APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/93-19
50-446/93-19

Operating Licenses: NPF-87
NPF-89

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

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

Inspection At: Glen Rose, Texas

Inspection Conducted: April 18 through May 29, 1993

Inspectors: D. N. Graves, Senior Resident Inspector
W. B. Jones, Senior Resident Inspector
R. M. Latta, Resident Inspector
G. E. Werner, Resident Inspector

Approved: LA Yandell June 11, 1993
L. A. Yandell, Chief, Project Section B Date
Division of Reactor Projects

Inspection Summary

Areas Inspected (Unit 2): Routine, unannounced safety inspections, including plant status, followup of events, operational safety verification, operational readiness assessment, surveillance observations, safety evaluation report review and followup, and followup on corrective actions.

Areas Inspected (Unit 1): No inspection of Unit 1 activities was performed.

Results (Unit 2):

- Unit 2 was manually tripped on May 4, 1993, in anticipation of an automatic reactor trip on low steam generator level due to the spurious closure of the main feedwater isolation valve to Steam Generator 1 (Section 2.1).

- The procedurally controlled fuel conditioning ramp rate limit of 3 percent per hour was exceeded on May 15, 1993. Concerns related to

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personnel performance, self-verification, and supervisory monitoring associated with this event remain an unresolved item (Section 2.2).

- Unit 2 experienced a turbine trip/reactor trip on May 20, 1993, as a result of the loss of primary water flow to the generator stator (Section 2.3).

- Station operating logs did not always contain sufficient detail with respect to major operations activities (Section 3.1).

- Unit 2 material conditions and housekeeping were good (Section 3.1).

- Impairments associated with the fire suppression system for the Unit 2 cable spread room were properly controlled (Section 3.2).

- On May 12, 1993, the Station Operations Review Committee (SORC) formally approved the 100 percent readiness self-assessment, and power operations above 50 percent power were authorized (Section 4).

- Surveillance test activities were effectively performed and appropriate corrective actions were implemented in response to identified discrepancies (Section 5).

Results (Unit 1): Not applicable.

Summary of Inspection Findings:

- Unresolved Item 445/9319-01; 446/9319-01 was opened (Section 2.2).

- Deficiency 446/92201-05 was closed (Section 7.0).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS (71707)

At the beginning of this inspection period, Unit 2 was operating at approximately 48 percent reactor power with various initial startup testing activities in progress. On May 4, 1993, following a reactor power reduction from 48 percent to approximately 23 percent, in preparation for a remote shutdown operability test, the unit was manually tripped in response to the spurious closure of the feedwater isolation valve (FWIV) to Steam Generator 1. Subsequent to this trip, a reactor startup was performed on May 5, 1993, and preparations continued for additional startup program testing. Remote shutdown testing was completed on May 6 and the turbine generator trip with loss of offsite power test was performed on May 8. On May 12 the licensee's SORC formally approved the 100 percent readiness self-assessment, and power escalation above 50 percent was authorized. On May 20, with Unit 2 operating at approximately 73 percent power, an automatic turbine trip/reactor trip occurred as a result of the loss of primary water flow to the generator stator. Following this event, the licensee elected to place the unit in Mode 5 and initiate a planned surveillance outage. At the conclusion of this reporting period, the licensee's outage work planning activities were in progress. Interim maintenance activities included FWIV troubleshooting and selected balance-of-plant corrective maintenance work. This outage is scheduled for a 41-day duration and will include requisite 18-month surveillance testing, integrated testing, and identified corrective maintenance activities.

2 ONSITE RESPONSE TO EVENTS (93702, 92701)

2.1 Manual Reactor Trip

On May 4, 1993, following a reactor power reduction from 48 percent to approximately 23 percent in preparation for a remote shutdown operability test, the unit was manually tripped in anticipation of an automatic reactor trip on low steam generator level due to the spurious closure of FWIV 2-HV-2134 to Steam Generator 1. Specifically, the feedwater flow to and level in Steam Generator 1 were observed to be decreasing. Operations personnel attempted to unisolate and open the preheater bypass valve to reestablish feedwater flow and recover steam generator level. However, the level in Steam Generator 1 decreased to 40 percent and, in accordance with the alarm response procedure, the operators manually initiated a reactor trip at 2:48 a.m. (CDT). Auxiliary feedwater automatically started on low steam generator level and the plant was stabilized in Mode 3 with all systems functioning as designed.

As determined by the inspectors, operations personnel had initially received a "ANY SG ANTI WTR HAMMER PERM NOT CLEAR" annunciator indicating that the anti-water hammer interlock was not satisfied for at least one FWIV. The anti-water hammer interlock initiates an FWIV closure if its associated low feedwater temperature is detected coincident with low feedwater flow.

Operations personnel also noted that Valve 2-HV-2134 remained in the intermediate position for several minutes following the transient in contrast to the normal closing time for this valve of less than 5 seconds.

The licensee's investigation into the cause of the FWIV closure determined that the anti-water hammer interlock for Valve 2-HV-2134 caused the valve closure. A defective Steam Generator 1 feedwater temperature Element 2-TE-2177A, which had failed during startup testing, satisfied a portion of the interlock's logic. Concurrently, the isolation valve for the high pressure side of the feedwater flow transmitter that provided feedwater flow input to the interlock logic was leaking steam. As feedwater flow was decreased during the planned power decrease, the steam leak caused a divergence in indicated feedwater and steam flows, with indicated feedwater flow decreasing at a higher rate. At the time of the trip, the indicated feedwater flow decreased sufficiently to actuate the low feedwater portion of the interlock logic and cause the FWIV to go closed. A similar divergence in feedwater and steam flow was observed on Steam Generator 2, which had a steam leak on the isolation valve for the high pressure side of its flow transmitter.

The licensee had previously identified the leaking transmitter isolation valves and had expedited the development of the work orders necessary to perform repairs. With regard to the observed slow closure of FWIV 2-HV-2134, the licensee initiated Work Order 1-93-045716-00 to investigate. The inspectors observed several operational checks of the valve both locally and from the control room, and all observed closures were within the 5-second time requirement. In that the slow closure rate of the valve could not be duplicated, the licensee removed the valve operating solenoids for inspection, examined and replaced the fluid strainers in the solenoid blocks, and sampled and replaced the hydraulic fluid. The inspectors observed these activities and determined that good work control practices were utilized. The licensee's analysis of the hydraulic fluid samples indicated that acid content and water content were within acceptable limits. Furthermore, no evidence of fluid coagulation was identified, nor were any obstructions or foreign material found in the fluid or in the strainers. The valve was subsequently reassembled and retested with satisfactory results.

Troubleshooting of feedwater temperature Element 2TE-2177A indicated that the temperature element had not failed, but that an unidentified 4 ohm resistance was present on one of the element leads. As a result of this condition, Temporary Modification 93-2-010 was implemented to compensate for the unbalanced circuit by the addition of a 4 ohm resistance in a separate element lead which rebalanced the circuit. The instrument was verified to be reading accurately and was determined to be consistent with the three remaining feedwater temperature channels. The inspectors reviewed the documentation associated with this temporary modification, including the safety evaluation, and determined that it was acceptable.

Based on the review of this event, the inspectors noted that the automatic reactor trip on low steam generator level was 34.5 percent. However, the applicable alarm response procedure for the Steam Generator 2-01 low water level alarm instructed the operator to manually trip the reactor if the level reaches 28 percent indicated narrow range level. This discrepancy was brought to the attention of the unit supervisor, who promptly initiated a procedure change to insert the correct value of 40 percent. The inspectors examined the alarm response procedures for the remaining steam generator alarms on both units and determined that the correct values had been included.

The inspectors also examined the licensee's posttrip review and found it to be comprehensive; however, the final evaluation of this event will be documented in a future inspection report subsequent to the issuance of the associated Licensee Event Report 2-93-003. A reactor startup was performed on May 5, 1993, and preparations continued for additional startup program testing.

2.2 Rapid Power Rate Ramp Increase

During this reporting period, the inspectors reviewed the licensee's preliminary response to Plant Incident Report (PIR) 93-1077, which documented that the fuel conditioning power ascension rate limit of 3 percent per hour had been exceeded. This warranty limit which is specified in Procedure IPO-003B, Revision 0, "Power Operations," paragraph 4.4.4.1, directs that power increases between 20 percent and 100 percent be limited to 3 percent per hour. However, as documented in the subject PIR, on May 15, 1993, during reactor power ascension from approximately 50 percent to approximately 67 percent, which occurred over a 4-hour period, the stated ramp rate limit was exceeded on two occasions. As indicated on nuclear instrumentation Channel N5174A (Power Range Flux, Auctionered High), reactor power was increased on May 15 from 50.38 percent at 2:32 a.m. to 59.71 percent at 3:32 a.m., which represented a 9.33 percent increase. Additionally, on the same shift, reactor power was increased from 61.34 percent at 4:32 a.m. to 64.68 percent at [illegible] a.m., which equated to a 3.34 percent increase in reactor power as indicated on Channel N5174A.

Subsequent to the identification of this event by the licensee's Performance and Test Group, Operations Notification and Evaluation (ONE) Form 93-1077 was initiated to document the procedural noncompliance. The ONE Form was later elevated to a PIR in accordance with Procedure STA-422, Revision 7, "Processing of Operations Notification and Evaluation (ONE) Forms," in order to evaluate the root cause, generic implications, and corrective actions associated with this event. Immediate actions which were initiated by the licensee included primary chemistry sampling in order to detect any fuel degradation. The results of this sample indicated no increase in primary activity levels. The licensee is currently consulting with the fuel vendor, Westinghouse, in order to evaluate long-term fuel performance implications. The licensee also instituted shift orders which classified all power change operations, increasing or decreasing, in excess of 3 percent as infrequent operations which require prebriefing and periodic unit supervisor monitoring. Additionally, as stated by the licensee, the two reactor operators and the unit supervisor involved in the event were suspended from licensed duties pending the reviews of their performance.

Followup to this event by the inspectors included the review of a preliminary copy of PIR 93-1077, examination of the personnel statements of the individuals involved in the event, and the examination of the associated nuclear instrumentation system data. The inspectors also reviewed the applicable unit and station operating log entries and conducted interviews with various operations department management personnel.

Based on these inspection activities, it was determined that, despite the general guidance provided by the unit supervisor to the reactor operator and the balance-of-plant operator, to limit the planned power rate ramp increase to 3 percent per hour the operators did not follow the fuel conditioning limitations specified in Procedure IPO-003B and appeared unaware that they had exceeded the governing procedural requirements. The failure of the operators to recognize this limit was demonstrated by the fact that they did not refer to the applicable procedural controls for performing power operations contained in Procedure IPO-003B, Attachment 4, "Power Change Worksheet," prior to initiating the planned power rate ramp increase on May 15. Furthermore, the unit supervisor did not specifically refer to the precautions and limitations of the governing procedure as specified in Procedure ODA-407, Revision 4, "Guidelines on Use of Procedures," paragraphs 6.2.1.1 and 6.2.1.3. During the first hour of reactivity change, the operators diluted the primary system with approximately 1000 gallons of reactor makeup water. This quantity was significantly greater than the normal dilution rate utilized for rate ramp increases as defined in Procedure IPO-003, Attachment 4, which states, in part, that batch additions should be done in very small increments. In practice, these small increments equate to typical dilutions of 50 gallons per hour.

Throughout the approximately 4 hours in which reactor power was being increased neither the reactor operator nor the balance-of-plant operator identified to the unit supervisor that any abnormalities had been experienced. It was also determined that, contrary to the requirements of Procedure ODA-031, Revision 10, "Operating Logs," paragraph 6.3.3, no unit log entries were completed during the shift which identified changes in reactor power level. The inspectors also determined, based on the review of personnel statements that the unit supervisor did not directly monitor reactor power ramp rate increases during the shift nor did he question operator performance during this event which was contrary to the requirements of Procedure ODA-102, Revision 14, "Conduct of Operations." This lack of direct involvement and oversight was apparently the result of a heavy work load which was experienced throughout the shift.

As a result of personnel performance concerns and the apparent lack of self-verification demonstrated by operations personnel, coupled with the inadequate supervisory oversight demonstrated during this event, the licensee expanded their evaluation process to include an assessment by the Independent Safety Evaluation Group. This independent evaluation of the events associated with PIR 93-1077, which included the examination of procedural controls, personnel actions, and root cause analysis, is tentatively scheduled for completion on June 7, 1993.

Three additional factors related to this event were being evaluated at the conclusion of this reporting period. The first factor included information derived from the digital rod position indication (DRPI) system. As stated in Procedure IPO-003B, paragraph 4.4.4.1.2, during power increases above 50 percent power, the control rod withdrawal rate is limited to three steps per hour. However, the DRPI data recorded during this event indicated that Control Bank D rods were withdrawn six steps at 5 a.m. on May 15, 1993. Pending the verification of DRPI data, this action represents another example of procedural noncompliance related to personnel performance during this event.

A second factor concerned the adjustment of chart speed on the installed Recorder NR-45, which plots reactor power and Delta I (reactor flux difference). Specifically, during the licensee's examination of reactor power increases associated with this event, it was ascertained that the chart speed had been shifted from normal speed to fast speed during initial reactor power increases on May 15, 1993, and that it was subsequently returned to normal speed later in the shift. This action resulted in decreasing the slope of the printed reactor power trace, thus giving the misleading indication that reactor power was not increasing as rapidly as it actually was. Based on the licensee's interviews with the reactor operators and the unit supervisor involved with this event, no immediate explanation for this occurrence was identified; however, the licensee is continuing to pursue resolution of this issue.

A third factor involved the inability of the licensee to retrieve the reactor over-power recorder (NR-46) strip chart data for the period encompassing the subject event. As stated by the licensee, the Recorder NR-46 chart covering the period between May 6-15, 1993, had been removed from the instrument on the evening of May 15, 1993, by the same operations crew involved with the excessive ramp rate event. Following the removal of this chart, it was to have been sent to the licensee records vault. However, subsequent retrieval efforts by the licensee were unsuccessful and the subject chart was presumed lost. Additionally, based on the review of recent reactor power operations, it was identified that the fuel conditioning ramp rate limit of 3 percent per hour had been exceeded on the previous day by the same crew involved in the May 15 excessive ramp rate increase event. This occurrence was preliminarily attributed to a secondary transient; however, the implications associated with the failure to recognize this event and the absence of unit log entries identifying this condition represent additional examples of personnel performance errors and procedural noncompliance.

At the conclusion of this reporting period, the licensee's actions associated with PIR 93-1077 had not been completed. Therefore, pending the resolution of this PIR and the associated personnel performance, self-verification, and supervisory oversight issues, this event is being identified as an unresolved item (445/9319-01; 446/9319-01).

2.3 Unit 2 Turbine Trip/Reactor Trip

On May 20, 1993, with Unit 2 at approximately 73 percent power, an automatic reactor trip occurred as a result of a turbine trip. The turbine trip occurred in response to a loss of primary water flow to the generator stator. Following the reactor trip, all components responded as expected with the exception of FWIV 1, which indicated an intermediate position, and the steam dump control circuitry, which did not operate properly in the automatic mode.

With respect to FWIV 1, the licensee initiated actions to shut manual FWIV 2FW-0057 to provide an isolation point. Subsequent review of computer data points which are generated from separate limit switches indicated that the valve actually closed in approximately 15 seconds. However, the FWIVs typically close in 3 to 4 seconds and Technical Specification 3.7.1.6 requires the valves to close in a maximum of 5 seconds. Subsequent testing of FWIV 1 resulted in acceptable isolation times; however, the licensee plans to perform additional troubleshooting activities to determine the reason for the slow closing time.

Relative to the steam dump controls, it was determined that, when they were placed in the automatic pressure control mode, erratic operation of the valves resulted in secondary pressure oscillations. The steam dumps were then placed in manual control. Further review of the posttrip data will be completed by the licensee prior to recommending corrective maintenance activities.

The inspectors were in the control room at the time of the event and were able to observe licensed operators' immediate response to the trip and subsequent actions to secure secondary plant equipment. Based on these observations, it was determined that the immediate actions initiated by the licensed operators to verify the reactor was shut down were good.

It was also noted that, after the operators identified that FWIV 1 had apparently failed to close, the unit supervisor directed the reactor operator to have an auxiliary operator close manually-operated Valve 2FW-0050 in order to provide isolation for feedwater to Steam Generator 1. However, after the valve was partially closed, the unit supervisor determined, through communications with the auxiliary operator closing the valve, that the wrong valve was being operated. A flow diagram of the feedwater system was referenced and Valve 2FW-0057 was identified as the correct valve. Accordingly, Valve 2FW-0050 was reopened and Valve 2FW-0057 was then closed.

Although the operations personnel response to securing the secondary plant was good and effective use of procedures and proper communications were demonstrated, the apparent lack of self-verification in identifying FWIV 2FW-0057 is identified as a weakness.

During the routine followup of this event, the inspectors reviewed the licensee's posttrip evaluation and found it to be comprehensive. However, the final examination of this occurrence will be documented in a future inspection report subsequent to the issuance of the associated Licensee Event Report 2-93-005.

Following this event, the licensee elected to place the unit in Mode 5 and initiate the planned surveillance outage on May 20, 1993, rather than the previously scheduled start date of June 11. At the conclusion of this reporting period, the licensee's outage work planning activities were in progress, including the associated outage risk assessment. Interim maintenance activities included FWIV troubleshooting and selected balance-of-plant corrective maintenance work. The subject outage is scheduled for 41 days and will include 18-month surveillance testing, integrated testing, and identified corrective maintenance activities.

2.4 Conclusion

Operations response to the two reactor trips experienced during this reporting period was generally good. However, one weakness was identified with respect to the apparent lack of self-verification demonstrated by operations during their response to the turbine trip/reactor trip of May 20, 1993. The corrective actions associated with FWIV 2-HV-2134 subsequent to the May 4 manual reactor trip were less than completely effective in that the slow closure time of this valve was identified again during the turbine trip/reactor trip experienced on May 20.

Additionally, one unresolved item was identified with respect to personnel performance deficiencies, the lack of self-verification, and inadequate supervisory monitoring associated with the rapid power rate ramp increase event which occurred on May 15, 1993.

3 OPERATIONAL SAFETY VERIFICATION (71707, 92701)

3.1 Plant Tours

During this reporting period, the inspectors performed routine plant tours, which included the witnessing of operations shift turnovers, independent verification of safety system status and limiting conditions for operations, corrective actions, and the review of unit operating logs. Based on these inspection activities, it was generally determined that good communications were exhibited during shift turnovers and that operations personnel were cognizant of plant conditions, equipment in service, and annunciator status. In particular, the inspectors periodically reviewed the Unit 2 annunciator summary list and determined that the out-of-service annunciators were properly annotated and that reactor operators were knowledgeable as to the basis for alarm discrepancies.

Based on the review of station operating logs, it was noted that the narrative descriptions of major operations activities occasionally contained superfluous information and that the content of these logs did not always reflect sufficient detail. This observation was provided to the Manager of Operations and the proper maintenance of operating logs will be evaluated during a subsequent inspection period.

General plant housekeeping in the safeguards, auxiliary, and service water buildings was determined to be good. Discrepancies which were identified during the performance of plant tours were promptly documented and appropriate corrective actions were implemented.

3.2 ONE Form Review

During this reporting period, the inspectors evaluated the licensee's response to ONE Form 93-971, which identified an impairment to the fire suppression system. Specifically, this ONE Form documented a potential operability concern associated with the main and reserve halon cylinders for the Unit 2 cable spread room. As determined by the inspectors, the nitrogen cylinders which actuate the automatic halon fire suppression system for the Unit 2 cable spread room had been removed from service prior to the licensing of Unit 2 on February 2, 1993, in order to prevent inadvertent actuation of the system during construction completion activities. This condition had been identified by the licensee and was addressed on Fire Impairment 93-2-137. Additionally, a continuous fire watch (93-027) was in effect until the closure of this impairment.

Subsequently, the licensee fire protection organization directed the installation of the subject nitrogen actuation cylinders in the halon system for the cable spread room in conjunction with the performance of preventive maintenance activities directed by Work Order 3-93-308064-01. During the conduct of this preventive maintenance, electrical maintenance identified the absence of the nitrogen cylinders as a potential operability concern.

The inspectors reviewed the technical disposition of ONE Form 93-971 and applicable work orders, fire impairment forms, fire watch logs, and the licensee's Fire Protection Report (Section IV). Based on this review, it was determined that the licensee had instituted the appropriate compensatory measures in response to the identified impairment and that the required actions specified in the Fire Protection Report had been properly implemented. The inspectors also verified that the halon system for the Unit 2 cable spread room had been properly returned to service.

3.3 Conclusion

Good communications were routinely observed during shift turnovers and operations personnel were cognizant of plant conditions. However, the narrative descriptions of operational activities contained in station operating logs did not always reflect sufficient detail. General plant housekeeping was acceptable in the safeguards, auxiliary, and service water buildings. Deficiencies identified during the conduct of routine plant tours were promptly documented and appropriate corrective actions were implemented. Impairments associated with the Unit 2 cable spread room fire suppression system were determined to be properly controlled.

4 OPERATIONAL READINESS ASSESSMENT (93806)

On May 11, 1993, the inspectors attended a special meeting of the SORC, which was convened to assess the licensees 100 percent readiness self-assessment. The SORC committee discussed the results of the subject assessment which was performed in order to assure Unit 2 readiness to proceed above 50 percent rated thermal power and to confirm the dual unit operating capability of Comanche Peak Steam Electric Station.

As determined by the SORC based on the review of the applicable departmental readiness letters, no conditions were identified which would restrain or prohibit Unit 2 power operation above 50 percent. Accordingly, the SORC established tentative approval for power operations above 50 percent pending the test review group's endorsement of Procedure ISU-222B, "Turbine Generator Trip With Coincident Loss of Offsite Power," Revision 0, test results. As determined by the inspectors, the test review group formally approved the test results of Procedure ISU-222B on May 12. The SORC correspondingly authorized power escalation above 50 percent power on the same day.

The inspectors reviewed the documentation associated with the licensee's self-assessment for 100 percent power readiness, which included initial startup test results, performance trend data, operations indicators, maintenance backlog and work activities, overview results, licensing assessments, and engineering summaries. Based on this review it was generally concluded that the licensee had established appropriate controls for the identification and resolution of operational issues and that no specific conditions had been delineated which would preclude operations above 50 percent rated thermal power.

5 SURVEILLANCE OBSERVATIONS (62703)

Selected surveillance activities were witnessed by the inspectors in order to determine whether the observed activities were being conducted in accordance with Technical Specification requirements and applicable procedural and administrative controls.

5.1 Safety Chilled Water System

The inspectors witnessed selected portions of the conduct of Procedure OPT-209B, Revision 1, "Safety Chilled Water System," which was performed in accordance with Work Order 5-93-503203-AA. The purpose of this surveillance activity was to satisfy the requirements of ASME Section XI testing and the requirements of Technical Specification Section 4.0.5 (inservice inspection and testing) and Section 4.7.12.a (verification of system alignment). Specifically, the inspectors observed the performance of

Section 8.3.1 of the subject procedure, which operationally verified the performance of Train A Chilled Water Recirculation Pump CP2-05.

Prior to the performance of this surveillance test, the inspectors observed the conduct of the pretest briefing in the control room. This briefing was well controlled and the test objectives were effectively communicated. It was also determined that the applicable prerequisites had been properly performed and that the precautions, limitations, and test acceptance criteria were correctly established.

During the performance of this activity, command and control functions were effectively demonstrated and communications were determined to be excellent. However, a test anomaly was identified with respect to an abnormally high discharge flow rate recorded subsequent to establishing the specified differential pressure test conditions. This test discrepancy was properly documented on the test data sheet and ONE Form 93-1064 was initiated to address the action limit high condition. The inspectors reviewed the corresponding Technical Evaluation (TE) 93-1049, which addressed the reported test discrepancy and provided the operability justification for Chilled Water Recirculation Pump 2-05.

Based on the review of the referenced ONE Form and TE, it was determined that an acceptable justification had been developed to establish pump hydraulic performance. Additionally, it was determined that Procedure OPT-209B had been revised to alternatively set the required flow rate (100 gpm $\pm$ 5) and verify pump differential pressure. Subsequent to revising this procedure, the licensee reperformed Section 8.3.1 of Procedure OPT-209B, which effectively re-established the referenced acceptance criteria. Additionally, the licensee documented their justification for the revised pump performance acceptance criteria on TE 93-1073. The inspectors reviewed this TE and determined that it provided an acceptable basis for the revised ASME Section XI test requirements.

5.2 Service Water System

The inspectors also witnessed the performance of Procedure OPT-207B, Revision 1, "Service Water System," which was conducted in accordance with Work Order 5-93-503637-AB. This surveillance test, which was similar to the previously referenced Procedure OPT-209B, was performed in order to comply with ASME Section XI testing and the requirements of Technical Specification Section 4.0.5. Additionally, the purpose of this surveillance test was to verify correct alignment of the station service water system per Technical Specification Sections 4.7.4.1a and 4.7.4.2.1a.

Based on the direct observation of the performance of this surveillance activity, it was determined that the specified precautions and limitations were properly adhered to and that the prerequisites were correctly performed. The inspectors also verified that the test equipment was properly calibrated and that test data was accurately recorded.

With respect to the performance of Section 8.2.1 of this procedure, a discrepancy was identified in that the measured discharge flow rate for Service Water Pump 2-01 was unacceptably high. In particular, with Valve 2SW-0023 (component cooling water Heat Exchanger 2-01 service water outlet valve) throttled to establish the required differential pressure of approximately 90 psig, the discharge flow rate for Pump 2-01 was approximately 4000 gpm too high.

Subsequent to the identification of this condition, the licensee initiated ONE Form 93-1064 and an associated TE 93-1049 to evaluate the operability of Service Water Pump 2-01. Based on the review of TE 93-1049, it was ascertained that the licensee had developed an appropriate justification for their conclusion that Service Water Pump 2-01 was operable. However, this TE also concluded that the subject surveillance test had not been satisfactorily completed in that the measured flow was not within the limits established by the ASME Section XI baseline for the pump.

Subsequent to the calibration of the Service Water Pump 2-01 discharge flow Transmitter 2-FT-4258 and the replacement of the flow transmitter snubbers, several additional surveillance tests were performed. The final test was conducted on May 19, 1993, with the measured flow of approximately 2000 gpm. During the final test, the licensee monitored the service water discharge flow from component cooling water heat exchanger flow Transmitter 2-FT-4265. As stated in the licensee's supplemental TE 93-1083, the flow rates measured at Transmitter 2-FT-4265 were approximately 12,712 gpm, which was compatible with the expected flow rates for Service Water Pump 2-01. Given the close correlation of the alternatively measured flow rates to the baseline ASME Section XI values and the supporting data contained in TE 93-1083, the inspectors determined that the licensee's evaluations with respect to the acceptability of Service Water Test 5-93-503637-AB as performed on May 19, 1993, were acceptable. The inspectors also determined that the licensee had initiated ONE Form 93-1064 to correct the deficiency associated with flow Transmitter 2-FT-4258.

5.3 Conclusions

Surveillance test preparations were excellent with effective communications demonstrated. Identified pump flow anomalies were properly documented and prompt engineering involvement was evident. Appropriate corrective actions were implemented in response to identified surveillance test discrepancies.

6 SAFETY EVALUATION REPORT REVIEW AND FOLLOWUP (92719)

Three Mile Island Action Plan Item I.D.1, Control Room Design Review, was reviewed and closed in Supplement 26 to NUREG 0797, "Safety Evaluation Report," with several commitments to be completed by the licensee prior to Unit 2 fuel load. These commitments were identified as Human Engineering Discrepancies in TU Electric Letter TXX-92563 dated December 18, 1992.

During this inspection period, the inspectors reviewed the documentation associated with the resolution and correction of the four identified discrepancies and concluded that the licensee had completed the actions necessary to satisfactorily address the issues prior to Unit 2 fuel load.

7 FOLLOWUP ON CORRECTIVE ACTIONS ON DEFICIENCIES (92701)

(Closed) Deficiency 92/201-05: Failure to Use or Follow Procedures

The Operational Readiness Assessment Team in NRC Inspection Report 50-446/92-201 identified several deficiencies with regard to the use of procedures. During the inspection, the licensee committed to review and revise Procedure ODA-407, "Guidelines on Use of Procedures," to clarify the wording regarding when procedures must be used or referenced.

The inspectors reviewed the revised Procedure ODA-407 and found it acceptable to address the identified deficiency.

ATTACHMENT

1 PERSONS CONTACTED

1.1 TU ELECTRIC

O. Bhatty, Site Licensing
W. J. Cahill, Group Vice President, Nuclear Engineering and Operations
R. R. Carter, Assistant to Manager, Maintenance
D. L. Davis, Manager, Plant Analysis
J. W. Donahue, Manager, Operations
S. L. Ellis, Work Control Manager
R. Flores, Shift Operations Manager
J. R. Gallman, Trend Analysis Manager
T. A. Hope, Site Licensing Manager
B. T. Lancaster, Manager, Plant Support
D. M. McAfee, Manager, Quality Assurance
D. R. Moore, Manager, Maintenance

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 May 28, 1993. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.