ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/96-02

License: NPF-87

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

Facility Name: Comanche Peak Steam Electric Station, Unit 1

Inspection At: Glen Rose, Texas

Inspection Conducted: January 17-30, 1996

Inspectors: A. T. Gody, Jr., Senior Resident Inspector
V. Ordaz-Purkey, Resident Inspector
D. N. Graves, Project Engineer

Approved: WD Johnson 3/4/96
William D. Johnson, Chief, Projects Branch B Date

Inspection Summary

Areas Inspected (Unit 1): Nonroutine, announced inspection in response to a Unit 1 safety injection and reactor trip following a failure of safety related Inverter IV1PC2 and a Unit 1 reactor trip following a loss of safety related Inverter IV1EC1.

Areas Inspected (Unit 2): No inspection of Unit 2 was performed.

Results:

Operations

- Inadequate alarm response and abnormal operating procedures related to inverters and protection instrument buses contributed to both the January 17 safety injection and reactor trip, and the January 22 reactor trip (Sections 4.4.1 and 4.4.2).

- Good command, control, and formality was noted by the inspectors during implementation of emergency and abnormal operating procedures (Section 2).

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- Several equipment failures were identified following the reactor trips. These failures did not adversely affect operator response to the transients (Sections 2.1 and 2.2).

Maintenance

- Maintenance personnel involved in the inverter diagnostic effort took appropriate personal and equipment safety precautions (Section 4.3).
- Maintenance personnel demonstrated a good questioning attitude prior to replacing the blown fuse on Inverter IV1EC1 (Section 4.2.1).
- Troubleshooting and postmaintenance testing on a feedwater isolation valve following the January 17 trip were not effective in identifying the problem in a hydraulic solenoid valve (Section 7.4).

Engineering

- Verification of the postulated sequence of events leading to the safety injection event of January 17 was comprehensive and thorough (Section 3).
- A team of engineering and maintenance personnel developed a comprehensive diagnostic plan to evaluate the as-found inverter conditions and correct any deficiencies following the January 22 event (Section 4.3).
- Inverter troubleshooting plans were detailed and well written following the January 22 event (Section 4).
- The Unit 1 10 kVA inverters required more corrective maintenance than the similar inverters in Unit 2, and the 10 kVA inverters of both units required more corrective maintenance than the 7.5 kVA inverters of either unit. The inspectors also noted that the failure rate of the Unit 1 10 kVA inverters appeared to increase since 1993 (Section 5).

Summary of Inspection Findings.

- Inspection Followup Item (IFI) 445/9602-01 was opened (Section 4.3).
- Violation 445/9602-02 was opened (Sections 4.4.1 and 4.4.2).
- IFI 445/9602-03 was opened (Section 5.4).
- IFI 445/9602-04 was opened (Section 7.4).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 EXECUTIVE SUMMARY

The inspectors reviewed the circumstances surrounding a Unit 1 safety injection and reactor trip that occurred on January 17, and a reactor trip that occurred on Unit 1 on January 22. Safety-related inverter failures contributed to initiation of the events either directly or by subsequent operator actions. The two inverter failures followed several previous failures within the past year which indicated a poor level of safety-related inverter reliability. The events of January 17 and 22 provide further evidence of an increasing equipment reliability concern at CPSES. A number of other plant trips and transients have been either initiated or complicated by equipment failures in the past four months.

1.1 January 17 Trip and Safety Injection

The January 17 event was caused by the loss of safety-related protection Inverter IV1PC2 and subsequent restoration of protection Bus 1PC2. Although no definitive cause for the inverter failure could be determined, the licensee indicated that the most probable cause of the inverter output breaker trip was due to an external ground in the 118 Vac distribution system of Inverter 1V1PC2 that could not be subsequently located.

The licensee postulated and subsequently provided positive evidence of the cause of the safety injection signal that was generated when Bus 1PC2 was restored. The investigation revealed that when Bus 1PC2 was deenergized, the main turbine first stage pressure transmitter, 1-PT-506, deenergized. The loss of Transmitter 1-PT-506 generated a C-7 steam dump arming signal. As Bus 1PC2 was reenergized from its alternate supply, reactor coolant Loop 2 average temperature (Tave) spiked high from the Nitrogen-16 (N16) hot leg circuitry and resulted in a spike in the input to the steam dump circuitry through an auctioneered high Tave circuit. With the steam dumps armed, and a momentary large difference between auctioneered high Tave and the reference temperature, all of the steam dumps to the main condenser quickly opened. The opening of the steam dumps caused a rapid increase in steam flow and corresponding rapid decrease in main steam line pressure, which initiated a safety injection actuation from a rate compensated low main steam line pressure signal.

The licensee also found that operating procedures for Inverter IV1PC2 did not provide sufficient guidance to operators on what would occur when its bus was reenergized. This lack of procedure guidance directly contributed to the safety injection and subsequent reactor trip and was one example of an inadequate procedure (Section 4.4.2).

1.2 January 22 Trip

The January 22 trip was initiated when a blown fuse was replaced in safety related instrument Inverter IV1EC1. The fuse replacement resulted in a loss of 118 Vac instrument Bus 1EC1 which caused the closure of all four feedwater isolation valves. Plant operators initiated a manual reactor trip in response to the loss of main feedwater flow.

Following the failure of Inverter IV1EC1, the licensee developed a comprehensive diagnostic plan to verify that all Unit 1 inverters were operating properly. Since the inverter outage was planned to last approximately 1 week, and technical specifications allow an instrument bus to be on its alternate power supply for only 24 hours without commencing a plant shutdown, the licensee placed Unit 1 in Mode 5 in accordance with technical specification requirements.

Although several component failures were identified and repaired in Inverter IV1EC1, the licensee could not determine the actual cause of the inverter failure. The licensee implemented several procedure changes as a result of the fuse replacement evolution which caused the trip. The procedure changes ensured that the inverters and other plant systems were placed in a more reliable condition prior to troubleshooting and provided more guidance to operators on what equipment actuations would occur when an inverter was lost. These procedure inadequacies contributed to the trip and were considered to be an additional example of an inadequate procedure (Section 4.4.1).

1.3 Inverter Outage

In response to the January 22 trip and the noted increase in inverter failures, licensee management decided to cool down Unit 1 to Mode 5, and implement a comprehensive diagnostic plan for inverters. The inspectors considered licensee management's decision to place the unit in Mode 5 and conduct the inverter diagnostic outage to be appropriate.

The inspectors found the licensee's diagnostic plans and generic work orders to be comprehensive.

2 EVENT DESCRIPTIONS

2.1 Unit 1 Reactor Trip and Safety Injection

At approximately 8:02 a.m. on January 17, Unit 1 was at 100 percent power when a control room alarm annunciated a loss of power to 118 Vac Bus 1PC2, simultaneous with a loss of letdown flow. Operators entered Abnormal Procedure ABN-603, "Loss of Protection or Instrument Bus," to restore power to Bus 1PC2. An auxiliary operator was dispatched and discovered an acrid odor in the vicinity of Inverter IV1PC2. The operator was instructed by the control room to reenergize the affected reactor protection bus by moving the manual transfer switch to the alternate power supply at the bottom of the protection panel in accordance with Procedure ABN-603. When this occurred, at approximately 8:08 a.m., a safety injection signal was generated due to a main steam line low pressure signal. The Unit 1 reactor tripped as a result of the safety injection actuation and all main steam isolation valves closed as expected. All control rods fully inserted into the core. Auxiliary feedwater started and injected to the steam generators. The emergency core cooling systems started per design and injected into the reactor coolant system. The safety injection was terminated at approximately 8:23 a.m., in accordance with Emergency Procedure EOS-1.1A, "Safety Injection Termination." Decay heat removal was accomplished utilizing the steam generator atmospheric relief valves. The unit was stabilized in Mode 3 while the licensee investigated the cause of the safety injection signal.

During the event, pressurizer level reached a maximum of 83 percent before normal charging and letdown was established in accordance with Procedure EOS-1.1A. Pressurizer level was high, as expected, because letdown flow was terminated when Bus 1PC2 was lost. The available plant data was limited due to a failure of the Unit 1 plant computer just prior to the safety injection.

A review of the available plant data showed that the limits in Technical Specification 3.4.8.2 for pressurizer heat up and cool down were not exceeded during the event.

The licensee conservatively performed an evaluation to determine the effects of the temperature transient on the structural integrity of the pressurizer and concluded that the pressurizer cooldown was bounded by the pressurizer design basis.

Several equipment failures or anomalies were identified during the safety injection and subsequent reactor trip, which included failures of Channel II circuit cards for N-16, main steam line pressure Channel 535, steam generator wide range level Channel 553, and pressurizer level Channel 460. The instrument failures were caused by the failure and subsequent reenergization of Bus 1PC2 (Section 6.1). The main turbine tripped, but the high pressure turbine stop valves indicated in an intermediate position longer than expected following the automatic main turbine trip signal initiation. As a precaution to ensure the turbine was tripped, operators manually tripped the turbine from the control room. Also, an operator noted that feedwater isolation Valve 1-HV-2135 indicated in its intermediate position until the reactor operator took manual control to close the valve (Section 7). The inspector noted that operator response was not adversely affected by the equipment failures.

2.2 Unit 1 Reactor Trip

At approximately 4:20 a.m., on January 22, Unit 1 was at 100 percent power when the control room received a Safety System Inoperable Indication alarm for 118 Vac on Train A. An auxiliary operator was dispatched and found that all mimic lights were out on Elgar Inverter IV1EC1. The prompt team, a quick-response team of engineers and maintenance personnel, was contacted to investigate. The team discovered that the inverter had failed and its loads had been automatically transferred to the alternate power supply through the static switch, and that Fuse F101 was blown on the DC to DC converter card. Operations declared Inverter IV1EC1 inoperable and entered Technical Specification 3.8.3.1 due to the abnormal condition, which placed the unit in a 24-hour action statement from the time the 118 Vac alarm was received at 4:20 a.m.

Discussions were held between operations, maintenance, and engineering on how to restore the inverter and the possible cause of the failure (Section 4.2.1). The licensee decided to replace Fuse F101. Plant operators and prompt team members questioned whether Inverter IV1EC1 should be placed in manual bypass before the new fuse was installed. Engineering concluded that replacing the fuse at power would have no effect on the plant. Operations concurred and instructed maintenance to replace the blown fuse. Upon attempting to replace the fuse, the static switch transferred back to the failed inverter and power to Panel 1EC1 was lost which sent a close signal to all four feedwater isolation valves. The control room operators observed the loss of feedwater flow to all four steam generators. At approximately 8:06 a.m., the unit supervisor directed the operators to manually trip the reactor as a result of the loss of feedwater flow and decreasing steam generator levels. Auxiliary feedwater actuated as expected on low steam generator level. Decay heat was removed through the atmospheric steam dump valves. The unit was stabilized in Mode 3 while the licensee investigated the cause of the inverter failure. Since there was no indicated output from Inverter IV1EC1, the control room directed an auxiliary operator to manually place the inverter in bypass. At 8:16 a.m., bypass power was utilized to restore power to Panel 1EC1.

Several equipment problems were identified as a result of the trip. Feedwater isolation Valve 1-HV-2135, to Steam Generator 1-02, did not close until 38 seconds after the low voltage alarm was received on the plant computer. This was evidenced by the higher level in Steam Generator 1-02 when the remaining steam generators were isolated by their respective feedwater isolation valves (Section 7). In addition, power range Channel N-42 failed to generate a negative rate trip.

The apparent cause of the feedwater isolation valve closure was attributed to the troubleshooting and subsequent loss of Inverter IV1EC1. The licensee established a task team to investigate the event and to evaluate the equipment failures.

2.3 Conduct of Operations

The inspectors responded to the control room following both of the Unit 1 events, and verified that all critical safety equipment responded as expected, and that the plant was maintained in a safe condition. The inspectors verified that operators entered and followed the applicable emergency operating procedures and abnormal operating procedures. Critical safety function status trees were monitored by the operators on a continual basis. The inspectors noted that a sufficient number of operators were present to respond to the events. Communication between the unit supervisor and the operators was clear and repeat-backs were utilized. The shift manager was present and maintained oversight of the unit. The inspector specifically noted that during both events, the unit supervisors stopped during the recovery of the plant and regrouped with the operators to review what was accomplished and what failures existed to ensure that the event was being treated properly and in an orderly fashion.

The inspectors also noted that system engineers walked down their systems to identify any problems. The inspectors concluded that operator responses to both events were very good. The operators implemented the emergency, abnormal, and operating procedures appropriately and with the proper formality. Operators stabilized the plant in a well organized manner and maintained the plant in a safe condition.

3 LICENSEE ROOT CAUSE EVALUATION OF STEAM PRESSURE TRANSIENT

3.1 Steam Pressure Transient Scenario Description

The safety injection that occurred on January 17 was initiated on a rate compensated low main steam line pressure. Observations by the operators at the time of initiation indicated that no low pressure condition existed in the main steam system, and the cause of the actuation signal was unknown. The loss of the plant computer several minutes prior to the safety injection actuation resulted in a limited amount of data available for prompt event analysis and reconstruction. Information was limited to personal observations, the sequence of event recorder, and chart recorders in the control room.

Subsequent analysis of the available data by the licensee concluded that the event that actually occurred was a rapid opening of all 12 steam dump valves in response to a steam dump actuation signal generated by the loss of and subsequent reenergizing of 118 Vac instrument Bus 1PC2. This sudden increase in steam flow caused a rapid reduction in main steam line pressure and resulted in a valid safety injection signal being generated.

The steam dump system was being operated in the Tave mode which would allow the steam dumps to modulate open to maintain reactor coolant system Tave near a reference temperature (Tref) which is generated from main turbine first stage pressure Transmitter PT-505. As actual Tave increases above Tref, the steam dumps would modulate open to maintain actual Tave near the Tref value. In the Tave mode, two controllers are available for control of the steam dump system, a load rejection controller and a plant trip controller. With no reactor trip present, the load rejection controller is the functioning controller. A second main turbine first stage pressure transmitter, PT-506, provides an input to a steam dump interlock, C-7. The C-7 interlock provides an arming signal to the steam dumps for quick actuation if a rapid reduction in main turbine load is sensed via turbine first stage pressure. This interlock would be actuated if a 10 percent step change in turbine load occurs, or load decreases 10 percent over a two-minute period. C-7 is also a seal-in interlock. Once it is actuated/armed, it must be manually reset by the operators. If C-7 is armed, the main condenser is available, and Tave exceeds Tref by approximately 14°F, two bistables will be actuated in the load rejection controller which would cause all 12 steam dump valves to open to the main condenser and reduce Tave to the Tref value. The steam dump system utilized at CPSES was typical of steam dump control systems utilized at other Westinghouse reactors.

The plant was initially at 100 percent power. The loss of Bus 1PC2 deenergized main turbine first stage pressure Transmitter PT-506. The loss of power to this transmitter caused its output to go to minimum, which the steam dump system sensed as a large reduction in main turbine load. C-7 was activated, and with the main condenser available, the steam dumps were armed, although not actuated.

The Tave signal is generated at CPSES by utilizing inputs from the cold leg temperature detectors and the corresponding N16 detectors. This Tave signal is generated for each of four reactor coolant system loops and provided to an auctioneering circuit which passes the highest of the available signals. The auctioneered high Tave signal is provided to the steam dump system and is compared to Tref which is generated by turbine first stage pressure Transmitter PT-505. Following the loss of Bus 1PC2, the N16 input from Channel II was deenergized, providing a minimum Tave signal. This had no effect on the steam dump system because of the auctioneering circuit. Had this been the highest Tave prior to the loss of Bus 1PC2, another channel Tave signal would have been processed through the auctioneering circuit, and no system actuation would have occurred. With Bus 1PC2 deenergized, several instruments had lost power to them, and the steam dumps had not actuated, although they were now armed.

At approximately 8:08 a.m., Bus 1PC2 was reenergized from its alternate power supply. When the bus was reenergized, the Channel II N16 instrument spiked high. This high spike was processed through the Tave instrument as a high Tave signal (630°F, the high end of the indicating range) and was provided to the steam dump system via the auctioneering circuit. This erroneous high Tave indication was compared to the Tref, which was unchanged. A large difference was generated between the indicated, auctioneered-high Tave and Tref (approximately 588°F), well in excess of the 14 degrees required to actuate the load rejection controller bistables. When the bistables tripped with the C-7 interlock armed, the steam dumps received a full open signal. When the steam dumps opened, steam flow increased rapidly, steam line pressure decreased rapidly, and a low steam line pressure safety injection signal was generated. The plant responded accordingly.

3.2 <u>Verification of Postulated Scenario</u>

3.2.1 Recreation of Loss and Restoration of Bus 1PC2

On January 19, the inspectors observed the licensee recreate the Bus 1PC2 reenergization scenario in accordance with Work Order 4-96-096691-00 to determine whether the postulated scenario described above was valid. Temporary recorders were installed in the N16 upgrade protection cabinet to collect data at several points, which included Tave on all four reactor coolant loops and auctioneered high Tave. The licensee implemented the revised Procedure ABN-603, "Loss of Protection or Instrument Bus," which defeated average temperature input to the steam dump system when Bus 1PC2 was restored to ensure an actual safety injection signal was not generated. The licensee retrieved data from the plant computer on the reactor coolant Loop 2 Tave output which indicated a significant spike. The licensee concluded that when Bus 1PC2 was reenergized from its alternate supply, reactor coolant Loop 2 Tave spiked high, and provided a false high Tave input to the steam dump circuitry through the auctioneered high Tave circuit.

The inspector noted that the verification sheet for installing and removing devices was maintained properly during the test. Questioning attitudes and good self-verification were utilized by instrumentation and controls technicians. The inspectors agreed with the licensee's conclusion and found the troubleshooting efforts to be appropriate.

3.2.2 Recreation of Steam Pressure Transient on Simulator

The licensee attempted to recreate the event utilizing the plant-specific simulator. Upon a loss of Bus 1PC2, the C-7 interlock did not activate to arm the steam dumps. A review of the simulator model by the licensee determined that the simulator did not provide power to Transmitter PT-506 from Bus 1PC2, and hence did not model the plant accurately. Also, upon reenergizing Bus 1PC2, a steam dump actuation did not occur. The N16 channel powered from Bus 1PC2 did not spike high when reenergized. The simulator had the capability to model instrument spikes, but this capability was not incorporated as part of the normal instrument response upon reenergizing. Once the steam dumps were actuated from full power, a safety injection still did not occur. This response was attributed to the fact that steam dump capacity in the simulator was based on 40 percent full steam flow at 1100 psig. The actual event occurred at an initial steam pressure of approximately 960 psig. Discussions with operations personnel and system engineering indicated that experience had shown that the steam dumps in the plant were actually capable of passing considerably more than 40 percent steam flow. This accounted for actual plant response differing from that modeled in the simulator. The inspectors' review of steam dump capacity is discussed in Section 3.3. Steam dump capacity was increased in the simulator, and a main steam line low pressure safety injection signal was generated at a steam dump capacity of approximately 42 percent.

Following the identification of the simulator modeling discrepancies, actions were initiated to correct the power supply for Transmitter PT-506, to revise the steam flow model for the steam dumps, and to create malfunctions to more accurately reflect instrument responses when reenergizing instrument buses. The inspectors concluded that the proposed revisions to the simulator modeling were appropriate.

3.2.3 Computer Model and Analysis of Event

The event was also evaluated by TU Electric Reactor Engineering utilizing a thermohydraulic model of CPSES developed for use with the RETRAN-02 computer code. According to the licensee, this model is the basis for TU Electric's approved core reload licensing methodology and had been benchmarked against several plant transients from the Unit 1 initial startup testing and first cycle of operation. During this evaluation, steam dump capacity was approximately 40 percent of nominal steam flow. Using this model, the C-7 arming signal was received, and Tave was stepped to 630 degrees instantaneously. The steam dump valves were forced open per the control circuitry, but the low steam line pressure safety injection signal was not generated. Subsequently, steam dump capacity was increased to approximately 44 percent (still below actual capacity per the licensee) and the transient was again initiated. In this instance, a low main steam line safety injection signal was generated within 5 seconds of reenergizing Bus 1PC2. This further substantiated the licensee's assertion that this scenario was the most likely sequence of events that occurred.

3.3 Steam Dump Modification Review

As a result of the inconsistencies between steam dump system capacity in the RETRAN-02 computer model, the plant-specific simulator model, and the actual in-plant installation, the inspectors reviewed the steam dump capacity documentation.

The original steam dump valves purchased by CPSES for both units, Fisher Controls Model 8X6-EWJ, were no longer available when replacement parts were needed during Unit 2 construction. According to the licensee, the valve vendor, Fisher Controls, recommended converting the body style to an EWD design which supposedly had the same flow characteristics as the original EWJ model. A design change was developed to allow changing the valve internals with parts believed to have the same flow characteristics as the original valve internals. Design Change Authorization 10285210 documented this design change. A similar change was incorporated into Unit 1 via Design Change Notice 5801. Over the next several years, the internals had been replaced in all steam dump valves with the new replacement parts.

Operations Notification and Evaluation (ONE) Form 95-114, issued on February 1, 1995, identified that a number of steam dump valves did not meet acceptable stroke time criteria. During the disposition of this ONE form, the licensee identified that the flow through the steam dump valves was approximately 824,500 lbm/hr at 90 percent capacity, which was significantly greater than the required 530,000 lbm/hr needed to provide adequate steam dump system cooldown capability.

ONE Form 95-489, initiated April 26, 1995, was written to address the steam dump steam flow discrepancy. The disposition of this ONE form concluded that although the steam flow was not per the original design, it was acceptable. The increased flow, per valve, was greater than the steam flow assumed for a steam generator safety valve or atmospheric relief valve. This excess capacity of the steam dump valves meant that final safety analysis report Section 15.1.4.2, "Inadvertent Opening of a Steam Generator Relief or Safety Valve," no longer bounded the open failure of a single steam dump valve. Nevertheless, the event was still bounded by the main steam line break scenario discussed in Section 15.1.5.

Safety Evaluation 95-024, dated June 16, 1995, was written to provide the justification for revising the final safety analysis report to reflect the updated steam dump flow information and concluded that the existing condition was satisfactory. Informal calculations of steam dump flow at that time indicated that flow through the valves could be as high as approximately 308 lbm/sec (1.109 X 10E6 lbm/hr). The licensee concluded that the flow characteristics were, in fact, different from the originally installed valve internals and resulted in higher steam flows. A revision to the Final Safety Analysis Report was initiated via Licensing Document Change Request SA 95054, dated May 5, 1995, to correct the Final Safety Analysis Report regarding a failed-open steam dump valve and referenced both of the above ONE forms. Calculations supporting the Final Safety Analysis Report change were formalized and approved (ME-CA-0202-4061 dated January 19, 1996).

The inspectors agreed with the licensee's conclusion that the increased steam dump capacity was bounded by the licensee's main steamline break analysis. The lack of accurate modeling in the simulator provided negative training in that actual plant response was somewhat different from that represented in the simulator which could have led the operators to expect a plant response that was different from the one that actually occurred. The design changes which replaced the steam dump valve internals were initially incorrect in assuming, apparently based on discussions with the vendor, that the flow characteristics remained the same with the new internals. Those initial assumptions have been corrected and documented in the above mentioned documents.

3.4 Conclusion

The inspectors reviewed the licensee's activities associated with determining the cause of the event and found the conclusions to be well presented and substantiated.

The licensee's "Post RPS and ESF Actuation Evaluation," performed per Procedure ODA-108, was reviewed and found to be thorough and comprehensive. The recommended follow up actions identified by the licensee were appropriate.

The inspectors noted that several different methods were utilized to determine the most likely cause of the event. Licensee personnel review of the available data determined that at the time of the event, a sudden increase in steam flow occurred at approximately the same time as a large positive spike on Tave. This was consistent with the proposed cause of the event.

The inspectors concluded that this scenario would not occur on other United States Westinghouse four loop pressurized water reactors because CPSES is the only plant where hot leg temperature is generated from N16 measurement, and since the Tave spike was generated in the N16 circuitry.

4 OPERATION OF AND MAINTENANCE ON SAFETY RELATED INVERTERS

4.1 Safety-Related 118 Vac Inverter IV1PC2

4.1.1 Troubleshooting Efforts

The licensee performed troubleshooting to determine the cause of the event on January 17, in which the output breaker of Inverter IV1PC2 tripped. The licensee initially found Inverter IV1PC2 with a low output voltage and initiated measures to remove and replace the ferroresonant transformer. The transformer was tested and found to be good. Technicians tested the overcurrent relay, which was determined to be good. Electrical maintenance verified proper cable insulation resistance between Panel 1PC2 and Inverter IV1PC2. The inverter was energized in order to perform a load test. The output frequency, which should have been 60 Hz, was measured at 89 Hz. The output voltmeter, which should have read approximately 118 Vac, pegged high with the output circuit breaker open. The licensee found that the printed circuit card for gating the silicone controlled rectifiers (SCR) had failed. When the licensee energized a replacement card, the output frequency was 59.95 Hz. The frequency was adjusted to 59.99 Hz, and the output voltage was approximately 120 Vac. The inverter was loaded for 15 minutes, and the frequency was adjusted to 60 Hz.

The licensee held discussions with Westinghouse, who recommended that the inverter be load tested for at least a 30 minutes to verify that the autotransformer that fed the ferroresonant transformer was good. The licensee's test revealed that the inverter operated satisfactorily during the load test.

Further troubleshooting included testing the load currents from each individual circuit. Design engineering verified that the actual load currents were consistent with the design load currents. At approximately 10:15 a.m. on January 17, the inverter was returned to service, and operations performed Procedure OPT-215, "Class 1E Electrical Systems Operability," satisfactorily, and declared the inverter operable.

The licensee concluded that a short circuit on the output of the inverter was the initiating event of the Inverter IV1PC2 output breaker trip, but the inspectors noted that no conclusive evidence was found. Westinghouse concurred with the licensee's hypothesis and recommended that the individual instrument power supply cards powered from Panel 1PC2, the current transformer that feeds the overcurrent relay, and the output breaker be tested.

The inspector witnessed portions of the current transformer testing and the output breaker testing in accordance with Work Order 4-96-096642-00. The output breaker was removed and tested per the applicable steps in Procedure MSE-SO-6303, "Molded Case Circuit Breaker Test and Inspection." The test results revealed that the breaker failed the instantaneous overcurrent trip test. The as-found overcurrent trip setpoint value was higher than the acceptable value on all three phases. The licensee indicated that a failure analysis would be performed on the breaker.

The inspector noted that the verification sheet was properly maintained for disconnected and reconnected leads. The inspector concluded that electricians performed the tests in accordance with procedure with appropriate precautions taken. In addition, the new output breaker was tested satisfactorily and installed. Overall, the inspector concluded that the troubleshooting performed on Inverter IV1PC2 appeared to be adequate.

4.1.2 Short Term Corrective Actions

As a result of the safety injection and reactor trip on January 17, the licensee initiated Temporary Modification 1-96-001 to monitor all of the load currents at distribution Panel 1PC2. The purpose of the temporary modification was to provide additional information to identify possible faults such as equipment load deviations and voltage transients in the event of another transient. The licensee installed the temporary modification prior to restart on January 21. The inspectors witnessed the installation of the temporary modification, which included the connection of 13 current transformers and test leads to each of the distribution panel breakers. The installation of the monitoring equipment had no impact on the equipment operation in distribution Panel 1PC2. The area that surrounded Panel 1PC2 and test equipment was marked with the appropriate barrier material. The inspectors noted that engineering and maintenance personnel appeared less than knowledgeable on the operation of the test equipment, and were not given the proper technical manuals to reference. Also, the cognizant system engineer was not present during the installation and was not contacted when questions arose. Nevertheless, the inspectors noted that the equipment was eventually set up properly with the only impact being a delay in the Unit 1 startup. The inspectors concluded that the corrective action to initiate and implement a temporary modification for troubleshooting possible faults was appropriate.

4.2 Safety Related 118 Vac Inverter IV1EC1

4.2.1 At Power Troubleshooting of Inverter IV1EC1

The inspector reviewed the licensee's troubleshooting performed on January 22, when Inverter IV1EC1 reverse transferred to its bypass power. An auxiliary operator found that the mimic lights on the front of the panel were out. The Prompt Team responded to the inverter and discovered that fuse F101 on the DC to DC converter card was blown. Discussions were held between maintenance and operations, and between operations and engineering. The Prompt Team questioned whether the inverter should be placed in manual bypass. However, engineering informed operations that replacing the fuse at power would have no effect on the plant. Operations concurred and instructed maintenance to replace the blown fuse in Inverter IV1EC1. As maintenance workers installed the new fuse in the inverter, a loss of feedwater flow to all four steam generators occurred when antiwaterhammer permissive interlock relays deenergized causing the closure of all four main feedwater isolation valves.

The inspector concluded that the troubleshooting efforts prior to pulling the fuse were adequate. The Prompt Team displayed a questioning attitude and although the correct questions appear to have been asked, the decision to attempt to replace the fuse with the inverter in the configuration it was in at the time was nonconservative.

4.3 Licensee Management Decision to Cool Down Unit 1 for Inverter Outage

In response to the January 22 trip and the increase in inverter failures, licensee management decided to cool down Unit 1 to Mode 5 and implement a comprehensive diagnostic plan for inverters. The inspectors noted that licensee management's decision to enter an inverter outage was appropriate.

The inspectors reviewed the licensee's diagnostic plans and generic work orders and found them to be comprehensive. During the implementation of inverter diagnostic work orders, the inspectors observed appropriate personnel and equipment safety practices. Meters and test equipment were verified to be calibrated and used properly.

The inspectors will review the conclusions of the licensee's diagnostic effort in a future inspection and will track this review as an inspection followup item (IFI 445/9602-01).

4.4 Operating Procedures for Safety Related Inverters

4.4.1 Alarm Response Procedures

The inspectors reviewed the operations and maintenance control of Inverter IV1EC1 troubleshooting and subsequent replacement of Fuse F101. When the Unit 1, Train A Safety System Inoperable Indication alarm was received in the control room, operators implemented alarm Procedure ALM-1901A, "Alarm Procedure SSII Train A." This procedure directed operators to determine the cause of the safety system inoperable indication alarm. Operators found that the cause of the safety system inoperable indication alarm was Inverter IV1EC switching to its bypass (unregulated) power source. The inspectors reviewed Procedure ALM-1901A and found that it was appropriate for use in determining the cause of the 118 Vac Safety System Inoperable Indication alarm.

Once plant operators found that Inverter IV1EC1 had switched to its bypass source of power, they appropriately recognized that they should have received an Inverter IV1EC1 trouble alarm in the control room. Operators appropriately implemented the Inverter IV1EC1 portions of Alarm Response Procedure ALM-0102A, "Alarm Procedure 1-ALB-10B," Revision 7. This procedure directed operators to determine the affected failure alarm using the alarm light indications on the front of the inverter. However, operations found no lights energized on Inverter IV1EC1. Although no procedural guidance was provided, they felt that the inverter was stable, and no immediate actions were taken to place the inverter in a more reliable condition.

The inspectors reviewed Procedure ALM-0102A, Revision 7, and noted that the apparent intended purpose of the procedure was to place the plant and the inverter in the safest and most stable condition possible given the as-found inverter conditions. The inspectors noted that Procedure ALM-0102A did not direct operators to place the inverter in a condition which would preclude its loss during troubleshooting. The inspectors concluded that Procedure ALM-0102A did not provide adequate guidance to operators to preclude a plant transient when Fuse F101 was replaced, and that this procedural inadequacy was violation of Technical Specification 6.8.1 (Violation 445/9602-02).

The inspectors assessed the licensee's review of Procedure ALM-0102A, which identified a number of procedure deficiencies. The licensee found that the procedure did not: (1) specifically indicate that when distribution Panel 1EC1 was deenergized, the Train A station blackout sequencer was inoperable and that the Train A emergency diesel generator would not start upon a loss of offsite power, (2) provide instructions to operators on what to do if all of the indicating lights on the mimic section of the inverter panel were dark, (3) have operators verify that the DC supply breaker, 1ED1/2-13/BKR, was closed when determining if power was being supplied to the inverter, or (4) direct operators to place the manual transfer switch in the bypass position when a problem with a 10 kVA inverter was identified or if troubleshooting was planned.

The inspectors reviewed the changes to Procedure ALM-0102A implemented by the licensee on January 30. The inspectors verified that the changes to Procedure ALM-0102A addressed the identified deficiencies and found that the procedure was relatively straightforward, easy to understand, and accurate with one minor exception.

4.4.2 Abnormal Operating Procedure Deficiencies

The inspectors' review of Abnormal Operating Procedure ABN-603, "Loss of Protection or Instrument Bus," Revision 2, identified several inadequacies.

Section 2.2 of Procedure ABN-603, "Automatic Actions," lists possible improper operation of control systems following deenergizing of specific protection set buses.

Step 6 of Section 2.3 provides instructions on the reenergization of a protection bus if the reactor is still in Mode 1, which it was during the reenergizing of Bus 1PC2 on January 17. A "CAUTION" statement just prior to Step 6 notes that "reenergizing the affected protection bus may cause instrumentation spikes on controlling channels which may, in turn, initiate unwanted actions." Although a reference was made to a possible flux doubling signal, no mention was made of any other specific potential system actuations. Attachment 1 to Procedure ABN-603 provides a partial list of loads powered from the protection set cabinets. No reference to the attachment was made in the steps providing instructions for reenergizing the protection set buses.

The licensee also recognized this procedure inadequacy and initiated a Procedure Change Notice, ABN-603-R2-4, to include steps to defeat the selected Tave channel prior to reenergizing Bus 1PC2, and to verify the status of the C-7 interlock. Had these steps been in place and followed prior to the loss of Bus 1PC2, the steam dumps would not have actuated and the subsequent safety injection would not have occurred.

Section 3.1, "Symptoms," of a loss of instrument bus, refers the reader to Attachments 3 and 4 of Procedure ABN-603. Attachments 3 and 4 listed loads from instrument Buses 1EC1, 1EC2, 1EC5, and 1EC6. Buses 1EC3 and 1EC4 were not addressed.

Section 3.2, "Automatic Actions," addressed the automatic actions that occurred on a loss of an instrument bus. Instrument Bus 1EC1 was deenergized when Inverter IV1EC1 failed on January 22 during troubleshooting. Section 3.2 states that no automatic actions occur as a result of a loss of an instrument bus. On January 22, when Instrument Bus 1EC1 was lost, a loss of main feedwater occurred when all four feedwater isolation valves went closed.

The licensee concurrently identified these procedural deficiencies and was reviewing Procedure ABN-603, along with other procedures, to identify where additional procedure inadequacies existed and could be corrected as well as to identify any other procedural enhancements that may be appropriate.

The failure of Procedure ABN-603 to provide adequate guidance to ensure that the protection buses could be reenergized without challenging safety systems, and to provide sufficient information as to major plant safety system component (feedwater isolation valves) actuations upon loss of an instrument bus, was a second example of violation of plant technical specifications (Violation 445/9602-02).

4.5 Conclusions

The inspectors noted that maintenance troubleshooting of Inverter IV1PC2 was performed in accordance with CPSES procedures. Troubleshooting of Inverter IV1PC2 was thorough and comprehensive. The licensee's decision to monitor the inverter's loads was appropriate since the cause of the inverter overcurrent could not be determined.

The inspectors concluded that inverter operating procedures for Inverter IV1PC2 were inadequate by directing operators to reenergize Bus 1PC2 from its alternate source of power without preventing a steam pressure transient and subsequent safety injection and unit trip on January 17.

The inspectors concluded that inverter operating procedures did not place Inverter IV1EC1 in a stable condition prior to correcting an off-normal condition on January 22.

The inspectors noted that licensee management demonstrated a conservative operating philosophy when the decision was made to place Unit 1 in cold shutdown (Mode 5) to perform diagnostic testing of Unit 1 inverters. The inspectors found the diagnostic plan to be thorough and comprehensive. The inspectors concluded that the licensee's decision to replace failure susceptible components was appropriate.

5 SAFETY RELATED INVERTERS

5.1 Equipment Description

The CPSES instrument inverters supply regulated uninterruptible 118 Vac power to the safeguards and reactor protective system instrumentation. The CPSES Final Safety Analysis Report, Section 7.1.2.1.3, specified the design basis for the 118 Vac inverters. The inverters were designed to comply with the Institute of Electronic and Electrical Engineers Standard 308 - 1974, Section 5.4 and NRC Regulatory Guide 1.32.

5.1.1 Westinghouse 7.5 kVA Inverters

The 7.5 kVA protection bus inverters supplied by Westinghouse provided power to each of the four protection channels. The Train A Inverters IV1PC1 and IV1PC3 supplied power to reactor protection Channels I and III. The Train B Inverters IV1PC2 and IV1PC4 supplied power to reactor protection Channels II and IV, respectively.

The normal source of power to the 7.5 kVA inverters was from a safeguards battery bus. The licensee operated the 7.5 kVA inverters with the AC input breaker normally open because the AC power contained considerable variations which could cause undesirable effects on the instrumentation loads.

5.1.2 Elgar 10 kVA Inverters

The 10 kVA safeguards instrumentation bus inverters supplied by Elgar provided power to each of four instrument channels. The Train A Inverters IV1EC1 and IV1EC3 supplied power to instrumentation Channels I and III, respectively. The Train B Inverters IV1EC2 and IV1EC4 supplied power to instrumentation Channels II and IV, respectively.

The 10 kVA inverters consisted of four sections; a rectifier section, an inverter section, a static switch, and a manual bypass switch. AC input power is rectified, provided to the inverter section in which it is switched by a silicon controlled rectifier and then filtered. DC input power is auctioneered with the rectified AC input power such that if AC voltage decreases, the DC power will provide power to the inverter section. The filtered 118 Vac is routed through a solid state static switch which will automatically transfer, without interruption, power to and from an alternate bypass source if the inverter or bypass supplies do not meet specifications. The manual bypass switch, a make before break switch, provides the ability to manually select either the static switch or a bypass source of power to the instrument bus.

5.2 Equipment Material History

The inspectors performed a brief review of the safety related inverter operating history data to ascertain the effectiveness of licensee corrective actions and reliability of the equipment. The inspectors noted that the 10 kVA inverters received considerably more corrective maintenance than the 7.5 kVA inverters. The inspectors also noted that Unit 2 inverter reliability was better than the Unit 1 inverter reliability. The final broad observation was that the operating history of the Unit 1 10 kVA inverters since January 1993 appeared to indicate an increased failure rate.

5.3 Use of Industry Operating Experience

Industry operating experience and the licensee's incorporation of this experience was reviewed by the inspectors. The inspectors found that significant industry operating experience was applicable to the 10 kVA Elgar inverters. The inspector noted that substantial industry experience regarding the quality of Elgar inverter parts, relay failures, and electrolytic capacitor degradation had been evaluated by the licensee.

5.4 Conclusion

The inspectors planned to continue their review of the licensee's corrective actions associated with the individual inverter failures noted above, inverter operating history, and incorporation of industry operating experience in a future inspection report. This is an inspection followup item (IFI 445/9602-03).

6 OTHER CIRCUIT CARD FAILURES

6.1 7300 Process System Circuit Card Failures

On January 17, the power supply voltage for two Westinghouse cabinets, TBX-XIELRK-02 and TBX-XIELSS-50B, was lost when the Inverter IV1PC2 output breaker tripped open. These cabinets were the Upgrade Protection Cabinet Protection Set II and the Process Protection Cabinet Set II. The loss and subsequent restoration of Bus 1PC2 resulted in the failure of seven Westinghouse 7300 series cards in these cabinets, which included several Channel II cards for N-16, main steam line pressure Channel 535, steam generator wide range level Channel 553, and pressurizer level Channel 460. The licensee believed that a short duration voltage surge occurred which resulted in damaging the power supply bridge circuits and caused the card fuses to blow. All damaged circuit cards were replaced, recalibrated, and returned to service. The licensee indicated that it was not uncommon to see failures on the cards when switching to an alternate power supply. Future planned corrective actions by the licensee to ensure reliability of the cabinets include checking both of the primary and alternate power supplies for ripple. In addition, the licensee planned to explore industry experience on preventive measures such as installing a surge protector on the 1E bypass power to prevent voltage spikes. The inspector found the immediate corrective actions to be acceptable.

7 FEEDWATER ISOLATION VALVE FAILURE

7.1 Feedwater Isolation Valve Description

The feedwater isolation valves are 18-inch carbon steel gate valves manufactured by Borg-Warner Corporation. The valves are operated by pneumatic-hydraulic actuators. The valves isolate the feedwater lines to the steam generators by closing on a safety injection signal, a steam generator hi-hi level signal, a reactor trip coincident with a low Tave signal, and when antiwaterhammer permissive interlocks are not satisfied. The signals generated are transmitted to redundant electrical trains in parallel in the actuator.

Each train is composed of a hydraulic solenoid, a nitrogen solenoid, and three filters with a common piston and nitrogen supply. The isolation signals cause the solenoids on each train to energize. Solenoid actuation allows nitrogen pressure from a pneumatic reservoir to be applied to the actuator piston in the closed direction, and also provides a bleed path for the hydraulic fluid from the valve operator, causing the valves to close within five seconds. The surveillance tests performed on the feedwater isolation valves included Procedure OPT-511, "FW Section XI Isolation Valves," Procedure PPT-S1-9403A "Feedwater Isolation Valve Response Time Test for Train A," and Procedure PPT-S1-9404B, "Feedwater Isolation Valve Response Time Test for Train B." Procedure OPT-511 was a dual train test that was performed quarterly to satisfy Section XI requirements in accordance with Technical Specification 4.7.1.6. Procedures PPT-S1-9403A and PPT-S1-9404B were single train tests to satisfy the response time testing requirements of Technical Specification 4.3.2.2, Technical Requirements Manual Table 1.2.1. One train of each actuator is tested every other refueling outage in accordance with the PPT procedures. All of the tests contain acceptance and/or review criteria for each feedwater isolation valve to close within 5 seconds.

7.2 Posttrip Maintenance and Troubleshooting (January 17 Trip)

During the trip on January 17, a control room operator observed that feedwater isolation Valve 1-HV-2135 to Steam Generator 1-02 was in its intermediate position longer than expected. The operator took manual control and closed the valve. No other plant parameters were impacted as a result of the slow closure. The closure time could not be verified with plant data due to the malfunction of the plant computer.

Since the trip placed the unit in a forced outage, the licensee chose to replace the Train B nitrogen solenoid on Valve 2135, which was on the forced outage maintenance list due to a previously identified nitrogen leak. Upon completion of the maintenance, operations performed the dual train stroke time test in accordance with Procedure OPT-511 to provide assurance of proper valve closure time, and to satisfy postwork testing requirements. The test results revealed that the valve closed satisfactorily within 5 seconds. Operations concluded that the valve was operable since it met its required stroke time.

7.3 Posttrip Troubleshooting and Maintenance (January 22 Trip)

On January 22, at approximately 8:06 a.m., Valve 2135 again experienced a slow closure when the loss of Inverter IV1EC1 resulted in a loss of Train A water hammer interlocks. Control room indications revealed that Steam Generator 1-02 level was higher than the other loops during the event. A review of the plant computer data indicated that the closure time of Valve 2135 was approximately 38 seconds.

The inspector observed the licensee's troubleshooting activities in determining the cause of the failure. On January 22, the licensee performed Procedure PPT-S1-9403A in accordance with Work Order 4-95-095685-00. The purpose of the test was to measure the closure time of Valve 2135 upon receipt of a K612 slave relay signal from the solid state protection system. The inspector verified that all prerequisites were met and that all jumpers were installed properly to defeat the water hammer interlocks. An external switch was placed on the Train A solid state protection system relay. Performance and test engineers actuated the K612 slave relay which sent a signal to Valve 2135 to close. The inspector observed the valve close in approximately 20 seconds with the valve sticking three times during the closure stroke. The valve did not stick during the opening stroke. Discussions were held between the unit supervisor and system engineer, and a decision was made to stop work activities associated with Valve 2135 until a troubleshooting plan was established. Operations initiated ONE Form 96-58 to document the problems associated with the valve. The inspector verified that the valve was maintained in its closed position, which satisfied technical specification requirements.

The troubleshooting plan included a search of industry information on related feedwater isolation valve problems, a review of previous test results on Valve 2135, and a disassembly of the valve actuator to determine if anything abnormal was apparent.

On January 23, the inspector observed the licensee's implementation of the troubleshooting plan in accordance with Work Order 1-96-096776-00. Maintenance obtained an oil sample from the hydraulic reservoir, which was later determined to be acceptable. The reservoir was drained and inspected with a boroscope, and no film or debris was found. The hydraulic solenoids were removed, and all of the filters in the actuator were inspected. There was no debris or damage found on the filters. The licensee installed new hydraulic solenoids and filters.

Procedure OPT-511 was repeated on Valve 2135 successfully. The response time test, Procedure PPT-S1-9403A, was repeated on Train A with a closure time of 5.18 seconds, which was unsatisfactory. In parallel with the disassembly of

Valve 2135, Procedure OPT-511 was performed on the remaining feedwater isolation valves. The test results were within the acceptance criteria of 5 seconds.

During an inspection of the original hydraulic solenoids, the licensee discovered an elongated piece of metal, approximately 5/16-inches long and 1/8-inches wide, lodged within the Train A hydraulic solenoid port. No problems were found with the Train B solenoid. Five micron filters were located on both sides of the hydraulic solenoids. The piece of metal was too large to have passed through the filters, and the licensee concluded that the source of the metal was internal to the solenoid and possibly a manufacturing defect.

The inspector questioned the licensee on whether there could be a generic concern with the remaining solenoid valves on the feedwater isolation valves. The licensee stated that both tests had been performed satisfactorily on the remaining valves with no failed results. This provided assurance that all actuation paths and solenoids were functional. In addition, the vendor representative was on site, and indicated that he was not aware of any other instances of this type of failure.

7.4 Conclusions

The inspector attended a licensee management meeting following the January 17 trip where issues requiring resolution prior to startup were discussed. The inspector noted that none of the managers were aware of the slow closure of Valve 2135 until the inspector brought it to their attention. The inspector later found that the slow closure of Valve 2135 had been recognized by a member of management in operations, but had not communicated it to other departments or upper management prior to the meeting.

The inspector questioned the adequacy of the initial troubleshooting since the "as found" condition of Valve 2135 was interrupted due to the replacement of the nitrogen solenoid before any stroke time tests were performed. The licensee agreed that tests should have been performed prior to removal of the nitrogen solenoid. In addition, the inspector noted that the postwork test on the Train B nitrogen solenoid replacement utilized Procedure OPT-511 which energized both Train A and B solenoids in order to verify closure of the valve within the required time. The inspector concluded that Procedure OPT-511 did not adequately test the Train B portion of Valve 2135 because proper functioning of the Train A portion would have masked any deficiency in Train B. However, Procedure PPT-S1-9404B was satisfactorily performed on Train B of Valve 2135 following the second trip. The inspector concluded that the troubleshooting for the first slow closure of Valve 2135 was ineffective in that it did not identify the solenoid valve problem.

The inspector concluded that the troubleshooting efforts on Valve 2135, following the second trip, were thorough and effective in identifying one possible cause of slow valve closure.

The inspector planned to follow the licensee's troubleshooting and root cause determination of the slow closure of Valve 2135 as an inspection followup item (IFI 445/9602-04).

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

NAME	ORGANIZATION
Beerck, C. L.	Planning and Scheduling Support
Bhatty, O.	Regulatory Affairs
Blevins, M. R.	Plant Manager, Nuclear Operations
Buschbaum, D. E.	Regulatory Affairs
Curtis, J. R.	Radiation Protection Manager
Davis, D. L.	Nuclear Overview Manager
DePierro, D. J.	System Engineering
Flores, R.	System Engineering Manager
Goodwin, D.	Operations Support
Hill, J. L.	Nuclear Overview Department-Human Performance Evaluation System
Hope, T. A.	Regulatory Compliance Manager
Kelley, J. J.	Vice President, Engineering
Lancaster, B. T.	Plant Support
Lucas, M. L.	Maintenance Manager
Martin, J.	Nuclear Overview Department
McAfee, D. M.	Nuclear Overview Department
Muffett, J. W.	Station Engineering Manager
Rickgauer, C. W.	Maintenance Overview Manager
Terry, C. L.	Group Vice President, Nuclear Production
Reimer, D. J.	Design/Support Engineering
Snow, D. W.	Senior Regulatory Compliance Specialist
Walker, J.	Nuclear Overview Department
Walling, D. L.	Plant Modification Manager
Weary, C. S.	Planning

1.2 NRC Personnel

A. T. Gody, Jr., Senior Resident Inspector
D. N. Graves, Project Engineer
V. L. Ordaz-Purkey, Resident Inspector

2 EXIT MEETING

An exit meeting was conducted on January 26, 1996. During this meeting, the inspectors summarized the scope and findings of the inspection. The licensee acknowledged the findings presented at the exit meeting. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.