ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-498/96-12
50-499/96-12

Licenses: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company
P.O. Box 1700
Houston, Texas

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

Inspection At: Matagorda County, Texas

Inspection Conducted: January 8-22, 1996

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Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1 and 2): Special, announced inspection of the events associated with the reactor trip on December 18, 1995 and the malfunction of Motor-Operated Valve SI-16B during surveillance testing on December 23, 1995.

Results (Units 1 and 2):

Operations

- Following a reactor trip on December 18, 1995, three control rods remained six steps withdrawn. Contrary to emergency operating procedure requirements, operators did not emergency borate. This was an apparent violation of Technical Specifications (Section 1.1).

- External communication by the crew following the reactor trip was inconsistent with management expectations. The initial notification of licensee management was untimely. The initial report to the NRC did not contain the fact that three control rods remained six steps withdrawn following the reactor trip (Section 1.3).

- During the reactor trip event, operators exhibited several deficient behaviors that had been observed in previous inspections (Section 1.4).

- Excessive auxiliary feedwater flow to the steam generators created a negative impact in that it required operators to manually decrease flow to prevent excessive cooldown seven minutes following the reactor trip. This has been a long standing situation that disrupts the intended flow of the emergency operating procedures (Section 1.5).

Maintenance

- A violation of Technical Specifications occurred when operators failed to declare a surveillance test unsatisfactory after an acceptance criterion was not met as a result of a malfunction of a safety injection system valve (Section 2.5).

Engineering

- The licensee's schedule for implementation of the molded case circuit breaker setpoint modifications was not a risk informed schedule (Section 2.4).

Safety Assessment/Quality Verification

- The licensee's initial event review process did not adequately address the operator response to the reactor trip event (Sections 1.3 and 3).

- Deficiencies in human resource management during the peak vacation demand period created by the holiday season contributed to poor crew performance and poor initial licensee event review (Sections 1.3 and 3).

Summary of Inspection Findings:

- An apparent violation of Technical Specification 6.8.1 related to failure to follow procedures was identified (Section 1.1).

- Violation 499/9612-01 was opened (Section 2.5).

- Unresolved Item 498;499/9529-01 was closed as a result of finding that one violation and one apparent violation had occurred (Sections 1.1 and 2.5).

- An Inspection Followup Item 498;499/9612-01 was opened (Section 1.5).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Sequence of Events
- Attachment 3 - Documents Reviewed

DETAILS

1 FOLLOWUP (IP 92701) - REACTOR TRIP ON DECEMBER 18, 1995

This inspection was a followup to a concern first reported in NRC Inspection Report 50-498/95-29; 50-499/95-29 and tracked as Unresolved Item 498;499/95029-01. A detailed description of the event was included in Section 2.1 of that report. An updated sequence of events is provided in this report as Attachment 2.

On December 18, 1995, following a reactor trip with a partial loss of off-site power, operators observed indications on the digital rod position indication system that three control rods each remained six steps withdrawn. The crew concluded that the rod position indications were inaccurate and that the three rods were at the bottom limit of travel. That conclusion permitted the crew to declare that all rods had fully inserted and proceed with emergency operating procedure implementation without initiating emergency boration. A subsequent evaluation on December 19, 1995, determined that the three control rods did in fact stop at six steps withdrawn following the reactor trip.

The objective of the special inspection was to better understand the reasons for the crew's determination that emergency boration was not required with indication of three control rods six steps withdrawn following a reactor trip. The inspectors were to further determine if there was evidence of a generic issue of inappropriate procedure interpretation or lack of adherence.

1.1 Operating Crew Performance

The inspectors found that the operators on shift in Unit 1 during the reactor trip inappropriately determined that the indications of the digital rod position indication system were invalid and then concluded that all control rods were FULLY INSERTED by the indications available in the control room. There was no history of unreliable or inaccurate digital rod position indication system performance with all control rods inserted to the bottom limit of travel. Further, the consistent interpretation of the procedural requirement had been to look for rod bottom lights lit. This interpretation had been consistently reenforced through recurring training. Finally, there was no safety significant basis to warrant consideration to refrain from initiating emergency boration. Therefore, the inspectors determined that the operators' failure to emergency borate when three control rods each indicated six steps withdrawn was an apparent violation of Technical Specification 6.8.1 which requires, in part, that written procedures be established, implemented, and maintained covering the emergency operating procedures required to implement the requirements of NUREG-0737 and Supplement 1 to NUREG-0737 as stated in Generic Letter 82-33.

The crew engaged in a number of deficient behaviors ranging from rejecting rod position indication as inaccurate without supporting information or indications to manually starting emergency diesel generators on the basis of invalid indications. The inspectors determined that operators at the South

Texas Project had exhibited similar behavior on multiple occasions over the past year (refer to Section 1.4 below). The inspectors concluded that a negative trend in operator performance was confirmed by the actions of the operators in response to the reactor trip on December 18, 1995.

1.2 Safety Impact

The inspectors agreed with the licensee's evaluation that there was negligible safety consequence resulting from the specifics of the reactor trip and subsequent control of the plant. The remaining reactivity worth of the control rods that did not fully insert was minimal. Further, as a result of automatic isolation of the letdown system, the outlet valve of the volume control tank eventually shut on low level, causing an automatic shift of charging pump suction to the refueling water storage tank. That resulted in injection of water at a boron concentration greater than that of the reactor coolant system. However, the potential safety impact of the operators' behavior, in the context of the indicated plant condition, was significant. The success of symptom based emergency operating procedures has depended heavily on operators acting in response to the most reliable plant indications to determine an appropriate course of action. In this event, operators concluded that the only available indication of actual rod position was inaccurate without sufficient evidence to support that conclusion and did not initiate emergency boration as a consequence. This behavior is contrary to the NRC's expectation that operators at the South Texas Project would act conservatively when faced with unexpected plant conditions.

1.3 Human Factors Assessment

A human factors assessment was conducted as part of the inspection of the event which occurred on December 18, 1995. The assessment was made by conducting interviews with those operators involved with the event as well as operators in similar positions on other shift crews, by interviewing the plant manager and the operations manager, and by observing several meetings. The interviews focused on understanding the human performance aspects of the reactor trip, the licensee follow-up actions and event investigation, and included questions to determine the level of understanding of management expectations and to assess the degree to which those expectations were being met.

1.3.1 Management Expectations

Interviews with individuals as well as a review of documents outlining management expectations indicated that site management had specifically and consistently outlined expectations in the areas of problem identification, work focus, procedure use and improvement, and self-checking. Discussions in meetings, especially the plan-of-the-day and shift turnover, demonstrated appropriate reinforcement of management expectations. All interviewed operators stated that verbatim procedure compliance was expected with the exception of those items outlined in the emergency operating procedure user guide or as allowed under 10 CFR 50.54. All those interviewed indicated a high degree of compliance to procedures despite the circumstances associated with the December 18, 1995, event. Based on the interview results and the meeting observations, the inspectors determined that there was a common understanding of management expectations in the areas of procedural adherence and self-checking.

1.3.2 Crew Composition and Support Staffing

Crew composition was investigated when interviewing the operating crew and operations management. Prior to the event, management had an informal policy regarding the number of substitute operators allowed on a shift. The policy called for no more than one senior reactor operator and one reactor operator to be replaced for any single shift. However, the crew in the control room for this event consisted of two substitute senior reactor operators, one substitute reactor operator and a substitute shift technical advisor. Licensee management cited a desire to allow holiday time off as a reason for not following their informal policy. The event occurred on the third night of the crew's rotation. By that time, the crew felt that everyone was accustomed to working together during steady state plant conditions. Crew members did not perceive that the number of substitute operators was a contributing factor in the event. The shift supervisor indicated that dealing with the additional plant problems subsequent to the trip proved to be a challenging workload for the crew but that the availability of plant operators from Unit 2 helped to accomplish all tasks.

While reviewing the licensee event documentation, the inspectors observed that all the principal participants to the decision that all control rods had fully inserted were substitute crew members (the shift supervisor, unit supervisor, and primary operator). Although the crew had time to become accustomed to one another during nearly three shifts of steady state operation, they were not exercised as a team to respond to abnormal or emergency conditions. When the unit supervisor read the step from the emergency operating procedure to verify all control rods fully inserted, the primary operator questioned the system indications with regard to the requirements of the emergency operating procedure step. That precipitated a brief discussion with the shift and unit supervisors wherein they determined that the indications were within the allowable tolerances of the digital rod position indication system and thereby concluded that all rods were actually at the lower limit of insertion. Therefore emergency boration was not initiated (previously discussed in Section 1.1). Through interviews with training personnel, the inspectors concluded that the behavior of the crew was uncharacteristic of the behavior reenforced through training regarding emergency operating procedure use. Further, training had conditioned operators to look for all rod bottom lights lit to satisfy the requirements of Step 3 in Procedure 0POP05-EO-ES01, "Reactor Trip Response." Virtually all operators interviewed confirmed a consistent understanding (prior to the event) that Step 3 of Procedure ES01 required that all rod bottom lights be lit. Therefore, the inspectors concluded that excessive substitution on the crew may have disrupted the expected team dynamic for abnormal and emergency events that led to behavior inconsistent with that reenforced through training.

The initial event review appeared to also have been influenced by off-normal support staffing. At the time of the event, the operations manager for Unit 1 was also assuming the responsibilities of the plant manager. The operations manager stated that having to cope with the responsibilities of two positions while trying to resolve the issues associated with this event delayed him from exploring operator performance issues. Additionally, some of the managers who were interviewed indicated that a significant portion of the initial event review team was comprised of individuals less experienced in event review than would normally have been assigned. A senior manager indicated during an interview that the initial event review team appeared to focus on technical issues because the event review team members were more comfortable with technical issues than human performance issues. As a consequence, operators were not interviewed regarding the event during the first 24 hours as expected by management. The inspectors concluded that off-normal staffing of the initial event review team contributed to a lack of human performance evaluation. The lack of human performance evaluation may have contributed to management's initial assessment that the operators' performance in this event as adequate.

1.3.3 Communication

Communication within the crew, crew communication with their management, and crew communication with the NRC were all reviewed as part of the event investigation.

Ineffective resource utilization made communication less that optimal. In the first hour after the reactor trip, the Unit 1 shift supervisor refused assistance when the Unit 2 shift supervisor offered to make the necessary notifications to the NRC or licensee management. The crew became so involved with establishing natural circulation within the reactor, as well as with handling secondary plant problems, that licensee management was not notified until about 1 hour and 10 minutes after the reactor trip. Ultimately, the on-coming shift supervisor assisted in compiling the information so that the NRC notifications could be made within the required 4-hour window.

An off-normal management staffing arrangement, due to holiday time off may also have contributed to some communication problems. In the past, when notified of plant trips, the plant manager routinely offered to handle some of the notifications for the shift supervisor, including notifications to the NRC resident inspector. However, since the plant manager was in transit to his vacation when he was notified, he did not offer to help with the notifications. Although the shift supervisor stated that he clearly understood that he was responsible for making the necessary notifications, this off-normal response by the plant manager represented a changed work-load for the shift supervisor from other similar events. Based on this information, the inspectors determined that resource utilization appeared to impact the response to this event.

The inspectors were concerned with the completeness and accuracy of the initial report of the reactor trip made to the NRC Operations Center. During that communication, the shift supervisor reported that all rods had fully inserted following the trip. When the operations center asked questions to confirm the accuracy of what they had recorded, the shift supervisor continued to report that all rods had fully inserted. When asked if all systems performed as expected, the shift supervisor did not report that the digital rod position indication system showed three rods at six steps out. During an interview, the shift supervisor reiterated that he believed that the control rod indications in the control room following the reactor trip satisfied the procedure requirement for all rods to be fully inserted and that his report to the agency was consistent with his interpretation of plant indications. The inspectors concluded that there was no intent to provide incomplete or inaccurate information to the NRC, but that the shift supervisor reported what he believed to be true. The inspectors further concluded that the shift supervisor was not aware of the level of detail desired by the NRC as part of an initial event notification and, therefore, did not report the unexpected rod position indication.

The inspectors concluded that external communications of the crew were untimely, and failed to identify information important to the NRC. Licensee management was not notified of the event for over an hour following the reactor trip. When the event was reported to the NRC Operations Center, the report did not include the fact that the digital rod position indication system displayed three control rods at six steps withdrawn.

1.3.4 Procedure Quality

When interviewed, the plant and operations managers indicated that they thought the wording of Step 3 of the reactor trip response Procedure ES01, was ambiguous. The step states, "Verify all control rods FULLY INSERTED." However, when the operators were asked how they normally verified this step they all responded that the rod bottom lights would be lit.

The operators were also asked to compare and contrast Step 1 of Procedure E000, which requires the operators to verify that the reactor has shut down by verifying that, "Rod bottom lights are LIT," with Procedure ES01, Step 3. Procedure ES01, Step 3 allows operators to use judgement in making the determination of whether or not the reactor has shut down while Procedure E000, Step 1 calls for verbatim compliance. All the operators were able to differentiate between the steps. They clearly understood the adequate shutdown margin basis for Step 3 in Procedure ES01. However, this knowledge, combined with their knowledge that the indicated position of the control rods was within the tolerance limits of the digital rod position indication system, appears to have influenced them to assume that they met the intent of Step 3 rather than following the procedure verbatim. Based on the operators' common understanding of the steps, the inspectors determined that the wording in Procedure ES01, Step 3 was not ambiguous.

1.3.5 Training

Operators indicated that training on the use of both Procedures E000 and ES01 had been extensive. However, the scenarios presented extreme cases of control rods failing to insert properly or moving out of step with others in a group. Under those conditions, the tolerances of the digital rod position indication system were less of an issue and the necessary response was clear. When presented with the control rod failures to insert the final 6 steps, the issue of the digital rod position indication system tolerance was introduced into the problem and presented a situation for which the operators had not been specifically trained. Although the operators had not been specifically trained in this situation, the inspectors determined that the overall training on the emergency operating procedures and abnormal events was adequate.

1.4 Prior Operator Performance Findings or Concerns

The inspectors reviewed inspection reports and other documentation generated in the past year to determine if operator performance deficiencies similar to those displayed during the event had been previously observed. The inspectors characterized those performance deficiencies as:

- Disregard or disbelief of indications,
- Operations without supervisory direction or concurrence, and
- Failure to detect inaccurate indications.

In the year of operation preceding the event, several findings were made that pointed to operator behaviors similar to those exhibited during this event.

1.4.1 Disregard or Disbelief of Indications

The inspectors concluded that the operators responding to the Unit 1 reactor trip on December 18, 1995, did not believe that the digital rod position indication system accurately displayed actual control rod position. A similar situation wherein operators did not believe indications was documented in NRC Inspection Report 50-498;499/95-23. The report stated that a fire occurred in the packing area of Motor-Operated Valve 1-MS-MOV-0084 on the main reheat steam line to the moisture separator/reheaters. However, upon initial receipt of the report of the fire, control room operators delayed activating the fire brigade to require the reactor plant operator who reported the fire to confirm that there was an actual fire rather than a small steam leak in the valve.

1.4.2 Operations without Supervisory Direction or Concurrence

The inspectors concluded that the reactor operator who started the Emergency Diesel Generators 12 and 13 within 30 seconds of the reactor trip on December 18, 1995, acted without proper supervisory concurrence. After referring to indication on a deengergized control panel, the reactor operator concluded that power had been lost to all engineered safety features busses and started Emergency Diesel Generators 12 and 13 without obtaining the concurrence of either the unit or shift supervisors. This was inconsistent with management expectations regarding independent operator performance. Similar behavior had been reported in NRC Inspection Reports 50-498/95-23; 50-499/95-23 and 50-98/95-27; 50-499/95-27.

- On August 18, 1995, a thermal power excursion above licensed limits occurred when a reactor operator arbitrarily increased the inservice time of the boron thermal regeneration system to control reactor coolant system temperature without the knowledge or concurrence of shift supervision.

- On October 18, 1995, a licensed operator manipulated a safety-related pump control handswitch prior to being directed to during the test, when a different pump was to have been used.

- On October 27, 1995, the actuation of cold overpressure protection was attributed, in part, to a lack of supervisory oversight.

1.4.3 Failure to Detect Inaccurate Indications

The inspectors concluded that the reactor operator determined that power had been lost to all engineered safety features busses following the reactor trip on December 18, 1995, because he did not recognize that the indications were inaccurate as a result of loss of power to the control panel. Alternate instruments were readily observable in the control room which indicated that off-site power had not been lost to the engineered safety features busses supplied by Emergency Diesel Generators 12 and 13. Similar performance was reported in NRC Inspection Report 50-498/95-23; 50-499/95-23.

- On July 28, 1995, operators failed to recognize that Reactor Coolant Flow Instrument FT-0447 was reading out of tolerance. The condition warranted placing a channel of the reactor protection system in the tripped condition. The condition was not recognized for more than 6 hours, which exceeded Technical Specification requirements.

- On September 5, 1995, a reactor operator failed to recognize that Radiation Monitor Instrument C2RART8034 had failed low. The condition required placing the control room ventilation system in recirculation. However, it went unrecognized for an additional 7 hours before it was identified as having failed low and declared inoperable.

1.5 <u>Auxiliary Feedwater System Performance Impact</u>

Following the reactor trip, the reactor coolant system cold-leg temperature went from 564 degrees F to 536 degrees F in a period of about 10 minutes. That represented a cooldown rate of 168 degrees F per hour. Since the main steam isolation valves were shut within a minute of the reactor trip, the cooldown was primarily the result of excessive auxiliary feedwater flow (approximately 2500 gallons per minute total) to the steam generators. The cooldown rate and rapid refill of the steam generators forced the operators to take manual control of auxiliary feedwater flow approximately 7 minutes after the reactor trip.

Step 1 of Emergency Operating Procedure ES01 required the operators to verify reactor coolant system cold-leg temperature steady or trending toward 567 degrees F. If temperature was less than 550 degrees F and decreasing, the "Response Not Obtained" column for Step 1 required that emergency boration be initiated. Less than a minute after operators assessed reactor coolant system cold-leg temperature greater than 550 degrees F and steady (approximately three minutes after the reactor trip), reactor coolant system cold-leg temperature went below 550 degrees F. If reactor coolant system cold-leg temperature had been less than 550 degrees F when the operators performed Step 1 of Emergency Operating Procedure ES01, the operators would have had to respond to an artificially created excessive cooldown event that resulted from excessive auxiliary feedwater flow.

The inspectors expressed concern over the impact that the auxiliary feedwater system performance created which compelled operators to take action outside the intended sequence of the emergency operating procedures. The licensee responded that operators were conditioned through training to monitor and control auxiliary feedwater flow following a reactor trip to minimize the cooldown created by full auxiliary feedwater flow. That practice stemmed from a study of contributors to excessive cooldown following a reactor trip, which included auxiliary feedwater system performance, conducted between March 1992 and March 1994. A memorandum dated March 31, 1992, and titled, "Rapid Cooldown After Reactor Trips Requiring Closure of MSIVs," was provided to the inspectors. The memorandum identified contributors to excessive cooldown following a reactor trip as a percentage of full thermal power. The four largest contributors were:

- Steam drains - 5.4 percent,
- Excess auxiliary feedwater flow - 3.3 percent,
- Main steam reheat vents - 2.3 percent, and
- Maximum auxiliary steam flow - 2.1 percent (actual expected - 0 percent).

The memorandum provided a range of possible technical solutions that included installing flow orifices in steam drain lines, automatically shutting main steam reheater supply or vent valves, automatically closing the auxiliary steam supply valves, and automatically tripping the feed pump turbines on indications of excessive cooldown or reactor trip. The memorandum also discussed a variety of operator actions to achieve similar results to the technical solutions. No specific technical recommendations regarding auxiliary feedwater flow were made.

The study employed a cost/benefit analysis that used selected event probabilities and revenue generation amounts to derive a revenue impact for the identified options and combinations of those options. A baseline comparison value was derived from the "take no action" option. The final resolution was to install steam drain orifices and to rely on operator action to mitigate the remaining contributors to excessive cooldown.

The inspectors asked the licensee about any risk analyses that considered the various options originally identified. The licensee responded that unless a modification was being considered for implementation no analysis was performed. Therefore, since modifications to the auxiliary feedwater system were not considered, no comparative analysis was performed to gain insight to the risk significance of modifying the auxiliary feedwater system versus relying on operator action to control cooldown. Further, the licensee provided nothing that assessed the lack of operator availability to respond to complications due to devoting time and attention to monitoring cooldown and controlling auxiliary feedwater flow.

The inspectors concluded that the auxiliary feedwater system created an impact to emergency response. Operators were required to monitor and control flow in the early stages of emergency operating procedure implementation to prevent overcooling. The impact was not unique to the specific event but affects response to virtually all emergency situations as a result of performance characteristics of the auxiliary feedwater system. The licensee's decision to rely on operator actions to control the cooldown due to the auxiliary feedwater system is considered an inspection followup item (498;499/9612-01).

2 FOLLOWUP (IP 92701) - MOV MALFUNCTION DURING SURVEILLANCE TEST

2.1 Background

On December 23, 1995, while performing Step 5.6.26 of Procedure 0POP03-SP-0009B, "SSPS Actuation Train B Slave Relay Test," Revision 5, dated December 20, 1995, the breaker for the Containment Sump 2B to Safety Injection Train A pumps suction Isolation Motor-Operated Valve SI-16B tripped. Since the successful stroke open of Valve I-16B was a required acceptance criteria of the surveillance test and Valve SI-16B did receive an open signal from the protection system, the Unit 2 shift supervisor authorized a surveillance test exception in accordance with Procedure 0PGP03-ZE-0004, "Plant Surveillance Program," Revision 15, Step 4.4.6.1, and operators closed the tripped open Valve SI-16B breaker. Once the breaker for Valve SI-16B was closed, Valve SI-16B immediately stroked open. The shift supervisor directed that the solid state protection system slave relay test be restarted at Step 5.6.1. Valve SI-16B stroked properly during the subsequent performance of Step 5.6.26 and the solid state protection system slave relay test was completed. Operators noted the Valve SI-16B discrepancy in the remarks section of the solid state protection system slave relay test package and initiated Condition Report 95-14538, to further evaluate the root cause of Valve SI-16B breaker trip. Later that evening, the shift supervisor and other licensee management determined during a conference call that the Valve SI-16B breaker failure had no operability impact on the facility.

On December 26, 1995, a Priority 3 work package was developed and approved. The work package authorized maintenance personnel to take as-found measurements of the Valve SI-16B actuator (B2SIMOV0016B) current readings and to inspect the Valve SI-16B molded case circuit breaker (E2B2 Cubicle M1) for damage in accordance with licensee Test Procedure 0PMP05-NA-0004, "Molded Case Circuit Breaker Test."

On December 27, 1995, the Valve SI-16B molded case circuit breaker was replaced with a new one because maintenance personnel suspected that the old breaker was "weak." Test Procedure 0PMP05-NA-0004 was subsequently performed and completed satisfactorily on the new breaker.

2.2 Implementation of the Plant Surveillance Program

The inspectors reviewed the shift supervisor's utilization of Procedure 0PGP03-ZE-0004, Step 4.4.6.1 to grant an exception to the solid state protection system slave relay test failure because Valve SI-16B did not meet the stroke-open acceptance criteria of Procedure 0PSP03-SP-0009B.

Step 4.4.6 of Procedure 0PGP03-ZE-0004 stated:

> "IF surveillance test results are unsatisfactory or do not meet the acceptance criteria, as specified by the surveillance procedure, THEN the surveillance is considered failed (unsatisfactory) and the Shift Supervisor is notified. Furthermore, IF the test data obtained during the performance of a surveillance test indicates that the acceptance criteria will not be satisfied, THEN the surveillance, once completed, is considered failed (unsatisfactory)."

The exception stated in Step 4.4.6.1 of Procedure 0PGP03-ZE-0004 indicated that:

> "An exception to Step 4.4.6 [stated above] is allowed IF during the surveillance test a deficiency is noted that can and SHOULD be corrected/resolved by immediate test coordinator or operator actions without the generation of an additional/external documentation (i.e., CR, etc.) and not within the scope of existing deficiency programs (Ref. 5.31). In those cases the appropriate action(s) SHOULD be taken, the surveillance test completed and the corrected deficiency documented in the surveillance test data package. This step does not allow the Test Coordinator to bypass procedural requirements under existing maintenance rules and procedures."

The inspectors noted that Condition Report 95-14538 was written on December 23, 1995, to investigate the cause of the SI-16B breaker trip. The inspectors questioned the licensee on their interpretation of Step 4.4.6.1, particularly the portion which indicated that a test exception could be given if the deficiency could be corrected without the generation of a condition report. The licensee indicated that since the surveillance test was being performed to verify that the solid-state protection system relays actuated, the intent of the procedure was met when the breaker was subsequently closed and the valve stroked. The licensee's position was that once the breaker was closed, the deficiency, at least as it related to the solid-state protection system slave relay test, was corrected. The inspectors were concerned because it appeared that the shift supervisor incorrectly used the process described in Step 4.4.6.1 to grant an exception to the Valve SI-16B stroke open acceptance criteria in Step 5.6.26 of Procedure 0PSP03-SP-0009B.

Further review by the inspectors revealed that molded case circuit breaker setpoints were already in a deficiency program and if the molded case circuit breaker setpoint was suspect, it would have not been appropriate to utilize the exception described in Step 4.4.6.1.

The inspectors concluded that the utilization of Procedure 0PGP03-ZE-0004, Step 4.4.6.1 to grant an exception to the solid state protection system slave relay test failure because Valve SI-16B did not meet the stroke-open acceptance criteria of Procedure 0PSP03-SP-0009B, was a failure to follow procedures and is considered a violation of Technical Specification 6.8.1 (499/9612-01).

2.3 Troubleshooting and Root Cause Determination of SI-16B Failure

The inspectors reviewed the completed condition report and developed several observations and concerns regarding the licensee's troubleshooting of the cause of the Valve SI-16B failure.

The first concern involved the limited scope of the troubleshooting of Valve SI-16B which, according to the condition report, was limited to measurement of actuator peak and running current, and circuit breaker setpoints. The inspectors believed that the troubleshooting plan did not investigate sufficient information to accurately determine the root cause of the breaker trip. Specifically, the inspectors were concerned that the licensee's troubleshooting did not consider the possibility of an intermittent locked or near-locked rotor condition on the Valve SI-16B actuator. The licensee indicated that they had eliminated the locked rotor concern early in their review of the breaker trip event and produced additional information to support their position. The additional information, although not part of the condition report package, logically supported the licensee's decision to limit troubleshooting to actuator current and breaker setpoints. The inspectors concluded that, although the additional information provided by the licensee satisfied the inspectors scope of troubleshooting concerns, the condition report package alone was not adequate to justify the limited troubleshooting performed.

Another concern involved the utilization of Procedure 0PMP05-NA-0004, to determine as-found data on the Valve SI-16B breaker. The inspectors noted that Step 6.3.7 directs the electrician to cycle the breaker open and closed a minimum of five times to verify that there was no apparent binding. Although, the inspectors recognized that cycling breakers prior to testing them was a standard industry practice, the inspectors were concerned that utilizing this practice during the troubleshooting of a potential breaker failure could result in the loss of potentially valuable as-found information. The licensee indicated that by the time maintenance personnel even began troubleshooting, the Valve SI-16B breaker had already been cycled a number of times. The licensee indicated that since the breaker had already been cycled a number of times, it didn't matter if it was cycled a few more. The inspectors found that although this was most likely true, the as-found information was never captured.

The third concern was noted when the inspectors read the condition report disposition documentation and found that the breaker had tripped several times during previous testing by motor-operated valve diagnostic testers who performed testing on Valve SI-16B following an actuator upgrade from a SMB-type to an SB-type and a pressure locking modification.

Additionally, the inspectors noted that the as-left breaker trip setpoints for the replacement breaker were actually slightly lower than the as-found breaker setpoints on the old breaker.

The instantaneous trip data for the SI-16B breakers taken in Step 6.6 of Procedure 0PMP05-NA-0004, were as follows:

Breaker Phase	As Left Dial Setting	Minimum Trip Current	Maximum Trip Current	As Left Trip Current
Old Breaker				
A-phase/ Positive	2	78.75 amps	147 amps	100.1 amps
B-phase/ Negative	2	78.75 amps	147 amps	111.4 amps
C-phase	2	78.75 amps	147 amps	115.3 amps
New Breaker				
A-phase/ Positive	2	78.75 amps	147 amps	108.9 amps
B-phase/ Negative	2	78.75 amps	147 amps	105.7 amps
C-phase	2	78.75 amps	147 amps	96.8 amps

The inspectors noted that the actual as-left instantaneous trip setpoint for the C-phase of the new breaker was 96.8 amps, which was only 1.26 times greater than its maximum voltage locked rotor current. NRC Information Notice 92-51, "Misapplication and Inadequate Testing of Molded-Case Circuit Breakers," dated July 9, 1992, indicated that licensees occasionally underestimate the inrush transient (starting) current during the first few cycles after a motor is started. NRC Information Notice 92-51, Supplement 1, indicated that the magnitude of inrush transient current, depending on the motor characteristics and the actual timing of the motor start, could be as high as two times the motor's locked rotor current.

The inspectors questioned the licensee on their molded case circuit breaker setpoint methodology. The licensee indicated that they committed to increase the molded case circuit breaker setpoints to two times full locked rotor current in a letter to the NRC dated October 16, 1995. The schedule for implementation of the design changes documented in the licensee's letter dated October 16, 1995, was prior to startup from the fifth refueling outage for Unit 2 and the seventh refueling outage for Unit 1. The inspectors also noted that the licensee's corrective actions were previously reviewed by inspectors and documented in NRC Inspection Report 50-498/9512; 50-499/9512.

2.4 Risk Impact of the Failure of SI-16B to Stroke Open Upon Demand

The inspectors questioned the licensee on what risk contribution the containment sump to safety injection pump suction isolation motor operated valves had on the safe operation of the facility. The licensee indicated that these valves had a common mode risk achievement worth of 2.705E+02 and a Fussell-Vesely importance contribution of 70.77 percent. The inspectors noted that the licensee's schedule for implementation of the molded case circuit breaker setpoint modifications was not a risk informed schedule.

The inspectors concluded that the licensee's planned increase in molded case circuit breaker instantaneous trip setpoints was appropriate with one exception. The one exception involved the inspector's observation that the schedule for implementing the design modification was not risk informed. This was a particular concern because the inspectors found that the actual instantaneous trip setpoint for the Valve SI-16B breaker, which provides power to a relatively risk significant valve, was only 1.26 times maximum locked rotor current, which was significantly lower than the recommended two times locked rotor current industry recommendation endorsed in NRC Information Notice 92-51.

3 SAFETY ASSESSMENT/QUALITY VERIFICATION

When interviewed, managers expressed an operations philosophy that encouraged operators, particularly senior licensed operators, to use judgement to strike a balance between reliance on procedures and skill-of-the-craft to carry out the daily operations of the plant. However, managers were slow to acknowledge that operators may have exceeded the intended scope of that philosophy during the reviewed events. Management was informed of the facts in both events on which this inspection focused within a few hours of each event and initially supported the actions of the operators.

The licensee's initial event review for the reactor trip was deficient in that it did not assess human performance. Management reported having identified a large number of human performance errors site-wide in recent months. In response, management created a "Human Performance Review Day" training requirement that was repeated about every 10 weeks. The review day consisted of a dedicated 4-hour period in which all personnel on site and not on shift participated in training focused on human performance error avoidance relevant to each employee's functional area. However, no specific effort had been directed toward analyzing operator performance errors in the context of the operations philosophy. Management expressed awareness of human performance errors related to procedure adherence and interpretation that had been identified through NRC inspections over the past year. However, management did not communicate a perception that their operations philosophy was being improperly applied. Further the recent events on which the inspection focused had not prompted management to consider a broader problem beyond the specifics of each event.

The inspectors discussed their concerns regarding the adequacy of shift and operations department staffing to accommodate the large demand for vacation at the time of the reactor trip event with licensee management. As previously noted, management exceeded their informal guidelines for crew substitutions and the personnel who performed the initial event review did not meet management expectations. The inspectors expressed a perception that management of personnel resources was a likely contributor to both crew and event review team performance. The licensee expressed disagreement, particularly with regard to the crew that responded to the reactor trip. Although the disagreement remained unresolved by the end of the inspection, the licensee expressed their intent to implement several corrective actions focused on ensuring that event review teams could satisfy management expectations even during periods of reduced staffing. The inspectors continued to hold the perspective that excessive substitution in the control room was a contributor to the crew's performance. By substituting four members of the crew, the licensee had created a new crew for all practical purposes since the normal control room complement was six operators including the shift technical advisor. This crew assumed the responsibility of operating the plant for several days without the benefit of preparation and conditioning that may normally have been given to a reconstituted crew. As previously noted, the crew was not exercised in the simulator to build or reenforce team dynamics or to evaluate crew response to abnormal or emergency conditions. The inspectors found that increased management attention is warranted in this area.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

*J. Calvert, Licensed Operator Requal-Training Supervisor
*J. Carlin, Nuclear Training Manager
*T. Cloninger, Vice-President-Nuclear Engineering
*W. Cottle, Group Vice-President, Nuclear
*D. Daniels, Manager, Operating Experience
*W. Dowdy, Continuing Improvement
*R. Fellingham Jr., Event Review Team Leader
*J. Groth, Vice President, Nuclear Generation
*S. Head, Supervisor, Compliance
*C. Johnson, Manager, South Texas Project Activities, Central Power and Light
*T. Jordan, Manager, Systems Engineering
*M. Lashley, Supervisor, Section XI
*J. Lovell, Unit 1 Operations Manager
*M. McBurnett, Licensing Manager
*L. Martin, General Manager, Nuclear Assurance and Licensing
*R. Masse, Unit 2 Plant Manager
*A. Mikus, Supervisor, Engineering
*L. Myers, Unit 1 Plant Manager
*R. Rehkugler, Director, Quality
*P. Serra, Manager, Emergency Response
*J. Sheppard, Assistant to Group Vice President
*A. Spencer, Manager, Operation Support
*K. Taplett, Supervisor, Licensing
*S. Thomas, Manager, Design Engineering
*T. Underwood, Administrator, Participant Services
*D. Wohleber, Project Manager

1.2 NRC Personnel

*P. Gwynn, Director, Division of Reactor Safety
*J. Keeton, Resident Inspector
*D. Loveless, Senior Resident Inspector
*J. Pellet, Chief, Reactor Projects Branch A
*W. Sifre, Resident Inspector

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

*Denotes personnel that attended the exit meeting.

2 EXIT MEETING

An exit meeting was conducted on January 22, 1996. During this meeting, the inspectors reviewed the scope and findings of the inspection. The licensee acknowledged the inspection findings as they were presented. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

SEQUENCE OF EVENTS

12/18/95

0336 Turbine trip/reactor trip on main transformer lockout.
Emergency Diesel Generator 11 started and tied to respective engineered safeguards bus.
Auxiliary feedwater pumps started and began feeding all steam generators (levels 2-4% narrow range).
Emergency Diesel Generators 12 and 13 and their respective emergency cooling water pumps were started manually.
Operators carried out immediate actions for EOPs from memory.

0337 Main steam isolation valves were shut manually (Valve B did not indicate fully closed).
Auxiliary feedwater flow at maximum ~2500 gpm.

0339 Operators completed verification of immediate actions and entered ES01, Reactor Trip Response.
RCS cold-leg temperature 557-553 degrees F.

0340 Operators observed indications on digital rod position indication system that three rods remained six steps withdrawn. Operators interpreted rod indications as satisfying the requirement to be FULLY INSERTED and proceeded without initiating emergency boration.

0341 RCS cold-leg temperature went below 550 degrees F Operators were beyond Step 1 of ES01 and did not initiate emergency boration.

0343 An operator took manual control of auxiliary feedwater and began to throttle flow to the steam generators.

0345 Charging pump suction shifted to the reactor water storage tank as a result of low volume control tank level.
Crew observed instrument air pressure at 95 psig and increasing.
An operator manually tripped the start up feedwater pump.
MSIV B indicated fully closed.

0346 Shift technical advisor observed RCS cold-leg temperature of 536 degrees F and recommended to one of the SROs that emergency boration be initiated. The STA was told that the operators had already gone beyond the EOP step that required emergency boration and that the requirement was not continuous; therefore, the supervisor did not act on the STAs recommendation. The STA then observed that the charging pumps had shifted suction to the RWST and did not pursue the matter further.

0347 Operators stopped AFW flow to the steam generators (levels 28-33% narrow range).

0350 A pressurizer power operated relief valve cycled open three times over about a 30-second period.
Operators placed auxiliary spray in service.

0351 Operators increased AFW flow to ~360 gpm total.

0352 Source range NIs energized - counts decreasing.

0354 Reactor coolant system cold-leg temperature increased above 550 degrees F.

0355 The shift technical advisor from Unit 2 arrived and was assigned to perform Procedure 0POP04-AE-0001.

0357 Normal letdown was restored (pressurizer level - 70.3 percent).

0405 Plant operator reported all AFW pumps running normally.
The emergency diesel generator engineered safety features sequencer was reset.

0407 The operators began using the steam generator power operated relief valves to control cooldown.

0408 Opened main condenser vacuum breakers.
(RCS pressure - 2146 psig, pressurizer level 68.2 percent).

0414 Verified that only undervoltage relays actuated on 13.8 kV auxiliary and standby busses.

0415 Reenergized 13.8 kV Auxiliary Bus 1J.

0417 Containment HI/LO alarm actuated - containment pressure at 0.3 psig, entered 1-hour Technical Specification action statement.

0425 Smoke (no fire) reported coming from LC 12 J1 feeder breaker. Unit 2 personnel investigate.

0428 Reenergized Auxiliary Bus 1F.

0433 Load Center 12J1 cross tied from Unit 2 via 12J2. Load Center 12J1 supply breaker racked out.
Plant status - RCS pressure 2125 psig, pressurizer level 67.5 percent.

0445 Main turbine on turning gear.
Auxiliary Bus 1G reenergized.
Unit 1 operations manager notified (within the next hour, the group vice president for nuclear operations arrived in the control room).
Plant status - reactor coolant system pressure 2176 psig, pressurizer level 57.6 percent.

0450 Auxiliary Bus 1H reengergized.

0454 Placed Emergency Diesel Generators 12 and 13 in cooldown.

0459 Stopped Emergency Diesel Generator 12 and unloaded Emergency Diesel Generator 11.

0503 Started reactor containment building supplemental purge.

0505 Started open loop auxiliary Cooling Water Pump 11.

0510 Started open loop auxiliary Cooling Water Pump 12.
Containment pressure HI/LO alarm cleared - exited Technical Specification action statement.

0511 Started Reactor Coolant Pump 1A.
Plant status - RCS pressure 2208 psig, pressurizer level 37.1 percent, Average RCS temperature 567 degrees F.

0522 Started Reactor Coolant Pump 1D.

0527 Opened volume control tank outlet valve.

0530 Shut charging pump suction valve to the reactor water storage tank.

0534 Started Train B reactor containment fan coolers.

0548 RCS boron sample - 963 ppm.

0549 Secured turbine driven auxiliary Feedwater Pump 14.

0555 Established normal control room envelope HVAC Trains A and C.

0602 Secured Essential Chiller 12A.
Stopped Emergency Diesel Generator 13.

0603 Restored normal offsite power to Engineered Safety Features Bus E1A
Placed Emergency Diesel Generator 11 in cooldown.

0606 Secured containment purge.

0608 Stopped Emergency Diesel Generator 11.

0609 Opened charging pump suction valve to the reactor water storage tank and shut volume control tank outlet.

0610 Completed shut down margin verification using short form. Required xenon free boron at 567 degrees F - 957 ppm, actual boron - 963 ppm.

0618 Opened volume control tank outlet valve.

0619 Shut volume control tank outlet valve.

0623 Started open loop auxiliary Cooling Water Pump 13.

0624 Opened volume control tank outlet valve and shut reactor water storage tank to charging pump suction valve.

0631 Exited EOP ES01 and entered Procedure 0POP04-ZO-0003, Secondary Plant Stabilization.
(NRC resident staff became aware of the trip sometime between 0630 and 0700 upon arrival onsite.)

0644 Oncoming shift supervisor prepares NRC report and validates DRPI-B indicates ALL rods on bottom.

0709 NRC notified via ENS of RPS and ESF actuations. (The licensee reported that all rods were fully inserted, but did not report that the DRPI system indicated three rod six steps withdrawn.)

12/18/95

An event review team was established and began to investigate the technical cause for the trip. Operators provided written statements but were not interviewed by the event review team.

12/19/95

In the 24 hours subsequent to the trip, the licensee determined that the rod position indication was accurate and that three rods initially stuck at six steps withdrawn.

12/20/95

Subsequent to discussions with the NRC, the licensee issued a memorandum to all operators clarifying management expectation regarding EOP use and interpretation as well as accuracy and completeness of information reported to the NRC.

The trip initiator was identified and corrected, control rod testing was performed and it was determined that rod drop times satisfied Technical Specifications, and the reactor was restarted.

12/28/95

A human performance review team was established to investigate operator performance immediately following the reactor trip.

ATTACHMENT 3

DOCUMENTS REVIEWED

0POP05-EO-E000, "Reactor Trip or Safety Injection," Revision 5
0POP05-EO-ES01, "Reactor Trip Response," Revisions 6 and 7
0POP05-EO-FRS1, "Response to Nuclear Power Generation - ATWS," Revision 4
0POP03-ZG-0006, "Plant Shutdown from 100% to Hot Standby," Revision 4
0PGP03-ZA-0010, "Performing and Verifying Station Activities," Revision 20
0POP01-ZA-0018, "Emergency Operating Procedure User's Guide," Revision 7
0POP04-CV-0003, "Emergency Boration," Revision 3
0PGP03-ZE-0004, "Plant Surveillance Program," Revision 15
0PGP03-ZX-0002, "Condition Reporting Process," Revision 11
0PSP03-SP-0009B, "SSPS Actuation Train B Slave Relay Test," Revision 5

Memorandum, "Rapid Cooldown After Reactor Trips Requiring Closure of MSIVs," dated March 31, 1992

Memorandum, "Emergency Operating Procedure Compliance," dated December 20, 1995

Operations Policies and Practices Manual, Revision 2

Human Performance Post-Trip Review Team Report, CR-14621, dated January 5, 1996

Condition Report 95-14355, SCAQ-S, Event Review Team Report

Executive Training Review Board Meeting Minutes dated March 30, 1995

Licensed Operator Training Technical Advisory Council Meeting Minutes dated January 9, 1995, February 7, 1995, March 1, 1995, March 23, 1995, and August 8, 1995

Licensed Operator Training/Licensed Operator Requalification Combined Operations Program Curriculum Review Committee Minutes dated May 18, 1995, July 27, 1995, and October 31, 1995

Nuclear Training Department Lesson Plan, LOT501.06, "Instrumentation and Control Failure Analysis," Revision 4

Nuclear Training Department Lesson Plan, LOT803.08, "Respond to Off-Normal Conditions," Revision 3

Nuclear Training Department Lesson Plan, LOT504.04, "Introduction to Emergency Operating Procedures," Revision 5

Nuclear Training Department Lesson Plan, LOT504.06, "Reactor Trip Response 0POP05-EO-ES01," Revision 5