APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-448/92-35
50-449/92-35

Operating Licenses: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company

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

Inspection At: Matagorda County, Texas

Inspection Conducted: November 30, 1992, through January 12, 1993

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EXECUTIVE SUMMARY

During the period November 30, 1992, through January 12, 1993, a team of NRC inspectors performed an Operational Safety Team Inspection (OSTI) at the STP, Units 1 and 2, facility. The intent of the inspection was to determine whether the facility was being operated safely and in conformance with regulatory requirements. This was accomplished through the direct observation of personnel within the organization that control and support plant operations.

The NRC team utilized the guidance provided in NRC Inspection Procedure 93802, "Operational Safety Team Inspection (OSTI)." During the inspection, the team observed over 60 hours of on-shift activities related to operations during the 2 weeks on site. This included the observation of backshift and weekend activities. The inspection included sustained control room observations, observation of maintenance and surveillance activities, technical support for operations, review of equipment hardware, corrective actions implemented to resolve deficiencies, and plant area tours.

The team noted several notable strengths in the area of plant operations. Control room decorum and operator professionalism was good. This was clearly reflected in excellent operator communications between themselves and also with plant workers. Shift turnover activities were well conducted. An observation was made that personnel access to the at-the-controls area was not as well managed on Unit 1 as Unit 2.

Operator response to alarms and control board indications was very good These attributes were clearly demonstrated during the operator's response to the Unit 2 feedwater transient, which was identified prior to any annunciators being received.

The operators maintained excellent control of equipment status. Equipment clearance orders were well documented and appropriately implemented. The operators logs accurately reflected plant evolutions and equipment status. Inoperable safety-related equipment was accurately documented in the operability tracking logs.

Work activities were clearly controlled through the control room. The team noted all observed work activities had received the required work start authority. Activities which required entry into limiting conditions for operation were appropriately considered and the required actions taken.

The operations staff input into maintenance scheduling was noted to be very good. In general, the team found that work activities were conducted in accordance with procedure requirements. Surveillance pretest briefings were good. The team noted that a lack of qualified instrumentation and control technicians provided a significant challenge for performing Unit 2 work activities while the completing the Unit 1 refueling outage. An instance was identified involving poor work planning which resulted in maintenance personnel having to reinstall the Unit 2 turbine auxiliary feedwater pump governor valve stem.

The team found that the licensee's program for the identification and resolution of hardware and program implementation deficiencies was well defined. It was noted that the station problem report (SPR) process provided the means for prompt identification of concerns to the shift supervisor and plant management. However, the team was concerned that the process was not consistently well implemented.

The team noted that the licensee had not been effective in identifying potential causes for erratic motor operated inservice test results. An additional burden has been placed on the plant operators because of the required increased testing frequency. The guidance for accessing equipment operability based on inservice test results was not conservative in that the time permitted to evaluate the test results often exceeded the Technical Specification limiting condition for operation time requirements.

The team noted that maintenance personnel had not received specific training on the revised corrective action process. The method used to disseminate information to maintenance personnel was not effective in assuring they were cognizant of the recent changes to the corrective action process. In addition, many plant workers indicated that they had never initiated an SPR. It was determined that management emphasized that plant workers should report deficiencies, which could result in SPRs, to their supervisors and that it was not their expectation for the plant worker to initiate an SPR. This expectation was found to contradict the specific requirements for initiating an SPR. The team was concerned that an informal undocumented review process may occur which could result in potentially generic or programmatic concerns not being identified to the shift supervisor or management. The team identified instances where SPRs were not initiated in accordance with the corrective action program. The team also identified several concerns with the resolution of known and sometimes repetitive problems.

The team identified two unresolved items involving the implementation of corrective actions for hardware deficiencies. The first unresolved item involves five examples where safety-related equipment or program implementation deficiencies were not properly identified or inadequate corrective actions were taken. Three of the examples included a repetitive corrective maintenance activity on the Unit 2 turbine-driven auxiliary feedwater pump; an electrical load sequence problem with an essential chiller; and design modifications which had not been implemented on the essential chillers.

The second unresolved item concerns the adequacy of corrective actions for a number of motor-operated valves (MOVs) that require an increased inservice test frequency per the American Society of Mechanical Engineers code.

These items will remain unresolved pending a further NRC review to determine whether the licensee is complying with 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. The second unresolved item will remain open pending a review of MOV corrective maintenance work activities and procedures.

An additional concern was identified for an SPR which was voided for MOV corrective maintenance procedures and other programmatic concerns relating to MOV maintenance.

The licensee's implementation of their lubrication control program was poor. Vendor recommendations for system flush recommendations were not incorporated into work instructions. Several engineering request for action documents were not promptly responded to.

The team also identified two observations where corrective actions were implemented to correct the immediate deficiency; however, the reason for the deficiencies occurring had not been determined. The deficiencies involved a residual heat removal MOV breaker that was upgraded per a temporary modification without determining the root cause for the breaker tripping and a reactor trip breaker bypass breaker chafed wire.

The team concluded that operations was generally well supported by other plant organizations. It was noted that procedures for which the biennial review had been completed still had outstanding field change notices posted against them. Because the procedure review process for the biennial review was not as extensive as that required for procedure reviews, the team was concerned that the less formal procedure review process, along with the policy not to incorporate all field change notices at the time of the biennial review, may not ensure that high-quality procedures were always provided.

The operations staff was generally well supported by the security organization. A concern was noted by the team that operations personnel may be unnecessarily delayed in responding to an actual plant event if the immediate need for the operator's response is not promptly conveyed to security personnel.

The team conducted several tours within the two units and the general area. The team noted that housekeeping has improved; however, some decline was noted during the 2 weeks the team was onsite, as was evidenced by materials not being picked up after completion of some work activities.

The team identified an issue of minor safety significance for a fire door which did not satisfy the National Fire Prevention Association requirements and transient combustibles being in a diesel generator room without the required combustible fire load permit. The licensee promptly addressed these conditions.

In general, plant personnel demonstrated the use of good radiological practice. However, two events of potential radiological safety significance were observed. An individual left and reentered the radiologically restricted area on several occasions, without frisking, while transferring storage drums at the 60-foot elevation of the maintenance auxiliary building. The team found that the radiological restricted area boundary had not been identified to the worker. A second individual violated a radiological posting by entering the control room while a radiation detector surveillance was in progress. The team noted that the radiological posting did not provide a conspicuous barrier to the restricted area.

Overall, the inspection team concluded that the plant was staffed by competent knowledgeable personnel who executed their duties in a professional manner. Several notable strengths were identified in the area of plant operations. The interface between operations and maintenance was good. The most significant concerns involved the identification and resolution of hardware deficiencies. The failure to identify the cause for repetitive equipment failure, and failure to implement design modifications on other safety-related equipment, resulted in unnecessary challenges to the operations staff and the equipment. Insufficient management oversight and support was noted to ensure that all plant personnel were fully cognizant of the corrective action program changes and their responsibility to utilize the process and to assure that the appropriate work activities, including design changes, were implemented.

DETAILS

1 INSPECTION SCOPE AND OBJECTIVES

From November 30 through December 11, 1992, a team of NRC inspectors conducted an Operational Safety Team Inspection at South Texas Project (STP). An additional in-office review was conducted on December 14 through January 12. The primary objective of this inspection was to verify the safe operation of the facility through the direct observation of organizations that control and support plant operations in order to verify that they are functioning effectively.

The inspection effort concentrated on control room operations and related activities that support the facility's safe operation. Most of the inspection team's efforts were focused on the effective implementation of programs at all levels within the organization. The principle areas reviewed were operations, maintenance, surveillance testing, engineering and technical support, safety reviews, and corrective actions.

2 PLANT OPERATIONS

2.1 Overview

The team performed over 60 hours of direct control room observations. These observations were conducted to review plant operations department activities and to determine the level of support to the plant operations department by the other parts of the licensee's organization. The team observed 12 shift-turnover briefings, 8 surveillance and maintenance prebriefings, and several postoutage and postmaintenance test prebriefings.

During the period the team was on site, Unit 1 was conducting activities associated with the fourth refueling outage. Unit 2 operated at essentially 100 percent power.

2.2 Conduct of Operations

2.2.1 Control Room Professionalism/Demeanor

The team found that Unit 2 control room activities were performed in a professional, well regulated manner. Access into the at-the-controls area of the control room was well controlled and strictly limited to persons requiring access.

The team observed that the Unit 1 control room operations personnel were not as formal in permitting access to the at-the-controls area. In several instances, plant personnel entered without any discussion with the unit supervisor or operators. This resulted in the area near the main control board being frequently crowded. The team noted that greater plant personnel access inside the at-the-controls area resulted from in-progress refueling outage activities. The team did not identify any instances when a relatively high number of plant personnel inside the at-the-controls area detracted from the ability of the operators to perform their licensed duties.

Operators in the Units 1 and 2 control rooms were fully cognizant of plant conditions and alert to changing main control board indications and annunciators. For example, on December 1, while Unit 2 was operating at 100 percent power, Steam Generator Feedwater Pump 21 discharge flow began to decrease. This resulted in a reduction in feedwater flow to all steam generators. The operators responded to the control board indications prior to any annunciators being received. The operator took manual control of the steam generator feedwater pump controller and returned the feedwater flow rate to normal.

Communications between operators in both units, inside and outside the control room, were precise and formal. Communications were routinely repeated back. For example, the team observed a nonlicensed operator place a cation bed demineralizer in service in accordance with Step 16 of Procedure 2POP02-CV-0004, Revision 5, "Chemical And Volume Control Systems." The nonlicensed operator obtained a controlled copy of the procedure, conducted a briefing with the control room operators, and maintained positive communications with the control room during the entire evolution.

The team considered the operations staff at the facility to be well motivated and proficient. They exhibited accountability for their actions and a professional attitude toward the safe operation of the facility.

2.2.2 Configuration Control

2.2.2.1 Equipment Clearance Orders

The team reviewed the Unit 2 equipment clearance orders tracking log and selected three active equipment clearance orders to verify the adequacy of the established clearance boundaries and that they were appropriately implemented. No discrepancies were noted in the review of the equipment clearance orders tracking log. The quarterly and annual audits were being conducted in accordance with the requirements of Procedure 0PGP03-Z0-0039, Revision 3, "Operations Configuration Management." The team walkdown of three equipment clearance order tagouts verified that the equipment status was in accordance with the equipment clearance orders.

2.2.2.2 Locked Component Deviations

The team reviewed the locked component deviation logs and performed a walkdown of all the locked components in the Unit 2 essential cooling water (ECW) system. All components observed were positioned in accordance with the locked valve requirements.

The team observed that equipment clearance orders were being used to administratively lock-in-place valves that are essential to assure equipment operability. Examples included ECW Valves EW 0031, EW 0068, and EW 0105, which were "locked" in a throttled position by use of the equipment clearance order danger tags. These valves were located at the discharge of Component Cooling Water Pump 2A, 2B, and 2C supplementary coolers, respectively. The valves were positioned in order to provide adequate ECW flow to cool the component cooling water pumps and motors during normal and accident conditions. These valves had single-handle or "quick-throw" operators and were not physically locked or secured to preclude their inadvertent operation. The team noted that the valve operator handles protruded into a frequently used path, which increased the possibility of their being inadvertently mispositioned. The team verified that the three valves were properly positioned.

The team questioned the susceptibility of these valves to be inadvertently mispositioned. The team determined that a plant computer alarm would be generated to alert operators if insufficient cooling existed, providing sufficient time for cooling to be restored. Licensee personnel stated that a modification was pending to install positive locking devices on these three ECW valves.

2.2.2.3 Operational Tracking Log

The team reviewed the operational tracking logs for both units and verified that the control room log entries were consistent with the safety-related equipment operability entries.

2.3 Maintenance/Surveillance Implementation

2.3.1 Operations and Maintenance Interface

The team found that all observed maintenance and testing activities were coordinated with the operating staff. The licensee implemented a daily meeting to review the service requests which had been initiated within the previous 24 hours to ensure that the work was appropriately prioritized. A licensed senior reactor operator was assigned in each unit to attend this daily meeting and a subsequent work scheduling meeting. The scheduling meeting was conducted to identify scheduling conflicts. The team observed that the plant operations department provided significant input into these meetings. A work control coordinator was observed soliciting operations personnel input while developing the work activity schedule.

Main control board deficiencies were consistently addressed in a prompt manner and resolved. Service requests for equipment malfunctions that required additional operator compensatory measures being taken received prompt management attention.

2.3.2 Maintenance Implementation

2.3.2.1 Steam Generator Feedwater Pump Controller Card Replacement

On December 1, Steam Generator Feed Pump 21 speed unexpectedly decreased. The event was promptly evaluated and a Priority 2 service request was initiated.

The maintenance had been scheduled to be performed that evening. With the concurrence of the shift supervisor, the maintenance was delayed until the following day. This delay occurred because the available instrumentation and control (I&C) personnel on duty lacked the required certifications to perform the maintenance. The available qualified night shift I&C technicians were assigned work activities associated with the completion of the Unit 1 refueling outage. The lack of qualified I&C technicians was repeatedly identified during licensee staff meetings as being a significant challenge for the Unit 2 staff. No instances were identified in which operators or plant equipment were significantly challenged because of delays in implementing work activities.

The work package was completed the following morning and reviewed by the Unit 2 I&C work supervisor. The team verified that the work package was properly developed and reviewed by the I&C supervisor and an independent reviewer.

In addition, the Unit 2 Operations Manager performed a review of the work package because of the sensitivity of the work. The licensee stated that this last review was conducted because incorrect performance of the maintenance task could lead to a trip of the steam generator feedwater pump and potentially a reactor trip.

2.3.2.2 Unit 2 Incore Detector F Replacement

On December 3, the team observed a reactor vessel Incore Detector F troubleshooting activity. This activity was performed in accordance with Service Request II-155650. The shift technical advisor oversaw the troubleshooting activity. It was determined that Incore Detector F required replacement.

The team observed the replacement detector breakdown voltage test, which was performed prior to the detector installation. Testing was conducted in accordance with the approved instructions. Good use of self-verification techniques was noted.

The team noted that the radiation protection prebriefing and the work activity emphasized good radiological control work practices.

2.3.2.3 Steam Generator Power-Operated Relief Valve Repair

On December 1, the team observed maintenance activities for the Unit 1 Steam Generator A power-operated relief valve. The work instruction provided in Service Request SR 147997 utilized sections in Procedure OPMP07-ZJ-1032, Revision 0, "Paul Munroe PORV EQ Replacement." The team verified that the equipment clearance order had been properly implemented and work-start authority granted. All work was conducted in accordance with the work instructions.

The work was not completed during the team's observation because of a problem encountered with the valve actuator "hunting." The work instructions were revised to troubleshoot the feedback problems.

The team revisited the job site on December 9. Although the power-operated relief valve maintenance had been completed and the power-operated relief valve returned to service, the team noted that 2 of the 10 threaded fasteners that retained the cover on the power-operated relief valve instrument panel were not tight. One appeared to have been cross-threaded such that it was 1/4 to 1/2 inch from engaging the cover. A second fastener was loose. This resulted in a poor gasket seal. The licensee later determined that the panel was not required to be environmentally qualified and, therefore, an immediate operability concern did not exist.

2.3.3 Surveillance Implementation

2.3.3.1 Main Turbine Throttle Valve Stroke Test

On December 9, the team observed Procedure OPSP03-MS-0003, Revision 2, "Main Turbine Steam Inlet Valve Operability Test." This Unit 2 surveillance procedure was performed to verify that the high pressure turbine throttle and governor valves, and low pressure turbine reheat stop and intercept valves, were operable as required by Technical Specifications (TS) 4.3.4.2.a and 4.3.4.3.b. This surveillance procedure was performed with the main turbine electrohydraulic control system in manual control.

Prior to beginning the test, the shift supervisor briefed the operating crew on the expected plant response and the cautions to be observed with the electrohydraulic control system in manual. In addition, the shift supervisor directed the unit supervisor and the secondary reactor operator to simulate the activity in order to be familiar with the coordination that would be required.

Following the unit supervisor's briefing with the secondary reactor operator, unit power was reduced 80 percent. This provided additional margin to reactor protection system trip setpoints and permitted full stroking of the valves. After the shift supervisor authorized starting the surveillance, the secondary reactor operator proceeded with the valve stroke testing under the direct supervision of the unit supervisor. The test was successfully completed and the unit was returned to 100 percent power.

The team noted that the manner in which the surveillance was prepared, briefed, and controlled was good. Both the shift supervisor and the unit supervisor exhibited good command and control during the surveillance.

2.3.3.2 Core Exit Temperature Cross-Calibration

On December 7, the team observed a Unit 1 activity associated with Procedure OPSP10-RC-0002, Revision 1, "Core Exit Thermocouple/Resistance Temperature Detector Cross Calibration Checks." The purpose of this procedure was to check the calibration of the core exit thermocouples relative to the reactor coolant system resistance temperature detectors. These calibration checks were conducted at several reactor coolant system temperature plateaus during the plant heat-up following the fourth refueling outage.

The team observed the surveillance activity with the reactor coolant system at the 245°F plateau. The test coordinator briefed operations personnel on the goals and objectives of the surveillance, in addition to reviewing all the pretest precautions. The shift supervisor supplemented the briefing with the operator's actions for completing the test requirements.

The team considered the pretest briefing by the test coordinator and the shift supervisor to be good; the areas of the brief that discussed plant safety were appropriately emphasized with the focus of ensuring that the operators were aware of the plant conditions that would be expected during the test.

2.3.3.3 Emergency Diesel Generator (EDG)

The team observed portions of the EDG 11 operability test run on November 30. This surveillance procedure was conducted following the outage maintenance on EDG 11 and in accordance with Procedure 0POP02-DG-0001, Revision 0, "Emergency Diesel Generator 11 (21)."

The shift supervisor and the test coordinator performed a comprehensive briefing for the control room operators and the maintenance test personnel. In addition to the operability test surveillance, several additional tests and readings were gathered in order to provide baseline data on the EDG following the outage work. The actions not normally addressed in the EDG operability surveillance test were reviewed in detail.

The team observed the return of the machine to the standby line up in accordance with Procedure 0POP02-DG-0001, Steps 6.1 through 6.30. Manipulation of a locked valve was properly entered in the locked valve deviation log as required in Procedure 0PGP03-ZO-0039, Revision 3, "Operations Configuration Management."

2.3.4 Inservice Testing (IST) of Pumps and Valves

The team reviewed the implementation of the licensee's program for the testing of safety-related pumps and valves, which was conducted in accordance with Section XI of the American Society of Mechanical Engineers (ASME) Code and is required by the TS. Generally, the IST program was being implemented in accordance with the applicable requirements, with some minor exceptions which are discussed below. However, the team noted that there were numerous safety-related, power-operated valves that have been tested for long periods on an increased frequency test basis as required by Section XI of the ASME Code, without the cause of the condition that necessitated the increased frequency testing being identified or corrected.

2.3.4.1 IST of Valves

The team identified that there were 25 power-operated valves that were currently being tested on a monthly basis, rather than on a quarterly or less frequent basis, as required by Section XI of the ASME Code. Article IWV-3417 of Section XI requires that stroke tests of a power-operated valve be performed once a month until corrective action is taken for those valves in which an increase in stroke time of 25 percent or more from the previous test for valves with full-stroke time greater than 10 seconds, or 50 percent or more for valves with full-stroke time less than 10 seconds, was observed. The team noted that 15 of these valves have been stroke tested on a monthly basis for 2 years or more because the conditions that have caused the change in stroke time have not been corrected. The team identified the following observations as a result of its review of the power-operated valves that are or have been tested on a monthly basis:

- Unit 2 Valve A2SBFV4150, Steam Generator 2D Blowdown Containment Isolation, which has been tested on a monthly basis since March 1989, was not stroke tested during the month of January 1992.

- Unit 1 Valve 1AFMOV0143-0, Main Steam to Auxiliary Feedwater Pump 14 Turbine, was removed from the monthly test schedule in September 1992 without documentation of the corrective action taken. Discussions with licensee personnel and a review of test data revealed that the most likely cause of varying times of valve stroke was caused by differences in valve stroke timing methodology.

- The licensee indicated that they have initiated action to request that a contractor test and evaluate the valves on increased test frequency to determine why these valves have such erratic stroke times.

The team was concerned that many of these valves have been tested on a monthly basis for 2 or more years. The team noted that potential causes for erratic stroke times could include valve degradation, inconsistent stroke timing methodologies, and system lineup anomalies. An additional burden was also placed on the plant operators because the valves must be tested more frequently.

Licensee actions relative to power-operated valves on increased test frequency will be tracked by an inspection followup item (498;499/9235-01).

2.3.4.2 IST of Pumps

The team reviewed selected records associated with the inservice testing of safety-related pumps. The following observations were identified by the team:

- At the time of the inspection, there were two Unit 1 pumps and four Unit 2 pumps that were on an increased test frequency schedule because a measured test parameter required by Article IWP-3100 of Section XI was in the alert range. Of these six pumps, four are associated with the ECW system. The length of time that these pumps have been on an increased test frequency schedule ranged from 5 months to approximately 1 1/2 years. The team also noted that several other ECW system pumps had been recently removed from an increased test frequency schedule.

- A review of Procedure OPGP03-ZE-0022, Revision 6, "Inservice Testing Program for Pumps," revealed that the guidance contained in Section 7.1 of the procedure was nonconservative. The procedure requires that, if the initial review determines that a pump cannot meet the IST requirements and, therefore, cannot fulfill its function, then the pump must be declared inoperable and corrective action taken. However, up to 96 hours were allowed to perform the initial review. The team noted that this guidance was nonconservative because the TS allowed outage time for many safety-related pumps is 72 hours. Therefore, the potential exists for violating a TS limiting condition for operation prior to reviewing the pump test results. The team did not identify any instances of this occurring; however, this issue will be followed in future resident inspector followup.

2.4 Conclusions

The Units 1 and 2 control room decorum was professional. Access to the Unit 1 control room was not as well controlled as Unit 2, resulting in maintenance personnel entering the at-the-controls area without operator permission. This was attributed, in part, to the unit being in a refueling outage. The operators demonstrated that they were fully cognizant of plant status and planned evolutions. Good communication was noted between licensed and nonlicensed personnel.

Equipment clearance orders and locked valves were very well controlled. An observation concerning the use of an equipment clearance order was noted for controlling valves in a throttled position.

Maintenance and surveillance activities were well coordinated with the operations staff. The operations department was active in assessing and prioritizing work activities. This contributed to main control board deficiencies being addressed in a timely manner. In general, work activities were well implemented. A poor work practice was noted for replacing the power-operated relief valve instrument cabinet cover.

The team noted that the licensee had not been effective in identifying potential causes for erratic motor operated inservice test results. An additional burden has been placed on the plant operators because of the required increased testing frequency. The guidance for accessing equipment operability based on inservice test results was not conservative in that the time permitted to evaluate the test results often exceeded the TS limiting condition for operation time requirements.

3 PROBLEM IDENTIFICATION AND RESOLUTION

3.1 Overview

The team reviewed the implementation of the corrective action program, including the station problem report (SPR) process and assessed licensee personnel knowledge of the corrective action program and their willingness to implement the program. The team also reviewed the corrective action the licensee had taken relative to previously identified and sometimes repetitive problems. These included program implementation problems and hardware deficiencies. Documentation reviewed included SPRs, service requests, and unimplemented design modifications. The priorities assigned to work activities to resolve hardware deficiencies and to improve equipment performance was also reviewed.

3.2 Problem Identification

3.2.1 Cold Overpressure Mitigation System

On November 30, 1992, the licensee identified a concern with the cold over pressure mitigation system during a periodic review of the nuclear network. Westinghouse was contacted the following day and it was determined that the nuclear network entry was applicable to STP. SPR 92-1354 was initiated that day and presented to the shift supervisor. Plant management subsequently became involved and, after several consultations with Westinghouse, the licensee initiated a justification for continued operation to provide additional conservatism to the TS Figure 3.4-4, "Nominal Maximum Allowable PORV Setpoint For The Cold OverPressure System." Because Unit 1 was in an operational mode required to have the cold overpresure system mitigation operable, revised power-operated relief valve setpoints were implemented. During the evaluation of this concern, it was noted that the operations shift supervisors were kept apprised of the engineering review.

3.2.2 Feedwater Isolation Valve Configuration Change

During the reassembly of the Steam Generator 1D feedwater isolation valve, it was identified that the piston lock set screw could not be installed. A plant change form was initiated requesting the set screw be raised 2 1/4 inches. This request was initiated on October 22, 1992.

The team reviewed the disposition of the plant change form, which concluded that the valve could be reassembled without reinstalling the set screw. It was found that the use-as-is basis was supported by the written technical justification and an operability concern was not identified. The plant change form was completed on October 30. The feedwater isolation valve was subsequently reassembled without installing the set crew. The team identified no problems with the licensee's conclusion.

3.2.3 Unit 2 ECW System Walkdown

On December 9, the team conducted a walkdown of Train C of the Unit 2 ECW system. The inspection was performed using the ECW system operating procedure and design drawings to determine whether component alignment was in accordance with the operating procedure.

During the system walkdown, the team observed that one of the ECW pump discharge strainer baskets was operating erratically. A gib key on the shaft of the ECW pump discharge rotating basket strainer was loose. This resulted from a locking screw backing off. Some degradation of the strainer basket shaft was noted at the gib key. The team was concerned that eventual failure of the rotating basket strainer could occur, resulting in a potential loss of the ECW train. In addition, the team noted that a similar condition existed on the ECW Train A strainer basket. The Train B rotating basket strainer gib key and locking screw were secure.

The team reported these conditions to the Unit 2 control room. The shift supervisor inspected both strainer baskets. The shift supervisor then issued a Priority 2 service request in order to repair both rotating basket strainers; completed a conditional release on ECW Trains A and C, in which it was determined that the ECW system was operable; and submitted an SPR identifying the degraded condition. Both rotating basket strainers were repaired within a 12-hour period. The Unit 1 ECW rotating strainer baskets were observed to be operating appropriately.

The team considered the actions taken by the shift supervisor to be appropriate. A Priority 2 service request was issued in accordance with the guidance in Procedure OPGP03-ZA-0090, Revision 5, "Work Process Program." The team concurred that Trains A and C of the ECW system would be able to perform their safety functions and, therefore, were operable. The initiation of an SPR would require that a root cause determination be performed in accordance with Procedure OPGP03-ZX-0002, Revision 0, "Corrective Action Program."

The team identified two observations related to the identification and resolution of the ECW rotating strainers. The first observation pertained to the loosened gib key set screws. It was apparent from the amount of wear on the gib key and the shaft of the rotating basket that the condition had existed on both Trains A and C for a significant period. Although the key was located in a position not readily accessible, the team considered it a condition which should have been identified during the system engineer's walkdown. Based on discussions with licensee management personnel, it is expected that the system engineer will assume ownership for their systems and be fully cognizant of the system status.

The second observation resulted from discussions between the shift supervisor and the general maintenance supervisor concerning the appropriate method to disposition the repairs of the rotating basket strainers. At one point, the general maintenance supervisor recommended to the shift supervisor that the maintenance activity could be conducted under minor maintenance, a method of working minor jobs with fewer work controls. Although the shift supervisor did not take the general maintenance supervisor's recommendation, the team was concerned with the appropriateness of the recommendation to perform corrective maintenance on a safety-related component in this manner. The use of minor maintenance for this type of corrective maintenance activity could result in the failure to identify repetitive equipment problems because there may be no root cause analysis performed or detailed documentation of the problem and its resolution.

3.2.4 EDG High Fuel Oil Differential Pressure

On December 2, the licensee performed a surveillance test on the Unit 2 EDG 23. During the surveillance test, the fuel oil high differential pressure alarm actuated. Service Request DO-186915 was initiated the same day to clean the fuel oil strainer.

The I&C technicians verified that the fuel oil differential pressure gage was properly calibrated. Mechanical maintenance personnel then prepared to clean the fuel oil strainer. On December 4, an attempt was made to align the fuel oil supply three-way valve to isolate the affected strainer. Licensee personnel then discovered that the valve was leaking significantly and the strainer could not be isolated. This required that the fuel oil system be removed from service and the EDG be declared inoperable. Service Request DO-186909 was written to repair the three-way valve during the next refueling outage.

While inspecting the fuel oil strainers, mechanical maintenance personnel identified small brown pieces of grit on the strainers. These particles were initially characterized as rust. Samples of the material were taken to the cognizant engineer for analysis. New fuel oil strainers were installed. The team noted that the maintenance personnel were knowledgeable about the work requirements, and appropriate material control around the strainer baskets was observed. Operations was promptly notified when the work activity was completed and the postmaintenance test was successfully performed.

The team reviewed the EDG 23 open service requests. No service requests were identified which appeared to pose an operability concern. No other service requests were performed while the EDG was out of service because it had not been anticipated that the EDG would have to be removed from service.

On December 7, the team inquired about the apparent rust particles found on the strainer and whether an SPR had been initiated. SPR 92-1439 was subsequently initiated on December 8 to formally track the analysis of the debris found in the fuel oil system.

Criterion XVI to 10 CFR 50, Appendix B, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action to be taken precludes repetition.

In addition, Procedure OPGP03-ZX-0002, Revision 2, "Corrective Action Program," Section 4.1, Station Problem Report Instruction, requires that "any person at STP who identifies or becomes aware of a condition adverse to quality (CAQ) or significant condition adverse to quality (SCAQ) shall promptly document the occu ›nce using an SPR Form. The failure to promptly initiate an SPR for an identified condition adverse to quality was the first example of a violation of the requirements of 10 CFR 50, Appendix B, Criterion XVI (498/499/9235-02).

3.3 <u>Problem Resolution</u>

3.3.1 Essential Chilled Water System

In order to determine the effectiveness of previous licensee corrective actions to address recurring essential chiller operability problems, the team selected several essential chilled water system corrective work history documents, an open service request status sheet, dated December 3, 1992, open technical evaluations, and outstanding design modifications as identified on the support engineering document tracking system, dated November 25, 1992. These documents were reviewed to determine the resolution for repetitive deficiencies and the status of pending actions. Three design changes were specifically reviewed based on their apparent safety significance and expectation for improving essential chiller reliability.

The team noted that the previous essential chiller task force had not been effective in identifying and correcting the root causes of several long-standing essential chiller problems. This resulted in continued reliability problems with the essential chillers. A review of the task team meeting minutes indicated that personnel attendance was not consistent. Recently, the licensee implemented the Chiller Improvement Task Force and designated a project manager to provide leadership and oversight. The licensee indicated that it was the objective of the task force leader to provide closer oversight and participation than had been previously received.

Design Change (Engineering Change Notice Package) ECNP 88-E-091, was initiated in 1988 to correct a condition with the main control board annunciators. The licensee had identified that, if an alarm was received on the main control board identifying trouble with a chiller, the alarm could be cleared after a period even though the condition still existed. The team noted that the ECNP to correct this condition had been completed for all safety-related 150 ton units, with the exception of the Unit 1 11C essential chiller. The team noted that, although the licensee was in the process of finalizing the Unit 1 fourth refueling outage activities, this ECNP had not been implemented. The team also noted that ECNP 88-L-0033 was initiated to provide a time delay on the Essential Chiller 11C to permit the oil pressure switch sufficient time to build up oil pressure; however, this ECNP was not implemented. The schedule had shown June 1991 for the later installation.

Design Change ECNP 90-J-0009 was approved in late 1990 to revise the evaporator low pressure and chilled water setpoints to prevent the chilled water system from freezing and rupturing the tubes. It was determined that this setpoint change had been implemented on the Unit 2 150 ton Essential Chiller 21A, but not for the other two trains. The team identified that Work Requests (WRs) CH-134731 and 134732 for Trains B and C, respectively, were not scheduled to be implemented until September 1993, despite there being adequate time available for these design changes to be implemented during the Unit 2 third refueling outage, which was scheduled to begin in February 1993. The Unit 1 300 ton essential chillers, to be worked under ECNP 90-J-006, are not scheduled for this enhancement until July and August 1993. Unit 1 150 ton essential chillers also had not been worked, as identified by ECNP 90-J-008. The team noted that the Unit 1 essential chiller modification was not scheduled to be implemented during the Unit 1 fourth refueling outage.

Plant equivalency changes were initiated for the installation of an oil line from the chiller's lower to the upper oil sump to reclaim the oil. These changes, initiated in June 1992, would provide a means of assuring that the essential chillers had sufficient oil level in the upper reservoir to satisfy the start logic. Several previous instances were noted where TS action requirements were entered while operators initiated actions to manually return the oil to the upper reservoir. WRs 178121, 178122, and 178123 were initiated to install the oil reclamation line for Unit 1 Essential Chillers 11A, 11B, and 11C, respectively. None of these WRs were implemented during the Unit 1 fourth refueling outage. WRs were also initiated to install the tubing on all the Unit 2 essential chiller units. WR CH-178119 was initiated in June 1992 to install the tubing on Essential Chiller 21C. It was noted that an implementation date had not been set. WR CH-178125, for Essential Chiller 21B, had an implementation date of December 1992, which was not met; and WR CH-178124, for Essential Chiller 21A, was completed on January 7, 1993.

On November 29, 1992, a service request was initiated identifying a deficient condition with Essential Chiller 21A in which the chiller was tripping on a low chill water outlet temperature of 40°F, as opposed to the intended 38°F. The service request was assigned Priority 3C to be worked during the next scheduled outage.

On December 9, Essential Chiller 21A again tripped because of low chill water outlet temperature. During the response to the essential chiller trip, the mechanical auxiliary building watch discovered the chiller with no visible oil indication in the lower sight glass. This condition required the chiller to be declared inoperable, placing Unit 2 in the action statement of TS 3.7.14, which requires that the unit be placed in Mode 3 within the following 72 hours. The licensee subsequently reclaimed the oil from the lower sump and restored the essential chiller to operable. No additional work activities were performed.

The inspectors noted that the units have entered into the TS on several occasions because of this repetitive problem with the essential chiller oil level. In December 1991, Unit 1 entered into TS 3.0.3 when Essential Chiller 11B was declared inoperable because the essential chiller oil level had migrated from the upper to the lower sump. This occurred concurrently while a second essential chiller train was out of service.

Criterion XVI to 10 CFR 50, Appendix B, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions to be taken preclude repetition. The failure to take prompt corrective actions to resolve a recurring deficiency identified in Essential Chiller 21A was the second example of a violation of 10 CFR 50, Appendix B, Criterion XVI (498;499/9235-02).

3.3.2 Overspeed Testing of the Turbine-Driven Auxiliary Feedwater Pump

On December 7, the licensee conducted a surveillance test prebriefing in preparation to conduct a Unit 1 turbine-driven auxiliary feedwater pump overspeed trip. This test verifies that the turbine will trip on an overspeed condition to prevent overpressurizing the auxiliary feedwater piping. The team noted that the test engineer provided a comprehensive prebriefing for the operators and maintenance personnel.

The team reviewed the work package and noticed that the governor stem that had been reinstalled had sustained pitting. The stem pitting was a concern because of the potential for the condition to restrict stem movement through the packing, resulting in erratic governor valve operation. In addition, it was identified that, during the performance of Preventive Maintenance Task 1-AF-8900 3576 in 1991, the stem also was pitted. Request for Action (RFA) 91-0575 was initiated to permit reinstallation of the valve stem in 1991. No additional RFA was performed to evaluate reinstalling the stem in 1992. The inspector questioned why a second RFA was not performed. Based on discussion with the licensee, it was determined that the shaft had been polished to remove the pits. The system engineer also considered the previous 1991 RFA to be applicable. The reason identified for not replacing the stem in 1992 was that the wrong part was received. The failure to verify that appropriate parts had been received to conduct the work activity was identified as poor work planning.

3.3.3 Turbine-Driven Auxiliary Feedwater Pump Overspeed Reset

The team reviewed several completed work documents for Turbine-Driven Auxiliary Feedwater Pump 24. This review also included several open and closed SPRs, licensee action to address industry experience, and open and closed RFAs.

In June 1990, the licensee initiated RFA 90-1248 to request that engineering evaluate the requirements for lubricating the turbine-driven auxiliary feedwater pump turbine. A response by September 1, 1990, was requested. This RFA was issued because previous Request for Engineering Action (REA) 1235 dated April 18, 1988, had not been answered. The RFA again identified that the vendor manual did not contain information as to what the lubrication frequency should be nor did it specify how to replace the oil. This information was needed to establish the appropriate preventive maintenance schedule and work practice for oil addition and change out.

In December 1990, the licensee noted that the turbine trip mechanism was sticking due to what appeared to be "sawdust." The work document, WR AF 133781, stated that the work performed on the Pump 24 trip mechanism consisted of cleaning and lubricating the trip mechanism. On February 3, 1991, the licensee noted that the overspeed reset plunger was sticking. The licensee issued WR AF 131746 to inspect and repair the sticking reset plunger. No work was performed under WR AF 131746 until May 28, 1991.

On May, 3, 1991, the licensee issued WR AF 151569 to document that the overspeed reset plunger was stuck in the tripped position. This work document was voided because WR AF 131746 (initiated February 3, 1991) was open and the work could be performed under the previously initiated document. When the licensee worked on the trip mechanism, a substance that resembled a sealing compound was found on the overspeed tappet and ball assembly. The licensee cleaned the components and returned the unit to service. The licensee then issued SPR 910223, on May 29, 1991, to evaluate the source of the apparent sealing compound. The licensee concluded that the substance was, in fact, sealing compound and took actions to preclude the application of excessive sealing compound in the future. This SPR was closed August 28, 1991.

On July 5, 1991, plant engineering provided an answer to RFA 90-1284 regarding the lubrication frequency. Engineering concluded that the plant could continue to use the specified oil type (Mobil Vaprotek Light oil) and to follow the oil sampling frequency specified in the plant general procedure.

During testing of the Pump 24 turbine on September 14, 1991, the turbine tripped on overspeed and could not be reset. The licensee issued Service Request AF 154225 to inspect and repair the cause for the reset mechanism not functioning. The licensee identified that the tappet and ball assembly was covered with what appeared to be a "tar-like" substance. The licensee cleaned the assembly (including an oil change with Mobil Vaprotek Light oil) and returned the unit to service. The licensee did not issue an SPR or investigate the situation any further.

On October 2, 1991, the licensee initiated RFA 91-1465 to determine whether the high temperatures identified by thermography of the Unit 1 turbine-driven auxiliary feedwater pump trip throttle valve, MOV-514, could cause the oil in the turbine to deteriorate. The RFA also requested that a determination be made if carbonized oil could affect the overspeed trip operation and to make recommendations/initiate design corrective action to correct conditions determined to be operationally unacceptable. This request was initiated for both units with a due date of October 3, 1991. A conditional release was provided on the due date based on a review of the oil flashpoint. The final disposition, including the authorization to utilize a different oil, Mobil DTE 797, was provided February 13, 1992. The engineering response identified that, if Mobil Vaprotec Light oil is exposed to temperatures greater than 120°F, the rust inhibitor could come out of solution and result in nonabrasive deposits in the system. This disposition was based in part on the vendor's letter dated November 6, 1992. The letter also identified that "prior to the addition of the concentrate (Mobil Vaprotec Concentrate) the system should be inspected to insure that deposits have not formed due to excessive temperatures and moisture."

On March 3, 1992, the system engineer issued the system health report for the auxiliary feedwater system. The report identified that "problems in both units with oil additives and oil system sludge accumulation has precipitated a change to the oil type used in the auxiliary feedwater terry turbines. Efforts are in progress to make the change." During the inspection, the team noted that the licensee had scheduled the oil replacement for the Unit 2 turbine for September 1993. The report also identified a line slope problem on the main steam supply to the Unit 2 terry turbine as well as the need to repair a leaking trip and throttle valve (AF-MOV 514) to minimize the possibility of an overspeed trip occurring due to condensate carryover. The team was informed at the time of the inspection that the trip and throttle valve had been repaired. This was based in part on discussion with the licensee and the thermography surveillance performed on December 10, 1992, which the team was informed did not indicate leakage past the valve. It was later learned that the valve had not been repaired until after the inspection period.

On March 6, 1992, the overspeed reset plunger again stuck and would not reset after a manual trip of the turbine-driven auxiliary feedwater pump. This time, the licensee found the ball and tappet assembly "caked with gummy oil." The licensee cleaned the assembly and returned the unit to service. The licensee did not issue an SPR or investigate the situation any further.

The licensee had numerous opportunities to identify and correct the root cause for the overspeed reset plunger sticking. The licensee failed to promptly identify and correct the root cause for the sticking. When the cause was finally identified, the licensee did not take prompt actions to correct the problem. The licensee replaced the Vaprotek Light oil in the Pump 14 turbine, during the latest Unit 1 refueling outage, and in the Pump 24 turbine on December 16, 1992, both several months after identifying the corrective actions required.

Criterion XVI to 10 CFR 50, Appendix B, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions to be taken preclude repetition. The failure to promptly identify and correct the cause of the sticking overspeed seat plunger was the third example of a violation of 10 CFR 50, Appendix B, Criterion XVI (498;499/9235-02).

During the inspection period, the team reviewed the turbine-driven auxiliary feedwater pump turbine vendor manual and found that the manual did discuss flushing of the turbine oil system for nuclear units, but did not provide a frequency for the flushing. The manual also stated that the oil should not contain any particles greater than 200 microns. Although these criteria were in the vendor manual, the licensee did not have any procedures addressing the flushing of the system, nor were there any requirements to evaluate oil samples for particulates. During the Unit 1 turbine oil replacement in August 1992, and the Unit 2 turbine oil was replaced on December 16, 1992, system flushing was not performed in accordance with the vendor manual recommendations. The licensee's basis for this action was that the Mobil Vaprotec Light oil and the Mobil DTE 797 are compatible. The team noted that, after March 1992, the two oils were mixed by the addition of Mobil DTE 797 to the turbine oil reservoirs, which contained Mobil Vaprotec, each time oil was added. The team was provided with a letter from the vendor stating the oils were compatible; however, this letter was not provided until December 9, 1992, after the team questioned the compatibility of the two oils. The team also noted that the licensee had not provided a justification for not performing the recommendation in the November 6, 1992, vendor letter to inspect the system to ensure that deposits had not formed from exposing the Mobil Vaprotec Light oil to excessive temperature and moisture.

3.3.4 Residual Heat Removal (RHR) System Valve Actuator Breaker Replacement

The team reviewed Temporary Modification T2-RH-90-0044 for the instantaneous current trip settings on the supply breaker for Motor Operated Valve (MOV) 2RH-0060B. The supply breaker was a type 10M breaker with an instantaneous trip setpoint of 84 amperes. The temporary modification replaced the 10M breaker with a 30M breaker, which had an instantaneous trip setpoint of 105 amperes. The motor that this breaker supplied had a rated steady state current of 7 amperes; however, during testing, the licensee found that the motor was drawing a starting current of approximately 28 amperes. No root cause evaluation was performed to determine the reason for the increased current demand. The licensee initiated the temporary modification on Valve 2RH-0060B and developed a permanent modification to upgrade the breakers for Valves 1RH-0060A and -B and 2RH-0060A and -B to 25M breakers. The team determined that the motors and cabling would be protected with the larger breakers installed. The team considered the lack of a root cause evaluation to be a weakness.

3.3.5 Maintenance Backlog Prioritization

Based on a review of the October 1992 Station Report, the team determined that the licensee was not meeting their service request backlog reduction goals (5,146 open service requests versus a year end goal of 1100). The average age of a service request was 169 days. The average time to complete a service request once scheduled was 73 days. The licensee stated that the backlog for the nonoutage unit, in this case Unit 2, typically was the largest at this stage since resources were diverted to the unit, which was in a refueling outage. The licensee stated that Unit 1 was accepted from construction with over 3000 open work items. Unit 2 was accepted with considerably fewer open work items. These work items principally pertained to balance of plant equipment. These work items were carried over into the present service request prioritization system. These items can be directly or indirectly attributed to many of the low priority work items.

The team reviewed the open Unit 2 service request log dated December 3, 1992. Nonemergency work items requiring licensee prompt attention (Priority 2 through 3C) were reviewed to evaluate their impact on safety-related equipment. Several service requests that could potentially represent operability concerns were identified for further review. All were determined to have been acceptably dispositioned except Service Request SF-101323, initiated on November 25, 1991.

Service Request SF-101323 was written to identify that the sequence start times for Essential Chiller 21B (3V111VCH002) did not meet anticipated design values during testing. The Updated Safety Analysis Report Table 8.3-3, Emergency Electrical Loading Requirements, identifies that the chiller should have started at 180 seconds for both a loss of offsite power test and a concurrent loss of offsite power and safety injection test. With Essential Chiller 21B running, a safety injection and a loss of offsite power were initiated. The chiller was stripped from its electrical bus and restarted at 139 seconds. During the second test, with Essential Chiller 21B running, a loss of offsite power was initiated; the chiller was stripped and restarted at 75 seconds.

TS 4.8.1.1.2.e.11 requires that each standby diesel generator shall be demonstrated operable at least once per 18 months, during shutdown, by verifying that the automatic load sequence timer is operable, with the first sequenced load verified to be loaded within 1.0 second and 1.6 seconds and all other load blocks within $\pm$10 percent of its design interval.

The licensee determined that the surveillance test met the intent of the TS because the load sequencer value was within tolerance. The subsequent failure of the chiller to load within the total 180 seconds was determined by the licensee not to be an operability concern. The timing difference was attributed to the chiller control circuit which is designed to block the "standby" chiller start signal until the postlube and prelube cycles are completed. The team determined that the vendor had previously communicated that the chiller was capable of starting under short cycle conditions. Service Request SF-101323 was written and assigned Priority 3C. The service request was scheduled to be worked in the next Unit 2 refueling outage, 2RE03, in February 1993.

Following the onsite inspection, the licensee declared Essential Chiller 21B inoperable and repaired the timing circuitry. A loose fuse clip, which deenergized a portion of the chiller control circuitry, was determined to be the cause of the failure.

The team identified that Surveillance Procedures 1/2-PSP02-SF-0001A, -1B, -1C, -2A, -2B, and -2C, "ESF Diesel Sequencer 1A/1B/1C/2A/2B/2C Timing Test," did not verify the entire time sequence corresponding to the loading of the chillers. These procedures only verify the time sequence to the point at which the chiller units receive a start signal and the units' compressor oil pumps are loaded (a fraction of the chiller's load). The time delay introduced by the chiller control circuit was not tested.

The failure to verify that the automatic load sequence timer was operable with the first sequenced load verified to be loaded within 1.0 second and 1.6 seconds, and all other load blocks within $\pm$10 percent of its design interval, was considered a violation of the requirements of TS 4.8.1.1.2.e.11 (498;499/9235-03).

3.3.6 Control of Personnel Overtime

The team reviewed the personnel overtime records for the operations, maintenance, engineering, and radiation protection departments. The records were requested for Unit 1 during the period of the fourth refueling outage, which was ongoing at the time of the onsite portion of the inspection. After the team requested the records, the licensee determined that four individuals had exceeded 72-hours worked in a 7-day period without prior plant manager approval. One occurrence involved an I&C technician and three additional occurrences involved electrical maintenance personnel.

TS 6.2.2, "Unit Staff," establishes limits on minimum shift crew composition and working hours. It requires that adequate shift coverage be maintained without the routine use of substantial amounts of overtime. The objective is to have operating personnel work a normal 40-hour week while either unit is operating. In the event that unforeseen problems require a substantial amount of overtime, or during extended periods of unit shutdown for refueling, maintenance, or modification, the 40-hour work week can be exceeded on a temporary basis. The TS establish the guideline that an individual should not be permitted to work more than 72-hours in a 7-day period, excluding shift turnover time. Any deviation from the guideline has to be authorized by the plant manager, or equivalent, in accordance with established procedures. The licensee implements this requirement by Procedure OPGP02-ZA-0060, Revision 4, "Overtime Approval Program."

There have been two previous occurrences, identified by NRC, in which the licensee failed to comply with the TS overtime requirements. A Notice of Violation was issued in NRC Inspection Report 50-498/91-11; 50-499/91-11 for four unit supervisors and two shift supervisors that exceeded the TS guidelines without prior plant manager approval. A noncited violation was documented in NRC Inspection Report 50-498/92-21; 50-499/92-21, paragraph 4.1, for a radiation protection technician working more than 72 hours in a 7-day period without plant manager authorization.

Criterion XVI to 10 CFR 50, Appendix B, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions to be taken preclude repetition. The failure to take adequate corrective action to preclude repetition was the fourth example of a violation of 10 CFR 50, Appendix B, Criterion XVI (498;499/9235-02).

3.3.7 MOV Maintenance Procedures

The team selected SPR 920045, which was initiated on February 4 and voided on February 21, 1992, to document concerns with the adequacy of MOV maintenance procedures in order to perform an in-depth review of the basis for voiding the SPR. The team made the following observations.

3.3.7.1 Voidance of SPR 920045

SPR 920045 was initiated because the originator of the SPR was concerned that mechanical maintenance was being performed on safety-related and nonsafety-related MOVs without approved maintenance procedures. The SPR identified that three MOV procedures were deleted in 1990 because the procedures were considered to be inadequate; however, no new procedures were implemented. The originator noted that MOV corrective maintenance was performed using work instructions and vendor drawings. The originator was concerned that the quality level of job specific work instructions was not consistent, thereby potentially affecting the adequacy of MOV maintenance. The originator was also concerned about the lack of formal MOV training for mechanical maintenance planners who had been given the new responsibility for planning MOV mechanical maintenance activities prior to the second Unit 2 refueling outage. Given the importance of MOV operability on the overall safe operation of the plant and the complex nature of certain types of MOV maintenance activities, the team was concerned with the adequacy of the licensee's actions to resolve the issues documented in this SPR. In addition, NRC previously documented an equipment failure stemming from the use of a vendor drawing during maintenance in lieu of approved procedures (refer to NRC Inspection Report 50-498/91-35; 50-499/91-35).

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This SPR was recommended to be voided on the basis of a February 21, 1992, memorandum from the Maintenance Manager to the SPR Coordinator just prior to an announced NRC inspection of the licensee's MOV program. The SPR was recommended for voidance primarily on the basis that adequate work instructions are developed for each MOV service request, that work instructions provide needed flexibility during the conduct of MOV maintenance, and that there was not evidence of MOV degradation because of a lack of properly performed maintenance. Discussions with some of the involved personnel revealed that there was a difference of opinion relative to the adequacy of this disposition. The team determined that there were several meetings and discussions regarding the validity of the issues documented in the SPR prior to it being voided.

3.3.7.2 MOV Material History

In order to perform an independent assessment of the adequacy of MOV maintenance activities and procedures, the team performed a review of selected MOV work packages. The team selected a sample of 25 MOV maintenance activities that were performed during the second Unit 2 refueling outage and the third Unit 1 refueling outage. In addition, other MOV work packages pertaining to the ECW and auxiliary feedwater systems were reviewed by the team during the conduct of other inspection activities. The following observations were identified by the team:

- The licensee identified several MOVs that were lubricated with the wrong grease. Previous NRC inspections have identified other examples of inadequate lubrication of other safety-related components.

- For two MOVs, licensee maintenance workers identified an improper torque switch setting and an improper limit switch setting.

- For two safety-related MOVs, repetitive problems were not resolved for 2 or more years.

- A craft worker identified that the work instructions associated with the disassembly of one MOV actuator were inadequate and had to be returned to the planners for revision.

- During the repair of the Unit 2 Centrifugal Charging Pump 2A Bypass Valve C2CVMOV8348, the craftsman noted that the shaft of the MOV actuator declutch level was bent at the handle and that it appeared to have been bent in order to clear the system piping associated with the valve so that the valve could perform its function. No SPR appears to have been initiated for this condition. In addition, the craftsman inadvertently installed the declutch fork backward, but the craftsman detected this error and corrected it.

On the basis of the issues discussed above, the team concluded that one or more of these problems may have been caused by deficient MOV work instructions or procedures. In addition, the problems discussed above are indicative of potential and actual MOV performance problems, of which the corrective actions taken may have been inadequate and untimely. As a result, the issues of whether SPR 920045 was appropriately voided in accordance with the SPR procedure and whether the corrective actions taken for MOV deficiencies were adequate will remain unresolved (498;499/9235-04) pending further NRC review of MOV maintenance practices, procedures, and material history in order to determine whether these issues constitute violations of NRC requirements.

3.4 Audit and Self-Assessment

The licensee's quality assurance (QA) group performs independent surveillances, audits, and assessments of the conduct of operations at STP. The team noted that QA audit findings concerning the corrective action program had resulted in significant program revisions. The team found that the latest corrective action program identified in Procedure OPGP03-ZX-0002, Revision 0, "Corrective Action Program," combined satellite corrective action programs (e.g., security incident reports and chemistry condition reports) into one program. The team noted that the licensee had not completed implementation of the revised corrective action program.

The team observed QA personnel during the performance of a QA surveillance. QA personnel observed the performance of Procedure PSP06-PK-0002, Revision 3, "4.16KV Class 1E UV Relay Channel Calibration/TADOT - Channel 2." The team noted that a service request had been initiated to replace similar relays located nearby. The team was informed that, during a review of the periodic surveillance test data, the system engineer determined that the relays were drifting excessively and initiated the service requests. The team considered the identification and initiation of corrective actions to be an effective integrated use of the overall corrective action program.

The team reviewed the results of QA Audit 92-10, which was conducted in July 1992. The QA audit identified examples in which root causes for problems were not adequately determined. The team reviewed 12 SPRs issued after September 9, 1992, and found three instances in which the root cause determination was a restatement of the problem. One of the examples involved a chafed wire in a reactor trip bypass breaker. The team found that each of the SPRs met the threshold for requiring a root cause analysis and consideration of generic implications. The team noted that, in each instance, the investigating manager and the corrective action group administrator approved/concurred with the analyses.

The team discussed the corrective action program changes, which became effective in September 1992, with plant personnel, including maintenance, operations, security, quality control, and QA personnel. These discussions were directed at ascertaining their knowledge and understanding of the revised corrective program. Excluding the licensed operators and the QA personnel, all but one individual stated that they were unaware of the revised corrective action program requirements. Of the maintenance personnel interviewed, none had ever initiated an SPR. The team found that licensee management had provided training on the changes to the corrective action program, as identified in Procedure OPGP03-ZX-0002 to the engineering staff, licensed operators, and management and supervisory personnel. The first line supervisors were expected to inform their workers of the corrective action program changes. The team noted that Procedure OPGP03-ZX-0002, Revision 8, Sections 4.1.1 and 4.1.2, states, in part, "any person at the STPEGS who identifies or becomes aware of a Condition Adverse to Quality (CAQ) or Significant Condition Adverse to Quality (SCAQ) SHALL promptly document the occurrence using an SPR Form . . . ." and "the initiator provides the SPR to his immediate supervisor for concurrence." The team concluded that maintenance personnel were not sufficiently cognizant of the procedure requirements to assure that they would appropriately initiate the corrective action program as required by Procedure OPGP03-ZX-0002 (refer also to Section 3.2 of this report).

The team observed portions of a Nuclear Safety Review Board conducted during the inspection. The team concluded that the Nuclear Safety Review Board was very thorough and performed its oversight functions effectively. The board members were well informed of the issues being discussed and continually focused on potentially safety significant issues.

3.5 Conclusions

The team found that the licensee's program for the identification and resolution and of hardware and program implementation deficiencies was well defined. It was noted that the SPR process provided the means for prompt identification of concerns to the shift supervisor and plant management. However, the team concluded that the process was not consistently implemented.

The team noted that maintenance personnel had not received specific training on the revised corrective action process. The methods used to disseminate information to maintenance personnel was not effective in assuring that they were cognizant of the recent changes to the corrective action process. In addition, many plant workers that were interviewed indicated that they had never initiated an SPR. The team determined that management emphasized that maintenance personnel should report deficiencies which could result in SPRs to their supervisors and that it was not their expectation to initiate an SPR. This expectation was found to contradict the specific requirements for initiating an SPR. The team was concerned that an informal, undocumented corrective action process is occurring, which could result in potentially significant concerns not being appropriately identified. The team identified instances where SPRs were not initiated in accordance with the corrective action program. In addition, the team identified several hardware and programmatic problems in which the corrective actions appeared inadequate or were untimely. A violation of 10 CFR 50, Appendix B, Criterion XVI with four examples was identified concerning the licensee's failure to take adequate corrective action.

A violation of the requirements of TS 4.8.1.1.2e.11 was identified. This violation concerned the failure to verify that the automatic load sequence timer was operable within its design interval.

An unresolved item will track the issues of whether SPR 920045 was appropriately voided in accordance with the SPR procedure and whether the corrective actions taken for MOV deficiencies were adequate.

The licensee's implementation of their lubrication control program was poor. Vendor recommendations for system flush recommendations were not incorporated into work instructions. Several engineering RFA documents were not promptly responded to.

The team also identified two observations where corrective actions were implemented to correct the immediate deficiency; however, the causes for the deficiencies occurring had not been determined. The deficiencies involved an RHR MOV breaker that was upgraded per a temporary modification without determining the cause for the breaker tripping and a reactor trip bypass breaker chafed wire.

4 OPERATIONS SUPPORT

4.1 Overview

The team reviewed various operational support activities in the areas of plant procedures, work activity planning and scheduling, radiological protection, and security.

4.2 Plant Operating Procedures

The team reviewed five safety-related procedures to determine whether field changes (FCs) were being incorporated into the latest procedure revision. The procedures were:

OPOP02-CC-0001, Revision 1, "Component Cooling Water System"
1POP02-CH-0001, Revision 9, "Essential Chill Water System"
1POP02-CS-0001, Revision 6, "Containment Spray Standby Line-up"
1POP02-RC-0004, Revision 4, "Operation of Reactor Coolant Pump"
1POP02-SI-0002, Revision 10, "Safety Injection System Initial Line-up"

Procedure OPGP03-ZA-0002 recommends, in part, that quality-related procedures shall receive a biennial review and that a revision to the procedure should be considered if it contains three or more FCs, or if it contains FCs more than 2 years old. The team determined that some of the procedures that were reviewed contained FCs greater than 3 years old. Procedure 1POP02-RC-0004, Revision 4, "Operation of Reactor Coolant Pump," had two FCs greater than 3 years old. Procedure 1POP02-SI-0002, Revision 10, "Safety Injection System Initial Line-up," had two FCs greater than 2 1/2 years old. It was later verified that these FCs were reviewed along with the biennial review but were not incorporated into the procedure in a new revision.

The team noted that the biennial review process did not include the same level of oversight as required for a procedure revision. The team noted that this could result in procedure inadequacies not being identified. This concern was discussed with licensee management personnel for their review. The licensee indicated that they were systematically addressing the FCs to incorporate them into procedures with more than five FCs and then to incorporate those FCs which were handwritten.

In addition, the team had numerous discussions with the operations staff. During these discussions, a number of operators, both licensed and nonlicensed, expressed their disappointment in the quality of new and revised procedures being produced by the technical operations support staff. Plant operators stated that many new and revised procedures were forwarded to the operations staff for comment without having been adequately reviewed or verified through system walkdown. In addition, some operators stated that a relatively high number of these procedures contained flaws and were of poor technical quality. However, the team did not identify any technical inadequacies relative to the procedures that were reviewed during the inspection.

4.3 Maintenance Outage Planning

The team reviewed the licensee's implementation of work outage planning activities. Maintenance work activities had been classified as either outage work or nonoutage work. Unit 1 Refueling Outage 1RE04 was planned based on the philosophy that only outage work would be scheduled for the outage. As a result, the Unit 1 EDGs were taken out of service for major rework without working the EDG nonoutage service requests. The licensee revised their planning philosophy during Refueling Outage 1RE04 to work off the backlog for certain selected safety-related systems. The EDGs were again taken out of service and the majority of the open service requests were completed on EDGs.

The licensee is evaluating whether to implement some nonoutage service requests for major equipment during the pending Unit 2 refueling outage. The team noted that the licensee's guidelines for evaluating the outage work scope does not include all major equipment.

4.4 Maintenance and Surveillance Scheduling

Routine surveillance testing, preventive maintenance, and long-range maintenance activities are scheduled by functional equipment groups. The equipment is taken out of service on a train window basis which coincides with the routinely performed surveillances. A rolling 12-week schedule was in use at the time of the inspection. The licensee planned to change to a rolling 24-week schedule during 1993. The licensee indicated that this should significantly decrease the time that equipment is rendered inoperable for maintenance and surveillance activities. The team noted that the licensee adhered to the established train windows during the 2 weeks onsite.

4.5 Radiological Controls Support

During tours of both units, the team observed several radiological control practices pertaining to radiologically restricted area (RRA) ingress and egress, contaminated and high radiation area postings, frisking techniques, and personnel control at the RRA entrance.

4.5.1 RRA Control Point Observations

The team observed numerous RRA ingress and egress by licensee personnel. Procedurally required log-in was accomplished during all team observations.

In addition, the team observed individuals correctly frisking their hard hats, shoes, and ankles upon exiting the RRA. The licensee's ALCOR computerized system of logging in and out of the RRA expedites and accurately accounts for personnel, in addition to providing good accountability for radiation work permit usage.

4.5.2 Material Removal From the Unit 1 RRA

On December 7, the team observed material being removed from the Unit 1 RRA through the equipment doors on the 60-foot level of the mechanical auxiliary building. This evolution required support from: the security force, which provided a compensatory posting while the doors were unlocked and open; health physics (HP), which provided a technician to frisk the material being removed from the RRA and to maintain control of the RRA exit point; site support services, which provided the crane and rigging support; and mechanical maintenance, which provided personnel to physically move the material.

The method utilized by the licensee required the crane operator to position an equipment basket on the ledge directly outside the doors to the 60-foot level of the maintenance auxiliary building. After the material was surveyed and determined to be releasable, the workers in the basket and inside the open doors (in the RRA) would load material into the basket. After the basket had been loaded, the material was lowered into a waiting truck for disposal. The team noted that the licensee had not established the entry area as an alternate RRA entrance/exit.

During the evolution, the team noted that a security officer was present, providing the appropriate compensatory posting while the maintenance auxiliary building doors were open. An HP technician was available and was utilized for surveying the R-11 refrigerant barrels that were being removed from the RRA. In addition, a group of three workers, under the direction of the HP technician, were loading the radiologically clean barrels into the material basket. The team observed that the HP technician was extremely thorough when frisking the barrels prior to permitting them to be moved out of the RRA and loaded into the basket. No activity was detected on any of the barrels.

The team noticed that the workers were permitted to move freely back and forth from the normal RRA boundary at the door sill over onto the outside ledge. One worker was observed to move from the ledge into the RRA, assist another worker in loading an R-11 barrel into the basket, and then return to the ledge outside the RRA. The worker conducted this activity twice without performing any type of survey. Following the worker's second move from the ledge into the RRA, the HP stopped the individual from returning to the ledge and frisked his feet.

TS Section 6.11.1 states that procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure. Procedure 0PGP03-ZR-0002, Revision 9, "Radiological Controlled Area Access and Work Control," Step 5.5, states, in part, that, when exiting the RRA, personnel will use a personnel contamination monitor and, if not available, will perform a whole-body frisk as directed by HP. The team identified the failure of the craft worker to frisk in accordance with Procedure OPGP03-ZR-0002 prior to exiting the RRA as a violation of Procedure OPGP03-ZR-0002 and TS Section 6.11.1 (498;499/9235-05).

The team interviewed the on-shift HP supervisor following the material transfer evolution. The supervisor stated that, although there was no procedure that established guidelines for the transfer of material through the mechanical auxiliary building doors, HP technicians typically established a radiologically clean buffer area approximately 25-feet from the mechanical auxiliary building doors in order to facilitate the movement of materials and to preclude the occurrence of RRA boundary violations. The supervisor was not aware that the material removal evolution had taken place without this buffer area being established. In addition, the team noted that no prejob briefing had taken place to caution the workers concerning the RRA boundary.

The team concluded that the radiological control practices associated with the transfer of material from the RRA were poor. This included the prejob planning, lack of procedural guidance, and actual conduct of the activity.

4.5.3 Unit 2 General Radiation Monitor Calibration

On December 4, while conducting sustained observations of the Unit 2 control room, the team observed calibration activities for General Radiation Monitor RT-8066. The team noted that the calibration was being conducted in accordance with Procedure OPRP05-RA-0025, Revision 1, "Non-Technical Specification Monitor Setpoints." The test source used for this calibration had a relatively high curie content, with radiation readings of 1500 mrem on contact and 22 mrem at 18 inches. The HP technicians were tasked with conducting this surveillance procedure.

The HP technicians installed the test source and conducted a radiation survey in order to determine the area boundaries where the radiation field dropped below 0.5 mrem in accordance with the surveillance procedure. The HP technicians established the boundaries within the control room and at the outside of the control room south door. The area boundaries within the control room were established with yellow and magenta rope. The control room south door was posted on the outside with a radiation sign. No barriers at the control room south door were established.

During the calibration, while the source was exposed, a licensee employee carded into the control room through the south door and violated the radiological posting in place for the surveillance. The HP technicians were able to stop the individual prior to his actual entry into the control room and exposure to the test source radiation field in excess of 0.5 mrem. It was noted that the individual was issued a TLD and was, therefore, monitored for any potential exposure.

The shift supervisor immediately suspended access into the control room through the south door. He directed that a rope with the radiation sign attached be suspended across the door's threshold such that a positive barrier to entry was available. In addition, the shift supervisor directed the card reader for the control room south door be disabled in order to preclude further breaches of the posting. Following the change in the posting, the calibration was completed without further incident.

Procedure OPRP02-ZX-0007, Revision 5, "Radiological Posting and Warning Devices," Paragraph 4.2.2 requires, in part, that, the radiological signs be hung from barriers such that the posting is clearly visible when approaching the area. Paragraph 4.3, establishes areas as requiring radiological postings at any area where access is controlled by HP for purposes of protection of individuals from exposure to radiation and or radioactive materials. Areas outside the main Units 1 and 2 radiologically controlled area should be identified as a radiologically controlled area if the dose rates at 18 inches exceed 0.5 mr/hr.

The team identified the failure to establish an adequate radiological barrier as a violation of Procedure OPRP02-ZX-0007 and TS 6.11.1 (498;499/9235-05).

4.6 Security Force Support

In general, security support for plant operations was good. However, one instance was noted in which an operator's access to a vital area was unnecessarily delayed. On December 9, while the team was conducting a walkdown of the ECW system, it became necessary for team members to access the Unit 1 ECW intake structure. The team discovered that the card reader had been taken off line and that security would have to open the intake structure door in order to gain access. In addition to the team requiring access, the Unit 1 yard watch, a nonlicensed operator, required access.

After contacting the security shift, both the team and the operator were required to wait approximately 20 minutes for a security officer to arrive and unlock the door. When the team later asked the security shift supervisor whether it was considered acceptable for an operator to wait 20 minutes to gain access to a structure containing safety-related equipment, the supervisor stated that, had the control room informed the security force that the request was important, an officer could have been dispatched much quicker.

Although the operator could have returned to the control room and obtained a set of keys, the team considered the security force response in this instance to be poor. The team was concerned that operations personnel may be unnecessarily delayed in responding to an actual plant event if the immediacy of the operator's response is not promptly conveyed to security personnel.

4.7 Conclusions

The team concluded that operations was generally well supported by other plant organizations. It was noted that procedures for which the biennial review had been completed still had outstanding FC notices posted against them. Because the procedure review process for the biennial review was not as extensive as that required for procedure reviews, the team was concerned that the operations support staffing was not sufficient to ensure that high-quality procedures were always provided.

A violation with two examples was identified for the control of personnel entering and leaving the RRA for the transfer of material without monitoring for contamination and for inadequate radiological posting for an area outside the Units 1 and 2 main RRA.

5 PLANT AND AREA TOURS

5.1 Overview

The team conducted extensive walkdowns of the facility to ascertain the physical plant condition and the adequacy of the level of housekeeping. The areas toured included the site protected area, electrical control buildings, mechanical auxiliary buildings, and Unit 1 reactor containment building.

5.2 Units 1 and 2 - Modification Authorization

During the tours conducted in both units, the team reviewed plant configurations which had been temporally altered from the original plant design. The team noted that, in each case, the modifications were properly authorized. One example involving the essential chilled water system, Temporary Modification T1-EW-89-0065, was correctly installed, but the temporary modification tag had fallen off. The system engineer indicated that the tag would be replaced. A similar nearby configuration was properly tagged.

5.3 Housekeeping

The team toured the Unit 1 reactor containment building on December 6. The accessible areas of the building were clean. A few bags of waste remained in accessible areas next to the escape hatch and the personnel airlock. These items were conspicuously staged for removal. Radiological posting material and a few extension cords remained. The licensee demonstrated they had accounted for the material and would remove it prior to entry into Mode 3.

On December 6, the team toured the Unit 1 mechanical auxiliary building. It was noted that this building required additional clean up effort to remove materials which were left over from completed refueling outage activities.

Prior NRC management visits to STP and the latest Systematic Assessment of Licensee Performance report had identified concerns with the licensee's housekeeping efforts. The team observed that considerable effort had been exerted by the licensee to improve station cleanliness prior to the team's arrival. During the inspection period, the team noted a slight decline in the overall housekeeping efforts.

During a tour of Unit 2, the team observed a wooden folding table and wooden scaffolding material stored in the EDG 23 room. The team noted that the table was not being controlled in accordance with Procedure OPGP03-ZF-0004, Revision 1, "Control of Transient Fire Loads." When this condition was reported to the Unit 2 control room, the shift supervisor took immediate action to have the material removed. The team identified the failure to control the combustible loads as a violation of Technical Specification 6.8.1.h and Procedure OPGP03-ZF-0004 (498;499/9235-06).

During a tour of the Unit 1, electrical auxiliary building, on December 7, 1992, the team identified that the fire doors to the qualified parameter display system rooms, which include the room for the auxiliary shutdown panel, was missing the door sill. The team noted that test cables were easily run beneath three fire doors in the area. The licensee initially indicated that the doors were acceptable as-is. They stated that the issue had been previously identified and that the doors were qualified.

The team continued to review the fire protection code requirements. Station Procedure OPGP03-ZF-0018, Revision 6, "Fire Protection System Operability Requirements," paragraph 4.8 requires, in part, "SEALING DEVICES in fire rated assembly penetrations (fire doors; fire dampers; and cable, piping, and ventilation duct penetration seals) shall be operable whenever equipment protected by the fire rated assemblies is required to be operable by the Technical Specifications." The licensee's Updated Safety Analysis Report 3.1.2.1.3 states, in part, that the plant has been designed in accordance with the recommendations of the National Fire Protection Association. The National Fire Protection Association National Fire Code, 1975 version, requires, in part, that clearances for flush-mounted doors shall not exceed 3/4 inch at the sill.

It was determined that the largest gap from the floor to Door 23 was 1 1/4 inch. After further discussions, three of the doors were determined not to meet the National Fire Protection Association requirement to maintain a maximum clearance of 3/4 inches at the sill. The team identified the failure to meet Procedure OPGP03-ZF-0018, "Fire Protection System Operability Requirements," and the National Fire Protection Association National Fire Code, 1975 version, as a second example of Violation 498;499/9235-06.

5.4 Emergency Lighting

The team identified several examples in which emergency lights did not have the green ready light illuminated. The team was subsequently able to verify, through discussions with the licensee, that the emergency lights were operable. The licensee demonstrated that they have implemented a routine program to perform preventive maintenance on the emergency lights required by 10 CFR 50, Appendix R. A design change was being evaluated to permit easy replacement of the ready status lights. In the current configuration, the ready light cannot be replaced without changing an entire circuit card.

5.5 Conclusions

The team conducted several tours within the two units and the general site area. The team noted that housekeeping has improved; however, some decline was noted during the 2 weeks the team was onsite, as was evidenced by materials not being picked up after completion of some work activities. The team identified two examples in which the requirements of the licensee's fire protection program were not satisfied.

6 FOLLOWUP (92701)

(Closed) Unresolved Item 498/9220-04; 499/9220-04: Temporary Modifications

The team reviewed the licensee's program for controlling temporary modifications and assessed its implementation. It was determined that the licensee was complying with the procedural requirements. Although several temporary modifications had exceeded the timeliness goals for being removed, including the temporary modification for the RHR valve breaker replacement, no violation of NRC regulatory requirements had occurred.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Energy Company

C. A. Ayala, Supervisory Engineer, Licensing
R. L. Balcom, Director, Nuclear Security
M. J. Berg, Manager, Division Manager, PED Engineering Support
C. T. Bowman, Administrator, Corrective Action Group
M. A. Burnett, Manager, Integrated Planning and Scheduling
M. K. Chakravorty, Executive Director, Nuclear Safety Review Board
R. Dolby-Paggett, Engineering Specialist, Licensing
D. J. Denver, General Manager, Nuclear Assurance
J. M. Gruber, Director, Independent Safety Enginneering Group
D. P. Hall, Group Vice President, Nuclear
R. W. Heward, Jr., Nuclear Safety Review Group, Consultant
W. H. Humble, Plant Programs Manager, Plant Engineering Department
G. W. Jones, General Manager, Information Resources
T. J. Jordan, General Manager, Nuclear Engineering
W. J. Jump, General Manager, Nuclear Licensing
W. H. Kinsey, Vice President, Nuclear Generation
M. A. Ludwig, Manager, Nuclear Training
T. A. Meinicke, Manager, Planning/Assessment
M. Pacy, Manager, Design Engineering
A. L. Parkey, Plant Manager
R. J. Rehkugler, Director, Quality Assurance
S. L. Rosen, Vice President, Nuclear Engineering
J. D. Sharpe, Maintenance Manager
J. W. Soward, Manager, Quality Control and Material Testing
T. E. Underwood, Deputy Plant Manager
D. O. Wohleber, Director, Records Management and Administration

1.3 NRC Personnel

A. B. Beach, Director, Division of Reactor Projects, Region IV
R. J. Evans, Resident Inspector
A. T. Howell, III, Chief, Section A, Division of Reactor Projects, Region IV
W. B. Jones, Senior Resident Inspector
J. I. Tapia, Senior Resident Inspector

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

2 EXIT MEETING

An exit meeting was conducted on January 12, 1993. During this meeting, the team reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the team.

ATTACHMENT 2

Inspection Finding Index

Inspection Followup Item 498;499/9235-01, paragraph 2.3.4.1

Violation 498;499/9235-02, paragraphs 3.2.4, 3.3.1, 3.3.3, and 3.3.6

Violation 498;499/9235-03, paragraph 3.3.5

Unresolved Item 498;499-9235-04, paragraph 3.3.7.2

Violation 498;499/9235-05, paragraphs 4.5.2 and 4.5.3

Violation 498;499/9235-06, paragraph 5.3