APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-445/92-14 Unit 1 Operating License: NPF-87
50-446/92-14 Unit 2 Construction Permit: CPPR-127
Expiration Date: August 1, 1992

Licensee: TU Electric
Skyway Tower
400 North Olive Street
Lock Box 81
Dallas, Texas 75201

Facility Name: Comanche Peak Steam Electric Station (CPSES), Units 1 and 2

Inspection At: Glen Rose, Texas

Inspection Conducted: April 26 through June 6, 1992

Inspectors: W. B. Jones, Senior Resident Inspector
G. E. Werner, Resident Inspector
C. E. Johnson, Project Engineer

Reviewed by: L A Yandell July 1 '92
L. A. Yandell, Chief, Project Section B Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted April 26 through June 6, 1992 (Report 50-445/92-14)

Areas Inspected: Unannounced resident safety inspection of plant status, followup on previously identified items, licensee event report followup, onsite followup of events, operational safety verification, maintenance observation, and surveillance observation.

Results: Within the areas inspected, a loss of spent fuel pool cooling event was identified as the result of several personnel performance problems, including communication and procedure adherence (paragraph 5.3). This event resulted in an NRC special inspection (NRC Inspection Report 50-445/92-20; 50-446/92-20). Prior to this event, five other personnel performance problems were noted and identified as two violations. The examples are a reactor trip caused by two I&C technicians not self-verifying (paragraph 5.1); a missed conditional surveillance required for the reactor startup (paragraph 5.2); auxiliary operator equipment logs not being properly implemented or reviewed for abnormal conditions (paragraph 6.5); work request tags and a fire impairment not removed following completion of the work activities

(paragraph 7.1); and a prerequisite step in a surveillance procedure being inappropriately marked as not applicable without supervisory approval (paragraph 8.1).

The operators responded very well to the reactor trip (paragraph 5.1) and the initiation of a Technical Specification required shutdown (paragraph 5.4). The shift supervisor appropriately classified the required plant shutdown condition as a Notification of Unusual Event (NOUE) and maintained positive controls over the recovery actions. Good management support was observed during the NOUE.

Observed maintenance and surveillance activities were generally well implemented. One example was noted where maintenance personnel did not implement management's expectations for promptly working a time-critical activity (paragraph 7.2). Excellent coordination was noted between operations and maintenance during the NOUE recovery activities (paragraph 7.4) The local leak rate testing requirements for three containment penetrations were properly implemented (paragraph 8.4).

The radiation protection program was properly implemented. Excellent radiation protection practices were observed for a reactor coolant spill and the decontamination of eight personnel. Radiation protection technicians were cognizant of work activities ongoing in the radiation controlled area (paragraphs 6.1, 6.2, 6.3, 8.2, and 8.4).

The security program provided for the proper control of personnel, packages, and vehicles into the protected area. Security intrusion and detection equipment appeared to be well maintained. Two instances were noted where security officers were not attentive to their duties (paragraph 6.3).

Inspection Conducted April 26 through June 6, 1992 (Report 50-446/92-14)

Areas Inspected: No inspection activities were conducted on Unit 2.

Results: Not applicable.

DETAILS

1. PERSONS CONTACTED

TU ELECTRIC

O. Bhatty, Site Licensing
R. D. Byrd, Manager, Quality Control
W. J. Cahill, Group Vice President, Nuclear Engineering and Operations
R. D. Calder, Director, Nuclear Engineering
R. Flores, Shift Operations Manager
J. J. Kelley, Plant Manager
B. T. Lancaster, Manager, Plant Support
D. M. McAfee, Manager, Quality Assurance
J. W. Muffett, Manager of Design Engineering
S. S. Palmer, Stipulation Manager
J. L. Patton, Operations Quality Assurance
A. B. Scott, Vice President, Nuclear Operations
J. C. Smith, Administrative Assistant to Plant Manager
C. L. Terry, Chief Engineer
R. D. Walker, Manager of Regulatory Affairs
B. W. Wieland, Maintenance Manager

CITIZENS ASSOCIATION FOR SOUND ENERGY (CASE)

O. L. Thero, Consultant

In addition to the above personnel, the inspectors held discussions with various operations, engineering, technical support, maintenance, and administrative members of the licensee's staff.

Also present at the exit interview was R. M. Latta, Resident Inspector.

2. PLANT STATUS (71707)

Unit 1 was operated at essentially 100 percent power until May 8, when a reactor trip occurred because of a sensed 2 out of 4 overtemperature (OT)/N16 condition. At the time, reactor power was being reduced to perform main turbine valve testing. Two instrumentation and control (I&C) technicians were performing a surveillance on the N16 power monitor module when they entered the incorrect cabinet bay door. While attempting to return the incorrect channel to its normal status, a reactor trip was initiated on sensed OT/N16. During the reactor startup on May 9, a conditional surveillance was not performed for a power range monitor neutron flux low setpoint. This surveillance was a Mode 2 restraint. The unit was returned to full power on May 11. The unit operated at essentially full power until June 3, when power was reduced to approximately 8 percent because of a Technical Specification (TS) required shutdown. Both control room heating ventilation and air-conditioning (HVAC) trains had been declared inoperable. One train

was out of service for a modification. When one of the two compressors in the second train tripped, that train was also declared inoperable. Both trains were subsequently restored to OPERABLE. On June 6 the unit returned to 100 percent power operation.

3. FOLLOWUP ON PREVIOUSLY IDENTIFIED ITEMS (92701)

3.1 (Closed) Inspection Followup Item 445/9210-02: Calcium deposits on stainless steel pipe

An observation was made during a tour of the Safeguards building at approximate Elevation 790 feet, Room 85D (pipe chase). The inspector noted a white substance that had precipitated out of the upper concrete ceiling onto the stainless steel piping below. Discussions with the licensee's representative indicated that the material was calcium from the overhead concrete roof. The inspector was informed that this condition had been well documented in several nonconformance (NCR) reports.

A chemical analysis of the material identified it as calcium carbonate with small traces of chlorides and hydroxides. Technical Evaluation No. TE 91-3089 determined that the precipitated material would not have a detrimental effect on the structural integrity of the concrete, piping or structural supports. Design Change Authorization (DCA) 97666 was issued to address NCR 89-4825. This DCA provided for the application of waterproofing material on selected Unit 2 concrete ceilings to preclude further precipitation of calcium carbonate onto structures in the area. The licensee plans to observe the effectiveness of the waterproofing material before a decision is made to apply the material to Unit 1. The inspector concluded the licensee's corrective actions were appropriate. This item is closed.

3.2 (Closed) Unresolved Item 445/9210-03: Status of Work Requests

The licensee determined that the five work requests identified by the inspectors had been completed and that the field work request tags should have been removed. The failure to remove the work requests is an example of the personnel performance issue and potential violation identified in NRC Inspection Report 50-445/92-20; 50-446/92-20. An additional discussion on the status of the field work requests is provided in paragraph 7.1 of this report. This unresolved item is closed.

3.3 (Closed) Inspection Followup Item 445/9210-04: Turbine driven auxiliary feedwater pump (TDAFWP) steam admission valves inservice test (IST) values

The inspector reviewed the work history for the TDAFWP steam admission Valves 1-HV-2452-1 and -2, the IST stroke time requirement and the associated TDAFWP response time safety evaluation, and discussed the system performance with the cognizant system engineer.

The TDAFWP steam admission valves are air operated, 4-inch globe valves, which are designed to fail open an a loss of air pressure. The air supply to the

valve operator is maintained through an accumulator and is regulated down to 70-75 psig. The valves will begin to open when air pressure over the operator diaphragm decreases to approximately 6-12 psig. The valve stroke time is regulated by the rate at which the air over the diaphragm is released. The rate at which the operator is depressurized is controlled by a three-way valve which will realign to vent through a needle valve.

The inspector reviewed the work history for both valves and the TDAFWP. It was noted that during the initial startup of the TDAFWP system, the licensee experienced problems with the response time of the turbine. The turbine governor was modified to provide a shorter response time. This modification included changing the speed bushing. The tests performed during the preoperational and power ascension testing established an optimal stroke time for the steam admission valves at 9-11 seconds to meet the 60-second TDAFWP response time established in the Technical Requirement Manual, Table 1.2.1. These values were incorporated into the IST program through DCA 89-137. It was found the TDAFWP response time increased with both shorter and longer valve stroke times.

In February 1991, the licensee became aware of a potential concern with TDAFWP cold starts and its ability to meet the flow requirement in 60 seconds. Operation and Event Notification (ONE) Form FX-91-257 was initiated to evaluate the response time requirement. Subsequently, the licensee reevaluated the 60 second response time requirement. Safety Evaluation SE-91-064 was reviewed and was found to adequately support revising the time response value to 85 seconds. This number was incorporated into the Technical Requirements Manual in April 1991.

The inspector noted that the IST of the steam admission valves has resulted in several valve stroke times outside the 9-11 second range. Typically the stroke times have been shorter. The inspector noted that deviations from the established IST stroke time requirements in excess of 30 percent have still resulted in acceptable TDAFWP response times. The inspector concluded that, on the basis of the valve design, the tests results, and the revised TDAFWP response time, that the deviations experienced during IST valve timing tests have not indicated degraded valve performance, and has not placed the plant outside the design basis for accidents mitigated by the TDAFWP. This IFI is closed.

4. <u>ONSITE FOLLOWUP OF WRITTEN REPORTS OF NONROUTINE EVENTS (92700)</u>

The inspector reviewed the below listed licensee event reports (LERs) to determine whether corrective actions were adequate and whether response to the event was adequate and met regulatory requirements, license conditions, and commitments.

4.1 (Closed) LER 90-028: "Automatic Reactor Trip Caused by Lightning Strike"

On September 8, 1990, Unit 1 automatically tripped from 38 percent reactor power on high negative flux rate. The licensee believed that a lightning strike caused a power surge in the 25 voltage direct current control power to the control rod drive system. This resulted in the actuation of the overvoltage protection circuit and deenergized the power supplies in the rod drive system, causing the associated control rods to drop into the core.

No specific component or system failure was identified as the cause of this event.

The licensee's corrective action was to install surge suppressors at the input to the control rod drive power supplies. This modification should provide adequate assurance that the control rod power supplies remain available in the event of additional lightning strikes.

The inspector reviewed the licensee's corrective action including field verification of the surge suppressors. The modification was also discussed with the cognizant system engineer. The inspector concluded the licensee's corrective action was appropriate. This LER is closed.

4.2 (Closed) LER 90-04 and Special Report SR 90-003: "Safety Injection Caused By a Failed Blocking Diode"

On March 12, 1990, with the unit in Mode 4, and prior to initial criticality, an inadvertent Train A safety injection actuation occurred. A failed blocking diode in the Train A solid state protection system resulted in the Train A safety injection actuation when a planned containment ventilation isolation signal was initiated during a maintenance activity.

An assessment of the event was conducted by an augmented inspection team (AIT) (NRC Inspection Report 50-445/90-11; 50-446/90-11). The AIT concluded that the licensee's investigation of the event was good and that the operators response was also good. The plant response to the safety injection was as expected. The lack of nuclear heat at the time complicated the restart of a reactor coolant pump. The inspector verified that the corrective actions specified in LER 90-04, Paragraph III.A and B were promptly implemented. This LER is closed.

4.3 (Closed) LER 90-13: "Reactor Trip Because of Loss of Feedwater Pump Speed Controllers During Maintenance"

On May 9, 1990, with the unit at 48 percent reactor power, a maintenance calibration activity on a main feedwater pump discharge pressure transmitter resulted in a loss of feedwater and a reactor trip. A jumper had been installed across the feedwater pump speed controllers causing the two pumps to coast down. The inspectors initial review of this event is documented in NRC Inspection Report 50-445/90-19; 50-446/90 19, Paragraph 4.b.

The maintenance calibration procedure was not intended to be utilized with the plant in Mode 1. The licensee concluded that the accepted practice of marking the prerequisite blocks as not applicable (N/A) without having performed a detailed technical review was a root cause to the event. The impact review of the work activity was also determined to be inadequate based on the special conditions stated in the calibration procedure.

The inspector reviewed each department's response to the use of N/A in procedure and work package signoffs. Additional guidance was added to procedures governing the use of N/A for the maintenance (instrumentation and control), radiation protection, and chemistry and environmental. A recommendation to review special conditions has been added to the biennial procedure review process. Work activities which could result in a "high risk" are required to be identified as part of the work package. This included work activities on single point failure components. High risk work activities are also identified during the plan-of-the-day meeting. The inspector concluded that the above corrective actions were appropriate. This LER is closed.

4.4 (Closed) LER 91-01: "Inadvertent Actuation of Control Room Air Conditioning Engineered Safety Feature Caused by Sensitivity of Radiation Monitoring Device to Overcurrent Conditions"

On January 3, 1991, a control room ventilation engineered safety feature actuation occurred. No actual high radiation condition existed. An auxiliary operator observed that the "operate" light on Radiation Monitor X-RE-5895A was not illuminated, although the monitor was operating. When the auxiliary operator attempted to change the bulb, a section of filament fell across the contacts and shorted out the power supply.

The licensee implemented Minor Modification 91-209 to change the filament bulbs with light emitting diodes. This work was completed in April 1992. The licensee's corrective action was adequate. This LER is closed.

4.5 (Closed) LER 91-20: "Reactor Trip Resulting from the Erratic Operation of the Main Turbine Electrohydraulic Controller"

On July 13, 1991, a reactor trip occurred from 82 percent power when the main turbine tripped on high steam generator level indications. The licensee believed that rapid electrohydraulic pressure oscillations had an effect on the steam generators through the rapid movement of the main turbine control valves. This rapid movement was believed to have affected the steam generators level variable leg sensing line and caused a sensed high steam generator level. This event was reviewed by the inspectors and is documented in NRC Inspection Report 50-445/91-32; 50-446/91-32.

The inspectors discussed the electrohydraulic control (EHC) system operation with the system engineer. No new information had been developed as to why the EHC system responded in an erratic manner. The inspector concluded that the

licensee had adequately reviewed the event, and met the reporting requirements. No additional NRC inspection effort is warranted. This LER is closed.

5. ONSITE FOLLOWUP OF EVENTS (93702)

5.1 Reactor Trip

On May 8, 1992, with the reactor at 93 percent power, a reactor trip occurred because of a sensed two out of four OT/N16 condition. All systems responded as expected with the exception of a steam dump valve and a sensed west bus breaker fault (8010).

At 10:47 p.m., (CST) two I&C personnel had received authorization from the shift supervisor to perform Surveillance Work Order S91-3092 for the Loop 4 N16 channel calibration. This work package implemented Procedure INC-7717A, "Channel Calibration N16 Power Monitor Module Protection IV, Channel 0440," Revision 1. The Loop 4 N16 channel was placed in defeat. The reactor operator logged that the Loop 4 N16 channel was verified to be in defeat in accordance with Procedure ABN-704A, "TC/N16 Instrumentation Malfunction," Revision 4. The I&C technicians then proceeded with the performance of Procedure INC-7717A, Section 11.1, "N16 Power Monitor Module (PMM) Calibration." Step 11.1.1.1 required the I&C technicians to go to the rear of Cabinet 10 N16 Power Protection IV and open the N16 high voltage power supply Breaker CB2. Concurrent with the I&C technicians opening the breaker, the operators received indications of a problem with the Loop 2 N16 (Channel 2 failed low). The Unit 1 supervisor instructed the I&C technicians to back out of the Loop 4 N16 channel calibration procedure. When the I&C technician closed Breaker CB2, the reactor tripped on a sensed OT/N16 on Loops 2 and 4.

During the review of the event, the licensee identified that the I&C technicians had entered into the correct cabinet but the incorrect bay. The I&C technicians were directed by Procedure INC-7717A to enter Cabinet 10 at Location 10-04-25 to obtain the "As Found" high voltage setting. This location corresponds to Cabinet 10, Bay 3. However, the I&C technicians entered into Cabinet 10, Bay 1, which houses Power Protector Channel II and obtained the "As Found" high voltage readings. The I&C technicians then went to the back of Cabinet 10 as required by Step 11.1.1.1, but instead of entering Bay 3 for Power Protection Channel IV, they again entered Bay 1. The I&C technicians failed to verify that they had entered the correct cabinet access door and opened Power Protection Channel II N16 high voltage power supply Breaker CB2. This caused Channel II to fail low. The operators received annunciation and other main control board indications that Channel II had failed. As a result of the operators believing the channel had failed, the Unit 1 supervisor directed the I&C technicians to back out of the procedure by restoring the channel to operable. Both the unit supervisor and I&C technicians believed they were in the Channel IV cabinet bay at that time. The I&C technicians then proceeded to the step in the procedure which closed Breaker CB2. When Channel II N-16 reenergized, the OT/N-16 tripped as the

channel spiked high. With Channel IV OT/N-16, tripped for the surveillance test, the 2 out of 4 OT/N-16 trip logic was satisfied and a reactor trip signal initiated.

The reactor trip breakers opened and all control rods indicated on the bottom. A main feedwater isolation occurred at the time of the reactor trip. The Loop 2 N16 reactor coolant system temperature average (Tavg) had failed low when the breaker was opened. When the channel was restored, the Loop 2 N16/Tavg bistable still sensed a low Tavg condition and concurrent with the Loop 4 N16/Tavg bistable tripped for the surveillance test, a main feedwater isolation was initiated. The auxiliary feedwater (AFW) system actuated as required. The feedwater transient resulted in Feedwater Heaters 3A and 3B blowout plugs actuating.

An abnormal response was observed for a failed open steam dump valve. The operators observed that Steam Dump Valve 2370H failed to fully close. This condition was promptly noted by the operators and an auxiliary operator was dispatched to manually close the valve. No appreciable reactor coolant system cooldown occurred because of the partially open steam dump valve. The valve was repaired under Work Request 128214 prior to returning to power operation.

Following the reactor trip, the main generator reverse power relays operated to trip open the Main Output Breakers 8000 and 8010. The breakers tripped as expected; however, the West Bus Breaker 8010 Relay 50-1/W3 contact failed to open. This relay protects against a fault by sensing current through the respective breaker. When the associated timer timed out with the fault still sensed, the west bus primary lockout relay actuated deenergizing the respective bus. This resulted in Breaker 8080 opening causing a loss of power to Unit 2 non-1E busses. Unit 2 equipment, which was affected, included both condensate pumps, Turbine Plant Cooling Water Pump 2-01, and instrument air. Texas Electric Service Company (TESCO) was responsible for the maintenance program for the switchyard components, including protective devices. The licensee later learned that the fault detector was out of calibration and no fault actually existed. The inspector discussed the switchyard preventive maintenance program with the responsible system engineer. It was learned that TESCO had established a biennial calibration program for the switchyard protective devices. The failure of the 50-1 relay to open appears to have resulted from an improperly performed calibration. The switchyard fault detectors were subsequently calibrated by TESCO.

The licensee initiated ONE Form FX92-415 to evaluate the reactor trip which occurred during the performance of Surveillance Work Order S91-3092. This ONE Form was elevated to a plant incident report in accordance with Station Administration Procedure STA-422, "Processing of Operation Notification and Evaluation (ONE) Forms," Revision 5. During the initial review of the event, the licensee determined that the event occurred because of inadequate self-checking. A task team was then appointed to review the generic concern of why personnel errors continue to occur.

The inspector met with the duty manager on May 9, 1992, to discuss the adequacy of the surveillance procedure, personnel performance during the test, and the short-term corrective actions which were planned.

The inspector reviewed Procedure INC-7717A and found that it properly identified the equipment and was adequate to perform the surveillance test. The I&C technicians had received proper authorization to begin the surveillance test. The surveillance test was conducted by a qualified I&C technician; however, he had not performed this surveillance previously. A second experienced I&C technician was present but was not qualified to perform the test. The cabinet doors were normally locked closed. A common key provided access to Cabinet 10 Bays 1 and 3. The I&C technician had possession of his own key to access the cabinet. Although the I&C technicians had received a briefing on the surveillance test, no additional supervision of the work activity was provided. When the I&C technicians entered into Cabinet 10, they failed to self-check to ensure that they had entered the correct cabinet and bay. The inspector noted that the Cabinet 10 front and back access doors were properly labelled. The failure to self-check and the second individual's failure to verify that they were in the proper cabinet resulted in their obtaining high voltage readings on the wrong channel and opening the incorrect breaker. After deenergizing the breaker and being instructed to back out of the procedure, the I&C technicians did not meet management's expectations to fully assess the actions they had taken and what actions should be taken to restore the channel.

The licensee's interim corrective actions included:

- All CPSES personnel shall know and practice the seven steps of self-verification. Supervisory personnel were required to check each of their employee's knowledge on the verification steps and provide prompt remedial training when necessary prior to their starting work.

- Licensee personnel were instructed on management expectations for independent verification, including communication during and after the verification process.

- A schedule was established for modifying the cabinet locking scheme for sensitive cabinets. Until the modification is completed, licensed operators are required to verify that personnel are entering the proper cabinet.

- All first time performances of sensitive tasks are to be completed under the observation of an individual who has successfully performed the evolution.

The inspector noted that there were several contributing factors to this event which were also noted during other recent events. In particular, the event involving work on a wrong valve by two I&C technicians on April 8, 1992,

resulted from several similar personnel performance and management oversight issues. The similarity included inadequate self-verification and independent verification, the second I&C technician who provided the independent verification was not a qualified I&C technician and supervisory oversight of the work activity was not provided to ensure management expectations were met. This event is documented in NRC Inspection Report 50-445/92-10; 50-446/92-10, Paragraph 5.4, "Work Activity Performed on Incorrect Valve."

This failure of the I&C technicians to meet the procedural requirements specified in Procedure INC-7717A is a violation of the requirements of Technical Specification (TS) 6.8.1 and Regulatory Guide 1.33 (445/9214-01). In assessing the significance of this potential violation, the inspector considered, in part, the effectiveness of the licensee's previous corrective actions, continuing personnel performance problems, inadequate use of self-verification, and an apparent lack of management's involvement to ensure these expectations were being met. In addition, the scope and findings from the special inspection on the loss-of-spent-fuel pool cooling on May 11 and 12, documented in NRC Inspection Report 50-445/92-20; 50-446/92-20, were considered. The inspector concluded that the plant personnel performance and management effectiveness issues, which contributed to both the reactor trip and loss-of-spent-fuel pool cooling, are similar and indicative of an overall personnel performance and management effectiveness concern.

5.2 Missed Technical Specification Surveillance Test

On May 11, 1992, the inspector was notified by the licensee of a missed TS surveillance test. Power range neutron flux Channel N41 low setpoint was required to be operable with the plant in Modes 1 (below P-10 interlock) and 2. TS Surveillance Requirement 4.3.1.1 states, in part, "Each reactor trip system instrumentation channel and interlock and automatic trip logic shall be demonstrated OPERABLE by the performance of the Reactor Trip System Instrumentation Surveillance Requirements Specified in Table 4.3-1." Table 4.3-1, "Reactor Trip System Instrumentation Surveillance Requirement, Functional Unit 2.b Power Range, Neutron Flux Low Setpoint," required that the analog channel operability test (ACOT) be performed for the applicable modes if not completed within the past 31 days. This surveillance requirement was implemented by Procedure INC-7375A, "ACOT CH CAL Neutron Flux PWR RN Chan N41," Revision 7.

Prior to the reactor startup on May 9, the licensee incorrectly identified that the performance of INC-7375A on April 25, 1992, satisfied Surveillance Requirement 4.3.1.1 for power range neutron flux Channel N41 low setpoint. The licensee subsequently determined that the last performance of INC-7375A was a partial test which, because the plant was above the P-10 setpoint, did not verify the low setpoint. The power range neutron flux Channel N41 low setpoint ACOT surveillance test was last performed on January 9, 1992. This failure to perform the low setpoint ACOT surveillance test is a violation of TS Surveillance Requirement 4.3.1.1 (445/9214-02).

The licensee initiated ONE Form 92-414 on May 11, to document the TS violation. The ONE Form was raised to a plant incident report. During the licensee's evaluation, personnel performance issues and some surveillance program weaknesses were identified. The personnel performance issues related to the I&C individual not actually verifying the status of INC-7375A. The inspector discussed the performance issue with licensee management and noted that the issue closely paralleled the personnel performance issues identified in NRC Inspection Report 50-445/92-20; 50-446/92-20.

In January 1992, the licensee initiated a surveillance review group to assess the adequacy of the surveillance program and to provide recommendations for improving program effectiveness. Following the latest missed surveillance, the group was tasked with completing their reviews by June 1992. The inspector discussed the groups efforts with cognizant licensee personnel. These efforts included:

- Assessment of the limiting condition for operation action procedures,
- Modifying the surveillance completion data base,
- Assessing the means of scheduling conditional surveillances (Mode dependent), and
- Providing conditional surveillance station bounds for operation surveillance tracking.

In addition, the I&C department initiated their own surveillance program review and, based on the results, developed a surveillance improvement plan. The review and action items included:

- Verifying all other I&C reactor startup surveillances were complete or still valid for the May 9, 1992, reactor startup,
- Verifying all reactor startup procedures were completed for the January 1992 reactor startup,
- Verifying all surveillance requirements for which credit was taken were valid for the period December 1991 through May 9, 1992,
- Verifying all surveillances from the period December 1991 through May 9, 1992, were valid and conducted within the specified frequency,
- Reviewing the surveillance schedule for the second refueling outage,
- Completing the review of the master surveillance tracking list for plant status, outage requirements, TS applicability, and surveillance frequency for reactor shutdown to 24 days,
- Creating an I&C conditional surveillance list, and

- Developing a list of expectations for supervisors, lead I&C technicians, planners, and the surveillance group.

The inspector found the licensee's corrective actions to address the programmatic concerns were thorough. The surveillance review group's final report and the long term corrective actions will be reviewed during the followup to the licensee event report (LER 50-445/92-10).

5.3 Loss of Spent Fuel Pool Cooling

On May 12, 1992, the inspectors noted contradictions in licensee log entries, active annunciators, and main control board and physical plant lineups for component cooling water to a spent fuel pool heat exchanger. The inspector identified these discrepancies to the Unit 1 supervisor. It was subsequently determined that the Unit 2 component cooling water system had not been correctly aligned to the Spent Fuel Pool Heat Exchanger X-02. As a result, the spent fuel pool, which contains the first cycle irradiated fuel off load, was without cooling for approximately 17 hours. This resulted in a 5°Fahrenheit (F) spent fuel pool temperature rise.

During the previous shift, the reactor and auxiliary operators had aligned the Spent Fuel Pool Pump X-01 to Spent Fuel Pool Heat Exchanger X-02. The operators had intended to align the Unit 1 component cooling water (CCW) as the heat sink for the spent fuel pool and thought that this had been accomplished. However, a design modification during the 1991 refueling outage isolated the Units 1 and 2 CCW nonsafeguards loops which prevented the Unit 1 CCW from being able to cool Spent Fuel Pool Heat Exchanger X-02 without reversing the installed spectacle flanges.

On the basis of the inspector's followup to the event, a special inspection was initiated. The results of this special inspection are documented in NRC Inspection Report 50-445/92-20; 50-446/92-20. The special inspection identified several areas of concern including the design modification process as it related to this event; the Unit 1/Unit 2 interface control program; and work control. However, of particular concern were the human performance problems. Prior to this event occurring, the inspectors had identified other personnel performance issues. These additional personnel performance concerns, identified in paragraphs 5.1, 5.2, 6.5, 7.1, and 8.1 of this report, included the operations and maintenance organizations.

5.4 Unit 1 Control Room HVAC Notification of Unusual Event

On June 3, 1992, at 2:50 a.m. CST, the license declared a notification of unusual event (NOUE) because of a reactor shutdown required by TS 3.0.3. The licensee entered this TS because both trains of control room HVAC were inoperable. The reactor shutdown was stopped at 6:40 a.m. CST when one train of control room HVAC was returned to an OPERABLE condition. The NOUE was exited at 8:23 a.m. CST.

The licensee had entered TS 3.7.7 on June 1, because Train B of control room HVAC was inoperable for a planned maintenance activity. This placed the unit in an active limiting condition for operation action requirement (LCOAR) requiring that the train be restored within 7 days or the unit be placed in Hot Shutdown within the following 6 hours and Cold Shutdown within the next 30 hours. This LCOAR was properly identified in the control room limiting condition for operation (LCO) tracking log and was discussed during the licensee's plan-of-the-day meetings.

At 1:23 a.m. CST on June 3, the control room HVAC Train A No. 2 compressor tripped on low lube oil pressure. The operators attempted to restart the compressor after verifying proper lubricating oil levels and again after adding oil. These attempts to restart the compressor were not successful and a reactor shutdown was initiated in accordance with Abnormal Operating Procedure ABN-203, "Control Room Ventilation Malfunction," Revision 2. The licensee continued to evaluate the operability of control room HVAC Train A with one compressor available. At 2:50 a.m. CST, after discussing the train operability status with engineering, licensing and management personnel, the shift supervisor declared the second train inoperable and entered a NOUE because of a plant shutdown required by the TS.

The required emergency notifications were made within the specified times. The resident inspector was also notified. Almost concurrently, a second resident inspector arrived in the main control room and observed the licensee's actions to shutdown the unit as required by Procedure ABN-203 and the TS. The emergency action level was properly classified in accordance with Emergency Plan Procedure EPP-201, "Assessment of Emergency Action Levels, Emergency Classification; and Plan Activation," Revision 8.

The following observations were made by the inspectors during the event:

- Appropriate management oversight was provided by the chief engineer, plant manager, manager of operations, and maintenance manager.
- Communication between the operators and their supervision was excellent.
- Reactor and plant control manipulations were well coordinated.
- Applicable procedures were followed and briefings on the procedures were conducted.
- Control personnel were cognizant of their duties and performed them well.
- Shift turnover was delayed until the plant was in a stable condition.

Control room HVAC is required to ensure habitability of the control room for personnel and equipment. TS 3.7.10, "Area Temperature Monitoring,"

establishes the maximum normal control room temperature at 80°F and abnormal conditions at 104°F. Exposure to temperatures in excess of the maximum abnormal temperature could degrade the equipment. During the period both control room HVAC trains were inoperable, the control room experienced a 1 degree temperature rise to 73°F.

The TS do not explicitly require both compressors in each train to be available in order for the train to be OPERABLE. The licensee considered the control room HVAC design bases documents in assessing the second train's operability. The system consists of two independent 100 percent trains which in turn have two 50 percent capacity refrigeration units. The lineup at the time of the event consisted of Train A (Compressors 1 and 2) supplying control room cooling. Train B (Compressors 3 and 4) was removed from service for a design change that added base mat hold-down bolts to increase the stiffness of the mounting frame. Compressors 3 and 4 were tagged out for the design change and were unavailable for immediate use.

While troubleshooting the control room HVAC system, the licensee discovered that control room HVAC Compressor 2 had a large amount of freon absorbed in the oil. An emergency work order and standby clearance were promptly initiated to change the compressor oil. After completion of the oil change, the compressor was restarted and allowed to run for approximately 45 minutes, under constant observation by operations and maintenance personnel, to ensure no operability concerns remained. The licensee exited the TS at 6:40 a.m. when Compressor 2 was declared operable and stopped the controlled shutdown at approximately 8 percent reactor power. Additional maintenance crews were working concurrently to restore Train B HVAC. Train B was returned to service later that morning. Further discussion of maintenance observations is provided in Section 7.4.

5.5 Summary of Findings

A loss of spent fuel pool cooling event resulted, in part, from several personnel performance problems. Other concerns were interface between Units 1 and 2, and operator training. Based on the initial review of this event, an NRC special inspection was performed.

A reactor trip resulted from the failure of two I&C technicians to verify they were working within the correct cabinet bay. This event closely paralleled personnel performance concerns noted previously during work on a wrong valve. The corrective actions from the previous event were not effective in preventing this event. Management involvement in preventing this event and in assuring its performance expectations were met was also not effective.

A conditional surveillance requirement was missed during the unit startup following the reactor trip. Personnel performance within the I&C department and surveillance program weaknesses were identified as contributing to the event. The corrective actions which were implemented to address the programmatic weaknesses were extensive.

The licensed and auxiliary operators performance during the NOUE was very good. The shift supervisor's decisions were conservative and appropriately considered the plant's design basis. Communication between the operators was concise. Management involvement addressing the event was evident. Appropriate measures were taken to ensure equipment control was maintained and personnel safety was not jeopardized.

6. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation, to assure that selected activities of the licensee's radiological protection programs were implemented in conformance with plant policies and procedures and in compliance with regulatory requirements, and to inspect the licensee's compliance with the approved physical security plan.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. Through in-plant observations and attendance of the licensee's plan-of-the-day meetings, the inspectors maintained cognizance over plant status and Technical Specifications action statements in effect.

The following paragraphs provide details of certain areas reviewed during this inspection period.

6.1 Radiation Protection Observations

The inspectors reviewed the activities associated with the implementation of the radiological protection program. The review consisted of observing activities requiring radiation work permits, tours of the radiologically controlled area, and reviewing activities documented in the radiation protection shift log. On April 29, the inspector accompanied a radiological protection technician during performance of routine surveys of the chemistry hot lab and the primary sample room. The technician was very thorough and demonstrated good radiological work practices throughout the surveys.

Additionally, the inspector observed the response of a radiation protection technician to a reactor coolant spill. The spill resulted from the draining of the chemical addition tank in preparation to add chemicals to the primary coolant system. The technician responded promptly and found no contamination associated with the overflowed floor drain. Excellent response and radiological precautions were observed during the cleanup and survey of the area.

6.2 Charcoal Replacement in the Floor Drain Tank Processing System

The inspector observed two radiological waste technicians performing the sluice of expended charcoal from a floor drain filter tank to a shielded

liner. The workers were using the procedure and checking off the appropriate steps as they were completed. In addition, the workers used appropriate radiological precautions and protective equipment while positioning removable hoses as described in their procedure.

6.3 Contamination Event

On May 4, 1992, while exiting the radiological control area (RCA), the inspector observed eight contractors with various levels of radioactive contamination on the soles of their shoes. Radiation protection (RP) technicians immediately isolated the individuals and thoroughly frisked each worker. One worker had a slight skin contamination which was cleaned with no traces of contamination remaining. The workers were immediately interviewed and the area of concern was identified as auxiliary building, Elevation 790. Followup surveys pinpointed the source to Room 163.

After an extensive radiological survey of Room 163, the licensee found that a weld on a common low pressure radioactive drain line had a small flaw open to atmosphere and was weeping liquid. The weld was immediately repaired and the system returned to service.

The inspector found the response of the radiological protection department to be excellent during the period of observation. Prompt attention to the contaminated workers and auxiliary building, Elevation 790 was good. This prevented the spread of contamination.

6.4 Security Program Implementation

The inspectors observed security access controls at the primary access point. Vehicles entering the protected area were searched prior to entry. Personnel and packages entering into the protected area were properly surveyed. An early morning observation of security access controls was performed. Appropriate personnel controls and staffing was maintained. Camera clarity remained excellent and there was very little reliance on compensatory posts. During the inspection period, the inspectors noted two instances where security officers were not fully attentive to their duties. These instances were discussed with licensee security management personnel. In each case, licensee management conducted a thorough review of the event and demonstrated that recent actions had been taken prior to the events, iterating management's expectations. The inspector considered the events to be isolated based on the overall performance of the security officers observed. Additional management and supervisory oversight was provided to assess security officer performance following the events.

6.5 Observation of Auxiliary Operator

On May 7, 1992, the inspector accompanied an auxiliary operator during the assigned shift monitoring of equipment status in the auxiliary and fuel buildings. The auxiliary operator demonstrated adequate knowledge of plant system interactions and component operation.

The inspector reviewed the completed shift logs for the period of April 21 through May 2, 1992. Numerous out of specification readings had not been identified as being abnormal by either the auxiliary operator or during the review by the unit supervisor. This is contrary to Procedure OWI-104, "Operations Department Logkeeping and Equipment Instructions," Revision 3, which states that abnormal conditions and out-of-spec readings should be circled in red and the following information should be included in the comment section: (1) the reason for the condition or reading, (2) the corrective action performed or attempted, (3) the results of the corrective action, and (4) the time and person notified. This failure by licensee personnel to properly assess equipment status logs is another example of a violation of the requirements of TS 6.8.1 and Regulatory Guide 1.33 (445/9214-01).

None of the out-of-specification readings affected operability or had an adverse impact on the equipment. Most of the abnormal readings were on nonsafety-related equipment, such as the nonsafety-related chillers. Operations management was notified and performed a detailed review of past logs. The results showed a widespread pattern of unidentified abnormal readings. These findings indicated a general lack of attention-to-detail by both the licensed and nonlicensed operators while performing and reviewing equipment logs. The licensee has developed an improvement plan to address equipment log taking and review. This plan will be reviewed during a subsequent inspection.

6.6 Reactor Startup

On May 9, 1992, the inspector observed different aspects of the reactor startup from Mode 3. At 11:48 p.m. CST the reactor was taken critical and Mode 1 entered at 4:02 a.m. CST the following day. On May 11 the reactor was returned to 100 percent power. The reactor startup was performed in accordance with integrated startup Procedure IPO-002A, "Plant Startup From Hot Standby," Revision 8. The inspector observed that the startup was well controlled and a unit supervisor was dedicated to monitoring the integrated plant startup. On May 10 at 12:50 a.m. CST the operators entered Procedure ABN-305, "Auxiliary Feedwater System Malfunction," Revision 3. Motor driven auxiliary feedwater pump (MDAFWP) 1-01 had been operated to supply the steam generators during the initial plant startup. When the pump was shutdown, the operators noted backleakage through one of the Borg-Warner check valves, which isolates the AFW lines from the main feedwater line. This leakage was identified by increasing temperature upstream of the valve as indicated by Temperature Indicator 1-TI-2472A. The pump was again started to try and seat the check valve. This attempt did not result in a reduction in the line temperature after the pump was shutdown. An auxiliary operator then vented the discharge line from the MDAFWP 1-01 which resulted in the check valve seating. The abnormal response procedure was then exited.

NRC Inspection Report 50-445/92-07; 50-446/92-07, Paragraph 8.3, documented a concern with the use of generic curves for inverse count rate versus boron concentration for the flux doubling circuitry. The licensee determined that the boron dilution mitigation system was inoperable in Modes 3, 4, and 5.

TS 3.3.1, "Reactor Trip Instrumentation," Table 3.3.1, Item 6.6, "Boron Dilution Flux Doubling," Action Statement 5, required that with no channels OPERABLE, all positive reactivity changes be suspended and Valve 1CS-8455 or Valves 1CS-8560, FCV-111B, 1CS-8439, 1CS-8841, and 1CS-8453 be verified closed and secured in position within 4 hours. In addition, the reactor trip breakers must be opened and all operations involving positive reactivity changes suspended.

During the licensee's preparations to enter Mode 2 on May 9, an evaluation was performed to determine if a reactor startup was permissible while in TS 3.3.1, Action Statement 5. TS Interpretation (TSI) 92-20, Revision 0, evaluated footnote h for Mode 3 which permitted the boron dilution flux doubling signals to be blocked during reactor startup. On the basis of the footnote and an evaluation of the boron dilution mitigation system function, the Station Operations Review Committee (SORC) approved the TSI. This approval was granted during SORC meeting No. 92-40. The inspector reviewed the basis for the TSI, including the boron dilution mitigation system function as identified in the Final Safety Analysis Report (FSAR), Paragraph 15.4.6, Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant. It was found that the TSI appropriately considered the TS requirement and the system functions.

6.7 Emergency Core Cooling System Valve Position Verification

During the inspection period, the inspector verified that valves within the emergency core cooling system flow paths were properly aligned. This verification was performed by verifying the main control board valve switch positions and indicating lights were positioned in accordance with the applicable station operating procedure. In addition, the inspector verified that the valve positions, as observed locally, were properly aligned.

6.8 Main Control Board Annunciators

The inspector reviewed the main control board annunciator status with the licensee. In particular, the inspector was concerned with the number of lit or inoperable annunciators which could desensitize the licensed operators to changing plant conditions. NRC Inspection Report 50-445/92-20; 50-446/92-20, paragraph 4.3, "Attention to Instruments and Indicators," documents that approximately 17 to 20 annunciators were routinely in alarm condition during normal plant operations, which may have reduced operator sensitivity to some annunciators.

Near the end of the inspection period, the licensee statused the main control board problems and identified the work document or design modification for each annunciator to clear the alarm. To provide visibility to the operators as to which annunciators currently have a modification associated with it, the licensee has established the use of a blue dot on the annunciator window. A standing order was developed which provides the status for each annunciator with a blue dot. The standing order references the design modification or

minor modification applicable to the annunciator and the schedule for implementing the modification.

To provide management visibility for main control board problems, an attachment has been added to the plan-of-the-day meeting package which statuses each annunciator including a problem description, responsible manager, current status, and estimated completion date. As of June 4, the licensee had identified 47 annunciators within the main control room requiring some type of work activity or design modification. The inspector will continue to assess the licensee's efforts to decrease the number of lit annunciators within the main control room. This is considered an inspection followup item (445/9214-03).

6.9 Summary of Findings

Radiation protection personnel demonstrated cognizance of work activities within the RCA. Their response to the contamination events was well coordinated and minimized the potential for the spread of contamination.

Security personnel performed well with the exception of two incidents where security officers were not attentive to their duties. Security assessment equipment appeared to operable and there was very little use of compensatory measures.

The reactor startup was performed in accordance with the integrated plant procedure requirements. Proper management oversight was provided. Communication between the operators was very good.

An additional personnel performance violation was identified which was considered similar to the concerns identified in NRC special inspection report 50-445/92-20; 50-446/92-20. This example involved the inadequate performance and review of equipment logs by licensed and nonlicensed personnel.

An inspection followup item was identified for the status of main control board annunciators.

7. MAINTENANCE OBSERVATION (62703)

Station maintenance activities for the safety-related and nonsafety systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with the Technical Specifications.

Maintenance activities observed included:

7.1 Status of Field Work Requests

During the previous inspection period, March 15 through April 25, 1992, the inspectors identified five work requests for which the work status had not

been determined (Work Request Nos. 101420, 103297, 101421, 101433, and 122419). It was subsequently determined that each work request had been completed, but the work request tag had not been removed after completion of the maintenance activity. In addition, the inspectors identified two additional work requests for safety-related batteries (Work Request Nos. 123351 and 124736) which were completed, but the work request tags had been left attached to the equipment. The licensee initiated ONE Form 92-405 on May 7 to evaluate personnel failures to remove work request tags following completion of the work activities.

During the review of Work Request 124525 (Work Order No. 92-1749), the inspector noted that page 7 of the work instructions reflected that Fire Impairment 92-X-196 for Turbine Building Rollup Door T102-J had been cleared and the door closed and locked. However, the inspector noted that the door was actually locked open and the fire impairment was still active. The inspector verified that the compensatory measures established by the fire impairment had remained in effect since the time the work instruction indicated the fire impairment was cleared on March 30, 1992, to the date of discovery by the inspector on April 27.

The failure to remove the work request tags after the work activity was completed and the failure to clear the fire impairment is another example of a violation of the requirements of TS 6.8.1 and Regulatory Guide 1.33 (445/9214-01).

7.2 Maintenance Surveillance/Work Scheduling Activities

The inspector periodically observed the licensee's plan-of-the-day (POD) meeting. The meeting was utilized to identify work schedules, provide coordination between departments, identify potential high risk activities, and to discuss general interest items. The inspectors have noted that the meetings are generally thorough and the departments are well represented by management personnel and personnel cognizant of specific scheduled work activities.

On May 4, 1992, the inspectors observed the POD meeting where the calibration of meters and relays for Containment Spray Pumps 1-02 and 1-04 and the AFW Pump 1-02 was discussed. The licensee identified that two active TS LCOARs had been entered (TS 3.6.2.1 and 3.7.1.2) to provide for calibration of the meters and relays. These active LCOARs placed the plant into a 72-hour shutdown action statement. Following the POD meeting, the inspectors discussed the work documents (P91-8583, P91-8582 and P91-8588) with the responsible metering and relay (M&R) technicians. It was then learned that the M&R technicians were not planning on performing the calibration until the following day.

The inspectors verified that the containment spray and AFW pumps had been rendered inoperable by the placement of their applicable clearances earlier that morning. These clearances opened the pump motor breakers. The delay in calibrating the meters and relays was discussed with M&R supervisory

personnel, the shift supervisor, and the shift operations manager. The licensee initiated prompt action to begin the calibrations. The work activities were initiated at approximately 1 p.m., (EST) the same day.

The licensee conducts a work activity status meeting each day at 1:30 p.m., in the technical support center. This meeting is headed by the shift supervisor and attended by the different maintenance departments and representatives from the work control center. Based on previous observations of this meeting, the inspector believes that the above work start issue would have been identified at that time and the work activity started or the clearances removed and the equipment returned to OPERABLE. Although the delay in the calibrations would have probably been identified during the status meeting, the delay by M&R personnel in performing the scheduled work activity, indicates that they did not fully understand management expectations for the conduct of time critical work activities.

7.3 Auxiliary Feedwater Pump Relay Testing

On May 4, 1992, the inspector observed the performance of meter and relay testing on No. 2 MDAFWP 1-02. This procedure consisted of long time inverse and instantaneous overcurrent current tests. Meter and Relay Test Procedure MSE-GO-0020, Revision 1, provided the work instructions to perform the testing as authorized by Work Order P91-8588. The M&R technicians were knowledgeable of their procedures, requirements, and precautions.

The inspector noted that the instantaneous pick up amps on Phase B of Component 50M-51/1APMD2 had drifted. The two previous calibrations indicated zero drift. Discussions with the M&R supervisor indicated that some drift was normal; although, he did acknowledge that the drift on this instrument was more than he expected. No additional monitoring was recommended by the supervisor. The out-of-tolerance reading was entered into the material history record and could be referenced at the next scheduled calibration (3-year calibration). Previous discussions with the technicians indicated that of the several hundred similar relays in the plant only one relay has been replaced.

7.4 Control Room HVAC

On June 3, 1992, the inspectors observed corrective maintenance on control room HVAC Compressors 2 (Train A) and 3 (Train B). Both compressors required the lubricating oil to be changed because of excessive freon. An emergency work order and standby clearance was used to drain and replace the lubricating oil on Compressor 2. The inspector verified through the review of the standby clearance and work control procedures, that the work had been properly prioritized, and that appropriate work controls and personnel protection was provided. The work activity was well documented and provided the necessary detailed accounting of the work performed to develop the Priority 1 emergency work order.

Following the return of Compressor 2 to service, the licensee monitored its operating parameters to identify why the excessive freon absorption had occurred in the lubricating oil and to ensure the proper operation before declaring control room HVAC Train A operable. In addition, the licensee called in the vendor representative who identified a probable cause for the abnormal oil absorption. The vendor found the oil return line from the oil trap to be open further than recommended. All the compressors were then checked and adjusted to the manufacturers recommended position.

The inspector reviewed the completed emergency Work Order 1-92-15185 and maintenance Procedure MSE-PX-7330, "Control Room HVAC Annual Inspection." These documents accurately reflected the work activity performed.

The oil on control room HVAC Compressor 3 was also replaced because of excessive freon absorption. In this case, the lubricating oil had not been warmed to drive the freon out of solution. The compressor was being started in attempts to restore Train B control room HVAC to OPERABLE in order to exit the TS required shutdown. The compressor had been secured with the sump heaters deenergized, during the planned work activity. This resulted in the freon being absorbed into the oil (Freon absorption into cool oil is normal and is removed prior to startup by ensuring the oil is above a certain temperature). The work was accomplished under Work Order C92-5769,"Implement Minor Modification 92-235 to Replace Oil Float Assembly On AC Unit." The inspector questioned the use of this work order to replace the oil since replacement was not covered in the work steps; however, Procedure MSE-PX-7330 was referenced and contained the steps necessary to accomplish the task. The work completed was referenced in the comment section and no procedural requirement was identified that prohibited such actions. The licensee initiated ONE Form 92-484 to review the work activity.

No discrepancies were identified with the oil replacement on Compressors 2 and 3. The inspector found the electrical maintenance technicians to be knowledgeable and used procedures throughout the work. Documentation of work performed was appropriate. Management oversight was provided by a shift foreman and assistant electrical maintenance manager.

7.5 Summary of Findings

Several examples of work request tags were left on equipment after the work activity had been completed. A fire impairment was also left in effect although the work document indicated the fire door had been locked closed. This violation is an additional example of an overall personnel performance concern that is discussed in NRC Inspection Report 50-445/92-20; 50-446/92-20. The inspector also identified an issue where management's expectations were not met for the performance of time critical activities.

Observed maintenance activities were well performed with proper approval obtained from operations and radiation protection. The work coordination during the NOUE was excellent.

8. SURVEILLANCE OBSERVATION (61726)

The inspectors observed the surveillance testing of safety-related systems and components listed below to verify that the activities were being performed in accordance with the Technical Specifications. The applicable procedures were reviewed for adequacy, test instrumentation was verified to be in calibration, and test data was reviewed for accuracy and completeness. The inspectors ascertained that any deficiencies identified were properly reviewed and resolved.

The inspector witnessed portions of the following surveillance test activities:

8.1 Solid State Protection System Testing

On May 8, the inspector observed the pre-surveillance briefing, performance, and system restoration of the solid state system Train B actuation logic test under surveillance Work Order S92-736. This surveillance was accomplished using Procedures OPT-446A, "Solid State Protection System Train B Actuation Logic Test," Revision 3; and, SOP-711A, "Solid State Protection System," Revision 2.

At the start of the surveillance the inspector noted that the reactor operator had marked Procedure OPT-446A, Section 6.6, "Train A SSPS Prerequisites," as not applicable. The inspector immediately pointed this out to the shift supervisor who then directed the operator to perform the indicated step.

Operations Department Administration Procedure ODA-407, "Guidance on the Use of Procedures," Revision 3, Section 6.2.3.2, required shift supervisor or unit supervisor's permission before any operations procedure step could be marked as not applicable. The operator's failure to obtain permission from the shift supervisor or the unit supervisor is another example of a violation of the requirements of TS 6.8.1 and Regulatory Guide 1.33 (445/9214-01).

Communications with all involved operators was excellent. The inspector observed the remainder of the surveillance activity. The shift supervisor provided oversight of the activity. Communications between the operators was good.

8.2 Calibration of Catalytic Recombiner "A" Hydrogen Analyzer 1104-A

The inspector observed the analog channel operability test (ACOT) and calibration of the Catalytic Recombiner "A" Hydrogen Analyzer 1104-A. The objective of this surveillance was to verify and, if required, reestablish the accuracies of the trip and safeguards functions of the channel sensor and its associated signal processing equipment by simulating with test equipment the process and reference signals and recording that information on the data sheets.

The inspector observed portions of the surveillance test. There were three I&C technicians: one lead and two I&C technicians. Observations indicated that the I&C personnel were knowledgeable of their duties and familiar with the procedure used. All required steps were either initialed or signed-off as required. Test equipment used was within its calibration frequency. Adjustments were made as appropriate to the analyzer when the values were outside of required tolerances. There were no deficiencies observed during this surveillance.

8.3 ACOT Containment Pressure Channel 0934

The inspector observed the ACOT of containment pressure Channel 0934. The purpose of this test was to verify and, if required, reestablish the accuracies and control functions of the channel sensor and associated signal processing equipment contained in Unit 1 Containment Pressure, Protection Set IV, Channel 0934.

The inspector reviewed Procedure INC-7855A, "ACOT and Channel Calibration Containment Pressure Channel 0934, Protection Set IV," Revision 5. This procedure contained clear instructions and acceptance criteria. Review of Procedure INC-7855A by the inspector indicated the procedure was adequate to perform its intended purpose. Observations of the I&C technicians indicated that they were experienced, knowledgeable of procedures and requirements. The test was well coordinated with all personnel involved including the unit supervisor. The test team consisted of a lead I&C technician and a senior I&C technician. Their supervisor was present to observe the activity. All test equipment used was calibrated as required. There were no deficiencies identified.

8.4 Local Leak Rate Testing (LLRT)

The inspector observed LLRT on Containment Penetration MV-14 (containment pressure relief system), and reviewed the latest test results for Containment Penetration MIII-018 (containment hydrogen purge exhaust system) and MV-02 (containment purge exhaust system). These penetrations are depicted on Final Safety Analysis Report Figure 9.4-6, Sheet 1, "Ventilation Containment," Amendment 83. This testing was performed to meet the requirements of 10 CFR Part 50, Appendix J, Type C, "Local Leak Rate Testing," and the TS surveillance requirements identified in Section 4.6.1.7, "Containment Ventilation System."

On May 20, with the reactor at 100 percent power, the licensee performed Surveillance Work Order S92-0586, which implemented Surveillance Test Procedure PPT-SI-8047, "Appendix J Leak Rate Test of Penetration MV-14," Revision 0. This test is required to be performed at least once every 92 days for the 18-inch containment pressure relief discharge isolation valve. The test was performed between isolation Valves 1-HV-5548 and 1-HV-5549. These isolation valves were installed with resilient seals.

The test was performed by plant engineering personnel. The procedure requirements and acceptance criteria were discussed with the shift supervisor prior to performing the test. Radiation protection personnel had also been appropriately briefed on the procedure scope. The test was performed by qualified personnel, utilizing calibrated instrumentation. During the pressurization of the penetration, the engineers were cautioned to limit the pressure to less than 65 psig as required by the procedure. The highest pressure noted was 59 psig. The leak rate was determined to be 414 standard cubic centimeters per minute (SCCM) at 49.6 psig. This was well within the acceptance criteria of less than or equal to 15,000 SCCM at a pressure between 48.3 and 50 psig. The inspector subsequently reviewed Surveillance Work Order S91-3082 performed February 26, 1992, for the same penetration. The leak rate during the test was documented as 681 SCCM at 48.9 psig.

The inspector reviewed the LLRT results for Penetration MIII-018 (containment hydrogen purge exhaust system). This is a 12-inch penetration with the local leak rate test performed between Valves 1-HV-5542, 1-HV-5563, and 1-HV-5543. The leak rate test acceptance criteria specified in Procedure PPT-SI-8014, "Appendix J Leak Rate Test of Penetration MIII-18 (1-HV-5543, 1-HV-5553, and 1-HV-5542)," Revision 0, was less than or equal to 12584 SCCM at a pressure between 48.3 and 50 psig. The test results from December 6, 1991, and May 15, 1992, were 12570 and 12520 SCCM respectively. Prior to testing the penetration on May 15, the licensee had established a work action plan to reduce the leak rate below the maximum acceptance criteria in the event the penetration failed the local leak rate test. This plan was reviewed during the plan-of-the-day meetings conducted the week prior to the test.

Lastly, the inspector reviewed the LLRT result for Containment Penetration MV-02 (containment purge exhaust system). This is a 48-inch penetration which is performed between Valves 1-HV-5539 and 1-HV-5538. Prior to performing the LLRT on May 29, the licensee had placed a blind flange near the containment outboard isolation valve to be used to seal the penetration if the test results exceeded the maximum leak rate test criteria of 12584 SCCM when pressurized between 48.3 and 50 psig.

The actual LLRT results as documented in Procedure PPT-SI-8037, "Appendix J Leak Rate Test of Penetration MV-02," Revision 1, indicated a leakage of 9140 SCCM at 48.8 psig. The penetration test results were subsequently accepted.

The inspector discussed the LLRT program with the LLRT coordinator. The individual was very knowledgeable of the program requirements and was cognizant of which penetrations were approaching their LLRT acceptance criteria limits. The inspector found that the test results were being appropriately tracked, and provided a meaningful LLRT history for each containment penetration.

8.5 Summary of Findings

Surveillance activities were generally performed in accordance with the procedure requirements. One example was identified where the prerequisite steps were marked not applicable without first receiving proper approval. This violation was identified as another example where personnel performance was not in accordance with managements expectations and was contrary to an approved procedure. The LLRT testing was well performed and included appropriate management review during the POD meetings.

9. SUMMARY OF TRACKING ITEMS

The following items were opened in this inspection report:

Violation 445/9214-01
Violation 445/9214-02
Inspection Followup Item 445/9214-03

The following items were closed in this inspection report:

Inspection Followup Item 445/9210-02
Unresolved Item 445/9210-03
Inspection Followup Item 445/9210-04
LER 90-28
LER 90-04 and SR 90-003
LER 90-13
LER 91-01
LER 91-20

10. EXIT MEETING (30703)

An exit meeting was conducted on June 5, 1992, with the persons identified in paragraph 1 of this report. The licensee did not identify as proprietary any of the materials provided to, or reviewed by, the inspectors during this inspection. During this meeting, the inspectors summarized the scope and findings of the inspection.