ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/95-23
50-499/95-23

Operating License: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company
P.O. Box 1700
Houston, Texas 77251

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

Inspection At: Matagorda County, Texas

Inspection Conducted: August 28 through October 7, 1995

Inspectors: D. P. Loveless, Senior Resident Inspector
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Approved: John I Pellet 10-30-95
J. I. Pellet, Acting Chief, Project Branch A Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events, operational safety verification, maintenance and surveillance observations, plant support activities review, evaluation of onsite engineering, followup on open operations, maintenance, and engineering items and in-office review of open items.

Results:

Plant Operations

- Control room operators and supervisors responded to the Unit 1 reactor trip in an excellent manner. However, operators questioned the validity of a reported fire. This delayed the response of the fire brigade (Section 2.1).

- An operator error caused a small power excursion slightly above licensed limits in the Unit 2 reactor. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.4).

- Operators failed to return a safety-related controller to the automatic position, making the associated ventilation system damper inoperable, although the controlled damper was in its required position. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.5).

- An operator failed to remove a hose from the spent fuel pool following transfer activities. A siphon was created, draining 6 inches of water from the pool. This event was determined to be of minimal safety significance (Section 2.6).

- Operators failed to increase the frequency of logging axial flux difference as required by Technical Specifications. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.7).

- Licensee management conducted a special independent assessment to evaluate recent human performance events. This approach to evaluation of human errors was comprehensive and aggressive (Section 2.9).

- Notwithstanding the human errors addressed in Section 2 of this inspection report, control room operators were observed to function at a very professional level. Operator response to a reactor trip was excellent (Section 3.1).

- An operator error was the cause of an unidentified reactor coolant system leak (Section 3.1).

- Operator performance of a reactor shutdown was excellent. Shift turnover meetings consisted of a detailed communication of plant status and recent events (Section 3.2).

- Operators properly identified the lifted spent fuel pool rack poison insert. Corrective actions addressed all aspects of this event (Section 8.2).

- A recent increase in the number of human errors in routine control room activities, particularly in the area of logkeeping, was noted (Section 2.8).

<u>Maintenance</u>

- A reactor trip was caused by the inappropriate actions of a craft supervisor. This event-identified and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (Section 2.1).

- Maintenance activities observed, other than above, were well controlled and conducted by knowledgeable technicians. Lifting and landing of leads were properly logged. In-field supervision was appropriate for the risk of the activity in progress (Sections 4.1, 4.2, 4.3, and 4.4).

- Operators did not identify a failed instrument channel during a Technical Specification required channel check. The unit supervisor failed to identify that these log readings did not meet the acceptance criteria during the second party review. This event-identified and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (Sections 2.2).

- An operator's inattention to detail during a channel check caused a Technical Specification violation that could have been avoided with proper self-verification techniques. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.3).

- During main steam safety valve testing, contingency actions were discussed and specific actions clearly delineated. Following a failure of one valve, control room operators entered the appropriate action statement, and a certified valve technician properly reset the valve lift setpoint (Section 5.2).

Engineering

- Cracks were identified on a residual heat removal system pump impeller. Engineering personnel stated that similar cracking should not affect the operability of the other five pumps (Section 7.1).

- An independent metallurgical laboratory concluded that the circumferential cracking in the shroud area of the pump impeller was caused by improper weld repair and machining. Licensee engineers stated that, if similar conditions existed in the other pumps, the pumps would not fail. The pump vendor recommended that all the pump impellers should be inspected at the next outage (Section 7.2).

- Preliminary engineering review of the residual heat removal system pump impeller was less conservative than the written vendor analysis. The review was presented to management in primarily a verbal format (Section 7.3).

Plant Support

- Direct radiation measurements confirmed health physics personnel surveys. On one occasion, a worker failed to follow the proper contamination control techniques (Section 6.1).

- Daily security force activities continued to be professionally discharged. On one occasion, marginal protected area lighting was identified by the inspector and corrected by the licensee (Section 6.2).

- Routine chemistry and plant monitoring activities indicated that water chemistry and radioactivity were maintained well within the Technical Specification limits (Section 6.3).

Summary of Inspection Findings:

- Violation 498/93036-02 was closed (Section 9.1).
- Violation 498/94010-01 remained open (Section 9.2).
- Violation 498;499/94007-01 was closed (Section 10.1).
- Violation 498/94007-02 was closed (Section 10.2).
- Violation 498;499/93005-05 was closed (Section 11.1.4).
- Violation 498;499/95008-01 was closed (Section 11.3.1).
- Inspection Followup Item (IFI) 498;499/95020-01 was closed (Section 8.2).
- IFI 498/95020-02 was closed (Section 8.3).
- IFI 499/95020-03 was closed (Section 8.4).
- IFI 498;499/93031-15 was closed (Section 9.3).
- IFI 498;499/93049-07 was closed (Section 9.4).
- IFI 498;499/93031-62 was closed (Section 11.1.1).
- IFI 498;499/93031-39 was closed (Section 11.1.2).
- IFI 498;499/93031-47 was closed (Section 11.1.3).
- Licensee Event Report (LER) 499/94-004 was closed (Section 8.1).
- LER 498/94-001 was closed (Section 10.3).
- LER 498/94-003 was closed (Section 11.1.5).
- LER 499/95-003 was closed (Section 11.2.1).

- LER 498/94-010 was closed (Section 11.2.2).
- LER 498/94-016 was closed (Section 11.2.3).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1 Plant Status

At the beginning of this inspection period, Unit 1 was operating at 100 percent power.

On August 29, 1995, at 11:29 a.m., the Unit 1 reactor tripped from 100 percent power on low reactor coolant flow in Loop 3 following an inadvertent reactor coolant pump trip. The unit remained in Mode 3 until restart commenced with entry to Mode 2 at 2:52 p.m. on August 30. Mode 1 was entered at 4:53 p.m. on August 30. The unit was returned to 100 percent power on September 1.

At the end of this inspection period, Unit 1 was operating at 100 percent reactor power.

1.2 Unit 2 Plant Status

At the beginning of this inspection period, Unit 2 was operating at 100 percent reactor power.

On October 6, 1995, at 7 p.m. Unit 2 operators commenced reducing reactor power. At 12:01 a.m. on October 7, the generator output breaker was opened starting Refueling Outage 2RE04.

At the end of this inspection period, Unit 2 was in Mode 5 with preparations under way to begin refueling operations for Refueling Outage 2RE04.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Reactor Trip (Unit 1)

On August 29, 1995, at 11:27 a.m., the Unit 1 reactor tripped from 100 percent reactor power on a loss of reactor coolant flow in Loop 3. The loss of reactor coolant flow was caused by an undervoltage trip of Reactor Coolant Pump 1C. The reactor coolant pump tripped on undervoltage when the bus Overload Protection Relay 51N/A1H in Cubicle 5 of 13.8 Kv Switchgear 1H, which supplies power to Reactor Coolant Pump 1C, was inadvertently actuated by manual manipulation.

Prior to the event, maintenance electricians had been performing calibration work on the relays in Cubicle 5 of 13.8 Kv Switchgear 1H. An electrician informed his supervisor of difficulties he was having in resetting the trip indication flag on the Phase B relay. The supervisor directed and assisted the electrician in the repair of the Phase B relay flag. Upon completion of calibration of the Phase C relay, the electrician noticed that the flag reset mechanism in the cover of Relay 51N/A1H was not properly aligned with the flag reset arm on the seal-in relay. The supervisor proceeded to adjust the mechanism. In order to adjust the mechanism, the seal-in relay contacts had to be manually closed. This activity required a performance with the relay cover and contact plug removed and the relay removed from the panel-mounted relay case.

During the first two attempts to adjust the mechanism, the supervisor adjusted the flag reset mechanism with the relay cover, contact plug, and relay removed from the relay case. On the third attempt, the supervisor only removed the relay cover and closed the seal-in contacts with the contact plug and relay installed in the relay case. The manual actuation of the seal-in contacts resulted in the opening of Feeder Circuit Breaker P-130 to the 13.8 Kv 1H Auxiliary Bus which provided power to Reactor Coolant Pump 1C. This resulted in a low reactor coolant system flow reactor trip. The supervisor immediately called the control room and informed the unit supervisor that his actions had caused the trip.

The inspectors observed Unit 1 control room activities immediately following the reactor trip. The unit supervisor had entered Plant Operating Procedure OPOP05-EO-EOOO, Revision 4, "Reactor Trip or Safety Injection." The control room operators responded to the reactor trip in an excellent manner. Each operator carried out his duties in a controlled, professional manner.

The operators developed Condition Report 95-10270 to address this event. The inspector reviewed the proposed corrective actions. The corrective actions included the development of a plan of action to achieve improved attention to detail, improved supervisory oversight, and a clarification of supervisory expectations.

The actions of the supervisor were in noncompliance with Plant General Procedure OPGP03-ZA-0090, Revision 13, "Work Process Program" and, therefore, were in violation of Technical Specification 6.8.1. This event-identified and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy.

During recovery activities following the reactor trip, a fire was reported on the 55-foot elevation of the turbine-generator building. A reactor plant operator reported that the fire was in the packing area of Motor-Operated Valve 1-MS-MOV-0084 on the main reheat steam line to the moisture separator/reheaters. This valve was designed to isolate on a high temperature signal following a turbine trip. The inspectors observed that the control room operators' initial response to the report of the fire was to question whether there was actually a fire in the area or a steam leak on the valve. The reactor plant operator responded by stating that he observed flames in the packing area of the valve.

The questioning of the reported fire delayed activation of the fire brigade by approximately 1 minute. This delay was inconsequential because the fire was extinguished in less than 5 minutes with no injuries and minimal damage to the valve actuator. The investigation determined that the fire was caused by lubricant that had leaked from the lower seal during valve motion. The lubricant ignited when it contacted the hot packing area of the steam valve.

2.2 <u>Failure to Identify an Inoperable Reactor Coolant System Flow Channel During a Technical Specification Required Channel Check (Unit 1)</u>

On July 28, 1995, during the performance of Plant Surveillance Procedure OPSP03-ZQ-0028, Revision 17, "Operator Logs," reactor operators identified that Reactor Coolant System Flow Instrument FT-0447 was indicating more than 3 percent higher than the other channels on Loop D. This failed to meet the channel check acceptance criteria and the channel was placed in the tripped condition within 6 hours as required by Technical Specification 3.3.1.1, Action 6.

Operators obtained a trend report from the emergency response facility data acquisition and display system. This report verified that the flowrate indication had been out of tolerance during the time that the previous shift logs had been taken. The logs had been taken between 4 a.m. and 6 a.m., and the values recorded had indicated that the channel was greater than 3 percent above the other channels at that time. However, neither the performer nor the unit supervisor, who had signed as the second party reviewer, had identified that this failed to meet the acceptance criteria. Therefore, the channel had not been placed in the tripped condition. The failure to place the channel in the tripped condition within 6 hours of the failure of a channel check was in noncompliance with Technical Specification 3.3.1.1.

The inspector reviewed Plant General Procedure OPGP03-ZE-0004, Revision 15, "Plant Surveillance Program." Section 4.4.11 stated, in part, that the designated second party reviewer shall sign for performing a review of the data package making a determination of whether or not the acceptance criteria were satisfied. In addition, Plant Operating Procedure OPOP01-ZQ-0022, Revision 6, "Plant Operations Shift Routines," specifically stated under Section 4.2, "Responsibilities," that the unit supervisor shall ensure that Technical Specification log readings satisfied the specified acceptance criteria. The inspector noted that the unit supervisor's only responsibility with respect to the operator logs was to determine if the log readings met the acceptance criteria and that the logkeeping practices were lax.

Licensee personnel performed a review of the corrective action data bases and determined that this failure to identify a failed channel check was an isolated case. The corrective actions proposed for the event were to counsel the reactor operator and the unit supervisor and to distribute a crew briefing item to make other operators aware of this event.

In addition, following several operator errors during this inspection period, licensee management established a special independent assessment to be performed. This review and the recommendations proposed were addressed in Section 2.9 of this inspection report. Although the failure to place the flow channel in the tripped condition following the failed channel check was in violation of Technical Specification 3.3.1.1, this event was isolated and was identified by control room operators. In addition, corrective actions were appropriate and included actions taken to minimize the number and effects of human performance errors. Therefore, this licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

2.3 <u>Failure to Properly Collect Data during a Technical Specification Required Channel Check (Unit 2)</u>

On the morning of September 5, the control room ventilation radiation monitors' indications were logged by a reactor operator at between 4 a.m. and 5:21 a.m. The indication for Radiation Monitor C2RART8034 was logged as, "1.20 E -06 micro curies per milliliter." This indication met the channel check acceptance requirements when compared with the other channel.

During the next shift, another operator took readings some time after 12:25 p.m. He noted that the indication was "1.29 E -07 micro curies per milliliter" and reported to the shift supervisor that channel check requirements were not met. The channel was declared inoperable at 1:52 p.m. and the control room ventilation was placed in the recirculation mode as required by Technical Specifications.

An investigation was performed to determine approximately when the channel had failed. Computer data showed that the channel had failed at approximately 1 a.m. on September 5, prior to the first channel check described. The operators developed Condition Report 95-10643 to review the previous channel checks, and prompt action was taken to determine the sequence of events. The investigators determined that the root cause of this event was the failure of the operator to self-verify his readings. The inspector noted that this was an additional example of poor logkeeping practices.

As indicated above, Control Room Ventilation Radiation Monitor C2RART8034 was found failed in the nonconservative direction. This channel was one of two monitors that provided an engineered safety feature actuation signal to automatically initiate the control room ventilation system in the recirculation mode upon a high intake radiation indication. Technical Specification 3.3.2, Table 3.3-3, Item 10.d, required that both channels be operable during Mode 1 operation. With one channel inoperable, Action Statement 28 required that the control room envelope be isolated within 1 hour and operation of the ventilation system be maintained in the filtered recirculation mode. These conditions required by Technical Specifications were not met for a period of approximately 12 hours. This was a Technical Specification violation.

The inspector found that the event had a low safety impact on plant operating conditions. This failure to meet the requirements of Technical Specifications constituted a violation of minor significance and is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy.

2.4 Reactor Power Exceeded Licensed Thermal Power Limits (Unit 2)

On August 18, 1995, with the Unit 2 reactor core near end of life, reactor operators were conducting routine deborations of the reactor coolant system utilizing the boron thermal regeneration system. The operators had been conducting deborations for approximately 1 minute 15-second intervals over the last several shifts.

During the day shift, the shift technical advisor performed a power range nuclear instrument calorimetric surveillance test. For approximately 30 minutes, no adjustments of thermal power were made. Following this test, the reactor operator noted that turbine load, average temperature, and reactor thermal power were all low. The operator arbitrarily increased the inservice time of the boron thermal regeneration system to 2 minutes 15 seconds in an attempt to increase average reactor coolant system temperature and reactor thermal power to 100 percent load values. Reactor thermal power increased above the 3800 megawatt (MW) licensed limit for approximately 70 minutes with a peak of 3817 MW thermal. Compensatory actions were commenced and average reactor power was reduced to less than 3800 MW thermal. In addition, the inspector noted that the 8-hour rolling average reactor power following the event was 3801 MW thermal.

Given that the design limits of the plant were based on 102 percent steady-state thermal power heat loadings, the safety significance of this event was low. However, this excursion did marginally exceed the full, steady-state licensed thermal power level as defined in the NRC Office of Inspection and Enforcement interim guidance issued on August 22, 1980. Therefore, this excursion constituted a noncompliance with License NPF-76 Condition C.1. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

In reviewing this event, licensee personnel determined that operator knowledge and plant procedures were inadequate to fully understand the operating characteristics of the boron thermal regeneration system. The inspector noted that the reactor operator had failed to discuss this deboration with shift supervision prior to the reactivity manipulation. Licensed operators stated that such a discussion was not required. However, the corrective actions for the event as discussed in Condition Report 95-10015 included a requirement for the plant operations organization to define which reactivity manipulations required supervisory oversight. The inspectors determined that the reactor operator had not been as conservative as would be appropriate, most likely because deborations had become a routine activity.

Overall the condition report review was thorough and addressed numerous contributing issues. Corrective actions following this event included:

- Discussions with the operating crew and counselling of the reactor operator were conducted.

- Communications regarding limiting the duration of boron thermal regeneration system deboration operations were delineated.

- Plant procedures were scheduled to be revised to include information about the boron thermal regeneration system demineralizer characteristics.

- Plant Operating Procedure OPOP03-ZA-0008, Revision 7, "Power Operations," was revised to define an over power condition and provide guidance on restoration from an over power condition.

In addition, this event was included as one of the principle events reviewed by the management's special independent assessment of human performance issues. This review and the recommendations proposed were addressed in Section 2.9 of this inspection report.

2.5 Fuel Handling Building Exhaust Damper Inoperable when Flow Controller Found in Manual (Unit 1)

On August 25, 1995, during a control board walkdown prior to shift change, the flow controller for Fuel Handling Building Exhaust Damper FV-9507 was found in the manual position instead of in the required automatic position. An investigation determined that the damper was placed in manual during the performance of Plant Surveillance Procedure OPSP03-HF-0002, Revision 8, "Train B FHB Emergency Exhaust System Operability," 32 hours earlier. The investigation also determined that the control room had gone through two shift changes prior to the discovery of the mispositioned controller. With the flow controller in manual, the exhaust damper would not have performed its designed safety function upon automatic actuation without operator action. The inspectors noted that routine control panel walkdowns had failed to identify this condition.

The licensee developed Condition Report 95-10187 to address this issue. The inspector reviewed the condition report and its resolution and ascertained that the reactor operator incorrectly placed the exhaust damper handswitch in automatic rather than the controller, as specified in the surveillance procedure. Additionally, a second reactor operator did not identify that the wrong component was placed in automatic while performing independent verification.

The specific corrective actions included counselling of the two reactor operators involved in the incident and the issuance of a memorandum from the plant managers to control room operators regarding proper control board walkdowns. Procedure feedback condition reports were developed to revise the surveillance procedures to more clearly identify the controller as the component to be operated

In addition, this event was included as one of the principle events reviewed by the management's special independent assessment of human performance issues. This review and the recommendations proposed were addressed in Section 2.9 of this inspection report.

Although of minor safety impact, the failure to restore the controller to automatic was in noncompliance with the plant surveillance procedure and, therefore, was in violation of Technical Specification 6.8.1. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

2.6 Spent Fuel Pool Siphon to Transfer Canal (Unit 2)

On September 17, at 4:25 p.m., a reactor power operator used a submersible pump to drain the Unit 2 transfer canal to the spent fuel pool for a leak test of the spent fuel pool outer gate seal. When the draining activity was completed, the operator secured the pump, lifted the end of the out of the water for approximately 10 seconds to ensure there was no siphon, and recorded the spent fuel pool level as 66 feet, 6 inches.

At 5:28 p.m., the "Spent Fuel Pool High/Low" annunciator alarmed in the control room. Upon investigation a reactor operator determined that water was siphoning back to the transfer canal from the spent fuel pool. The pump was restarted and the spent fuel pool level was restored. The spent fuel pool level had dropped to a minimum of 66 feet. Condition Report 95-10786 was developed to address this issue.

The inspector reviewed the condition report and the proposed corrective actions. From this review, the inspector ascertained that the lowest level the spent fuel pool would have reached without operator intervention was 65 feet, 9 inches, the level of the end of the hose. This level was significantly higher than the Technical Specifications minimum level of 62 feet. Therefore, this event was of little safety significance. The inspector further concluded that no plant procedures had been violated.

The corrective actions included amending Plant Operating Procedure 0POP02-FC-0001, Revision 8, "Spent Fuel Pool Cooling and Cleanup System," to ensure that the hose was not placed with the end below the highest expected water level in the spent fuel pool.

In addition, this event was included as one of the principle events reviewed by the management's special independent assessment of human performance issues. This review and the recommendations proposed were addressed in Section 2.9 of this inspection report.

2.7 Axial Flux Difference not Logged every 30 Minutes as Required (Unit 1)

On September 26, 1995, operators performing Plant Surveillance Procedure 0PSP03-ZQ-0028, Revision 17, "Operator Logs," discovered that the requirements of Technical Specification 4.2.1.1.b were not being met. Technical Specification 4.2.1.1.b states that the axial flux difference shall be determined to be within its limits by monitoring and logging the indicated axial flux difference at least once per hour for the first 24 hours, and at least once per 30 minutes thereafter, when the axial flux difference monitor annunciator was inoperable. The annunciator was controlled by the plant computer. On September 25, 1995, at 10:59 a.m. the plant computer system failed, resulting in a failure of the axial flux difference monitor annunciator. At that time, operators began to log the axial flux difference indications on an hourly basis as required. On September 26, at 2:30 p.m. operators determined that 30-minute logs had not been taken since 11:29 a.m., as required.

Procedure OPSP03-ZQ-0028, Logsheet 4, required that:

> "When 24 hours have elapsed since the alarm was inoperable. Then discontinue this logsheet and perform axial flux difference conditional surveillance Logsheet 12 until the alarm is restored."

Logsheet 12 required logging at 30 minute intervals. Following this discovery, the control room staff began logging the axial flux difference on Logsheet 12 at 30 minute intervals at 2:30 p.m. on September 26. A review of the control room recorders and the hourly axial flux difference logs indicated that the axial flux difference remained in the target band throughout the time that 30-minute logs were not being performed. Therefore, the safety significance of this event was low. However, the inspectors noted, once again, that routine activities were not receiving the requisite attention to detail.

Although of minor safety significance, the failure to log axial flux difference at 30-minute intervals starting 24 hours after the failure of the plant computer was in noncompliance with the plant surveillance procedure and was in violation of Technical Specification 4.2.1.1.b. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

2.8 Generic Issues Reviewed

The inspectors reviewed the human errors documented throughout Section 2 of this inspection report for common causes. All of the events involved items that were routine in nature. Several events involved errors in logkeeping and the review of logs; a number involved control board walk downs; and several of the conditions involved were missed during shift turnovers. The inspectors were particularly concerned that several events involved inappropriate actions or the failure to act by first line supervision.

In parallel with the management review conducted as described in Section 2.8 of this inspection report, the inspectors concluded that management expectations for routine evolutions and attention to detail were not being satisfied. Management's expectations were conveyed to plant workers through first line supervisors. The inspectors concluded that in several instances these expectations were not met by first line supervisors.

2.9 Review of Management Special Independent Assessment

From September 20 through October 5, 1995, the licensee management conducted a special independent assessment to evaluate recent human performance events and identify common themes and develop recommendations for corrective actions. The team determined that the significance of the individual events was low. However, collectively they represented a decline in human performance at the plant. Recommendations were focused on correcting the causes of the common deficiencies in performance.

The review focused on eight recent human performance error events. However, data was retrieved and analyzed from numerous low significance events that had occurred since the first of the year. The licensee's team identified two issues that were present in a number of the events reviewed which required increased management attention:

- Control and assessment of evolutions failed to consider the need for increased oversight and/or compensatory measures.

- The work risk assessment process was weak because of lack of clear guidance, differing levels of implementation, and failure to address operations evolutions that do not involve the work control process.

In addition, the team identified contributing issues in four general areas: (1) management failed to assert a consistent set of expectations prior to the performance of a task and lacked ability to evaluate real-time performance; (2) personnel were not completely familiar with their duties and tasks, had real and perceived pressures that were effecting attention to detail, and some were not willing to accept responsibility for their actions; (3) supervisors were reluctant to take the initiative to identify and correct low consequence errors; and (4) on-the-job training was not consistently reinforcing management expectations.

The recommended actions of the team were reviewed by the inspectors. These actions included:

- Developing methods to reconfirm management's expectations in the areas of work performance, corrective action, and training.

- Reviewing administrative burden on supervisors to permit more in-field time.

- Developing standards for documenting low consequence events that positively reinforce the identification of these problems.

- Developing and implementing consistent standards for preevolution briefings.

- Evaluating the effectiveness of the work risk assessment process.

- Developing and implementing standards for evaluation of routine and repetitive evolutions.

The inspectors reviewed the team's report dated October 10, 1995. Plant management was already implementing corrective actions associated with the recommendations. The inspectors noted that the event review team following the August 29 Unit 1 reactor trip developed comprehensive corrective actions with respect to the work risk assessment program. Licensee personnel stated that the program changes would not be implemented until after the Unit 2 outage was completed. This was based on a licensee philosophy that no programmatic changes should be made during a refueling outage. In the exit meeting, the Vice President, Nuclear Generation committed to implement these programmatic changes following the Unit 2 outage.

The inspectors concluded that the licensee's approach to the evaluation and correction of the recent increased number of human errors at the plant was aggressive and the scope of the review comprehensive; the corrective actions implemented and proposed appeared to appropriately address the generic issues associated with the recent human performance events.

2.10 Conclusions

A reactor trip was caused by the inappropriate actions of a craft supervisor. This event-identified and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (Section 2.1).

Control room operators and supervision responded to the Unit 1 reactor trip in an excellent manner. However, operators questioned the validity of a reported fire. This delayed the response of the fire brigade (Section 2.1).

Operators did not identify a failed instrument channel during a Technical Specification required channel check. The unit supervisor failed to identify that the log readings did not meet the acceptance criteria during the second party review. The combined failures indicated that logkeeping practices were becoming lax. This event-identified and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (Section 2.2).

An operator's inattention to detail caused a Technical Specification violation that could have been avoided with proper self-verification techniques. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy. This event may also be an indicator that logkeeping was becoming too routine (Section 2.3).

An operator error caused a minor power excursion above licensed limits in the Unit 2 reactor. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.4).

Operators failed to return a safety-related controller to the automatic position, making the associated damper inoperable. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.5).

An operator failed to remove a hose from the spent fuel pool following transfer activities. A siphon was created, draining 6 inches of water from the pool. This event was determined to be of minimal safety significance (Section 2.6).

Operators failed to increase the frequency of logging axial flux difference as required by procedure and Technical Specifications. This noncompliance constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 2.7).

The recent number of human errors indicated that routine control room activities were becoming lax, particularly in the area of logkeeping. First line supervisors' role in the reactor trip and several minor Technical Specification violations indicated a need to further assess supervision's position as the conveyor of management's expectations (Section 2.8).

Licensee management conducted a special independent assessment to evaluate recent human performance events. This approach to evaluation of human errors was comprehensive and aggressive (Section 2.9).

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that the facility was operated safely and in conformance with license and regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. The following paragraphs provide details of selected, specific inspector observations during this inspection period.

3.1 Control Room Observations

During this inspection period, the inspectors observed activities in the control rooms of both units during normal, backshift, and weekend hours. During these observations, the licensed operators performed in a professional manner. Shift turnover information was detailed and thorough. Alarm response was prompt and accurate with good use of alarm response procedures. Communications techniques among control room operators were formal and closed loop. Communications with reactor plant operators in the plant were also very good. Although several occurrences of personnel errors were noted, as observed, operator attention to detail was very good.

On August 29, 1995, the inspectors observed operators responding to a reactor trip in Unit 1. All activities were conducted in an excellent manner. The plant condition was stabilized in a timely manner. These observations were described in more detail in Section 2.1 of this inspection report.

On September 6, the inspector attended the evening shift turnover meeting in Unit 1. The level of detail communicated by the attending representatives of various groups was very good. Plant management representatives were in attendance and conducted a review of lessons learned from the August 29 reactor trip.

On October 6 and 7, the inspector observed the control room activities during the Unit 2 downpower and shutdown for the refueling outage. All activities were conducted in a very controlled manner. It was evident that the evolution had been planned and practiced by the operators. All major evolutions were performed in accordance with the published schedule.

3.2 Plant Tours

Throughout this inspection period the inspectors toured the mechanical auxiliary buildings, electrical auxiliary buildings, and turbine-generator buildings of both units. The inspectors routinely reviewed log books kept at local reactor plant operator stations. The plant chemistry and radioactive waste system logs were maintained in accordance with log keeping procedures and supervisory expectations.

On August 31, the inspector toured the 55-foot elevation of the Unit 1 turbine-generator building and observed that Motor-Operated Valve 1-MS-MOV-0084 had been completely restored after the fire on August 29. With the exception of some discoloration of the actuator, the material condition of the valve and surrounding area was very good.

On October 3, the inspectors toured the Unit 2 turbine deck and observed equipment staging activities in preparation for the upcoming refueling outage. Overall outage preparation activities were good and did not interfere with the continued safe operation of the units. The inspector expressed concern to licensee management over the ability to secure the outage-related equipment in the event of a hurricane or tropical storm. Management assured the inspector that all equipment would be properly secured and compensatory measures taken in accordance with Plant General Procedure OPGP03-ZV-0001, Revision 1, "Severe Weather Plan."

3.3 Essential Cooling Water Alignment Verification (Unit 2)

On September 14, 1995, during the evening shift, the inspector performed a flowpath alignment verification on the Train C essential cooling water system for Unit 2. The train had been taken out of service earlier in the week for routine maintenance. All valves in the main flow path were found to be in their correct position. All maintenance and surveillance equipment had been removed and appropriate levels of housekeeping in the areas restored.

3.4 Erroneous Indication of Unidentified Reactor Coolant System Leakage (Unit 1)

On September 4, 1995, the Unit 1 reactor coolant system inventory calculations indicated an increase in unidentified leakage to 0.4 gpm. Unidentified reactor coolant system leakage had normally been in the 0.1 gpm range. Condition Report 95-10401 was written to address the increase in unidentified leakage. An investigation determined that the source of the leakage was the chemical and volume control system. On September 11, 1995, the unidentified leakage was traced to a primary sample valve which had been left open following sampling activities during the unit restart on August 30. The valve was closed and the reactor coolant system unidentified leakage returned to the normal value of 0.1 gpm. This valve did not permit leakage directly from the reactor coolant system. However, it did cause erroneous results from the required reactor coolant system leakage tests being performed by the licensed operators. The inspectors also noted that the leakage had been directed to the recycle holdup tank. Therefore, the event did not impact the radiation protection of plant workers or the public.

The inspectors reviewed the disposition of Condition Report 95-10401. This document stated that the cause of this event was the failure to verify that Valve 1-XPS-0296 was closed following sampling of the volume control tank on August 30. The sampling was performed in accordance with Plant Chemistry Procedure 0PCP07-ZS-0001, "Sampling at Primary Panel ZLP-131 (Reactor Grade Sink)." According to the condition report, the chemistry technician performing the activity "forgot" to close the sample purge valve because of other activities taking place in the area.

The inspectors reviewed the licensee's recommended corrective actions. An operator aid on the sample panel was revised to include the volume control alignment for sampling purge paths. This event was discussed with chemistry supervision and technicians, and the individual technician involved was counseled.

This event was an isolated case. Although of minor safety impact, the failure to close the sample isolation valve was in noncompliance with the plant chemistry procedure and, therefore, was in violation of Technical Specification 6.8.1. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

This event was included as one of the principle events reviewed by the management's special independent assessment of human performance issues. This review and the recommendations proposed were addressed in Section 2.9 of this inspection report.

3.5 Conclusions

Direct observations indicated that operators continued to function at a very professional level. Operator response to the reactor trip was excellent.

Operator performance of a reactor shut down was excellent. Shift turnover meetings consisted of a detailed communication of plant status and recent events (Section 3.1). The Unit 2 Essential Cooling Water Train C was found to be in good material condition with no alignment discrepancies noted (Section 3.3).

The failure to close a volume control tank sample isolation valve resulted in water being diverted from the reactor coolant system to the recycle holdup tank. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 3.4).

4 MAINTENANCE OBSERVATIONS (62703)

The station maintenance activities addressed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC regulations. The inspectors verified that the activities were conducted in accordance with approved work instructions and procedures, the test equipment was within the current calibration cycles, and housekeeping was being conducted in an acceptable manner. Activities witnessed included work in progress, postmaintenance test runs, and field walk down of the completed activities. Additionally, the work packages were reviewed and individuals involved with the work were interviewed. All observations made were referred to licensee management for appropriate action.

4.1 Control Circuit Component Replacement on Steam Generator Power-Operated Relief Valve 1D (Unit 1)

On October 2, 1995, the inspectors observed instrumentation and controls technicians performing portions of preventive maintenance activity PM:IC-1-MS-90002194, "Replace Servo-Amp and Terminal Board" on Steam Generator Power-Operated Relief Valve 1D. The purpose of this activity was to replace some of the control circuit components that were nearing the end of their 10-year expected service life.

The inspector reviewed the work package and determined that it clearly and accurately identified the equipment and scope of tasks performed. The technicians were knowledgeable and familiar with the tasks. The inspector observed good coordination with the control room during the prejob brief. On October 3, the inspector verified successful completion of the work package, including postmaintenance testing.

4.2 Troubleshoot Core Exit Thermocouple (Unit 1)

On October 3, 1995, the inspectors observed instrumentation and controls technicians performing troubleshooting activities on core exit thermocouples. This activity was performed to determine the nature of the core exit thermocouple channel failures and whether the necessary repairs could be performed at power or required deferral to a unit outage. The inspector observed the prejob briefing and noted good communications techniques between the reactor operators and the technicians. The briefing entailed a detailed discussion of the scope of the activity and potential hazards to the plant and personnel. The technicians demonstrated good working practices by carefully logging the lifting and landing of electrical leads. The inspector verified the current calibration status of the measuring and test equipment instruments used.

4.3 Troubleshoot and Repair Condenser Available Permissive Interlock, C9 (Unit 2)

On September 19, 1995, a licensed operator noticed that the status light for "Condenser Available for Steam Dump," C9, was not illuminated. A lamp bulb check indicated that the light bulbs were in proper functioning condition. Condition Report 95-337687 was written to investigate and repair the circuit. A Priority 2 service request and plan of action was developed and issued on September 20.

The inspector reviewed the plan of action and verified that a reasonable approach was being taken with appropriate sensitivity to plant conditions and potential impact on related circuits with respect to turbine or reactor trip. The inspector accompanied the instrument technicians during the trouble-shooting phase of the activity. The problem was found to be in Inverter Card NPL10628 in Panel ZRR40. A new card was obtained from the warehouse and verified to be in an identical configuration to the failed card. The card was replaced, verified to operate properly, and returned to service.

The inspector noted that the technicians were accompanied by their supervisors and the shift supervisor during all phases of the trouble-shooting effort. All persons involved demonstrated a detailed knowledge of the circuits and systems effected. The shift supervisor continually cautioned the technician that they were working on sensitive systems where mistakes could result in a turbine trip and a reactor trip.

4.4 Reset Chiller 21B Temperature Control to 42°F (Unit 2)

On April 13, 1995, Condition Report 95-5739 was developed because Annunciator Window 22M3 B-5, "Control Room Temperature HI/LO," was continuously in alarm. The corrective actions included development of design change packages for all three trains of chillers in Unit 2. The package called for adjusting the operating setpoint of the 150-ton essential chillers from 48°F to 42°F to allow the chilled water delivered to the control room air handler to be at 50°F instead of 56°F, thus precluding the high temperature alarm.

On September 28, the inspector observed the setup for making the temperature adjustments on Chiller 21B. Calibration of all instruments in use were verified to be within current cycles. Procedures were reviewed and found to be complete and properly approved. The package contained a copy of Design Change Package 95-5739-6. The package also contained a properly completed unreviewed safety question determination form.

The inspector determined by interviewing the individuals and by direct observation of the work activities that the maintenance technicians responsible for chiller maintenance demonstrated superior system knowledge.

4.5 Conclusions

Preventive maintenance on a steam generator power-operated relief valve was successfully completed by knowledgeable technicians (Section 4.1).

The lifting and landing of leads during the troubleshooting of failed core exit thermocouples was carefully logged and controlled (Section 4.2).

Troubleshooting and maintenance activities on the Unit 2 Control Permissive C9 circuit were controlled in an excellent manner. Technician's activities were supervised. The operation's shift supervisor followed troubleshooting activities very closely (Section 4.3).

Resetting of the 150-Ton essential chiller outlet temperature controller was well documented and properly performed (Section 4.4).

5 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were performed in accordance with the licensee's approved programs and Technical Specifications.

5.1 Remote Shutdown Monitoring and Accident Monitoring Instrumentation Channel Checks (Unit 1)

On September 15, 1995, the inspectors observed the performance of instrumentation channel checks by control room operators. The inspector reviewed the in-hand Plant Surveillance Procedure 0PSP03-SP-0001, Revision 12, "Remote Shutdown Monitoring and Accident Monitoring Instrument Channel Check." The inspector verified that the current revision was being utilized and that approval signatures were in place. The reactor operator was knowledgeable and familiar with the activity. The inspector ascertained that the reactor operator was cognizant of potential problems and how they may be addressed. The inspector verified that calculations were accurate. The inspector observed the reactor operator utilizing alternative methods such as reviewing the emergency response facility data acquisition and display system indications to verify the status of instrumentation channels indicating out of range on the qualified display processing system.

5.2 Main Steam Safety Valve Setpoint Testing (Unit 2)

On October 2, 1995, the inspector observed portions of the performance of Plant Surveillance Procedure 0PSP11-MS-0001, Revision 6, "Main Steam Safety Valve Inservice Testing." The portions that the inspector observed included the preevolution briefing and the testing of Main Steam Safety Valve 2-MS-PSV-7430 on Main Steam Line C. The preevolution briefing was thorough and included a discussion by the shift supervisor on the contingency actions to be taken if a valve were to stick in the open position following the test. Communications techniques to be utilized and specific actions to be taken were clearly delineated. The inspector noted that this was evidence of noteworthy command and control.

The inspector reviewed the licensee approved test procedure, which had been revised on September 11, 1995. All the appropriate reviews and approvals were in place. The procedure implemented Technical Specification Surveillance Requirements 4.7.1.1 and 4.0.5. The inspector determined that the test met these requirements, including those delineated in the ASME Boiler and Pressure Vessel Code Section XI, IWV-3510. Additionally, the inspector reviewed the certification of the vendor representative designated to adjust the lift setpoints of the valves, as necessary, to ensure that he met the requirements for Pressure Relief Valve Technician Level III.

The inspector independently verified that the prerequisites of the procedure had been met prior to the initiation of testing. Pressure Gauge 100.00043.0006 had been calibrated on August 20, 1995, had a range of 0 - 1500 psig, and had an accuracy of +/- 0.10 percent. The gauge was located at Root Valve N2-MS-PI-7430 as required by the procedure.

A calibration check of the testing equipment had been performed earlier that morning, as required by the procedure. The inspector reviewed the recorder strip charts generated during the calibration. Several of the calibration points appeared to be out of tolerance. The inspector questioned the Level III technician. He stated that those points were in fact out of tolerance. However, the machine had been calibrated to have the best accuracy in the range of the anticipated test results. Any test results that fell outside of this range would have to be evaluated based on the inaccuracies.

At 9:43 a.m., Valve 2-MS-PSV-7430 was tested. The lift setpoint was calculated to be 1328 psig. The nominal setpoint for this valve was 1285 psig. Therefore, this valve had lifted approximately 3.3 percent above the nominal setpoint. Technical Specification 3.7.1.1, Table 3.7-2, requires that main steam safety valves lift within +/- 3 percent of the setpoint, as-found. The test director contacted the control room and informed the reactor operator that the valve had failed to meet its acceptance criteria. Following appropriate exercising of the valve, the Level III technician supervised the resetting of the valve's setpoint. An as-left test was then performed, and the valve setpoint was determined to be 1280 psig. This was within the 1 percent tolerance allowed for the as-left setpoint. The inspector independently calculated the lift setpoint and verified the accuracy of the technicians observations and calculations. A final test was performed and the valve again lifted at 1280 psig, indicating that the lift point was repeatable.

Following the test, the inspector returned to the main control room and reviewed the control room logbook. Appropriate entries had been made declaring the valve inoperable and entering the action statement of Technical

Specification 3.7.1.1.a. Following the second test, indicating that the valve setpoint had been returned to within specifications, the valve had been declared operable and the actions of Technical Specifications exited. The licensee personnel tested 18 additional valves over the next 2 days. All of these valves were determined to be within the 3 percent as-found tolerance and had been returned to within the +/- 1 percent as-left tolerance delineated in Technical Specification 3.7.1.1 Table 3.7-2 Note 2.

5.3 Conclusions

In general, surveillance testing observed was performed by knowledgeable individuals, utilizing calibrated equipment, following approved procedures. During a safety-related instrumentation channel check, calculations were accurate and operators utilized alternative monitoring methods (Section 5.1).

During the main steam safety valve testing, contingency actions were discussed and specific actions clearly delineated. Following a failure of one valve, control room operators entered the appropriate action statement. and a certified valve technician properly reset the valve lift setpoint (Section 5.2).

6 PLANT SUPPORT ACTIVITIES REVIEW (71750)

The objectives of this inspection were to ensure that selected activities of the licensee's support programs were implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

6.1 Health Physics Activities

During routine tours of the plant, the inspectors observed that postings and labeling of areas and radioactive materials were in compliance with the regulations and the licensee's procedures. Direct radiation measurements by the inspectors were utilized for independent confirmation of health physics personnel surveys. A sample of doors required to be locked for the purpose of radiation protection were verified to be secured. Plant workers were observed to be in compliance with the appropriate radiation work permits and were knowledgeable of plant radiological conditions.

The inspector had several occasions to observe plant workers exiting contamination control areas. In one instance, a worker was observed removing clothing in a different sequence than prescribed in the radiation worker training program. This error did not cause the spread of contamination. Health physics technicians were very attentive to control of contamination. Logging of equipment taken into Housekeeping Zone IV areas was noted to be very detailed.

6.2 Physical Security Observations

The security force officers searched packages and personnel professionally. Vital area doors were verified locked and in working condition. Protected area barriers were properly maintained and in good condition. The inspectors verified that isolation zones around protected area barriers were maintained free of equipment and debris. During backshift tours, the inspectors determined that the protected area was properly illuminated. In one case a low-boy trailer was noted as having questionable illumination underneath. A security supervisor was informed and temporary lighting was installed under the trailer.

6.3 Plant Chemistry and Monitoring Reviews

The inspectors routinely observed indications that plant water chemistry and radioactivity were within the Technical Specification limits. Chemistry reports were reviewed, radiation monitoring traces observed, and main control room logs audited. Annunciator status and the secondary plant Nitrogen-16 monitoring equipment indicated steam generator tube integrity. Additionally, the inspectors audited the status of meteorological equipment.

6.4 Conclusions

Direct radiation measurements confirmed health physics personnel surveys. On one occasion, a worker failed to follow the expected contamination control techniques (Section 6.1).

Daily security force activities continued to be professionally discharged. On one occasion, marginal protected area lighting was identified and corrected (Section 6.2).

Routine chemistry and plant monitoring activities indicated that water chemistry and radioactivity were well within the Technical Specification limits (Section 6.3).

7 EVALUATION OF ONSITE ENGINEERING (37551)

7.1 Residual Heat Removal System Pump Impeller Cracking

On September 26, 1995, while replacing the gaskets on Residual Heat Removal Pump 13, cracks were identified by maintenance technicians on the pump impeller. According to interviews, a group of engineering and maintenance personnel were sent into containment to assess the cracking. A number of large cracks were visible in the wear ring area of the impeller.

After discussions with plant management a decision was made to replace the impeller and further evaluate the cracking. Through interviews the inspector determined that engineers evaluated the impeller and determined that the cracking could be generic to the other five pumps. However, engineering judgement indicated that the cracking would not affect the operability of these pumps. The inspectors were informed that the shift supervisors of both units were present at this meeting and concurred that the other five pumps remained operable during further testing and evaluation.

7.2 Evaluation of Cracks and Generic Applicability

The inspector noted that the initial evaluation of the pump impeller was not documented. In addition, there was no formal operability determination of the other pumps at that time. The impeller was shipped to a metallurgical laboratory for investigation. A spinning test of the impeller was performed to determine mechanical integrity. The casting was then sectioned for evaluation of the cracks. The inspector reviewed the preliminary results dated October 6, 1995. The following facts were ascertained:

(1) The stainless steel casting had been extensively repair welded. The casting was repair welded on the face, in the radius, and on the wearing surfaces.

(2) Dye penetrate inspection revealed extensive circumferential cracks in the radius and axial cracks on the outer diameter surface of the wear ring.

(3) Sectioning the casting revealed inadequate thickness in the radius region. In some areas, the wall thickness was almost a knife edge, about 0.027 inch in thickness. The radius region, 180 degrees removed from the cracking, had no cracking. The thickness in the noncracked radius region was 0.100 inch.

(4) In the proximity of the cracks in the radius and on the wear ring, the impeller had been weld repaired. Most of the cracking was intergranular in nature. The cracking pattern was not typical of fatigue cracking.

(5) Microhardness testing of the welds indicated that the welds were in the nonheat treated condition. The material specification recommends that welded martensitic steel be heat treated.

(6) The wear ring region was discolored. This indicated that heat had possibly been generated. It was considered possible that the extensive cracking had caused some misalignment and increased the contact stresses between the surfaces.

(7) Based on frequency impulse testing, it was determined that resonant responses most likely did not contribute to the failure.

The laboratory concluded that the circumferential cracking had been caused by the casting weld repairs being machined, resulting in inadequate thickness in the radius region. It was considered most probable that improper heat treatment caused higher hardness and increased stresses because of a reduction in wall thickness and welding residual stresses. These combined factors resulted in intergranular attack from the water environment. Licensee engineers stated that the results indicated that the cracks were terminating in thicker metal. Therefore, they concluded that, if similar cracking existed in the other pump impellers, they would not fail. The inspector could not reach the same conclusions based on the preliminary report and inspection in this area is ongoing.

In a letter dated October 6, 1995, the pump vendor reviewed the statement by the licensee that the shroud thickness in the region of the crack was identified as 0.020 to 0.100 inches, as opposed to the 0.312 inch nominal thickness. The vendor stated its opinion that, "a 0.020" shroud thickness is totally unacceptable." Based on its evaluation, the vendor also recommended that all the impellers should be thoroughly inspected at the next scheduled outage. The vendor recommended that any impellers with cracks should be replaced; also, any impellers that have a shroud thickness less than 0.100" at any location on the shrouds should be replaced.

7.3 Open Issues

As of the end of this inspection period, licensee evaluation of the pump impellers was ongoing. The inspectors had asked licensee engineers the following questions:

(1) What was the basis for the conclusion that the licensee need not inspect the Residual Heat Removal System Pumps 21, 22, and 23 impellers during the current outage, 2RE04?

(2) Was the vibration noted in Pump 22 when it was placed in service related to the potential for impeller cracks?

(3) Could small pieces of the wear ring or shroud area become detached and cause bypass flow or collateral damage?

(4) What were the long-term corrective actions for the impeller cracking going to be?

In addition, the inspectors were concerned that a formal operability determination for the other five pumps had not been developed. Engineering evaluations had not been documented. Reviews of the impeller reliability and mechanical attributes were not completely supported by written vendor analysis and appeared to be based on verbal discussions with the laboratory and the vendor as opposed to the written documentation provided. The review itself was presented to management in primarily a verbal format.

7.4 Conclusions

Cracks were identified on a residual heat removal system pump impeller. Engineering personnel stated that similar cracking should not affect the operability of the other five pumps (Section 7.1).

A metallurgical laboratory concluded that the circumferential cracking in the shroud area of the pump impellers was caused by improper weld repair and machining. Licensee engineers stated that, if similar conditions existed in the other pumps, they would not fail. The pump vendor concluded that all the pump impellers should be inspected at the next outage (Section 7.2).

Material engineering reviews and management assessments were conducted utilizing verbal reports that contained conclusions that were not fully supported by written vendor reports. The review itself was presented to management in primarily a verbal format. Several significant questions remained unanswered. Inspectors will continue to review this condition (Section 7.3).

8 FOLLOWUP ON OPEN OPERATIONS ITEMS (92901)

8.1 (Closed) LER 499/94-004: Engineered Safety Features Actuation while Shutdown Caused by Overfilling a Steam Generator

This LER discussed an event involving an inadequate turnover of the at-the-controls reactor operator. Upon returning from a short break, the lead operator resumed his duties at the reactor panel. The secondary plant operator failed to notify the lead operator that Steam Generator 2D was being filled. A steam generator High-High level signal was generated. No plant equipment was affected because the main feedwater system and the main turbine were not in service. The report indicated that the root cause of the event was an improper turnover and lack of operator awareness. These problems were generic issues at the time of the restart. However, as documented in Section 3.3 of NRC Inspection Report 50-498/95-20; 50-499/95-20 and Section 3.1 of this inspection report, licensed operators improved to and continued to function at a high level of professionalism, even considering the errors discussed earlier in this report.

This event was reviewed at that time in detail by the NRC on-shift restart inspector, as documented in NRC Inspection Report 50-498/94-17; 50-499/94-17. All aspects of the event were addressed at that time, with one exception. The shift crew failed to identify this as a reportable event because no equipment had changed state. Therefore, this 4-hour reportable event was reported 4 days later.

The inspector reviewed the enhanced guidance issued by the licensee on the reportability of engineered safety features actuation and found it to be appropriate.

8.2 (Closed) IFI 498;499/95020-01: Spent Fuel Rack Poison Insert Assembly Displacement During Spent Fuel Movement (Unit 1)

This IFI was established to track the ongoing review of an event that occurred on August 21, 1995, when a poison insert assembly in the spent fuel pool rack was inadvertently raised approximately 18 inches from its normal position during spent fuel assembly movement. During this inspection period, licensee personnel completed their initial evaluation of this event and formulated a plan of action to preclude recurrence. This event was determined by licensing personnel not to meet the requirements for formal reporting to the NRC. However, information was sought and provided to the industry to solicit and share experiences.

The inspector reviewed the corrective actions completed and those developed in the plan of action. The inspector reviewed the engineering evaluation performed under Condition Report 95-10071, "Spent Fuel Pool Rack Poison Insert Assembly Lifted during Fuel Assembly Removal."

Upon reviewing the safety significance of the event, licensee engineers stated that bent or overhanging spent fuel rack lead-in guide edges can cause fuel assembly damage during insertion or withdrawal. For this event; however, fuel assembly damage was not suspected. Removal or lifting of a boraflex poison insert can challenge spent fuel storage rack criticality assumptions for poison material geometry. Based on a review of the spent fuel pool storage configuration at the time of this event, K_{eff} remained less than 0.95, assuming 0 ppm boron concentration in the spent fuel pool.

Licensee personnel could not determine the cause of the misalignment. Apparent causes were determined to be inadequate fuel handling machine hoist controls and inadequate fuel assembly loading practices. Corrective actions developed by licensee engineers included: providing administrative controls to prevent fuel storage in the affected rack cells, revising the fuel handling procedure to provide appropriate precautions, and evaluating a modification to the spent fuel handling machine to prevent recurrence.

The inspector determined that operator diligence had identified the lifted poison insert. Additionally, licensee actions addressed all aspects of the event.

Based on this review, the inspector considered the actions to be appropriate and determined that no further NRC review was necessary.

8.3 <u>(Closed) IFI 498/95020-02: Fuel Handling Building Emergency Exhaust Damper Controller in Wrong Position</u>

This IFI was established to track the ongoing review of a condition that resulted in a fuel handling building exhaust damper being inoperable longer than allowed by Technical Specifications. This review was completed as documented in Section 2.5 of this inspection report. Therefore, this item is considered closed.

8.4 <u>(Closed) IFI 499/95020-03: Excess Dilution Using the Boron Thermal Regeneration System</u>

This IFI was established to track the ongoing review of an overpower condition in the Unit 2 reactor that occurred on August 18, 1995. This review was completed as documented in Section 2.4 of this inspection report. Therefore, this item is considered closed.

9 FOLLOWUP ON OPEN MAINTENANCE ITEMS (92902)

9.1 (Closed) Violation 498/93036-02: Regarding a Freeze Seal That Was Not Established

This violation cited the failure of a contractor to properly establish a freeze seal prior to releasing it to operations personnel for work start approval in Unit 1. More significantly, the violation addressed the licensees' poor control of contractors and the adequacy of administrative procedures governing review and acceptance of contractor procedures.

Corrective actions taken by licensee personnel and reviewed by the inspector specifically addressed the control of freeze seals. Additionally, a broad review of contractor control procedures was performed, including various event investigations. A management review of the contractor field work control process was conducted. Several short-term actions were identified, and a contractor work control policy statement was issued. A special training program was developed for contract technical coordinators to provide management expectations and communicate responsibilities inherent to proper contractor oversight.

Based on a review of the licensee's comprehensive contractor control program, this violation is closed.

9.2 (Open) Violation 498/94010-01: Failure of Operators to Follow Plant Surveillance Procedures

This violation cited five examples of failure to properly implement and maintain procedures. The specific examples were addressed as follows:

(1) The first example involved the failure of an operator to perform the procedural steps of a surveillance procedure in the correct order. The licensee denied this example, stating additional information about the occurrence. This example was withdrawn by NRC letter dated September 29, 1994.

(2) Example 2 involved the failure to utilize the appropriate unit's data package during a surveillance test. The licensee determined that this was a self-checking error and that an established barrier caught the error. The corrective actions involved human factors enhancements to the procedure process and counselling the individual involved.

(3) This example involved the failure to properly log the execution and completion of a surveillance test. This was attributed to lack of attention to detail and lack of management oversight. Shift briefings were conducted on proper logging techniques. In addition, the licensee changed the logging requirements for this specific procedure.

(4) This example involved the failure to log entry into the Technical Specification Action Statement 3.4.6.2.6 upon failure of a reactor coolant system water inventory balance. The licensee increased management monitoring and feedback on control room log entries.

(5) In this example, an operator failed to identify that the stop watch used during surveillance testing had not been properly calibrated. Management stated that this was clearly the failure of the individual to meet management expectations. The operator involved was counseled.

The inspector determined that each of the specific corrective actions were adequate for the significance of the examples. In addition, the licensee addressed generic corrective actions. Management had increased observations and adherence to expectations, reinforcing self-checking and attention to detail. A module on procedure usage in continuing training and increased presence in the field were added to the supervisors' repertoire. Finally, the response letter referenced an ongoing surveillance procedure enhancement program that should greatly improve the ability to meet regulatory requirements during surveillance testing.

The generic issue of surveillance procedure adequacy at the South Texas Project was identified by several means during the 1993 plant shutdown and throughout the restart efforts. The licensee's corrective actions included the long-term surveillance procedure enhancement program. The specific corrective actions for each example, and the generic corrective actions provided in the licensee's response to this violation, have been reviewed and determined to be acceptable. However, this violation will remain open to track to completion the surveillance procedure enhancement program. This review will also address the concerns documented in Sections 2.2 and 2.2.8.1 of the NRC's Diagnostic Evaluation Team Report dated June 10, 1993.

9.3 (Closed) IFI 498;499/93031-15: Technical Specification Surveillance Program and Procedures Need Enhancement

Previous LERs and NRC enforcement actions documented that the surveillance testing procedures did not ensure all Technical Specification surveillance requirements were being met. Numerous instances had been identified where procedures were inadequate to meet Technical Specification surveillance requirements, thereby reducing assurance that the equipment was operable. Among these was a failure to completely test a manual reactor trip handswitch and the nonconservative setting of one of the four reactor protection channels during a reactor startup.

To address these inadequacies, the licensee committed to perform a sample review of Technical Specification surveillance tests and verify their technical adequacy. The licensee's sample indicated that the Technical Specification surveillance program needed strengthening but did appear to satisfy Technical Specification. The licensee later committed to enhance the Technical Specification surveillance procedures.

This item had been reviewed in NRC Inspection Reports 50-498/93-46; 50-499/93-46 and 50-498/94-17; 50-499/94-17. As documented in these reports, the issue had been addressed sufficiently to permit restart of the units. However, this item remained open pending further NRC inspection of the adequacy of surveillance procedure acceptance criteria.

The generic issue of surveillance procedure adequacy at the South Texas Project was identified by several means during the 1993 plant shutdown and throughout the restart efforts. The licensee's corrective actions included the long-term surveillance procedure enhancement program. The generic issue, including the tracking and evaluation of the completion and effectiveness of the surveillance procedure enhancement program will be tracked as described in the review of Violation 498;499/94010-01 as documented in Section 9.2 of this inspection report. Therefore, this item is administratively closed.

9.4 <u>(Closed) IFI 498;499/93049-07: Surveillance Testing Procedures Did not Contain Technical Specification Requirements</u>

This item documented that the surveillance testing procedures did not contain all required Technical Specification attributes. Other contributors to the maintenance and testing weaknesses were poor communications and coordination, the quality of the management information system, and the limited staffing to perform vibration analysis for predictive maintenance.

Communications and coordination in the area of maintenance and testing was reviewed as documented in NRC Inspection Report 50-498/94-20; 50-499/94-20. Communications initiatives such as the plan of the day meetings, the operations work control group, and trending of service request backlog levels were reviewed. A revised station problem reporting system, detailed shift briefings, and Unit 1 lessons learned documents were addressed as positive management information systems. In addition, maintenance staffing levels were determined to be adequate. This review had determined that the licensee's corrective actions were sufficient to permit restart of the units as evidenced by the closure of Restart Issues 3 and 9 involving the maintenance process, service request backlog, and licensee management's effectiveness.

Therefore, the inspector determined that the only remaining issue to be addressed under IFI 498;499/93049-07 was the generic issue involving surveillance testing procedure adequacy. The generic issue of surveillance procedure adequacy at the South Texas Project was identified by several means during the 1993 plant shutdown and throughout the restart efforts. The licensee's corrective actions included the long-term surveillance procedure enhancement program. This generic issue, including the tracking and evaluation of the completion and effectiveness of the surveillance procedure enhancement program will be tracked as described in the review of Violation 498;499/94010-01 as documented in Section 9.2 of this inspection report. Therefore, this item is administratively closed.

9.5 Conclusions

Specific past events caused by improperly maintained surveillance procedures were properly corrected. Additional inspection and review of the surveillance procedure enhancement program will be necessary (Sections 9.1, 9.2, and 9.3).

10 FOLLOWUP ON OPEN ENGINEERING ITEMS (92903)

10.1 (Closed) Violation 498;499/94007-01: Five Examples of Failure to Properly Control and Implement the Design of the Emergency Containment Sumps

This violation documented errors in the design and installation of the emergency containment sump enclosures in both units that resulted in the sumps being maintained in a condition that was not in accordance with the emergency core cooling and containment spray systems' design basis.

In its response, the licensee concurred with Examples 1, 2, and 4 of the violation. The response cited failure to translate the design basis information for the emergency sump enclosures during the design, fabrication, and installation. The design drawings should have included a limitation in the size of fit-up gaps. The specific corrective actions and modifications to the sump enclosures were reviewed and verified as documented in Sections 2.9 and 2.10 of NRC Inspection Report 50-498/94-07; 50-499/94-07.

Example three involved the failure to design the slots in the sump enclosures that provided access for the installation of the vortex breakers during the installation of a modification. Following the original inspection, licensee engineers provided the inspectors with Document Change Notice BC-02344. This document, as identified in a table on Drawing 3C26-9-S-1516, provided the design criteria for the installation of the slots. The inspector reviewed these documents and determined that the slots had been properly designed and installed. Based on the additional information provided, the NRC withdrew the third example of this violation as documented in a letter dated June 20, 1994.

Example 5 cited a conflict between a cross section of Design Drawing 3C26-9-S-1525 and a separate detail in the same drawing. This conflict resulted in the failure to install a 1/8-inch gasket in the Unit 2 sump enclosures. In its response the licensee agreed that the conflict existed. However, they stated that the gasket should not have been installed. Design Change Notice DC-1999 had been written to delete the gasket. The design change had failed to identify both locations on Drawing 3C26-9-S-1525. Therefore, the licensee engineers considered this a drafting error. The inspector reviewed Design Change Notices DC-1999 and CD-229.

The response letter statements were verified to be correct by the inspectors. In addition, the revision provided by Notice CD-299 corrected the drawing error by removing the requirement for a gasket. The inspector found the revision to be acceptable. In a letter dated June 20, 1994, the NRC agreed that the error was a drawing discrepancy, and not a failure to install the gasket.

To document the safety significance of the gaps in the sump enclosure screens, licensee engineers performed an analysis and determined that the gaps had little adverse effect on the operation of the plant. This statement was based on: (1) no negative consequences to containment pressure/temperature mitigation; (2) no negative consequences to postaccident core cooling; and (3) only minimal impact on the available design margin for control room, technical support center, and offsite doses. The inspector reviewed the licensee's analysis as documented in Station Problem Report 94-0022.

In addition, the inspector reviewed the analysis for correction of the nonconservatism that had been found in the preliminary assessment, as documented in Section 2.11 of NRC Inspection Report 50-498/94-007; 50-499/94-007. The inspector noted that the most serious of the items had been corrected; others had been clarified. Although the analysis still contained a substantial number of engineering judgements, the analysis was reasonable. The overriding consideration was the fact that the deficiencies had been corrected. Therefore, despite the significance of the past problems, the containment sump enclosures met the design basis of the plant. Therefore, this item is closed.

10.2 (Closed) Violation 498/94007-02: Failure to Verify the Condition of the Containment Sump Suction Inlets in Accordance with Technical Specification Requirements

This violation cited the failure of licensee personnel to properly implement the surveillance requirements of Technical Specification 4.5.2.d. Maintenance technicians had been utilizing mirrors to verify that the subsystem suction inlets were not restricted by debris and that the sump components showed no evidence of structural distress or abnormal corrosion. This action was as opposed to actually entering the sump to make the observations. The inspectors had determined that these requirements could not physically be implemented from outside the sump enclosure with a mirror.

The licensee concurred that the violation had occurred, and stated that Plant Surveillance Procedure OPSP04-XC-0001, "Inspection of Containment Emergency Sumps" had been revised as corrective action. Revision 5 to this procedure was reviewed and found to be acceptable as documented in Section 2.9 of NRC Inspection Report 50-498/94-007; 50-499/94-007. Therefore, this item is closed.

10.3 (Closed) LER 498/94-001: Small Gaps in the Reactor Containment Building Emergency Sump Screens

This LER documented the findings of an NRC inspection as cited in Violations 498;499/94007-01 and 499/94007-02 as discussed in Sections 9.1 and 9.2 of this inspection report. This LER described the results of a detailed analysis of the potential effects of the gaps in the sump enclosure screens. This analysis was reviewed for accuracy and supported results, as documented in Section 9.1 of this inspection report. The inspector determined that the stated corrective actions as listed in the LER were bounded by those committed to by the licensee in its responses to the associated violations. Therefore, this LER is administratively closed.

10.4 Conclusions

Although, the analysis of the significance of design and construction errors in the containment emergency sump enclosures still contained a number of nonconservative engineering assumptions, the deficiencies had been corrected. Therefore, differing engineering views need not be resolved (Section 10.1).

11 IN-OFFICE REVIEW OF OPEN ITEMS (90712)

11.1 Administrative Closures based on Effective Corrective Actions for Restart Issues

The following open NRC inspection items were reviewed during this inspection period. The issues documented by these items had been previously reviewed by the NRC as part of the restart review process. In each case, the inspector determined that the item had been reviewed prior to the restart of the units in 1994, the actions that licensee personnel had taken had been reviewed and found to be acceptable by the NRC, and that those actions were documented in an NRC inspection report. The items had remained open to review the longer term effects of the licensee corrective actions. The inspector determined that:

- The issues had been resolved and performance continued to improve in those areas;
- The licensee's corrective actions were appropriate; and
- No additional NRC response was warranted.

11.1.1 (Closed) IFI 498;499/9331-62: Criteria for Maintenance Effectiveness and Material Condition

This IFI identified six independent licensee management restart goals for NRC inspection followup. They were described as follows:

- No outstanding service requests that affect unit safety or reliability, and no Priority 1 or 2 service requests outstanding at the time of restart.
- Demonstrated ability to manage maintenance workload - Total open service requests meets goal (less than 1000 in Unit 1) and work off rate trend remains positive.

- Changes in service request generation rate are evaluated and understood to ensure that the threshold for deficiency identification is acceptable.

- Preventive maintenance task deferrals are analyzed and corrective actions in progress - The goal of less than 20 met, and the trend remains positive.

- Main Control Board deficiencies - The goal of less than 10 met, and the trend remains positive.

- Inoperable automatic control functions - The aggregate of all inoperable functions does not adversely affect Operations' ability to perform quality rounds and handle normal work load. A positive trend continues in resolving inoperable functions.

Bullets 1, 2, and 6 had been closed previously as documented in NRC Inspection Report 50-498/94-08; 50-499/94-08 and, likewise, Bullet 4 had been closed as documented in NRC Inspection Report 50-498/93-53; 50-499/93-53.

The inspector reviewed the system for tracking and trending of service requests. The changes in service request generation rate were appropriately evaluated and understood by plant management to ensure that the threshold for deficiency identification was acceptable. This system was effectively capturing and presenting the service request generation rate. Therefore, Bullet 3 above was considered closed.

The inspector reviewed the licensee's tracking system for main control board deficiencies. The system was effective in maintaining high visibility of this issue. Main control board deficiencies had been maintained well below the identified goal set for the restart of the units. Therefore, Bullet 5 above was considered closed.

Based on these reviews of maintenance effectiveness and an established pattern of good to excellent equipment material condition, the inspector considered this item closed.

11.1.2 <u>(Closed) IFI 498;499/93031-39: Impact of Outstanding Service Requests at Time of Restart</u>

This item was reviewed and documented in NRC Inspection Report 50-498/94-020; 50-499/94-020, Section 2.2 as part of the closure of Restart Issue 3. The inspectors routinely reviewed the status of the service request work load. The number of service requests active remained significantly below the level established by the licensee as the goal for restarting the units and were clearly being properly managed. Thereby, this item is administratively closed.

11.1.3 (Closed) IFI 498;499/93031-47: Impact of Inoperable Automatic Functions at Time of Restart

This item was reviewed and documented in NRC Inspection Report 50-498/94-017; 50-499/94-017, Section 15.3, as part of the restart readiness inspections. The resident inspectors routinely reviewed the impact of inoperable automatic functions on plant operations and the effect of the associated operator work arounds. The number of items remained low, and each item has been aggressively addressed by management until resolution. Therefore, this item is administratively closed here.

11.1.4 (Closed) Violation 498;499/93005-05: Failure to Ensure Proper Surveillance Testing of Turbine-Driven Auxiliary Feedwater Pump

This item was reviewed as documented in NRC Inspection Report 50-498/93-38; 50-499/93-38. At that time, the item remained open pending successful Mode 3 testing of the turbine-driven auxiliary feedwater pumps.

On February 9-2, 1994, the inspectors observed the testing of Auxiliary Feedwater Pump 14 as documented in NRC Inspection Report 50-498/94-009; 50-499/94-009. In addition, on May 16, 1994, the inspector observed the testing of Auxiliary Feedwater Pump 24 as documented in NRC Inspection Report 50-498/94-017; 50-499/94-017. The resident inspectors were continuing review and inspection of the condition and availability of the turbine-driven auxiliary feedwater pumps through routine core inspection activities. Therefore, this item is administratively closed.

11.1.5 (Closed) LER 498/94-003: Inoperable Tornado Damper caused by Interference between the Damper linkage and an Air Conditioning Gusset

This issue was resolved in NRC Inspection Report 50-498/93-42; 50-499/93-42 with the understanding that this condition would be corrected at a later date.

The inspector reviewed Service Request 1-VE-210282 in which the air conditioning system gusset was trimmed to provide clearance for the tornado damper linkage. The inspector also reviewed the documentation of satisfactory testing of the tornado damper. Based on these reviews, this item is closed.

11.2 Administrative Closure of LERs based on Prompt NRC Review

The following LERs documented licensee actions to address events that had previously been reviewed by the NRC. In each case, the inspector determined that immediate actions, observations, and reviews had been taken by the NRC and that those actions were documented in an NRC inspection report. The inspector also determined that:

- No additional NRC response was warranted;

- The licensee's corrective action, as described in the LER was appropriate;

- The information reported by the licensee satisfied the reporting requirements; and

- The event did not result in issues that were considered generic.

11.2.1 (Closed) LER 499/95-003: Reactor Trip on Overtemperature Delta Temperature Caused by a Failed Fuse Holder

This LER addressed the failure of a fuse holder in one channel of the solid state protection system while surveillance testing was being performed on the other. This met the protection system logic to initiate a reactor trip.

Resident inspectors on site at the time responded immediately. A thorough investigation of the circumstances surrounding the trip was performed as documented in NRC Inspection Report 50-498/95-006; 50-499/95-006. In addition to the corrective actions discussed in that report, licensee personnel perform quarterly thermographic inspections of the solid state protection system cabinets and have determined an upper limit temperature threshold for these fuse holders.

11.2.2 (Closed) LER 498/94-010: Inappropriate Use of Equipment Clearance Order Program to Meet Surveillance Requirements

This LER addressed the use of equipment clearance order program danger tags instead of locking devices required by Technical Specification 4.7.4. This NRC identified issue was cited as a violation in NRC Inspection Report 50-498/94-24; 50-499/94-24. Violation 498;499/94024-01 was reviewed and closed as documented in NRC Inspection Report 50-498/94-33; 50-499/94-33.

The inspector reviewed the LER and determined that the issues and corrective actions addressed were bounded by the more comprehensive review and corrective actions developed by the licensee as documented in its response to Violation 498;499/94024-01 dated September 29, 1994.

11.2.3 (Closed) LER 498/94-016: Control Room Ventilation System not Placed in Recirculating Mode with More than One Toxic Gas Analyzer Inoperable

This LER addressed the failure of a control room toxic gas analyzer in a manner that was not evident in the control room, while another control room toxic gas analyzer was out of service. This event was reviewed in NRC Inspection Report 50-498/94-33; 50-499/94-33 in which the inspectors observed that the corrective actions included providing operator guidance to ensure that the control room envelope ventilation system was placed in the recirculation mode when one toxic gas analyzer was inoperable. In addition, based on a 10 CFR Section 50.59 evaluation, the toxic gas analyzers have been removed from plant equipment along with the associated operability requirements.

11.3 Administrative Closure: NRC Retracts Violation

11.3.1 (Closed) Violation 498;499/95008-01: Failure to Identify a Condition Adverse to Quality Involving the Standby Diesel Generator Lubricating Oil Pressure Switches

This violation was cited for the failure to evaluate and trend numerous out-of-tolerance conditions on the subject switches as found by Technical Specification required surveillance testing. In the licensee's response dated June 20, 1995, they denied that a violation occurred. Licensee engineers stated that the conditions were incipient and only outside of the manufacturers recommended tolerance and not beyond the threshold that would affect the operability of the standby diesel generators. Therefore, the response indicated that the condition was not adverse to quality.

However, licensee engineers began trending these incipient conditions found during surveillance testing as an enhancement to this program. In a letter dated September 28, 1995, the NRC concurred with the position that the circumstances did not violate NRC requirements. Therefore, the NRC retracted this violation.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

T. Cloninger, Vice President, Nuclear Engineering
W. Cottle, Group Vice President, Nuclear
D. Daniels, Manager, Operating Experience Group
T. Dunaway, Staff Specialist
J. Groth, Vice President, Nuclear Generation
C. Johnson, Owner, Central Power and Light
J. Lovell, Manager, Unit 1 Operations
L. Martin, General Manager, Nuclear Assurance and Licensing
R. Masse, Plant Manager, Unit 2
M. McBurnett, Manager, Licensing
L. Myers, Plant Manager, Unit 1
G. Powell, Senior Reactor Operator
S. Rosen, Director, Industry Relations
D. Schulker, Engineer, Compliance
J. Sheppard, Assistant to Group Vice President
S. Thomas, Manager, Design Engineering Department

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

2 EXIT MEETING

An exit meeting was conducted on October 12, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the information presented at the exit meeting. The Vice President, Nuclear Generation committed to implement programmatic changes to improve the work risk assessment program following the completion of the Unit 2 refueling outage. The Group Vice President, Nuclear stated that he agreed with the findings addressing the operators' response to a fire following the Unit 1 reactor trip. However, he was concerned that improper communication of this issue to the licensed operators could have a negative effect on operators' assessment role during events. Licensee personnel did not identify as proprietary any information provided to, or reviewed by, the inspectors.