ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/96-04
50-446/96-04

Licenses: NPF-87
NPF-89

Licensee: TU Electric
Energy Plaza
1601 Bryan Street, 12th Floor
Dallas, Texas

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

Inspection At: Glen Rose, Texas

Inspection Conducted: Febr. ary 18 through March 30, 1996

Inspectors: A. T. Gody, Jr., Senior Resident Inspector
H. A. Freeman, Resident Inspector
V. L. Ordaz-Purkey, Resident Inspector

Approved: W D Johnson 4/16/96
W. D. Johnson, Chief, Project Branch B Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection, including plant operations; maintenance and surveillance observations; engineering; plant support; and operations followup.

Results (Units 1 and 2):

Plant Operations

- Unit 2 was operated for approximately thirty minutes above its licensed thermal power limit on February 14. The inspectors noted several weaknesses during their review: (1) operators had a misconception about the effect reactor coolant system temperature had on excore nuclear instrument shadowing; (2) the physical location of the Nitrogen-16 detector meters was not conducive to their use during a transient; (3) the Updated Final Safety Analysis Report, Chapter 15, Section 15.1.1 analysis for a feedwater temperature transient underestimated the maximum potential temperature swing by approximately 200 degrees F; (4)

the unit supervisor was focused on restoring the balance of plant and did not identify the overpower condition until the shift manager provided an additional senior reactor operator (Section 8).

- Operator response to the February 23, Unit 2 manual reactor trip was very good (Section 2.1).

- An auxiliary operator inadvertently isolated the operating residual heat removal pump discharge isolation valve while performing a safety injection system clearance and caused a partial loss of decay heat removal. This was an example of a violation of Technical Specification 6.8.1 (Section 3.2.1).

- An auxiliary operator failed to bypass a Unit 1 reactor coolant pump seal return filter prior to isolating it for replacement on February 3. A relief valve in the seal return line lifted and caused a loss of approximately 450 gallons of reactor coolant. This was an additional example of a violation of Technical Specification 6.8.1 (Section 3.2.2).

- Operators failed to contact instrumentation and control technicians to disable a safeguards sequencer prior to deenergizing safeguards Bus 2EA1. When safeguards Bus 2EA1 was deenergized, a partial loss of spent fuel pool cooling occurred. This was a noncited violation (Section 3.2.3).

- A failure to follow locked component deviation requirements resulted in the operation of the Unit 2 positive displacement pump for 63 minutes with its suction source only partially open. This was an additional example of a violation of Technical Specification 6.8.1 (Section 3.2.4).

Maintenance

- The quality of work by instrument and control technicians during installation and testing of the reactor protection system bypass modification was very good (Section 5.3).

- Although the licensee identified more foreign material control issues than normal, the inspectors noted that they were mostly administrative in nature and that the licensee's efforts to reduce foreign material exclusion problems were very good (Section 5.5).

- An error in removing a clearance while restoring Transformer XST1 to service resulted in an engineered safety features actuation. This was an additional example of a violation of Technical Specification 6.8.1 (Section 5.6).

- The inspectors found that the accuracy and repeatability of main steam safety valve testing was in question and may not meet code requirements. The issue was an unresolved item (Section 6.2).

Engineering

- Reactor engineering oversight of fuel and insert movement was excellent (Section 3.1).

- The engineering department developed a comprehensive action plan to determine the cause of the Safety Injection Pump 2-02 failure (Section 4.3).

- Implementation of the reactor protection system bypass modification reflected a well thought out and well planned design modification (Section 5.3).

- Engineering involvement was effective in dealing with warped wet annular burnable poison inserts (Section 4.1).

Plant Support

- Inspectors observed mechanics use poor radiological practices during maintenance on a mechanical seal for safety injection Pump 2-02 (Section 5.4).

- Personal contamination data and licensee ALARA reviews were evaluated and found to be thorough, self-critical, and complete (Section 7.1).

- The Unit 2 reactor coolant system decontamination was successful in removing significant amounts of Cobalt-58 and Nickel. The inspectors noted that the licensee's report identified areas for improvement and concluded that the crud burst and clean up process was effective (Section 7.3).

Summary of Inspection Findings:

- Violation 50-445/9604-01; 50-446/9604-01 was opened (Sections 3.2 and 5.6).

- Unresolved Item 50-445/9604-02; 50-446/9604-02 was opened (Section 6.2.3).

- Unresolved Item 50-446/9601-01 was updated (Section 8).

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

Unit 1 operated at approximately 100 percent power throughout the report period.

Unit 2 began the report period at approximately 94 percent power, coasting down for its second scheduled refueling outage. On March 23, the second refueling outage began several days early when operators manually tripped the reactor following an unplanned load rejection. At the end of the report period, Unit 2 was still in its second refueling outage.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Unit 2 Manual Reactor Trip

On February 23, Unit 2 was at approximately 63 percent power and decreasing for its second scheduled refueling outage (2RF02). At 7:26 a.m., one minute after a control room operator manually reduced turbine load by 10 MWe, an unexpected turbine load decrease occurred from approximately 742 MWe to 160 MWe. Other indications included steam flow/feed flow mismatch alarms and level deviation alarms for all four steam generators, all the steam dumps cycling open, and the main generator output remaining in load control at 160 MWe.

In response to the immediate load decrease, the unit supervisor instructed the operators to manually trip the reactor due to the uncertainty regarding main turbine load control. At approximately 7:29 a.m., operators manually tripped the reactor and entered Emergency Operating Procedure EOP-0.0, "Reactor Trip." All control rods fully inserted into the core. Operators manually started both motor-driven auxiliary feedwater pumps. The turbine-driven auxiliary feedwater pump automatically started because of low-low steam generator levels in two of the four steam generators from the transient. Subsequently, operators secured the turbine-driven auxiliary feedwater pump since adequate flow was available from the motor-driven auxiliary feedwater pumps and to minimize the temperature and pressure decrease in the primary system. Decay heat was removed using auxiliary feedwater and the steam dumps. The unit was stabilized in Mode 3 while the licensee investigated the cause of the load rejection.

During the event, all systems functioned as designed with the exception of source range Channel N31, which failed to automatically or manually reenergize. The prompt team responded and found that a faulty test switch caused the source range instrument failure. The switch was repaired, and Channel N31 was placed back in service. The licensee subsequently replaced the N31 drawer during 2RF02 to enhance the future reliability of the nuclear instrument.

The inspectors responded to the control room and verified that all critical safety equipment responded normally and that the plant was in a safe condition. The inspectors verified that operators entered and followed the applicable emergency operating procedure and abnormal operating procedures. Communication between the control room operators was clear and repeat-backs were utilized. The inspectors reviewed the operator logs and determined that the reactor coolant system temperature and reference temperature responded normally. The inspectors concluded that the operator response to the event was very good, the applicable procedures were appropriately implemented, and the plant responded as designed.

3 PLANT OPERATIONS (71707)

The inspectors conducted daily examinations of plant operations. The inspectors' review of control room staffing and access, adherence to procedures, compliance with technical specifications, and operator behavior and attentiveness was performed to ascertain if the plant was being operated safely and in accordance with requirements. Logs for shift operations, clearances, and for limiting conditions for operation were reviewed for accuracy and appropriate actions.

3.1 Unit 2 - Conduct of Refueling Operations

The inspectors periodically observed the licensee conduct refueling operations in accordance with Station Refueling Manual Procedure RFO-102, "Refueling Operation," Revision 7, dated February 16, 1996. The inspectors noted that foreign material control was utilized, personnel safety guidelines were adhered to, and that radiation protection support was excellent with very good contamination control. Oversight of contractors was notable and reactor engineering oversight of fuel and insert movement was excellent.

3.2 Operations Procedure Adherence Issues

3.2.1 Unit 2 - Partial Loss of Decay Heat Removal Following Inadvertent Isolation of Residual Heat Removal Pump 2-02

The inspectors reviewed licensee Operations Notification and Evaluation (ONE) Form 96-0410, dated March 28 which documented an event where core decay heat removal was inadvertently reduced during installation of Clearance 2-96-00949.

Shortly after midnight on March 28, operators noted that Unit 2 letdown flow was slowly decreasing. An auxiliary operator was dispatched to the reactor coolant system filter to determine if the filter differential pressure had increased and operators made preparations to start the Train A standby residual heat removal pump. After the Train B residual heat removal pump low flow alarm was received, operators started the Train A residual heat removal pump and secured the Train B residual heat removal pump. Shortly after operators started the Train A residual heat removal pump, an auxiliary operator informed the control room he had inadvertently isolated the operating residual heat removal pump during a Train B safety injection system clearance installation. Operators then vented, properly aligned, and placed the Train B residual heat removal pump in service and placed the Train A residual heat removal pump in standby.

The inspectors reviewed the operator actions associated with the loss of the Train B residual heat removal pump and found that operators had appropriately followed both alarm response and abnormal operating procedures. A review of plant data during the period of time decay heat removal was degraded indicated that reactor coolant system level increased about three inches and temperature did not significantly change.

The purpose of the clearance and tagging order was to place Safety Injection Pump 2-02 in a testing lineup. The inspectors noted that the clearance and tagging order was simple, specifying only two tags to be hung. One of the tags directed the operator to close the Safety Injection Pump 2-02 discharge isolation Valve 2-8921B. The other directed clearance tag to be removed from the safety injection pump handswitch. Rather than closing Valve 2-8921B, the operator inadvertently closed the operating residual heat removal pump discharge isolation Valve (2-8724B). This failure to follow procedure was an example of a violation of Technical Specification 6.8.1. (50-445/9604-01; 50-446/9604-01)

3.2.2 Unit 1 - Improper Implementation of Maintenance Tagout on Reactor Coolant Pump Seal Water Return Filter Resulted in Reactor Coolant System Leakage

The inspectors reviewed Plant Incident Evaluation Report (PIR) 96-00094-00-00 dated March 29. The PIR documented the licensee's evaluation of an incident which resulted in unplanned leakage from the Unit 1 reactor coolant system when it was in Mode 4 with a heatup in progress.

On February 3, an auxiliary operator implemented a clearance for Work Order (WO) 4-96-097125-00 which prepared the chemical and volume control system for replacement of a reactor coolant pump seal water return filter. When the auxiliary operator isolated and vented the filter, the control room operators noted an increase in reactor coolant flow to the containment sumps as evidenced by containment sump pump run alarms. When the control room notified the auxiliary operator, he noted that the inlet pressure to the filter was abnormally high and he then bypassed the filter. The leakage was caused by a high pressure condition opening relief Valve 1-8121 on the inlet to the reactor coolant pump seal water return filter. A total of 450 gallons of reactor coolant were lost, 150 gallons were left in the pressurizer relief tank, and the remainder entered the containment sump.

The maintenance tagout permit instructed the operator to use System Operating Procedure (SOP)-103A, "Chemical and Volume Control System," Section 5.3.11, prior to placing tags. The licensee found that the auxiliary operator did not perform Step 5.3.11.A of Procedure SOP-103A, which opened the seal water return filter bypass valve. Therefore, when he isolated the filter, reactor coolant system pressure was transmitted to the inlet relief valve. The licensee also found that the clearance processing senior reactor operator was busy with some other task which resulted in the Unit 1 unit supervisor approving the work and that no pre-evolutionary brief had taken place. This failure to follow procedure was a second example of a violation of Technical Specification 6.8.1 (Violation 50-445/9604-01; 50-446/9604-01).

3.2.3 Unit 2- Improper Deenergization of 6.9kV Safety-Related Bus 2EA1 Resulted in a Partial Loss of Spent Fuel Pool Cooling

ONE Form 96-0271, dated March 10, documented an operator failure to follow Procedure SOP-603B, "6900V Switchgear," when deenergizing 6.9kV safety-related Bus 2EA1. Step 2.2 of Procedure SOP-603B states, "if a safeguards 6900 V bus is being deenergized, THEN contact I&C [Instrument and Controls] personnel to remove the Safeguards Sequencer from service AND ensure the Diesel is in the MAINTENANCE MODE per Procedure SOP-609B." Operators did not contact I&C to remove the safeguards sequencer prior to deenergizing Bus 2EA1. Therefore, when Bus 2EA1 was deenergized, the safeguards sequencer shed loads, as designed. One of the loads which shed was spent fuel pool cooling Pump X-01. As a result, a partial loss of spent fuel pool cooling occurred. Operators promptly restarted the spent fuel pool cooling pump and spent fuel pool temperature did not significantly change. Other corrective actions are outlined in Section 3.2.6.

The inspectors reviewed Procedure SOP-603 and found that the licensee's failure to perform the prerequisite step of removing the safeguards sequencer was an additional example of a violation of Technical Specification 6.8.1. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

3.2.4 Unit 2 - Failure to Follow Locked Component Deviation Control Procedures Resulted in Operation of the Positive Displacement Pump With Its Suction Isolated

During a review of operator logs on March 18, the inspectors noted that the Unit 2 positive displacement pump was operated for a total of 63 minutes with its suction flowpath partially isolated on March 17. The operator logs indicated three separate attempts to run the pump. Following the first attempt, which lasted approximately two minutes, operators appropriately verified that the chemical volume and control system was properly filled and vented. After the second attempt, which lasted 12 minutes, operators again verified that the system was properly filled and vented but did not perform a valve lineup. Following the third attempt at running the positive displacement pump, which lasted 48 minutes, operators performed a complete valve lineup and found that the positive displacement/centrifugal charging pump crosstie Valve 2-8341 was only partially open with a locked open tag on it. The licensee wrote ONE Form 96-0348 on March 17 and it was assigned to mechanical maintenance as a personnel error.

The inspectors reviewed portions of WO 3-95-314632-01 which was written to perform maintenance on Valve 2-8341 in accordance with licensee Procedure MSM-CO-8813, "ITT Grinnell Diaphragm Valve Maintenance (Manual Operators)." The remote manual valve actuator, which was locked in the open position, was disconnected from the valve. Step 8.3.3.38 of Procedure MSM-CO-8813, if properly completed, would have aligned the remote manual actuator with the actual valve position when the actuator was reconnected. The inspectors noted that Step 8.3.3.38 of the working copy of MSM-CO-8813 indicated "N/A" with a note that stated, "step could not be performed as valve handwheel was locked open with locked open tag." This step would have placed the valve in the proper position.

The inspectors reviewed Operations Work Instruction (OWI)-103, "Locked Component Listings and Deviation Control." Procedure OWI-103, Step 5.4, states that the shift manager, unit supervisor, and qualified operators are to ensure that the locked component that is repositioned or unlocked is done so in accordance with the requirements of Operations Department Administration Control Manual (ODA)-403, "Operations Department Locked Component Control." Procedure ODA-403, Step 5.4, states, that the shift manager or unit supervisor ensures that any locked component which is repositioned or unlocked is properly logged in the Locked Component Deviation Log, OWI-103-3. OWI-103, Form 2103, indicated that Valve 2-8341 was a locked open valve because it was in a safety-related flowpath.

The inspectors noted that contrary to the requirements of Procedures OWI-103 and ODA-403, the licensee did not control the locked component deviation which occurred when Valve 2-8341 was released for maintenance. This failure to follow procedure requirements was a third example of a violation of Technical Specification 6.8.1 (Violation 50-445/9604-01; 50-446/9604-01).

3.2.5 Significance

Two of the above examples involved a partial loss of decay heat removal, none of which were very significant individually. In each of the events where a partial loss of decay heat removal occurred, no significant spent fuel pool or reactor coolant system level or temperature changes were noted. One example involved a relatively small loss of reactor coolant inventory and did not challenge the ability of the reactor coolant system to remove decay heat from the core. The final example, which involved the failure to maintain cognizance over the position of a locked valve in the safety injection flowpath, was of little significance because the particular safety injection flowpath affected was not being relied upon for core reactivity or temperature control.

The significance of the above examples is that they represent a relatively recent negative trend of inadequate procedure adherence and a continued higher than normal licensee personnel error rate.

3.2.6 Licensee Corrective Actions

The licensee recognized the negative trend in personnel errors and implemented a human performance task team on February 26 to evaluate the circumstances surrounding a number of previously identified errors. The inspectors reviewed the licensee's task team report which concluded, in part, the following: (1) ineffective communications were associated with about one-third of the events, due to a less than adequate prejob briefing which occasionally did not include all the involved personnel; (2) details of personnel errors were not routinely discussed with site personnel; (3) the seven step self-verification process was being implemented by the workers but for continued improvement in the reduction of personnel errors, sponsorship and implementation of the seven steps will require heightened vigor.

Additionally licensee management met with individual work groups in March to discuss the importance of self-verification. The inspectors noted that the discussions were self-critical and contained sufficient detail to be informative to the workers. The inspectors concluded that management efforts to heighten personnel awareness of the increased error rate were appropriate.

3.3 Unit 1 - Monthly Containment Isolation Walkdown

The inspectors verified a selected portion of the primary containment isolation lineup on Unit 1 in accordance with Procedure OPT-218A, Revision 6, "Primary Containment Integrity Verification (ORC)." The procedure ensures containment integrity by verifying that penetrations, which are required to be closed during accident conditions, and are not capable of being closed by operable containment automatic isolation valves, are in their required positions. The inspectors concluded that the selected valves were in the correct positions, components were locked when required, and red caps were utilized in accordance with procedural requirements.

4 ONSITE ENGINEERING (37551)

The inspectors assessed the effectiveness of the onsite engineering organization in identifying, resolving, and preventing plant problems. This assessment was accomplished through a review of licensee corrective actions, root cause determinations, safety committee involvement, and self-assessment in engineering.

4.1 Unit 2 - Wet Annular Burnable Absorber (WABA) Warping Issues

On March 10, while performing fuel insert movement in Spent Fuel Pool X-01, a 24-rodlet WABA insert disengaged from its handling tool. Although disengaged, the WABA insert was contained within the handling tool and was resting on top of a fuel assembly. After the WABA insert was recaptured and verified to have no significant damage, operators placed the tool with the insert attached in the wet cask area for safe storage. The licensee stopped all work in the spent fuel pool until an action plan was developed.

The licensee developed a WABA insert recovery plan which involved first placing the WABA in Spent Fuel Pool X-02 and then inspecting the handling tool. The licensee found that the handling tool was working properly. The recovery plan included provisions to closely monitor the movement of other WABA inserts and provided guidance to operators on how to move WABA inserts and when to place warped WABA inserts in Spent Fuel Pool X-02.

Thirteen additional WABA inserts were found to be warped sufficiently to prevent their reinsertion into spent fuel assemblies once removed. As a result, the licensee wrote ONE Form 96-328 on March 12. The licensee indicated that similar problems had occurred at other nuclear facilities.

The inspectors observed that reactor engineering facilitated the development of a comprehensive and detailed WABA recovery plan which was successfully implemented. The inspectors observed as reactor engineering provided continuous oversight of the insert shuffle and WABA recovery efforts. The inspectors noted that engineering provided unsolicited guidance and direction that was typically concise and sufficiently detailed as needed. Foreign material exclusion and personnel safety practices were observed to be very good around the spent fuel pools. The inspectors concluded that conservative decision making was used in determining when a WABA was placed in Spent Fuel Pool X-02.

4.2 Unit 2 - Rod Drop Testing

On February 23, the inspectors observed rod drop testing on Unit 2 in accordance with WO 5-95-500300-AA and Procedure NUC-206, "Control Rod Operability." The Westinghouse Owner's Group requested the rod drop test data due to problems encountered during recent events at other utilities in which control rods failed to completely insert upon a reactor trip signal. The test was performed while the unit was in Mode 3 prior to cooling down for Outage 2RF02.

The test measured the rod drop times for all control and shutdown rods by using the digital rod position indication system. During normal operation of the digital rod position indication system, the test points on the detector/encoder cards in each data cabinet measure the alternating current excitation applied to the coils of a particular rod. When the voltage to the coil is removed by turning off the power supplied to the data cabinets, the residual magnetism of the rod causes a voltage to be momentarily induced in each coil as the rod drops. The induced voltages are displayed on a trace, which reflects the time the rod control cluster assembly rodlets enter into the dashpots in the fuel assembly guide tubes. The time between the beginning of stationary gripper voltage decay to dashpot entry is determined.

The inspectors attended the prejob briefing, which was held in the control room. The inspectors observed as each control or shutdown bank was fully withdrawn for rod drop time measurement. The control room verified that the digital rod position indication was operable by comparing its rod position indication to the demand position indication using the step counters.

Operators opened the reactor trip breakers to drop the respective control or shutdown bank. During this process, the stationary gripper voltage and the induced voltages in the appropriate detector/encoder card test point of the digital rod position data cabinets were recorded. Reactor engineering personnel analyzed the results of the traces to obtain the time between the beginning of stationary gripper voltage decay and dashpot entry. The results revealed that each individual rod drop time from the fully withdrawn position was within the acceptance criteria of 2.4 seconds. The traces included the amount of recoil on each rod. Recoil is a dampening effect that is normally seen in the traces as a result of contact of the control rod assembly spider hub spring against the fuel assembly. Reactor engineering personnel assessed the amount of recoil on the traces for each rod, and determined that each rod displayed some recoil. However, the amount of recoil varied on several of the rods. These data were being provided to Westinghouse for evaluation.

The inspectors concluded that reactor engineering personnel performed the rod drop test appropriately and in accordance with procedure. The prejob briefing was thorough and included all the pertinent individuals. The inspectors verified that the rod drop times were within the acceptance criteria by reviewing the traces and subsequent results.

4.3 Safety Injection Pump 2-02 Action Plan

During work to replace the mechanical seals in accordance with WO 1-95-083938-00, licensee personnel reported binding of the shaft at various points while it was hand rotated. The licensee initiated an investigation with the assistance of the pump vendor and wrote ONE Form 96-00295. The internal rotating element was removed and the internal dimensions were checked and found to be too tight by several thousandths of an inch. Although previous surveillance testing had indicated no pump performance degradation, the licensee replaced the entire pump and implemented a detailed action plan to ascertain the root cause of the casing distortion and determine if the condition was reportable.

The inspectors reviewed the licensee's action plan and found it comprehensive and timely. The new safety injection pump was installed and the old safety injection pump was sent to the vendor for inspection and repair. The inspectors noted that engineering involvement was very good.

5 MAINTENANCE OBSERVATIONS (62703)

To ensure safe operation of the plant and plant equipment, the inspectors conducted a review of the licensee's safety-significant maintenance activities. This review entailed the visual inspection of plant structures, systems and components, as well as interviewing maintenance personnel, to ensure reliable safe operation of the plant and compliance with regulatory requirements. The maintenance activities observed during the report period are listed below and inspector observations follow.

- Unit 1 - Corrective maintenance to troubleshoot Emergency Diesel Generator 1-02 in accordance with WO 1-96-098160-00.
- Unit 2 - Preventive maintenance on Emergency Diesel Generator 2-02 to inspect the fuel injectors in accordance with WO 3-95-328407-01.
- Unit 2 - Preventive maintenance on Emergency Diesel Generator 2-02 to inspect the pistons and liners in accordance with WO 3-95-328441-01 and WO 1-95-090626-00.
- Unit 2 - Corrective maintenance on Emergency Diesel Generator 2-02 to replace cylinder liner 1L in accordance with WO 1-95-090626-00.
- Unit 2 - Preventive maintenance on Emergency Diesel Generator 2-02 to inspect engine internals in accordance with WO 3-95-328425-01.
- Unit 2 - Corrective maintenance on Emergency Diesel Generator 2-02 to weld Starting Air Receiver 2-04 in accordance with WO 1-94-078225-00.
- Unit 2 - Preventive maintenance on Unit 2 Safety Injection Pump 2-02 to inspect the bearing shaft seal in accordance with WO 1-95-083938-00.

5.1 <u>Emergency Diesel Generator 2-02 Fuel Injector Inspections/Replacements</u>

The inspectors observed portions of a preventive maintenance activity performed on the fuel injectors for Emergency Diesel Generator 2-02 in accordance with WO 3-95-328407-01 and Procedure MSM-CO-3338, Revision 2, "Emergency Diesel Engine Fuel Injector Inspection." The maintenance entailed a removal, general inspection, and replacement of each fuel injector. The inspectors verified that the appropriate safety tagout boundaries were established for the maintenance work. During the activity, the inspectors verified that the fuel injectors that were removed were subsequently replaced with refurbished injectors.

The inspectors questioned the licensee about the amount of carbon deposits on the injectors that were removed, and were informed that the amount was indicative of normal buildup during the previous operational cycle of approximately 100 hours. Maintenance workers found two gouge marks in the fuel injector line for Cylinder 7L. The injector was removed, the port was cleaned, and a new injector was installed in accordance with procedure. Housekeeping and cleanliness were properly maintained when the injectors were removed to prevent foreign material from entering the open system. The fuel injector ports were covered in the cylinder heads, and all tube openings were properly bagged. Maintenance workers exercised caution when handling the fuel injectors to prevent the parts from being scratched or marred. All parts that were disassembled were appropriately stored. During the replacement of the fuel injectors, the inspectors verified that mechanical maintenance technicians applied the proper torque on the stud fasteners with no movement detected. The torque wrenches used were within calibration, and were independently verified by both of the maintenance workers. The maintenance workers utilized the quality independent verification process for the quality control hold points during the activity. The inspectors concluded that the removal, inspection, and replacement of the fuel injectors were conducted in accordance with procedural requirements, the quality independent verification process was used properly and effectively, and communication between the maintenance workers was good.

5.2 Emergency Diesel Generator 2-02 Piston and Liner Inspections

The inspectors observed portions of a preventive maintenance activity performed on the pistons and liners for Emergency Diesel Generator 2-02 in accordance with WO 3-95-328441-01 and Procedure MSM-CO-3341, Revision 1, "Emergency Diesel Engine Cylinder Liner and Piston Inspection." The purpose of the maintenance was to visually inspect the cylinder heads for evidence of wear and cracking, and inspect the intake, exhaust, and air start valves for unusual conditions with a boroscope. The inspections were performed by a vendor representative and the system engineer. The only notable discrepancy found was on Cylinder 1L, which had significant scoring and full length scuffing. There was evidence of some scuffing on this cylinder earlier in the operational cycle. Also, the vendor representative determined that marks that were previously discovered on Cylinder 1R during the operating cycle were considered to be in a slightly improved condition.

As a result of the discrepancies found during the inspections on Cylinder 1L, the licensee replaced the liner for Cylinder 1L and the associated piston rings. The inspectors observed portions of the liner replacement in accordance with WO 1-95-090626-00. The licensee's inspection of the removed liner revealed hard, solid carbon deposits above the top piston ring, with evidence of continuous liner contact, which could remove lube oil film and cause the oil ring to overheat. The carbon formation was most likely caused by extensive no load operation that occurs during normal startup testing.

The inspectors concluded that the piston and liner inspections were thorough and performed in accordance with the procedure. The installation of the new liner on Cylinder 1L was performed well with one minor exception. The installation involved various workers reaching in the openings on either side of the crankcase to correctly position the liner and piston, and a worker stationed on top of the platform. The worker on the platform was both responsible for assisting in the work as well as maintaining the personnel accountability. The inspectors identified that all personnel who were reaching with tools into the diesel crankcase were not formally accounted for in the foreign material exclusion log. When the inspectors brought it to the licensee's attention, the log was immediately corrected.

5.3 Unit 2 - Reactor Protection System Bypass Modification

The inspectors observed various aspects of the installation of the reactor protection system bypass modification. The modification was designed to allow testing of the various channels in "bypass" rather than in "trip." This was intended to increase reliability of the system and to reduce the occurrence of spurious or operator induced protective actions. Additionally, the modification installed 50 pin connectors which provided a convenient means to measure channel parameters during routine surveillance tests. To install the modification, every circuit card in the protection system was removed and inspected.

The inspectors reviewed the licensee's retest plan to assure that the modification was installed correctly and functioned as planned. The licensee retest consisted of point-to-point continuity checks, functional check of each annunciator channel in the bypass mode, and a loop functional test. Following these tests, the licensee performed analog channel operational tests and then the surveillance tests. The inspectors concluded that the test plan was comprehensive and should identify any errors in installation or design.

The inspectors observed instrument and control technicians during the installation and testing phases of the modification. The inspectors also observed quality control inspectors present during significant periods of time. The inspectors noted that the cable wraps appeared professional and that newly installed wire runs were neatly routed. The inspectors concluded that the bypass modification was planned, implemented and tested well.

5.4 Unit 2 - Safety Injection Pump 2-02 Maintenance

The inspectors observed portions of the preventive maintenance performed on the Unit 2 Safety Injection Pump 2-02 to inspect the bearing shaft seal in accordance with Work Order 1-95-083938-00. The inspectors noted that two of the mechanics donned thin, blue, latex gloves. The inspectors questioned the mechanics regarding the use of the gloves. The mechanics stated that although they were reinstalling the seal assembly, which was not contaminated, that the radiological protection group had requested that they wear the gloves as a precautionary measure.

The inspectors watched the mechanics reinstall the seal assembly. The inspectors observed the mechanics scratch their faces and touch other unprotected areas without first frisking their gloved hands. Additionally, the inspectors observed a foreman use an ungloved hand to assist in the reassembly. The inspectors concluded that while they were not contaminated, the mechanics demonstrated poor radiological practices to prevent the spread of contamination.

5.5 Foreign Material Exclusion

The inspectors reviewed new Procedure STA-625, "Foreign Material Exclusion," which was effective on December 1, 1995, and the number of deficiencies that the licensee identified associated with this procedure that occurred during Outage 2RF02. The inspectors noted that the amount of deficiencies increased during the outage; however, the majority of the deficiencies pertained to administrative errors and not to actual foreign material exclusion events. The inspectors also noted that the deficiencies that were considered actual events were not significant. The Nuclear Overview Department was effective in ensuring that Procedure STA-625 was implemented properly. The inspectors held discussions with the Foreign Material Exclusion Coordinator, and with personnel in the Nuclear Overview and Training Departments regarding the licensee's corrective actions in response to the increased amount of deficiencies in this area. The licensee's corrective actions included the development of a desk top instruction that restated the administrative requirements of the procedure, which was distributed to the department supervisors. Also, a foreign material exclusion hotline was established to respond to any questions regarding the implementation of the procedure. After Outage 2RF02, the licensee planned to evaluate Procedure STA-625 for improvement to prevent future deficiencies. The inspectors questioned the licensee on the training that was conducted on Procedure STA-625 prior to the outage. The licensee indicated that all workers were trained on the procedure, and a mock up was placed in the maintenance building during the outage as an example of how to control a foreign material exclusion area.

The inspectors concluded that the licensee's overall effort to reduce foreign material exclusion events during Outage 2RF02 was very good, and had improved from previous outages. However, some confusion existed among various work groups during the outage on how to administratively implement Procedure STA-625.

5.6 Unit 2 - Error in Clearance Removal Results in Engineered Safety Features Actuation

ONE Form 96-0409, dated March 28, documented an error which resulted in an engineered safety feature actuation. While releasing Clearance X-95-1867 to restore Transformer XST-1 to service, licensee personnel opened the wrong fuse drawer which resulted in a engineered safety feature (blackout sequencer) actuation.

The inspectors reviewed the clearance and tagging order and noted that it contained approximately thirty-one steps. Step 13 directed the electrician to remove the tag for the 7200-120 V potential transformer fuses which were labeled "PT-A/ST1/Fuses(4)" and were located in Switchgear 2EA1, Cubicle 3. The inspectors were told by operations management that when the group removing the clearance (two electricians, an auxiliary operator, and the field support supervisor) got to the step to install the potential transformer fuses, they became confused by the nomenclature on the switchgear. The group then decided to open the drawer labeled PT-2/2EA1 even though a label on the drawer stated "CAUTION - Opening This Drawer Will Cause an Undervoltage Trip of This Bus." When the drawer was opened, the station blackout sequencer was actuated. This failure to follow procedure was a fourth example of a violation of Technical Specification 6.8.1 (Violation 50-445/9604-01; 50-446/9604-01).

6 SURVEILLANCE OBSERVATIONS (61726)

The inspectors reviewed the effectiveness of surveillance activities by direct observation in order to ascertain that testing of safety-significant systems and components was being conducted in accordance with technical specifications and other regulatory requirements. Specific tests observed are listed below and detailed observations follow.

- Unit 1 - Instrumentation and Control Procedure INC-7673B, Containment Hydrogen Analyzer, Train B, Channel 550 Calibration, in accordance with WO 3-95-316432-01.

- Unit 2 - Instrumentation and Control Procedure INC-7761B, Analog Channel Operational Test and Channel Calibration of Reactor Coolant Loop 1, Protection Set II, Channel 0415; and INC-2086, Instrument and Controls Component Alignment, in accordance with WO 5-96-500251-AA.

- Unit 1 - Instrumentation and Control Procedure INC-7294A, Analog Channel Operational Test and Channel Calibration of Main Steam Pressure, Loop 1, Channel II, in accordance with WO 5-95-500138-AA.

- Unit 2 - Main Steam Safety Valve Testing in accordance with licensee Procedure MSM-SO-8702, "Main Steam Safety Valve Testing," Revision 2, dated February 23, 1993.

6.1 Instrumentation and Control Surveillances

The inspectors observed the implementation of instrumentation and control surveillances described above and noted the following: (1) technicians used good self-verification techniques which included using the practice of two-person verification without flaw; (2) attention to personal safety was apparent in that technicians never entered energized equipment with metal jewelry; (3) meters and test equipment were calibrated and in good physical condition; (4) the appropriate test leads were used to connect meters and test equipment to circuit cards and test jacks; (5) nuclear overview presence was observed; and (6) work package documentation was complete and timely.

The inspectors concluded that instrumentation and control maintenance surveillances were performed in a controlled and safe manner.

6.2 Unit 2 - Main Steam Safety Valve Testing

On February 22, the inspectors observed the licensee test the setpoint of two main steam safety valves (MSSV). The licensee intended to test the four safety valves with the lowest setpoint as part of pre-outage testing. Each steam generator had five Crosby style HA self-actuated nozzle type safety valves.

The inspectors observed the maintenance technicians, quality control inspectors, and engineers, as they prepared, tested, and restored two of the safety valves. The inspectors followed the procedure controlling the testing and concluded that the licensee performed the tests, and obtained satisfactory results, in accordance with the procedure.

6.2.1 Testing Requirements

Technical Specification 4.0.5 required that inservice testing of main steam safety valves be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," required that valve testing be performed in accordance with the requirements stated in ASME/ANSI OM, Part 10. Paragraph 4.3.1 of Part 10, stated in part that safety and relief valves shall meet the inservice test requirements of Part 1.

Part 1, Section 1.4.1 required in part that all instruments be calibrated to standards traceable to the National Bureau of Standards; and that test equipment, inclusive of gauges, load cells, assist devices, etc., have an overall combined accuracy within +2 percent to -1 percent at the pressure level of interest. The effect of the overall combined accuracy specified above is that the limits of the actual set pressure may be 1 percent above to 2 percent below the measured set pressure.

6.2.2 Procedure

The inspectors reviewed Procedure MSM-SO-8702, "Main Steam Safety Valve Testing," Revision 2, dated February 23, 1993, to determine whether testing performed in accordance with the procedure met the requirements of the Technical Specification. The inspectors reviewed the calculations and assumptions to determine their validity. The inspectors noted that the assist devices used to test the MSSV set pressures were not included in the licensee's calibration program and that the calculation used to convert air motor pressure into MSSV assist pressure did not appear to account for the weight of the assembly.

The inspectors and the licensee discussed the construction of the air motor assembly. The licensee stated that the interior of the motor consisted of a housing, a push rod assembly, and a diaphragm, and that it was not likely that the degradation of any of these components would affect the operation of the motor. The licensee stated that there was enough clearance between the motor body and the push rod assembly so that friction was not a factor and that degradation of the diaphragm would not affect the measured set pressure.

MSSV set pressure was determined by using an assist device to apply a lifting force to the valve spindle. Air was applied to the motor until the safety valve began to lift and the pressure was noted. The air pressure was converted to an assist pressure and added to the measured steam line pressure to determine the valve's set pressure.

The test apparatus consisted of the air motor mounted above the valve to apply a lift force to the safety valve spindle. Air pressure pushed the diaphragm against the push rod assembly. When the force exerted by the air pressure exceeded the weight of the test apparatus, the push rod assembly would begin to extend. The movement of the push rod assembly caused the test apparatus to move upward and apply a lifting force on the valve spindle.

The inspectors reviewed the calculation used to determine MSSV set pressure and concluded that the calculation (Local Steam Pressure - Measured Steam Pressure Height Correction + Correction Factor X Air Motor Pressure), did not appear to account for the weight of the air motor assembly. The inspectors estimated that the air motor assembly weighed 50 pounds. Therefore, the force developed by air pressure must first overcome approximately 50 pounds before applying any force to the valve spindle. With a diaphragm area of 50 square inches, 50 pounds corresponded to 1 psi. The inspectors noted that 1 psi should be subtracted from the air motor pressure before being multiplied by the correction factor.

The licensee stated that the correction factor was determined from a vendor-supplied graph showing air motor pressure versus assist pressure and that the graph had been reportedly developed through empirical data. The inspector reviewed the vendor manual for the safety valves, (VTMR 001-802) and noted that the graph was a straight line which passed through both axis at zero. The inspectors noted that the graph was developed for a generic class of air motor assemblies and not for the licensee's specific air motors. The inspectors questioned how the performance of the air motors was verified to meet the assumed measurement accuracy. The licensee stated that the valve vendor dimensionally checked the air motors, which were purchased from a contractor, but did not know whether the vendor actually tested each air motor.

6.2.3 Conclusions

The inspectors concluded that the accuracy and repeatability of the air motor assembly affected the measured accuracy of the main steam safety valve setpoint and that the code required all instruments used in determining safety valve setpoints be calibrated. The inspectors noted that the licensee believed that the accuracy of the air motor would not change over time and did not require calibration. The inspectors concluded that this was an unresolved issue and required further review. The licensee was attempting to confirm the vendor's validation of the test method accuracy at the end of the inspection period. The inspectors will review any information regarding the accuracy of the air motor and its effect on the overall test accuracy. Additionally, the inspector will determine whether the licensee's assertion regarding the lack of air motor performance degradation was valid (Unresolved Item 50-445/9604-02, 50-446/9604-02).

Following the inspection period, the inspectors questioned the licensee regarding their position on the issue. The licensee stated that they did not believe that the operability of the MSSVs was affected. The licensee noted that manufacturing tolerances and weight changes were negligible and were probably on the order of 1 psi. Additionally, the licensee stated that they had not seen any trends in measured set pressures over the past six years using the same air motors and that this indicated that there was no degradation in air motor performance. The licensee intended to have the vendor test one of the air motors to confirm that the generic graph accurately portrayed the air motor's performance. The inspectors concluded that the possibility that any degradation in the air motor's performance caused the accuracy of the test apparatus to be outside the ASME Code requirements was small and that the operability of the MSSVs was not in question. The inspectors will review the test results to determine whether the air motor requires periodic calibration.

7 PLANT SUPPORT ACTIVITIES (71750)

The inspectors observed licensee activities in the areas of plant security and radiological protection to ascertain if the licensee took appropriate measures to protect the plant, its staff, and the public.

7.1 Unit 2 - Personnel External and Internal Contaminations

The inspectors reviewed personal contamination data and ALARA [As Low As Reasonably Achievable] review information through noon of March 25, 1996. A total of 196 contamination events were recorded for 1996, and the licensee performed an ALARA review on a total of 42 events, 23 of which the inspectors reviewed in detail. The inspectors found the ALARA reviews to be thorough, self-critical, and complete. Inspectors concluded that the licensee's use of a dedicated person for ALARA reviews was a strength.

7.2 Unit 2 - Chemistry Support of Reactor Coolant System Decontamination

In preparation for the second Unit 2 refueling outage, the licensee initiated a controlled crud burst. The process was used to perform a controlled release of corrosion products from incore and excore surfaces. The inspectors reviewed the licensee's report concerning the effectiveness of the crud burst. The inspectors concluded the licensee was successful in removing a significant amount of Cobalt-58 and Nickel. The licensee reported lower dose rates than expected on residual heat removal piping and a much higher peak Cobalt-58 activity than previous outages. The inspector noted that the licensee's report identified areas for improvement during future outage preparations. The inspectors concluded that the licensee's crud burst and cleanup process was effective and that the licensee would continue to improve the process.

7.3 Filter Carousel Decontamination

On March 5, the inspectors observed the decontamination of the filter carousel in accordance with Radiation Work Permit 96002500. The decontamination was performed in an enclosed room within the fuel building by radiation protection technicians. Technicians flushed the carousel filter with demineralized water in a controlled manner without spreading contamination. The inspector verified that the contamination and radiation boundaries were appropriately established. A survey was present, which included the dose rates inside the filter carousel. The inspectors verified that technicians wore the proper dosimetry and followed the appropriate radiation work permit. Proper ventilation was established to prevent the spread of contamination. The inspectors concluded that radiation protection personnel had good controls during the filter carousel flushing evolution, and utilized proper ALARA techniques.

8 FOLLUWUP - PLANT OPERATIONS (92901)

8.1 (Open) Unresolved Item 50-446/9601-01; Operation of Unit 2 Greater than 100 Percent Power

This unresolved item involved two overpower events that occurred in Unit 2 on February 14, 1996. Unit 2 was operating at 95 percent rated thermal power when a condensate transient caused a significant reduction of feedwater temperature. This caused a reduction in the reactor coolant system cold leg temperatures and caused reactor power to increase to approximately 102.2 percent by the nuclear instrumentation system (NIS) before the Nitrogen-16 detection system (N-16) initiated a turbine runback. Reactor power was stabilized at approximately 97 percent by NIS. A second similar transient caused reactor power to increase to approximately 102 percent by NIS before another turbine runback stabilized power at approximately 100 percent by NIS. During the subsequent 30 minutes, reactor power was at approximately 100 percent by NIS with reactor coolant temperatures below normal. A licensed operator noted that the N-16 detection system indicated approximately 106 percent and that the computer based plant calorimetric system indicated approximately 102 percent power. Reactor power was reduced to less than 100 percent by all indications. This item was left unresolved until the licensee finished their determination of actual power levels during the transients.

8.1.1 Power Determination

The licensee reviewed data from the transients and concluded that the most accurate indicator of reactor power was the N-16 detection system. The licensee concluded that during the time following the second turbine runback when NIS indication was reasonably stable at or below 100 percent, that the actual power was 103.8 percent.

The inspectors independently verified the licensee's power determination by reviewing a copy of an N-16 channel strip chart covering the time frame of interest. The chart recorded the power indication from one of the four N-16 channels. The inspectors noted that reactor power was being maintained at 95 percent, based on the computer based calorimetric, prior to the first runback. The strip chart recorder indicated a steady power level that oscillated in an approximately three percent wide band. The inspectors used this indication as a reference equivalent to 95 percent rated thermal power for this detector channel.

The inspectors compared the reference to the various power levels during the two transients. The inspectors concluded that reactor power reached 107 percent before being turned by the turbine runbacks. The inspectors also concluded that at approximately 10:10 a.m. (7 minutes after the second runback), that actual power was approximately 104 percent and that power slowly decreased over the next 30 minutes to approximately 102 percent. Actual power was then reduced to approximately 99 percent.

8.1.2 N-16 Detection System

The N-16 detection system measured the high energy gamma rays generated during the beta decay of the N-16 isotope. N-16 was formed by the fast flux activation of the oxygen in water and was proportional to thermal power. The subsequent gamma decay (7.2 second half-life) was detected by ion chamber detectors located just outside of the biological shield on each hot leg.

The N-16 detection system was compensated for both T_{Cold} and power distribution. Temperature affected N-16 indication by affecting coolant density. Increased coolant density increased the amount of N-16 per unit volume which caused an increase in gamma concentration and higher indicated power than actual. Power distribution affected the N-16 detectors due to gamma rays produced from fission in the fuel. Gamma rays produced near the top of the core could stream directly to the ion chamber detectors. This streaming affect was compensated by a signal taken from the top two nuclear instrument ion chambers.

The licensee concluded that the N-16 detection system was not significantly affected by the decrease in feedwater temperature events on February 14. The licensee stated that the compensation factor for the decrease in T_{Cold} was 0.0006. The inspectors acknowledged that this factor was small and that temperature changes appeared to have little effect on N-16 indicated power. The inspectors noted that the N-16 system was based on gamma detectors and that gamma ray absorption by water was relatively unaffected by temperature changes.

8.1.3 Temperature Effects on Power Indication

The licensee noted that the computer based calorimetric was two percent lower than actual thermal power. The licensee stated that the calorimetric was based on a fourth order polynomial which was based on 100 percent power with 440°F feedwater. The licensee stated that more inaccuracies were introduced into the calculation the farther actual conditions deviated from assumed values.

The inspector reviewed the licensee's procedure for performing a unit calorimetric (OPT-309). The inspector noted that the procedure required stable plant conditions and that average reactor coolant system temperature must be within 1.5°F of reference temperature. The inspector noted that during the time after the second transient this condition was not met.

8.1.4 Operations Weaknesses

The inspectors reviewed the event with respect to operator performance. The inspectors concluded that several operator misconceptions and weaknesses led to operating the unit above 102 percent for 30 minutes on February 14.

The inspectors reviewed the event with the operators. The operators noted that following the second runback, reactor power was less than or equal to 100 percent by NIS. The operators stated that they knew that the NIS indication could be shadowed due to the colder feedwater and reactor coolant system cold leg temperature, but that they were maintaining average reactor coolant system temperature approximately 3°F above reference temperature and that they believed that the NIS indicated conservatively (i.e., higher than actual). The reactor operator noted that during transients, the N-16 indicators were generally not referenced since they were located across the room. The inspectors discussed general operating philosophy with several other operators and concluded that using the reactor coolant system average temperature/reference temperature mismatch as a indication of NIS accuracy was a general misconception. Additionally, the inspectors concluded that operators typically did not reference the N-16 detectors during transients.

The inspectors discussed the supervisory aspects of the transient with the crew. The shift manager indicated that approximately 37 minutes following the second runback, he toured the control room and noted that the unit supervisor was deeply involved in the restoration of feedwater heaters and extraction steam. The shift manager assigned an additional licensed senior reactor operator to direct the secondary system restoration. After being relieved of the secondary restoration, the unit supervisor noted that the N-16 detectors indicated greater than 100 percent power. After consulting the computer based calorimetric which indicated 102 percent, the shift manager ordered that power be reduced below 100 percent by all available indication. The inspectors concluded that the shift manager provided the appropriate level of oversight and direction required by the position. However, the inspectors concluded that the unit supervisor became deeply involved in the restoration of the secondary system which may have contributed to the delay in identifying the overpower condition. The licensee stated that the unit supervisor acted appropriately and was expected to oversee the restoration of the secondary systems.

The inspectors discussed with licensee management how temperature affected the NIS. The licensee stated that prior to the event, they did not recognize the magnitude of the effect that temperature had on NIS indication. The licensee stated that the reactor vendor typically assumed that NIS power indication would change 0.6 percent per degree and that their own analysis assumed 0.8 percent per degree. They stated that the actual effect probably was somewhere between the two.

The inspectors reviewed license training documents related to the effects that temperature had on NIS indication and discussed the training with the operator training staff. The inspectors noted that while temperature shadowing was discussed in training, the magnitude of the effects, management expected actions and the insights which could have been gained by the operators from other indications had not been explicitly included as part of operator training. The inspectors concluded that the magnitude of temperature shadowing had been available prior to the runbacks and could have assisted the operators in recognizing that reactor power was greater than 100 percent had it been incorporated into operator training.

8.1.5 Requirements

Comanche Peak Steam Electric Station, Unit 2, Facility Operating License Number NPF-89, dated April 6, 1993, stated in part that the licensee was authorized to operate the facility at a reactor core power level not in excess of 3411 megawatts thermal (i.e., 100 percent).

Procedure ODA-102, "Conduct of Operation," paragraph 6.2.1 stated in part that operational decisions should not be based solely on a single plant indication when more than one of the same parameter was available. At the start of the transients, the plant computer based calorimetric calculation was unavailable. While all four nuclear instrument channels indicated approximately the same value, they were affected by cold water shadowing. The N-16 detectors were not consulted until 37 minutes following the second runback.

Technical Specification 6.8.1 required the licensee to establish, implement, and maintain procedures covering the activities referenced in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Appendix A referenced general plant operating procedures for power operation. Integrated Plant Operating Procedure IPO-003B, "Power Operations," Revision 2 dated July 13, 1995, Section 5.5 stated in part that, thermal power shall not exceed 102 percent. Thermal power exceeded 102 percent in Unit 2 during transients which occurred at 8:32 a.m. and 10:03 a.m. on February 14, 1996. Additionally, the licensee unknowingly allowed thermal power to exceeded 102 percent from approximately 10:10 a.m. until approximately 10:40 a.m. the same day. This item will remain unresolved pending further NRC staff review.

8.1.6 Corrective Actions

On March 29, the inspectors discussed corrective actions with licensee management. The licensee discussed several planned corrective actions and lessons that had been learned regarding this event. The licensee stated that the analysis of the event revealed that the most accurate indication of actual power following the runbacks was N-16 detectors and that they intended to emphasize this new operating philosophy. The inspectors noted that the Conduct of Operations procedure had previously emphasized that operators use all available indications. The licensee stated that they now recognize the magnitude of the effect that temperature changes had on indicated power and were in the process of revising training lesson plans. The licensee also stated that they were considering moving the N-16 indicators to a more useful location and were considering design modifications to the secondary system to improve reliability.

The inspectors questioned the licensee on actions that had been taken to date to ensure that, if another loss of feedwater heater transient were to occur, the reactor would not again unknowingly be operated greater than the licensed thermal power limit. Licensee management stated that they had not yet implemented any corrective actions. The inspectors concluded that the licensee could not demonstrate with any certainty that if a similar transient were to occur with another crew, the same mistakes would not be made and that core would be operated at less than the licensed thermal power limit. The inspectors acknowledged that the licensee was taking appropriate long-term corrective actions. The following week, the licensee issued a memorandum to all operations personnel discussing the event, the causes and effects, and issued management guidance to operators concerning the use of N-16 detectors.

8.1.7 Communications

The inspectors had previously concluded in NRC Inspection Report 50-445/96-01; 50-446/96-01 that a significant communications breakdown between departments had occurred. After further review of communications which occurred during and immediately following the event, the inspectors concluded that, while weaknesses had been noted, these weaknesses did not significantly affect the licensee's performance.

8.1.8 Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

The licensee identified that the analysis in Chapter 15 of the Comanche Peak Steam Electric Station Final Safety Analysis Report did not bound the transient. The inspectors noted that Section 15.1.1 analyzed feedwater system malfunctions that would result in a decrease in feedwater temperature. The analysis assumed that the low pressure heater bypass valve opened and that the heater drain pumps tripped and thus reduced feedwater temperature. The results of the analysis stated that the calculated reduction in feedwater temperature would be less than 35°F and would result in an increase in heat load on the primary system of less than 10 percent of full power.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

Bhatty, O., Regulatory Affairs
Beerck, C. L., Senior Maintenance Analyst
Bird, R. D., Jr., Nuclear Planning Manager
Blevins, M. R., Plant Manager
Calder, R. D., Engineering Analysis Manager
Clouser, T. P., Shift Operations
Curtis, J. R., Radiation Protection Manager
Davis, D. L., Nuclear Overview Manager
DePierro, D. J., System Engineering
Flores, R., Shift Operations Manager
Hope, T. A., Regulatory Compliance Manager
Killgore, M. R., Nuclear Engineering
Kelley, J. J., Vice President, Nuclear Engineering and Support
Kross, D. C., Operations Support Manager
Lancaster, B. T., Plant Support Manager
Lucas, M. L., Maintenance Manager
Moore, D. R., Operations Manager
Pope, L. G., System Engineering
Prince, R. J., Mechanical Maintenance Manager
Rickgauer, C. W., Maintenance Overview Manager
Snow, D. W., Senior Regulatory Compliance Speciali t
Sunseri, M. W., Training Manager
Terry, C. L., Group Vice President, Nuclear Prod ction
Walker, J., Nuclear Overview Department
Walling, D. L., Station Engineering

The personnel listed above attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

1.2 NRC Personnel

A. T. Gody, Jr., Senior Resident Inspector
H. A. Freeman, Resident Inspector
V. L. Ordaz-Purkey, Resident Inspector
L. C. Austin, Office Resident Assistant

2 EXIT MEETING

An exit meeting was conducted on April 4, 1996 During this meeting, the inspectors reviewed the scope and findings of the report. The licensee provided clarifying information that supported the inspector's conclusions during the exit. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.