable.

Technical Specification 3.4.6.1 specifies that the reactor coolant system leakage detection system shall be operable. On February 26, the inspector verified that the control room logsheet required operators to monitor for particulate and gaseous radiation levels and containment sump levels for changes in the parameters. The inspector verified that the most recent digital channel operational check demonstrated operability of the radiation monitors. Personnel performed the digital channel operational check in accordance with Procedure OPSP02-RA-8011, "RCB Atmosphere Monitor DCOT (RT-8011)," Revision 1. In addition, the inspector determined that licensee personnel completed the channel calibration test in accordance with Procedure OPSP14-RA-1018, "RCB Atmosphere Monitor (NIRA-RT-8011) Calibration," Revision 4, within the last 18 months. The inspector found that the gaseous and particulate radiation monitor checks satisfied surveillance requirements for the Technical Specifications.

Technical Specification 3.4.6.2 specifies reactor coolant system leakage limits. On February 26, the inspector verified that the licensee had performed the leakage determination for the reactor coolant system pressure isolation valves in accordance with Procedure 1PSP03-SI-0023, Revision 4, "SIS Pressure Isolation Check Valve Leak Test." The inspector confirmed that the licensee performed the reactor coolant system water inventory balance within the required time limits.

Technical Specification 3.4.7 specifies the reactor coolant system chemistry limits. On February 27, the inspector reviewed the chemistry results for the previous 30 days. The inspector noted very good chemistry conditions for fluorides and chlorides. The inspector determined that the concentrations had remained a factor of 10 below the limits allowed for transient conditions.

Technical Specification 3.5.1 specifies the operability requirements for each safety injection system accumulator. On February 18, the inspector verified operability of the accumulators by checking that the discharge isolation valve for each accumulator was open and power to the valve had been removed. On February 22, 1994, the inspector verified compliance by observing control panel indications of the Safety Injection Accumulators A, B, and C nitrogen pressures and water levels and that the discharge valves were open. The inspector contacted chemistry personnel and determined that the most recent boron concentrations for Safety Injection Accumulators A, B, and C were 2717, 2719, and 2844 ppm, respectively. Because the boron concentration in Safety Injection Accumulators A and B approached the 2700 ppm lower limit, the inspector questioned the licensee about whether the boron concentration values indicated in the Technical specifications included a margin to account for instrument inaccuracies. The licensee engineers determined, after consultation with the nuclear steam supply system vendor, that instrument accuracies were not included; however, a 1 percent deviation of boron concentration in the nonconservative direction did not significantly alter the affected design basis analyses. The three accident analyses affected included the postloss of coolant accident minimum sump boron concentration, hot leg switchover and minimum flow verification, and postloss of coolant accident sump pH values.

During the investigation into the effects of a 1 percent laboratory uncertainty, the nuclear steam supply system vendor discovered an error in the original calculations that supported the safety injection accumulators and refueling water storage tank maximum boron concentration values of 3000 ppm. Specifically, a transposition error in the calculation resulted in incorrectly determining the value of the emergency sump mixed mean boron concentrations. The nuclear steam supply system vendor determined that the actual switchover time with and without boron concentration uncertainties of 1 percent should occur at 6.6 and 6.7 hours, respectively. The nuclear steam supply system vendor previously calculated the switchover time to be 13 hours. The nuclear steam supply system vendor determined that the error only affected STP since they had provided the revised analyses to support the STP Technical Specifications to reflect the increased safety injection accumulator and refueling water storage tank boron concentration ranges to 2700-3000 ppm and 2800-3000 ppm.

Technical Specification 3.5.2, specifies that the emergency core cooling system subsystems shall be operable. These include the high head safety injection pump, low head safety injection pump, residual heat removal heat exchanger, and associated flow paths. On February 19, initially the inspector verified, through control board indications, that the high head hot leg and low head hot leg recirculation isolation valves were closed and that power had been removed from these valves. The inspector also reviewed the results of the most recently performed surveillance tests which had tested the automatic actuation of the system valves and pumps. No problems were noted. The inspector also verified that the surveillance tests were performed within the appropriate period.

Technical Specification 3.5.5 specifies the operability requirements for the refueling water storage tank. On February 21, the inspector observed that actual water level was greater than 458,000 gallons by Level Indicator LI-0932 on the main control panel. The alarm annunciators were not illuminated. The inspector verified that the boron concentration was 2852 ppm, as evidenced by the last chemistry sample analyzed on February 15.

Technical Specification 3.6.1.3 specifies that each of the containment air locks shall be operable. On February 22, the inspector reviewed the licensee's results of the most recent Type B leak rate tests that were performed on the containment airlocks. The tests were found to be performed at the appropriate pressure requirements, and the total leakage identified did not exceed the limits set forth in the Technical Specifications. The inspector also verified that the tests were performed within the appropriate period.

Technical Specification 3.6.1.4 specifies the internal pressure limits of the primary containment. On February 22, the inspector verified that containment pressure was within the limits set forth in the Technical Specifications. The inspector identified this through the use of the qualified display processing system and the emergency response facility data acquisition and display system. The inspector also verified that the licensee performed this check within every 12 hours.

Technical Specification 3.6.1.5 specifies the average air temperature limits of primary containment. On February 22, the inspector verified, through the use of control board indication and the qualified display processing system, that the primary containment temperature did not exceed the Technical Specification requirements. In addition, the inspector verified that the licensee had routinely taken these temperature measurements within the prerequisite period.

Technical Specification 3.6.4.2 specifies that two independent hydrogen recombiner systems shall be operable. On February 22, the inspector verified the operability of the hydrogen recombiners through the review of the results of the most recent biannual surveillance test. The results met the requirement set forth in the Technical Specification. The inspector also verified that the channel calibration of the hydrogen recombiner instrumentation, visual inspection, and integrity check of all the heater electrical circuits had been performed within the last 18 months.

Technical Specifications 3.7.1.1 specifies the operability requirements for all main steam line safety valves for each steam generator. On February 20, the inspector verified that all main steam line code safety valves were operable. The inspector verified that the safety valves had the required lift settings specified in Technical Specification Table 3.7-2 by ensuring that the surveillance test was performed with satisfactory results and within the specified frequency as shown by the licensee's surveillance data base. Also, the inspector noted that the alarm annunciator was not illuminated.

Technical Specification 3.7.1.3 specifies that the auxiliary feedwater storage tank shall be operable. On February 23, the inspector verified that the volume of the auxiliary feedwater storage tank met the requirements stated in the Technical Specification. This was done by checking control board indications and parameters listed on the qualified display processing system. The licensee was found to perform this operability check within every 12-hour period.

Technical Specification 3.7.1.5 specifies that the main steam isolation valves shall be operable. On February 23, the inspector reviewed the most recent stroke test results for the main steam isolation valves. No problems were noted.

Technical Specification 3.7.1.7 specifies that the main feedwater isolation valves shall be operable. On February 23, the inspector reviewed the most recent surveillance test result of the valve stroke times. The inspector noted that the results did not exceed the surveillance test acceptance criteria. No problems were noted.

Technical Specification 3.7.3 specifies that at least three independent component cooling water loops shall be operable. On February 27, the inspector verified that the system was in proper valve alignment. The inspector observed that the control board pump and valve indications showed a correct system alignment. Also, the train status lights and alarm annunciator were not illuminated indicating that the trains were properly aligned.

Technical Specification 3.7.4 specifies that at least three independent essential cooling water loops shall be operable. On February 27, the inspector verified that the system was in proper valve alignment. The inspector observed that the control board pump and valve indications showed a correct system alignment. Also, the train status lights and alarm annunciator were not illuminated indicating that the trains were properly aligned.

Technical Specification 3.7.5 requires that the ultimate heat sink shall be operable and specifies a minimum water level and a maximum temperature. On February 23, the inspector verified, locally, that the water level and temperature were within the requirements set forth in the Technical Specification. The inspector verified that the licensee verified operability at least once per 24 hours. On February 27, the inspector verified, by observing control board indication, that the water level was greater than 25.5 feet and that essential cooling water in take temperature was less than 99°F.

Technical Specification 3.7.7 specifies that three independent control room make up and clean up filtration systems shall be operable. The inspector reviewed the associated procedures and verified that the systems were operable. On February 28, the inspector also verified that the monthly and quarterly surveillance test frequencies were met by reviewing completed surveillance records. The inspector noted some discrepancies with the surveillance frequencies, but verified that the surveillances were not performed solely as postmaintenance testing. When requirements were not met, the operators had placed the remaining trains in the recirculation and makeup mode as required.

Technical Speci   .ion 3.8.1.1 specifies the minimum electrical power sources that shall be operable. On February 26, the inspector verified that the minimum number of electrical power sources were available by touring the control room vital power control board and verifying power availability based on handswitch alignments, lights, and dial indicators. The three standby diesel generator rooms were toured to verify valve alignments and control panel alignments. The inspector reviewed the completion dates for the previous monthly and semiannual surveillance tests and concluded that the surveillance tests were completed within the required time intervals.

Technical Specification 3.8.1 1.b requires that three operable standby diesel generators be available in Modes 1 - 4. If one diesel is inoperable, operators are required to verify offsite power sources and verify that the other diesels remained operable. After Standby Diesel Generator 11 failed to come up to rated voltage following a test on March 1, as documented in Section 2.2 of this inspection report, the inspector observed the licensee take the required actions. The inspector observed the licensee verify the availability of other offsite sources and verify that the other diesel generators would start on demand.

Surveillance Requirement 4.3.1.1.2.a.2 requires that the power range nuclear instruments be calibrated on a daily basis consistent with calorimetric power. On February 26, the inspector independently verified that the values used in the calorimetric were obtained from the required instruments and that calculated values were accurate. The inspector observed the licensed operator making gain adjustments to all four power range channels, then independently verified that the gains were set at the calculated value.

6.2 Conclusions

The inspectors found that the licensee effectively verified and maintained compliance with Technical Specifications. Throughout the inspection period, 34 Technical Specification requirements were specifically verified. During a review of Technical Specification 3.5.1 requirements of operability for each safety injection system accumulator, the inspector identified that chemistry personnel did not account for instrument inaccuracies during boron concentration determinations. During a review of instrument inaccuracies, the nuclear steam supply system vendor identified an error in boron concentration uncertainties.

7 SUSTAINED CONTROL ROOM AND PLANT OBSERVATION (71715)

From February 15 through March 1, 1994, the inspectors provided 24-hour augmented resident inspector coverage of the Unit 1 restart activities. The purpose of this inspection was to: independently assess the safety of the licensee's operations during the restart of Unit 1; provide timely NRC response to operational problems and events; and provide a sound technical basis for determining the effectiveness of licensee management's controls for continued safe facility operation.

7.1 Operator Performance and Control Room Observations

Overall licensed operator performance in the control room was found to be good. Operators were found to be knowledgeable of their responsibilities during each evolution. They were aware of existing plant conditions and knew the reason for each lit annunciator. Operator actions to reduce noise levels and traffic in the control room, especially during complex or critical evolutions, was found to be excellent. Operators were also noted to use repeat-back communication in a very good manner, such that there was minimal opportunity for personnel to misinterpret instructions or information that had been relayed. This became important in those instances when communication with personnel in the field was difficult because of background noise. Repeat-back communication techniques were also used effectively when licensed operators were to leave their work station, to be relieved of control panel duties, or to walk behind the control boards. The announcements alerted the remaining licensed operators, and the subsequent acknowledgements provided verification that the operator had been heard. In all instances noted, the operators that made the announcements waited for the acknowledgements prior to leaving the area.

During the inspection period, the inspectors observed shift turnovers on station. The operators on shift provided clear and concise information to the oncoming operators, regarding equipment and plant status. Oncoming licensed operators were also noted to review the operators log.

Throughout this inspection period, the inspector observed operations personnel perform several operational evolutions using the following plant operating procedures:

- OPOP03-ZG-0001, Revision 2, "Plant Heatup"
- OPOP03-ZG-0003, Revision 0, "Secondary Plant Startup"
- OPOP03-ZG-0004, Revision 5, "Reactor Startup"
- OPOP03-ZG-0005, Revision 1, "Plant Startup to 100%"
- OPOP02-AS-0001, Revision 8, "Auxiliary Steam System"

In general, good procedural compliance was noted throughout this inspection period. Operators were found to perform these activities in a slow deliberate manner, stopping when questions were raised, and resuming only when the questions were adequately answered. If the answers to the questions were not quickly forthcoming, the operators were noted to either remain in the condition that they were at or back out of the procedure. These decisions depended on the type of procedure that was being performed and the plant conditions. The operators' actions in this area were deemed to be adequate. None of the observed decisions placed the plant in an unsafe condition. The inspector verified that procedural steps that were marked as not applicable were done in accordance with licensee Procedure OPGP03-ZA-0010, "Performing and Verifying Station Activities," with one exception described in Section 5.9 of this report. Command and control by supervisory personnel during these efforts was generally found to be good.

Operators were observed reviewing procedures prior to the commencement of an activity. It was noted that, as a result of these reviews, a number of errors were identified by the operators who took the appropriate corrective actions. Many of the errors in question were minor in nature, such as misnumbered procedural steps, mislabeled valve numbers, and missing text, but they indicated a lack of attention to detail by the personnel involved in the original review process.

Prior to initiating complex or infrequently performed activities, the licensee held preevolution briefings on the subject to coordinate efforts between control room operators and personnel stationed locally in the plant. Although the preevolution briefings were detailed in nature, it was noted that, on occasion, the personnel attending the preevolution briefings did not avail themselves of the opportunity to ask questions. One such occasion was during the performance of Plant Surveillance Procedure OPSP10-RC-0002, Revision 1, "Core Exit Thermocouple Resistance Temperature Detector Cross Calibration." On this occasion, operators raised questions just prior to and during the test activity. These questions indicated a lack of understanding of the full scope of the activity that was being undertaken. Even though the questions were addressed before proceeding with the activity, the failure to ask adequate questions during the preevolution briefings indicated a lack of attention by operations personnel.

The unit supervisors remained cognizant of ongoing activities and main control board annunciators that alarmed during the shift. Personnel remained knowledgeable of the reason for each lit annunciator. Overall, reactor operators provided good repeat-back communications for alarming annunciators and for repeating directions from the unit supervisor. Qualified personnel provided good oversight of trainees when they performed surveillance tests and other activities. While the operations work control group personnel were unavailable on the weekend, the inspector found that the unit supervisors maintained cognizance of control room activities and processed the limited number of service requests. The shift supervisors effectively utilized the personnel on duty. During periods of high activity, the shift supervisors assigned dedicated personnel to interface with other work groups on major activities such as main feedwater and main turbine testing.

Although overall operations were considered good, a number of areas were inconsistently implemented by the control room operators. A listing of these areas and some examples follow:

7.1.1 Control Room Professionalism

As noted above, in general, control room decorum and operator professionalism were found to be good, although not always consistent from crew to crew. One crew returning from vacation failed to properly utilize quiet time to refamiliarize themselves with plant conditions. Also, as described in Section 2.1 of this report, a reactor operator did not properly respond to a turbine trip first out annunciator. On an other occasion, multiple equipment failures caused operator frustration, and decorum suffered. Although shift management was present, they did not respond to correct the problem.

7.1.2 Control Room Communications

In general, communications were good and improved over the inspection period. However, proper communications and formality varied widely among the shifts. When communications were weak, supervisors and managers rarely stepped in to immediately correct the situation. When control room activities increased, some crews failed to utilize repeat-back communication techniques. On one occasion, an improper pretest brief caused operators to hesitate before performing the immediate actions during a main turbine overspeed test. Additionally, at one point, security officers failed to inform the control room that an investigation was in progress.

7.1.3 Self-Assessment and Corrective Action

At times, operators exhibited the failure to initiate corrective actions for known problems. On one occasion, a refueling water storage tank level alarm remained in an annunciated state for over 2 days with no action to correct the situation. Several other times, operators had to be prompted to clear long-standing annunciators. Additionally, during the event described in Section 2.4 of this report, operators continued to perform procedural recovery steps after identifying an error, without first initiating the corrective action program requirements.

7.1.4 Self-Verification

Reactor operators' use of the licensee's self-verification program was inconsistent. An operator performing main turbine testing consistently failed to reconfirm that he was manipulating the proper controls. Handswitch numbers were not verified during the fast start testing of Standby Diesel Generator 11. An operator did not verify that the proper handswitches were manipulated during the setup for steam generator blowdown valve operability testing. Additionally, shift supervision was rarely seen correcting these deficiencies while testing was taking place.

7.1.5 Procedural Controls

Although operators were routinely observed complying with procedures, some acceptance of procedural deficiencies was noted. Operators did not always check off or initial steps as performed. A main turbine test requirement to conduct three trips within 15 minutes could not be performed. A reactor trip signal was received during instrumentation testing but was not anticipated by the operators because of a procedural deficiency.

7.1.6 Operator Log

The operators were observed to take the appropriate action when Technical Specification limiting conditions for operation were not met. The inspector also noted that the operators kept a detailed log of these and other ongoing activities, including inadvertent alarms and their causes, if known. The inspector observed that the logging of information was not always timely. The use of late entries into the log was found to be quite common. Although some of the items were justified and could not be avoided, other delays had no explanation other than forgetfulness. This condition did not constitute a serious problem; however, it should be discouraged, based on the significant role that the log plays during shift turnover.

7.2 Transition from Mode 5 to Mode 4 (Unit 1)

On February 6, the inspector observed operators performing a plant heatup to change the unit status from Mode 5 to Mode 4. The transition was made in accordance with Procedure OPOP03-ZG-0001, "Plant Heatup." Prior to the mode change, the shift supervisor conducted a crew briefing to insure that all personnel involved were aware that piping temperatures throughout the plant would be increasing. The transition was uneventful and professionally performed by the operations crew.

The inspector independently verified that all steps in the procedure had been completed prior to the mode change. The inspector also verified that the main control board controls for the emergency core cooling systems were aligned in accordance with Technical Specification requirements and that operability checks required upon mode change were completed within the required time frame.

7.3 Transition From Mode 4 to Mode 3 (Unit 1)

On February 8, the inspector observed operators transition from Mode 4 to Mode 3 in accordance with Procedure OPOP03-ZG-0001, "Plant Heatup." A detailed crew briefing was conducted by the shift supervisor to ensure that all individuals knew what to expect. The mode transition was smoothly performed by the crew.

The inspector verified that the licensed operators were cognizant of plant system status and that Technical Specification tracking logs indicated that limiting conditions for operation were satisfied for the mode change. The procedure was verified to have been completed through the required steps.

7.4 Manual Reactor Trip Because of Unanticipated Test Results (Unit 1)

On February 14, Unit 1 was in Mode 3. A test of the solid state rod control system modification to prevent uncontrolled asymmetrical rod withdrawal was being conducted. During a portion of the test, operators attempted outward motion on a bank of control rods. Motion was not expected to occur based on the design of the test. The rods started stepping inward. The rod bank was manually tripped by the operators when the unanticipated rod motion occurred. Station Problem Report 94-0347 was issued to investigate the problem.

Licensee management determined that the best course of action was to remove the unproven modification that was installed in May of 1993 and replace the circuit cards with cards in the original configuration obtained from Unit 2. The removal of the modification was performed in accordance with Service Request 1-RS-305739. Upon completion of the card replacement, postmodification testing was performed in accordance with Plant Maintenance Procedure OPMP08-RS-0001, "Control Rod Drive Mechanism Timing Test."

The inspector observed the postmodification testing in the control room. The operators were very knowledgeable about the test condition and why the testing was required. Also, the operator allowed individuals in the licensed operator training class to perform actual rod motion for hands-on experience. This evolution was supervised by the licensed operators in an excellent manner.

7.5 Unanticipated Alarms

On February 18, while mechanics and system engineering personnel performed postmaintenance testing for Service Requests 159684 and 159687, the control room operators noticed that the turbine generator bearing deluge valves for Bearings 4, 5, 8, and 9 indicated open. From discussions with the reactor operators, the inspector determined that the operators had not anticipated the valve actuation and that they believed the dry fire protection piping had filled with water.

Subsequent review of the circuitry by the system engineer identified that the main control board deluge valve position indications illuminate from a sensed high pressure rather than a valve position limit switch. The valve had not actually opened. The operators and the system engineer were unaware of this method of position indication.

The inspector expressed concern about operators being surprised by testing activities indicating that the pretest review lacked thoroughness. The licensee then initiated Station Problem Report 940466 to document and assure corrective actions related to the deficiency would be implemented. The inspector determined that this action should have been initiated by the operators without prompting of the shift inspector. As short-term corrective action, training personnel issued a bulletin to licensed operators describing the system operation.

7.6 Observation of Operator Response to a Potential Auxiliary Boiler Trip

On February 18, the inspector observed the operators transfer the plant auxiliary steam demand from the auxiliary boiler to main steam. During the test preparations, operators identified that this evolution could cause the auxiliary boiler to trip prematurely, before main steam was supplying the system requirements. This could have resulted in a loss of vacuum in the condenser. Operations personnel took additional actions to minimize the risk of a boiler trip. The inspector noted that this review should have been performed earlier during the preparation of Procedure OPOP02-AS-0001 and added as a precautionary statement. This was considered another example of procedural weaknesses. The operator who identified this condition had previously been a reactor plant operator. He demonstrated a unique knowledge of the facility which was found to be beneficial in this situation. During this evolution, excellent communication between control room personnel and personnel in the field was noted.

7.7 Annunciators Alarms Present During Ongoing Activities

The inspectors questioned licensee personnel about the following annunciators being illuminated:

7.7.1 Refueling Water Storage Tank Level High/Low Alarm

On February 19, 1994, the inspector noted that the refueling water storage tank level high/low alarm had been lit for the previous 2 days. The reactor operator informed the inspector that instrumentation and controls technicians had performed a calibration test on the refueling water storage tank level setpoints. The water level in the tank was slightly lower than the low level alarm setpoint. He stated that, once makeup water was added to the tank, the water level would increase, resetting the lower setpoint level alarm. The actual water level in the refueling water storage tank was within Technical Specification limits and operator logs were taken for 8 hours to ensure operability. The inspector noted that the alarm was cleared on February 21.

7.7.2 Pressurizer Power-Operated Relief Valve High Discharge Temperature

The inspector noted that the pressurizer power-operated relief valve high discharge temperature alarm was annunciating. The reactor operators stated that the high discharge temperature setpoint was close to the ambient temperature in containment and that normal temperatures were most likely the cause of the alarm. The system engineer stated that he intended to pursue a setpoint change after obtaining a detailed temperature profile of the valve and the relief line. After performing the temperature profile, the system engineer concluded that the pressurizer power-operated relief valve was leaking internally through one of the bleed ports.

Subsequently, the system engineer requested that operators close the associated block valve. After closing the block valve, the operators properly entered Technical Specification 3.4.4, Action a, for excessive seat leakage, even though the leakage was minimal. From discussions with the operators and a review of the reactor coolant system inventory balance determinations, the inspector verified that the valve had minimal leakage. Total reactor coolant system leakage at that time was approximately 0.113 gpm.

After closing the pressurizer power-operated relief valve block valve, the temperature decreased and the alarm cleared. Upon reopening the block valve, the discharge temperature remained constant. This indicated that the valve had more fully seated and that the leakage had stopped. This was considered an additional example of the operators not understanding the cause of control room annunciation.

7.7.3 Residual Heat Removal Heat Exchanger 1B Not Full Alarm

The inspector questioned the status of the residual heat removal system Heat Exchanger 1B not full alarm. The reactor operator stated that he was aware of the annunciator status and that the most probable cause was leakage from the sample test valves upstream of the heat exchanger. After a satisfactory explanation that assured system operability, the inspector observed no further operator action. The inspector reviewed the annunciator response procedure for Control Panel CP001, Alarm B6. The procedure discussed excessive back leakage through Check Valve 1-SI-0030B as a probable cause for the alarm, but did not mention the sample test valves, which had leaked in the past. The procedure directed the operator to start Low Head Safety Injection Pump 1B to fill the heat exchanger, if the heat exchanger could not be maintained full. If this action did not clear the alarm, operators were directed to contact plant engineering and take appropriate actions for applicable Technical Specifications. The inspector questioned the adequacy of the annunciator response procedure and the willingness of the operators to accept this alarm.

The control room operators made efforts to clear the alarms after questioning from the NRC inspectors.

7.8 Technical Specifications Trip Actuating Device Operational Test (TADOT) Testing Frequency Error

On February 22, while operations support group personnel reviewed Plant Surveillance Procedure OPSP03-SP-0006R, Revision 1, "Train R Reactor Trip Breaker TADOT," to incorporate licensed operator comments, the personnel determined that the procedure failed to implement the requirements of Technical Specification Table 4.3-1, "Reactor Trip System Instrumentation Surveillance Requirements," Functional Unit 22, Note 15. The note required that personnel verify the local manual shunt trip actuated prior to placing the bypass reactor trip breakers in service. The operators initiated Station Problem Report 940473. The shift supervisor performed an initial operability review and determined that, although not prior to placing the breaker in service, the test had verified proper operation of the manual shunt trip.

On February 24, licensee personnel found the event to be reportable as a violation of Technical Specification Table 4.3-1, Functional Unit 22, Note 15 and Final Safety Analyses Report Section 7.2.2.2.3.10 in accordance with Section 2.g of Operating Licenses NPF-76 and NPF-80. The licensee engineers determined that Plant Surveillance Procedures OPSP03-SP-0006S, "Train S Reactor Trip Breaker TADOT," OPSP03-SP-0005R, "SSPS Logic Train R Functional Test," and OPSP03-SP-0005S, "SSPS Logic Train S Functional Test," similarly failed to test the local manual shunt trip prior to placing the reactor trip bypass breakers in service. Although licensed operators failed to meet the requirements of Technical Specification Table 4.3-1, Functional Unit 22, Note 15, this violation will not be cited because the criteria in paragraph VII.B.2 of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice" were satisfied. Licensee personnel identified the problem, evaluated operability and reportability, reviewed other procedures for similar problems, and implemented prompt actions to prevent recurrence. This event was reported as Licensee Event Report 50-498,499/94-007. Licensee personnel attributed the root cause to inadequate procedure preparation and review when engineers first developed the procedures. Long-term corrective actions included: development of procedure basis documents; enhancement of the procedure change review process; and evaluating the adequacy of 10 CFR 50.59 safety evaluation training.

During operations support group assessment of Station Problem Report 940473, operators discovered that facility personnel had not performed Plant Surveillance Procedures OPSP03-SP-0005R, OPSP03-SP-0005S, OPSP03-SP-0006R, and OPSP03-SO-0006S on a staggered test basis as defined by Technical Specifications. The failure to perform the surveillance on the correct frequency violated Technical Specification 4.0.2 by exceeding the 25 percent maximum allowable monthly extension of 7 days. The surveillance coordinator determined that they had not exceeded the required 84-day interval for the individual channels as indicated in the Technical Specification notes. However, the allowable extension based on the monthly interval of 31 days required on a staggered basis was exceeded. The shift supervisor entered Technical Specification 4.0.3 that allowed a delay of 24 hours to verify operability by completing the required surveillance tests if the only reason for inoperability was a missed surveillance as specified in Technical Specification 4.0.2. The shift supervisor determined that they had not satisfied the requirements of Technical Specification Table 4.3-1, Note 7, and Table 4.3-2, "Engineered Safety Features Actuation System Instrumentation Surveillance Requirements," Note 1, that required that each train shall be tested at least once every 62 days on a staggered test basis. Licensee engineers determined that the last performances of the applicable surveillance tests for Unit 1 were on December 23 and 24, 1993, and that Train R or S should have been tested by January 23, 1994.

Maintenance technicians satisfactorily performed the surveillance tests within 24 hours. No failures occurred. Licensing personnel determined the event to be reportable and will issue Licensee Event Report 50-498/94-008. Licensee personnel continued to review surveillances performed since June 24, 1988, to identify any other tests not properly performed on a staggered test basis. The failure to meet the requirements of Technical Specification 4.0.2 for testing the reactor trip breakers and the solid state protection system will not be cited because licensee personnel satisfied the criteria in paragraph VII.B.2 of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice." The event was reported to the NRC upon discovery in accordance with Paragraph 2.g of License NPF-76. The root causes of the failures were identified as inadequate training of the recently appointed surveillance coordinators and as an inadequate surveillance program. Controls used to establish proper surveillance intervals following an outage were determined to be less than adequate. Licensee management determined that the personnel filling the surveillance coordinator position had changed twice in the previous 2 months. Also, no programmatic controls existed to assure that the staggered intervals were reestablished. The licensee attributed that failure to frequency-based rather than calendar-based scheduling. The corrective actions that will be implemented include upgrading the training of surveillance coordinators and altering the program to properly reestablish the staggered intervals.

7.9 Main Turbine Mechanical Overspeed Trip Testing

On February 25, the inspector observed licensed operators and system engineers perform main turbine mechanical overspeed testing in accordance with Plant Engineering Procedure OPEP07-TM-0007, Revision 1, "Main Turbine Generator Startup Following Major Outage," Section 5.12.3 and Plant Operating Procedure OPOP03-ZG-0005, Revision 1, "Plant Startup to 100%," Steps 6.28-6.48. The inspector observed several instances of self-checking weaknesses during performance of this activity. Operators did not perform self-checking in accordance with management expectations in that the operators consistently failed to refer to the procedure to reconfirm the component being operated agreed with the component listed in the procedure. The inspector determined that the operators initially verified that they had the correct component and determined that no adverse consequences occurred and no components were incorrectly operated.

The inspector determined that the operators could not meet Precaution 3.12.2 as written in Procedure OPEP07-TM-0007. This section specified that operators should perform three main turbine trips within 15 minutes to minimize chilling of the rotors. The inspector noted that the evolution took 56 minutes and each trip sequence took approximately 20 minutes. Additionally, transitions from the operating procedure to the engineering procedure complicated the activity. Further delays were caused by operators failing to review the required actions following the mechanical overspeed trip as listed in Procedure OPOP03-ZG-0005 prior to beginning the evolution. This resulted in additional delays following the first mechanical overspeed trip sequence.

The shift supervisor identified that Procedure OPEP07-TM-0007 did not meet the licensee's upgraded procedure requirements for performance steps. The unit supervisor identified the need for a note prior to Procedure OPOP03-ZG-0005, Step 6.37, reminding operators to limit the rate of increase of the turbine speed. The unit supervisor also recognized that the procedure needed improvement after operators opened the control valves too rapidly and caused a small steam flow perturbation. The inspector determined that Procedure OPOP03-ZG-0005 required a reminder prior to Step 6.31 about pressing "auto open" to limit the close travel of the extraction steam block valves. A quality assurance auditor identified that performing Procedure OPOP03-ZG-0005, Steps 6.28 - 6.48, three times with initial blocks on the same steps for each main turbine trip provided more opportunity for error.

The unit supervisor discussed with the test coordinator that the 15-minute limit would be exceeded. The engineers informed the inspector that the 15-minute limit was a guideline that assured even heating of the turbine rotors. The engineers informed the inspector that the 15-minute limits minimized the stresses while admitting low pressure steam. The operators could not physically perform the test within 15 minutes under their present method for conducting the test. Also, the operators' failure to perform a detailed review of their required actions, such as entry into Procedure 0POP03-ZG-0005 and quickly pressing "auto open," indicated insufficient preparation for conducting this test.

7.10 Plant Startup Manipulations

On February 25, the inspector witnessed the closure of the main generator output breaker performed in accordance with Plant Operating Procedure POP03-ZG-0005, Revision 1, "Plant Startup to 100 Percent." This evolution was well coordinated, and repeat-back communications and self-verification of proper controls prior to manipulation were noted.

On February 26, the inspector observed an operator recover from a transfer of the steam generator level controller from automatic to manual. This occurred while Steam Generator Feedwater Pump 13 was being placed in service. The operators stopped the reactor power increase and took manual control of the master steam generator level controller. A service request was written to repair the control circuit. The inspector noted that the operator had been attentive to plant conditions.

7.11 Observation of a Reactor Power Decrease

On February 27, the inspector observed operators decrease power in accordance with Plant Operating Procedure 0POP03-ZG-0006, Revision 1, "Plant Shutdown from 100% to Hot Standby." The unit supervisor directed the power decrease because Main Feedwater Isolation Valve A began drifting closed. The reactor operators surmised that the most likely cause was air binding of the air-driven hydraulic pump. With the pump air bound, the hydraulic oil pressure could not be maintained and the valve began drifting closed. Subsequent review indicated that one of the air pumps had failed the previous day and had introduced air into the system. The inspector observed the unit supervisor station a reactor plant operator at Main Feedwater Isolation Valve A, a reactor operator at the primary plant controls for manual rod control, another reactor operator at the turbine control panel to decrease load, and a third reactor operator controlling the Main Feedwater Regulating Valve B because the valve was in manual. The inspector observed that this was evidence of notable command and control. The power decrease occurred quickly, yet in a well controlled manner. Good repeat-back communication techniques were utilized throughout the evolution.

7.12 Steam Generator Feed Pump Overspeed Trip Test

On February 27, the inspector observed the performance of Temporary Engineering Procedure 1TEP07-FW-0019, Revision 1, "SGFP Turbine Overspeed Trip Test." Communications between the control room and the system engineer were very good. The inspector noted the use of repeat-back communications throughout the test. The technicians used calibrated equipment to collect feedwater pump turbine data.

The inspector observed that the reactor plant operators lacked a questioning attitude regarding the status of turbine control indications and did not identify that the bearing oil pressure gauge was pegged high. The system engineer did not investigate and determine that the cause of the high reading was attributed to cold bearing oil until the inspector identified that the condition existed after the test had started. The indicator was not required to be utilized for the test. Therefore, it was not manually reset.

The inspector observed that the system engineer attempted to start the procedure performance in the middle of the procedure. The plant conditions necessary to start the test at this point had not been attained. The scope of the procedure was still met, but starting of the test was significantly delayed. Operators decided to reperform the procedure to attain the required plant conditions. The inspector concluded that, although the impact was of minor safety significance, the test may have been completed in a timely manner if appropriate procedure controls were instituted.

7.13 Solid State Protection System Relay Testing

On February 28, the inspector observed a portion of Plant Surveillance Procedure OPSP03-SP-0009B, Revision 1, "SSPS Actuation Train B Slave Relay Test." Good use of repeat-back communications and operator self-verification of the proper components prior to manipulation was observed. The reactor plant operator displayed a good questioning attitude. He did not properly reset Breaker E1 B4 H1 after the test was completed. However, the reactor plant operator contacted the senior reactor operator to appropriately reset the breaker.

7.14 Partial Stroke Testing of Feedwater Isolation Valves

On February 28, the inspector observed a partial stroke test of all main feedwater isolation valves in accordance with Plant Surveillance Procedure OPSP03-FW-0001, Revision 0, "Feedwater System Valve Operability Test." The test was performed well, and repeat-back communications were noted. The test coordinator obtained assistance from the unit supervisor as the procedure reader. The test coordinator was knowledgeable about the mechanics of the valve operation and proper procedure step sequencing.

7.15 Verification of Safety Function Checklist Following Manual Reactor Trip

On March 1, following the reactor trip described in Section 2.3 of this inspection report, the inspector verified the completion of Plant Operating Procedure OPOP01-ZQ-0022, "Safety Function Checklist." The minimum number of required components and instruments were operable with the exception of Centrifugal Charging Pump 1B, which had been placed in a pull-to-lock condition following unexpected cycling of the associated auxiliary lubricating oil pump.

The auxiliary lubricating oil pump cycled on and off when the centrifugal charging pump handswitch was placed in the automatic position. The reactor operator stated that the auxiliary lubricating oil pump pressure switch tended to cycle, which caused the pump to cycle, as the lubricating oil pressure decreased. The cycling of the pump did not adversely impact the operation of the centrifugal charging pump. Nevertheless, the unit supervisor conservatively placed the pump in pull-to-lock to ensure protection of the centrifugal charging pump. The operators appropriately entered the associated Technical Specification action statement and initiated a service request.

The safety function checklist was used as a means to status safety-related equipment operability following the reactor trip. The emergency operating procedure Plant Operating Procedure 0POP05-EO-ES01, "Reactor Trip Response," required that the safety function checklist be completed prior to exiting the emergency operating procedure. No restrictions were placed on totally satisfying the checklist in order to exit the emergency operating procedure.

7.16 Conclusions

Overall, licensed operator performance in the control room was found to be good. Generally, shift turnovers, communications, response to annunciators, and command and control improved over the inspection period. However, some weaknesses and inconsistencies were noted in the areas of control room professionalism, communications, self-assessment and corrective actions, self-verifications, and procedural controls. Operators did not always follow through to determine the cause and correct the problems initiating plant annunciators.

Two noncited violations were identified. In the first, the operators failed to verify the manual shunt trip capability of reactor trip breakers prior to placing the breakers in service. The other resulted from technicians failing to test certain solid state protection system relays in a staggered test basis as required by Technical Specification.

8 FOLLOWUP ON OPERATIONAL READINESS ASSESSMENT TEAM FINDINGS (92702)

8.1 (Open) Deficiency 93-202-01: Weaknesses in Controls for Maintaining Configuration Management

During the operational readiness assessment, licensee management had committed to establish and implement a configuration management action plan to identify and implement corrective actions to prevent configuration management deviations during the Unit 1 restart, power ascension, and subsequent operation. This plan was outlined on January 20, 1994.

Licensee management commissioned a task force to review each of the 33 previously identified 1993 events to ensure that the lessons learned, both individually and collectively, were properly identified and acted upon. The set of events that were reviewed consisted of unanticipated component actuations, as well as some other events selected from adverse trends at the station. A symptom classification technique was used by the task force. Each event was reviewed and causal factors and event characteristics were identified. Subsequently, common causes and characteristics were grouped to identify those factors that were most often associated with events. The task force then assessed higher level causal factors for the identified issues. This was based on the knowledge of the events as well as their collective knowledge of station programs and processes. Recommended actions were proposed to institute effective improvements to processes identified as significant in causing station events. The task force found that the majority of causal factors could be correlated into the following three categories:

- Configuration Control Problems - Basic configuration control principles and practices had not been consistently communicated and reinforced. The sensitivity of station personnel crews to the importance of sound configuration control did not always act as a barrier to station events.

- Failure to Implement Adequate Corrective Actions - Station problem investigations and corrective actions had not received the proper focus and oversight to ensure timely and effective results. As a result, several repeat events had occurred.

- Inadequate Work Practices - Insufficient levels of supervisory oversight of field activities had been provided to reinforce fundamental work practice expectations. As a result, the identification of performance weaknesses and the opportunity to reinforce expectations were missed.

The task force concluded that, prior to Unit 1 ascension to Mode 2, line management should reinforce expectations that quality work performance, maintaining a questioning attitude, and procedure adherence were essential elements to successful operations. Additionally, line supervisors were to be reminded of their essential role in monitoring performance and reinforcing positive work practices.

Several additional recommendations were provided, targeted at reducing station events, particularly those that related to unexpected component actuations or configuration control issues. Some recommendations were of a specific nature while others focused on broader programmatic issues. Licensee management reviewed the task forces' recommendations and developed a plan of action, including a schedule, to implement appropriate corrective actions.

On February 11, licensee management distributed a crew briefing sheet to provide information, as recommended by the task force, to be communicated to line workers including operators, maintenance craft, contract maintenance personnel, and Ebasco craft prior to Mode 2 operations. The inspectors observed four crew briefings given to two maintenance crews, a health physics crew, and an operations crew.

On February 14, licensing personnel added actions to the Commitment Tracking & Control Report which covered the additional recommendations of the task force.

The inspectors concluded that licensee management had established and implemented a configuration management action plan to identify and implement corrective actions to prevent configuration management deviations during the upcoming Unit 1 restart, power ascension, and subsequent operation as outlined in the action plan. The implementation of this action plan will be reviewed during future NRC inspections.

8.2 (Open) Deficiency 93-202-D4: Improper Operation of Two Centrifugal Charging Pumps

During the operational readiness assessment, the licensee management had committed to implement corrective actions, prior to the restart of Unit 1, to ensure that motor-operated valves did not open as a result of system pressure.

Licensee personnel reviewed the equipment clearance order database and updated it to ensure that motor-operated valves that had been manually closed, and were susceptible to partial opening upon system pressurization, were electrically closed prior to releasing the equipment clearance order. The database now contains a note stating "Electrically Close, Do Not De-Clutch" for these valves. Additionally, caution labels were installed on the susceptible valves, stating that they should be electrically closed as opposed to operated manually.

The inspectors concluded that the corrective actions to ensure that motor-operated valves did not open as a result of system pressure had been correctly implemented. The causes and generic implications of this event will be reviewed during future NRC inspections.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

J. Blevins, Supervisor, Procedure Control
J. Calloway, Consultant, Participant Services
T. Cloninger, Vice President, Nuclear Engineering
K. Coates, Maintenance Manager, Unit 2
M. Coughlin, Senior Licensing Engineer
R. Fellingham, Operations, Specialist, Acting Operations Support Manager
J. Grant,Shift Supervisor, Unit 2
W. Harris, Supervisor, Engineering Program
S. Head, Senior Consultant Engineer
D. Keating, Director, Quality Assurance
A. Kent, Division Manager, System Engineering Department
L. Meyers, Plant Manager
W. Mookhoek, Assistant to Operations Manager
W. Moran, Manager, Metrology Laboratory
K. Richards, Manager, Work Control Unit 2
J. Sheppard, General Manager, Nuclear Licensing
D. Stonestreet, Outage Manager

The personnel listed above 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 March 17, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the information presented at the exit meeting. The plant manager concurred that control room operations were still inconsistent in their formality, but stated that this area was improving and that corrective actions were still underway. The licensee did not identify as propriety any information provided to, or reviewed by, the inspectors.