APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/90-30
50-499/90-30

Operating Licenses: NPF-76
NPF-80

Dockets: 50-498
50-499

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

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

Inspection At: STP, Matagorda County, Texas

Inspection Conducted: September 1 through October 12, 1990

Inspectors: J. I. Tapia, Senior Resident Inspector, Project Section D
Division of Reactor Projects

R. J. Evans, Resident Inspector, Project Section D
Division of Reactor Projects

W. B. Jones, Senior Project Engineer, Project Section D,
Division of Reactor Projects

D. N. Graves, Resident Inspector, Comanche Peak, Project
Section B, Division of Reactor Projects

Approved: William B. Jones
for A. T. Howell, Chief, Project Section D
Division of Reactor Projects

11/20/90
Date

Inspection Summary

Inspection Conducted September 1 through October 12, 1990 (Report 50-498/90-30; 50-499/90-30)

Areas Inspected: Routine, unannounced inspection included plant status, onsite followup of events at operating power reactors, onsite followup of written reports of nonroutine events at power reactor facilities, licensee action on previous inspection findings, followup on corrective actions for violations and deviations, operational safety verification, monthly maintenance observations, monthly surveillance observations, preparation for refueling, spent fuel pool activities, and refueling activities.

Results: During this inspection period, personnel errors resulted in one automatic reactor trip (paragraph 3.c), one ESF actuation (paragraph 3.d), and one manual reactor trip (paragraph 3.e). A Unit 1 mode change from hot shutdown to hot standby was made with one train of the high head safety injection (HHSI) system inoperable, which is allowed by the Technical Specification (TS). However, the HHSI system was not restored to operable prior to exceeding the temperature limit specified in the TS (paragraph 3.b). This latter event also appears to have been caused by personnel error, and was the subject of a special NRC inspection (NRC Inspection Report 50-498/90-31; 50-499/90-31). Challenges to safety-related equipment during surveillance and other activities appears to represent a continuing declining trend in these areas.

During this inspection period, the licensee commenced the first Unit 2 refueling outage. Initial outage activities appeared to be well planned and implemented.

The licensee performed work activities in a controlled manner and provided documentation which accurately reflected the work activity. The inspector noted that the licensee did not demonstrate the good coordination for the conduct of maintenance on the Unit 2 spent fuel pool cooling and cleanup system. This system was drained on several occasions for activities that could have been performed with the system drained once. The filling and venting and then draining activity required a significant amount of operations support.

DETAILS

1. Persons Contacted

*W. H. Kinsey, Vice President, Nuclear Generation
*M. R. Wisenburg, Plant Manager
*J. R. Lovell, Technical Service Manager
*G. L. Parkey, Manager, Integrated Planning and Scheduling
*A. K. Khosla, Senior Engineer, Licensing
*W. J. Jump, Maintenance Manager
*C. A. Ayala, Supervising Engineer, Licensing
*A. W. Harrison, Supervising Engineer, Licensing
*W. L. Mutz, INPO Coordinator
*M. K. Chakravorty, Nuclear Safety Review Board Executive Director
*J. D. Bumgardner, Work Control Center Manager
*R. L. Balcom, Manager, Audit and Assessments
*L. G. Weldon, Manager, Operations Training
*M. A. McBurnett, Manager, Nuclear Licensing
*D. W. McCallum, Manager, Plant Operation Support
*S. M. Shropshire, Central Power and Light
*D. F. Bednarczyk, Consulting Engineer, Independent Safety Engineering Group
*D. J. Denver, Manager, Plant Engineering Department
*H. B. Ray, Engineer, Licensing
*F. A. White, Supervisor, Operations Support
*G. N. Midkiff, Director, Nuclear Plant Operations Department
*A. C. McIntyre, Manager, Design Engineer

In addition to the above, the inspectors also held discussions with various licensee, architect engineer (AE), maintenance, and other contractor personnel during this inspection.

*Denotes those individuals attending the exit interview conducted on October 12, 1990.

2. Plant Status (71707)

Unit 1 began the inspection period at 100 percent reactor thermal power. The unit remained at full power until September 10, 1990, when a unit shutdown was required by the Technical Specifications (TS) because of a vital inverter being out of service for more than 24 hours (TS 3.8.3.1 action statement). Unit 1 entered Mode 4 (hot shutdown) on September 11, 1990. The vital inverter was returned to service and a unit startup was initiated. The unit entered Mode 3 (hot standby), followed by Mode 2 (startup) on September 12, 1990. Unit 1 entered Mode 1 the following day. Unit 1 reached 100 percent power on September 16, 1990, following delays in power increases because of inoperable steam generator feedwater pumps.

Unit 1 remained at 100 percent power until September 24, 1990, when power was reduced to 90 percent following a trip of Circulating Water Pump

No. 11. Reactor power was again increased to 100 percent the same day. The next day, a secondary side transient (isolation of extraction steam) occurred, which temporarily dropped reactor power to 99 percent. On September 29, 1990, a manual reactor trip of Unit 1 from 100 percent power was performed because of a problem that developed during Feedwater Isolation Valve 1A surveillance testing. The unit was cooled from Hot Standby to Hot Shutdown (Mode 3 to Mode 4) the same day to allow shutdown of the secondary plant. This was necessary to repair a steam leak from a bellows on the extraction steam line into the main condenser (damage that apparently occurred during a secondary side transient on September 25, 1990). A condenser tube was also repaired because of a leak that appeared following the manual reactor trip.

Unit 1 remained in Mode 4 until October 7, 1990, when Mode 3 was entered following completion of secondary side repairs. The unit entered Mode 2 on October 9, 1990, and then entered Mode 1 the following day. The unit returned to 100 percent power on October 12, 1990, and remained at that power level at the end of the inspection period.

Unit 2 began the inspection period at 100 percent reactor power. The unit remained at full power until September 17, 1990, when the reactor was inadvertently tripped during performance of a surveillance test. Unit 2 was restarted and entered Mode 1 the next day. Unit 2 reached 100 percent power operation on September 19, 1990. The unit remained at full power until September 28, 1990, when an orderly shutdown from 100 percent power was initiated. This planned shutdown was required to begin the Unit 2 first refueling outage. Unit 2 entered Mode 5 (cold shutdown) operation on October 1, 1990, followed by Mode 6 (refueling) operation on October 7, 1990. The unit remained in Mode 6 through the end of the inspection period.

3. Onsite Followup of Events at Operating Power Reactors (93702)

a. Technical Specification Required Shutdown Because of an Inverter Failure (Unit 1)

On September 9, 1990, the inverter that fed Class 1E AC Vital Distribution Panel DP002 failed in Unit 1. This failure caused an engineered safety features (ESF) actuation of the reactor containment building (RCB) and fuel handling building (FHB) heating, ventilation, and air conditioning (HVAC) systems because of a loss of power to their respective radiation monitors. Within 4 minutes of the power failure, power was restored to the distribution panel from its alternate power supply. TS 3.8.3.1 action statement required that a plant shutdown be initiated within 24 hours if Distribution Panel DP002 was not reenergized from its respective DC bus. Because extensive troubleshooting activities, Distribution Panel DP002 could not be returned to service within 24 hours, prompting a unit shutdown in accordance with the TS action statement.

On September 10, 1990, a unit shutdown from 100 percent power was initiated. A Notification of Unusual Event (NOUE) was declared as required by the licensee's emergency implementing procedures for a shutdown required by the TS. Unit 1 reached Mode 3 operation the same day. The NOUE was terminated when the inverter was returned to service the next day. The cause of this event was a failure of the 24 vdc power filter capacitor, which had interrupted power to the inverter controller circuit card and blew two main power fuses. The cause of the power filter capacitor failure had not been clearly identified, although high output voltages on a converter board were suspected to have been a contributing factor. Corrective actions taken by the licensee included: (1) replacement of a converter board, filter capacitor, and fuses; (2) revision of the maintenance manual for troubleshooting activities; (3) trending and analysis of converter board voltage levels; and (4) a review of the generic implications. Licensee Event Report (LER) 50-498/90-21, was issued describing this event in detail.

b. Mode Change with Less than TS-Required Number of High Head Safety Injection Pumps (Unit 1)

On September 12, 1990, a Unit 1 startup was in progress following the required shutdown. A reactor mode change from 4 to 3 occurred during the reactor coolant system (RCS) heatup as defined by the TS. The TS permitted two trains of the high head safety injection (HHSI) system to be inoperable upon entering Mode 3, provided the trains were restored to operable within 4 hours or prior to exceeding 375°F as indicates for an RCS cold leg temperature. During the heatup, the unit supervisor noted that one train of the HHSI system (Train B) was inoperable with the RCS cold leg temperature greater than 375°F. The pump was subsequently determined to have been inoperable (in pull-to-lock) in Mode 3, with the RCS cold leg temperature greater than 375°F for 22 minutes. The cause of the event has been attributed, in part, to poor command and control on the part of the unit supervisor. This event was addressed in detail in NRC Inspection Report 50-498/90-31; 50-499/90-31.

c. Automatic Reactor Trip During Performance of Train S Reactor Trip Breaker Test (Unit 2)

On September 17, 1990, a reactor plant operator (unlicensed) inadvertently tripped Unit 2 from 100 percent power during the performance of a surveillance test. The operator had been performing the Train S reactor trip breaker test in accordance with Procedure 2PSP03-SP-00065, Revision 0, "Train S Reactor Trip Breaker Trip Actuating Device Operational Test (TADOT)." At approximately 3:30 a.m., the operator incorrectly performed Step 7.7.22 of the procedure. Instead of depressing the Train S auto shunt trip test push button, the operator opened the Train R reactor trip breaker panel door and depressed the Train R auto shunt trip test pushbutton. The solid state protection system, which consisted of two logic

trains, R and S, actuated the reactor trip because the Train R reactor trip breaker had not been bypassed for testing.

Following the reactor trip, a main feedwater isolation occurred on low reactor coolant system average temperature and the auxiliary feedwater system actuated on a low-low steam generator level signal. All plant systems responded as expected. The cause of the event was subsequently determined to be a failure of a nonlicensed operator to self-verify that he was in position to open the correct reactor trip breaker panel prior to actual manipulation of the auto shunt trip test pushbutton. Corrective actions taken by the licensee included the generation of a training module emphasizing the importance of attention to detail and self-verification and the training of all plant personnel on self-verification. The licensee has issued LER 50-499/90-013 for this event. This LER will be reviewed during a subsequent inspection.

d. Inadvertent Actuation of Containment Ventilation Isolation System (Unit 2)

On September 26, 1990, an inadvertent ESF actuation of the Unit 2 containment ventilation isolation occurred. The cause of the actuation was a technician incorrectly hooking up a digital multimeter (DMM) in the back of radiation monitoring system Control Panel 2-CP-023. The technician had performed Departmental Procedure 2PSP14-RA-1108, Revision 0, "Spent Fuel Pool Exhaust Monitors A2-RT-8035 and C2-RA-RT-8036 Surveillance Procedure," for the FHB radiation monitors. The inadvertent actuation was caused by the technician placing the DMM leads in the AMPERES jacks instead of the VOLTAGE jacks. When the technician tried to measure the voltage between ground and a terminal point, during performance of Step 5.1.2, a short to ground occurred. Radiation Monitors RT-8012 and -8013 actuated, causing an unplanned actuation of the containment isolation ESF signal. The procedure was suspended, the RCB isolation valves restored, and the sample pump on RT-8011 (tripped by the short) restarted.

e. Manual Reactor Trip Because of a Partial Loss of Feedwater Flow (Unit 1)

On September 29, 1990, with Unit 1 at 100 percent power, Feedwater Isolation Valve (FWIV) 1A went full closed during the performance of a temporary engineering procedure. A manual reactor trip was initiated and an auxiliary feedwater (AFW) system actuation occurred on low-low steam generator (SG) levels. The cause of the event was the incorrect performance of Temporary Engineering Procedure 1TEP07-FW-0018, Revision 0, "Feedwater Isolation Valves Solenoid Dump Valves Alternate Operability Test." During performance of Step 5.4.3, a jumper wire was placed on the wrong terminal points by a technician. The jumper inadvertently landed on Terminal Board TB21 Terminal 02 instead of TB21 Terminal 01. This caused

FWIV 1A to travel full closed, isolating main feedwater flow to SG 1A. A manual reactor trip was initiated by an operator to minimize plant response to the reduction in feedwater flow. RCS temperature was maintained by controlling steam flow to the main condenser through the main steam bypass valves. Approximately 1 hour after the manual plant trip, RCS cooling was transferred from the condenser to the SG power operated relief valves (PORVs). A licensed operator opened SG 1C PORV to an indicated position of 5 percent, but the actual position went to 35 percent open. SG 1C level shrank to 33 percent and, again, the AFW system automatically actuated (ESF actuation) to recover the SG level. The AFW system actuation was reset, steam driven AFW Pump 14 was secured, and the AFW flow was placed in manual control. The licensee placed the unit in Mode 4 to repair secondary side leaks and perform "self-verification" training for all personnel that were involved with plant operations or maintenance/surveillance activities. The licensee initiated two station problem reports (SPR) to investigate and review this event (SPR 900427 and 900428). The licensee will issue LER 50-498/90-023 describing the event and the licensee's corrective actions. This LER will be reviewed during a subsequent inspection.

f. Fuel Tank Truck Fire and Explosion Outside of the Protected Area

On October 1, 1990, a vendor (Evans Oil Company of Bay City, Texas) fuel tank truck and stationary fuel storage tank caught on fire and exploded in a laydown yard west of the protected area. This laydown area is within the owner controlled area, but well away from the two reactor plants. The fire occurred during a diesel fuel transfer from the truck to the stationary 500-gallon storage tank. The driver (an employee of Evans Oil Company) of the fuel tank truck was seriously burned and was subsequently transported to the plant first aid station. After he had stabilized, the driver was then transported to Matagorda General Hospital by the plant ambulance. An NOUE was declared by the Unit 1 shift supervisor because of an onsite explosion combined with a personnel injury. The fire had no effect on plant operation. The onsite fire brigade responded to the fuel fire and no offsite assistance was requested. The NOUE was terminated when the injured person reached the hospital. The injured person was then transported by helicopter to a burn center in Galveston. The injured man died on October 5, 1990. The accident was investigated by an Occupational Safety and Health Administration (OSHA) compliance officer. SPR 900433 was written by the licensee to document the investigation of the event.

The above events, with the exception of the fuel truck fire, represented a declining trend in personnel performance that has resulted in increased challenges to the plant. This concern has been further addressed in a special balance of plant inspection which was conducted October 9-18, 1990. This inspection is documented in NRC Inspection Report 50-498/90-29; 50-499/90-29.

4. Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

The inspector reviewed the LERs listed below to determine whether corrective actions were adequate and whether response to the event was adequate and met regulatory requirements, license conditions, and licensee commitments.

a. (Closed) LER 499/89-017: Reactor Trip and Partial Loss of Offsite Power Due to a Main Transformer Failure

On July 13, 1989, an internal fault on the Unit 2 Main Step-Up Transformer 2A resulted in a main turbine trip with a subsequent reactor trip. The fault also caused a loss of offsite power to the ESF Train A bus and nonsafety-related auxiliary buses which feed the reactor coolant pumps. The Train A standby diesel generator started and loaded as expected. Offsite power was then restored to the ESF safety-related bus through the standby transformer.

The licensee initiated SPR 89-0531 to document the investigation of the event and identify corrective actions. The licensee, along with McGraw-Edison (transformer manufacturer), concluded that the most probable cause of the transformer failure was the failure of the high side Phase A bushing. The apparent intrusion of water into the insulating oil may have caused the catastrophic failure of the insulator. The licensee reviewed the operating history of the transformer and found no occurrences where the transformer was operated outside the intended design parameters. An inspection of the remaining transformer bushings did not reveal any problems.

The licensee was unable to specifically identify the failure mechanism because of the damage that resulted to the transformer when it failed. The review and corrective actions taken were appropriate and extensive. This LER is closed.

b. (Closed) LER 498/89-21: Unplanned Actuation of the Unit 1 Control Room Ventilation Due to an Unknown Cause

On October 17, 1989, with the reactor at 7 percent power, an ESF actuation of the main control room ventilation system to the recirculation mode occurred. No apparent cause for the ESF system actuation was identified during the licensee's review of this event.

The licensee initiated SPR 89-0752, on October 17, 1989, to investigate the event. The licensee reviewed the control room ventilation recirculation actuation signals and determined that no valid signal was present. The control room ventilation recirculation system would have actuated for a high radiation signal process signal from the control room ventilation radiation monitors or an ESF Mode I, II, or III signal. Since no ESF signal was received and no high

radiation signal was noted, the licensee concluded that a spurious failure of the control room ventilation system radiation monitors occurred.

The licensee subsequently inspected the radiation monitor actuation relay wiring for loose connections or incorrect wiring but none were found. A thermography examination was conducted with no abnormalities identified. Surveillance testing of the radiation monitors prior to and subsequent to the ESF actuation had not identified any condition which could cause the spurious actuation.

The inspector found the licensee's review of this event to be thorough and well documented. The corrective actions taken were appropriate for the event. This LER is closed.

c. (Closed) LER 499/89-025: Technical Specification Violation Because of a Failure to Properly Calibrate Power Range Nuclear Instrumentation √

On October 6, 1989, with Unit 2 at 100 percent thermal power, the licensee identified that a nonconservative error had been introduced into power range nuclear instrument (NI), NI-41 Channel A. This occurred during the performance of Departmental Procedure OPSP05-NI-0041A, Revision 0, "NIS Axial Flux Difference Calibration (N-0041A)." The calibration error resulted in the instrument being inoperable.

During the previous day, incore-excore NI measurements were taken to determine the target axial flux difference and and new excore power range monitor parameters. These test results were then used to align the axial flux difference outputs of NI Channel NI-0041A and -0042A. Following the calibration of the two NIs, the operators noted a 5 percent axial flux difference between NI-0041 and NI-0042. The licensee subsequently identified that a nonconservative error had been made during the calibration of NI-0041A.

The licensee's review of this event identified two principal factors that resulted in the calibration error. The first factor involved the lack of an approved procedural means to verify axial indications following axial flux difference calibrations. The second factor involved inadequate training of the instrument & control (I&C) technician assigned to perform the calibration and the lack of familiarity of the supervisor overseeing the activity with the particular calibration.

The licensee revised OPSP05-NI-0041A to include a caution step which states, "Incorrect performance of Step 7.4 could cause undetectable inaccuracy throughout the remainder of the calibration, rendering the channel inoperable." Step 7.16.5 was also revised to provide a calculated value for the axial flux difference which must be within 2 percent of the delta flux indication.

The licensee had been using Procedure OPMP01-ZA-0035, "Qualification and Certification of Personnel," which delineated the certification levels for personnel performing maintenance and testing on safety-related equipment. Since December 1988, the licensee has been phasing in Departmental Procedure IP-8.18, "OJT/Qualification Program." This procedure established the matrix relating a task to the job an individual was qualified to perform. This departmental procedure was fully implemented for personnel qualifications following December 1, 1989. This procedure appeared to have been effective in identifying personnel that are qualified to perform a specific task. This LER is closed.

d. (Closed) LER 498/89-19: Failure to Obtain Reactor Containment Building Atmosphere Grab Samples Within 24 Hours as Required by the Technical Specifications

On September 25, 1989, with Unit 1 in a refueling outage, the licensee removed the containment atmospheric monitor from service. TS 3.3.3.1 required that grab samples be taken and analyzed every 24 hours. On September 28, 1989, the licensee identified that the required 24-hour grab sample had not been taken and analyzed as required. The sample was obtained and analyzed 2 hours after it was due. Grab samples had been taken and analyzed every 12 hours, however, the analysis did not include iodines and noble gasses.

The licensee's review of this event identified that adequate procedural controls were not in place to ensure the TS requirement was met. A departmental procedure was implemented in November 1989, which clearly established controls to ensure that the requirement in TS 3.3.3.1 was met. The licensee reviewed other TS action statements and identified that TS 3.3.3.6 did not have programmatic controls to ensure an alternate method of monitoring reactor vessel inventory was initiated. The licensee implemented a TS interpretation which established an alternate means for monitoring reactor vessel inventory. The above corrective actions appear adequate to prevent recurrence and ensure that an alternate means of monitoring reactor vessel inventory is implemented if needed. This LER is closed.

5. Licensee Action on Previous Inspection Findings (92701)

a. (Closed) Unresolved Item 498/8901-01: Complete Corrective Actions to Prevent Overdue Instrument Calibrations.

During a previous inspection, an apparent weakness was identified in the licensee's calibration program for instrumentation not specifically addressed in the TS. The apparent weakness involved a lack of procedural controls which resulted in a large number of calibration deferrals. This subject area was previously identified by the licensee and was documented in SPR 880342. However, corrective actions were not completed prior to the NRC review of the

calibration program. Therefore, this issue was identified as an unresolved item (498/8901-01).

During this inspection period, a review of the controls in place for preventive maintenance (PM) scheduling was performed. Procedure OPGP03-ZM-0002, Revision 20, "PM Program," provided the general guidelines for the PM program. Procedure OPMP02-ZG-0009, Revision 0, "PM Scheduling," provided specific instructions for the scheduling of PMs. Section 4.10 of OPMP02-ZG-0009 provided instructions on how to defer PM activities.

PM activities can be deferred into the next calendar quarter with justification and with the department manager's permission. A third deferral requires the plant manager's permission. Additionally, Procedure OPGP03-ZM-0016, Revision 4, "Installed Plant Instrumentation Calibration Verification Program," delineates programmatic controls for calibration and status verification of installed plant instrumentation. This procedure lists all instruments required to be included in the PM program. The licensee uses a computer program (PM Program) to track all PMs, their due dates, and end of grace periods. The licensee currently has 2591 instrument calibrations in the PM program. Of this number, only 35 are overdue (1.35 percent). Therefore, the licensee has completed the corrective actions necessary to prevent and minimize overdue calibrations of instrumentation not specified by the TS. This unresolved item is closed.

b. (Closed) Open Item 498/8708-61: Lack of Documentation of Deviations From the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERG).

The inspector reviewed Procedure OPOP01-ZA-0016, "Emergency Operating Procedure Writers Guide," and Procedure OPOP01-ZA-0017, "Emergency Operating Procedure Revision and Implementation," Steps 2.4 and 3.4, addressed the development, revision, and documentation of the emergency operating procedure (EOP) technical guidelines.

The licensee issued the ERG reference plant comparison in July 1990. The WOG low pressure generic reference plant design configuration was used as the STPEGS comparison plant. This review established the differences between the low pressure reference plant and the STPEGS from the standpoint of the emergency operation systems.

The STPEGS EOP technical guidelines were issued in June 1990. These guidelines provided the basis for deviations in the EOPs from the WOG ERGs. The deviations in the EOP procedures for "purpose" and symptoms or entry conditions from the WOG ERGS have also been included in the guidelines. This open item is closed.

c. (Closed) Open Item 499/8882-07: Incomplete Unit 2 Radiation Protection Facilities and Equipment.

During a previous inspection, the inspectors determined that the licensee's Unit 2 radiation protection facilities were in an adequate state of readiness except for: (1) completion of the primary radiologically restricted area ingress and egress control at the 41-foot elevation level; and (2) placement and stocking of emergency kits in the required locations within Unit 2.

The ingress and egress area at the 41-foot elevation was in operation prior to Unit 2 exceeding 5 percent power. Additionally, the area was remodeled and upgraded recently by Work Request (WR) XM-134463 and Modification Package 89123 in preparation for the Unit 2 first refueling outage. The emergency kits were installed and stocked for emergency response activities, if required. A review of selected emergency lockers was performed during this inspection period and the findings are documented in Section 7 of this inspection report. This open item is closed.

d. (Closed) Open Item 499/8886-01: Nonconforming Molded-Case Circuit Breakers

On November 22, 1988, the NRC staff issued NRC Bulletin 88-010, "Nonconforming Molded-Case Circuit Breakers." The licensee issued their report relative to NRC Bulletin 88-10 in June 1989. Molded-case circuit breakers which were not directly traceable were examined and determined not to be refurbished. The licensee did not identify any fraudulently marked circuit breakers. This open item is closed.

6. Followup on Corrective Actions for Violations and Deviations (92702)

(Closed) Deficiency 498/8842-03; 499/8842-03: The Evacuation of Nonessential Personnel During the Emergency Drill was Slow and Not Well Organized

A similar deficiency was identified during the 1989 emergency preparedness drill. This deficiency is documented in NRC Inspection Report 50-498/89-12; 50-499/89-12 as Deficiency 498/8912-04; 499/8912-04. The licensee's improvement actions will be reviewed during a future emergency drill. This deficiency is closed.

7. Operational Safety Verification (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements, to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. This inspection also included verifying that selected

activities of the licensee's radiological protection program were being implemented in conformance with requirements and procedures and that the licensee was in compliance with its approved physical security plan.

The inspectors conducted control room observations on a routine basis and verified that control room staffing, operator decorum, shift turnover, adherence to TS limiting conditions for operation (LCOs), and overall control room operation was in accordance with requirements. The inspectors conducted tours in various locations of the plant to observe work activities and to ensure that the facility was being operated in conformance with license and regulatory requirements.

The following paragraphs provide details of certain observations identified during this inspection period.

a. Unit 2 Startup

The inspectors maintained a continuous observation of the Unit 2 startup during the period September 17-19, 1990. The continuous coverage was discontinued after the main generator was synchronized to the grid. The unit had previously tripped on September 17, 1990, because of a personnel error. Communications were maintained between the unit supervisors and reactor operators during the plant startup. Several alarms were received on the control panels that could be considered "nuisance" alarms that temporarily distracted the operators. The startup was conducted in a controlled manner, utilizing the appropriate procedures. No significant challenges were encountered by the operators. The operators communicated well during the startup and remained cognizant of changing plant conditions.

b. System Walkdowns

As part of the operational safety verification portion of the inspection, two systems were walked down to determine if they were aligned to support plant operation. The systems included the Unit 1 Electrical Auxiliary Building (EAB) heating, ventilation and air conditioning (HVAC) system and the Unit 1 steam generator (SG) blowdown system. The systems were compared to their system operating procedures and piping and instrument diagrams (P&IDs). Specific attributes inspected included verification of major flow paths, equipment condition, switch and power supply positions, and availability of support systems.

During the review, the inspector noted several minor weaknesses associated with the SG blowdown system. These included:

- Some specified switch positions had no such actual position;
- Six nonsafety-related valves were missing from the valve lineups;

- A nonsafety-related pressure relief inlet isolation valve was missing its seal lock; and

- Ten minor P&ID errors were noted.

None of the above observations affected plant or system operation.

c. Emergency Equipment and Supplies

A partial review of emergency equipment and supplies inventory was performed during this inspection. Emergency equipment lockers were located throughout the plant and provided needed supplies during emergency conditions and during scheduled drills. The licensee inventoried the lockers at least quarterly to ensure the proper equipment was maintained in the cabinets. The locker inventories reviewed included the Unit 2 postaccident sampling system (PASS) laboratory, control room envelope, and technical support center (TSC) lockers. The following items were observed and reported to the licensee:

- A locker seal number was not documented on the inventory checklist as required by Procedure OL-PP01-2A-0002, Revision 7, "Emergency Equipment Supplies Inventory."

- Per OEPP02-ZA-0002, Section 5.6, batteries stored in the lockers shall be replaced every 6 months, during first and third quarter inventories. A review of third quarter (July-September) forms was performed. None of the forms indicated that the batteries had been changed out as required by OEPP02-ZA-0002. The licensee subsequently changed the batteries and documented the replacements on the required forms.

- None of the emergency lockers inspected contained radiation survey instrument check sources, although they were items listed on the inventory checklists. The licensee was aware that the check sources were missing and had several on order. The survey instruments could have been checked during an emergency with other check sources available in the plant.

d. Unit 2 Spent Fuel Pool Cooling and Cleanup System Work Activities

A review of selected work requests and associated equipment clearance orders was performed on the Unit 2 spent fuel pool cooling and cleanup system (FC). The inspection was performed to determine if work scheduling had been conducted in an organized manner with minimal impact on operations personnel. No spent fuel was in the pool at the time the maintenance activities were performed. The inspector noted that the system was drained three times in 8 days for six work activities. This forced operations personnel to perform three fill, vent, and drain evolutions on one train. The scheduling of work on the fuel pool cooling and cleanup system was not

indicative of any significant weaknesses in the licensee's scheduling program; however, the work activities did appear to unnecessarily impact plant operators.

e. Plant Tours

Routine plant tours were conducted in accessible areas, including the Unit 2 reactor containment building (RCB). The following items were observed and reported to the licensee:

- The Unit 2 FHB had a large number of nonessential area lightbulbs that were burned out and required replacement.

- The Unit 2 mechanical auxiliary building (MAB) Room 327, Hot Tool Room, was not maintained in accordance with the licensee's housekeeping program. Trash, including nails, sawdust, pieces of tape, and used ear plug containers were located throughout the room. Cables, electrical cords, and rope were laying around the area on the floor and were not neatly stacked. One large bag, labeled as contaminated material, extended beyond the radioactive materials area boundary.

- The Unit 2 RCB was generally clean, and radiation boundaries were properly displayed. However, miscellaneous tools and trash were noted in and around work areas.

- The Unit 2 TSC was properly equipped to allow prompt activation. The door to the TSC was locked to prevent unauthorized removal of essential materials. Despite this measure, chains had been removed from the TSC conference rooms. The ready availability of the TSC during an emergency was a significant concern addressed in NRC Systematic Assessment of Licensee Performance Report 50-498/90-06; 50-499/90-06.

The inspectors concluded that the facility was being operated in accordance with plant procedures and regulatory requirements. Although improvement has been noted, additional attention in maintaining TSC emergency supplies was needed.

8. Monthly Maintenance Observations (62703)

Selected maintenance activities were observed to verify whether the activities were being conducted in accordance with approved procedures, industry codes of standards, and in conformance with the TS.

The activities observed included the following:

- PM EM-2-PK-87016591, Switchgear E2B, Cubicle 12, Relay/Device Calibration.

PM EM-2-PK-87016597 was performed by electrical technicians on Unit 2 safety-related Switchgear E2B, Cubicle 12. The work consisted of calibration checks on two relays and one ammeter. One relay tested was an ITE-51 relay, which was a three phase instantaneous/time overcurrent relay. The ITE-51 relay was tested by Procedure OPMP05-ZE-0037, Revision 2, "Calibration of JTE-51 Relays." Sections 6.4.5 and 6.4.6 of OPMP05-ZE-0037 provided instructions to perform 5 percent tap pickup tests but failed to mention that the test leads had to be moved to different relay terminals for each of the three phases. However, the technicians were aware of the requirement to move the test leads for each phase and correctly performed this activity. Following performance of the time delay and pickup instantaneous circuit tests, the relay was found out of the acceptance criteria tolerance range. The relay was adjusted to new limits and successfully tested. Step 6.7.9.1 was added to OPMP05-ZE-0100 by a field change request. This step provided instructions to ensure the as-left relay settings were recorded in Table A of OPMP05-ZE-0037. However, Step 6.6.7 provided the same instructions, therefore, Step 6.7.9.1 was unnecessary. The ammeter on Cubicle 12 was satisfactorily tested per OPMP05-ZE-0100, "Panel Meter Calibration," Revision 5.

During the performance of PM EM-2-PK-87016597, the work activity had to be stopped several times because of power failures. The test equipment was plugged into a wall outlet that was being shared by other workers in the area during a scheduled B train outage. Power overloads were causing the circuit breakers to trip, which would deenergize the relay test equipment. The technicians had to locate an alternate power source and some other activities had to be stopped (such as vacuuming out the switchgear cubicles) to prevent power overloads from occurring. During the performance of this PM, the relay cover lockwire seals were installed. The inspector noted that this practice, although unwritten, would be beneficial in identifying unauthorized adjustments to relays.

- WR NZ-78522, Testing of Commercial Grade Molded Case Circuit Breakers.

WR NZ-78522 was performed by electrical technicians on two 70-ampere, 480-volt AC circuit breakers. The breakers were purchased commercial grade and required testing per the commercial grade item dedication program. The testing consisted of an instantaneous trip, time overcurrent trip, and insulation resistance tests. The tests were performed using Procedure OPMP05-NA-0004, Revision 5, "Molded Case Breaker Test." The two breakers failed the instantaneous trip tests. The as-found values were well below the instantaneous trip current acceptance criteria lower limit of 800 amperes. A receipt inspection deficiency report was written and submitted to spare parts engineering (material technical services) for disposition of the two breakers.

- PM IC-2-AF-90001205, Auxiliary Feedwater Flow Transmitter Calibration.

  PM IC-2-AF-90001205 was performed by I&C technicians on the Unit 2 Auxiliary Feedwater Flow Transmitter D2-AF-FT-7526. The work consisted of testing the flow transmitter per selected sections of Procedure 2PSP05-AF-7526, Revision 1, "Auxiliary Feedwater Flow Loop 4 Channel D Calibration." The procedure had been performed every 18 months, but the test frequency was increased to every 26 weeks. The increased calibration frequency was based on NRC Bulletin 90-001, "Loss of Fill Oil in Transmitters Manufactured by Rosemount." This procedure, in part, verified the integrity of the fill oil in the differential pressure capsule. The transmitter was found and left within acceptance criteria limits. Items observed during the PM performance included: (1) Section 7.4, calibration of recorder NZ-AF-FR-7526, was performed by the technicians, but the section was not required by the PM (a conservative action); (2) Recorder NZ-AF-FR-7526, located on Control Room Panel CP-018 did not identify the engineering units (gallons per minute/gpm) on the recorder scale; and (3) the incorrect location (room number) was listed in the calibration data package for the location of the transmitter.

- WR MS-125322, Faulty Low Steam Line Pressure Alarm.

  WR MS-125322 was performed by I&C technicians on the Unit 2 Steam Generator 2C Low Steam Line Pressure Safety Injection Channel 1. The associated alarms previously actuated for no apparent reason. The work consisted of replacing the "NLL" card at Panel Location P01-0622. The licensee previously noted the card output was fluctuating. The associated circuity was tested per 2PSP05-MS-0534, Revision 0, "Steam Pressure Loop 3, Set 1 Calibration." The low steam pressure safety injection setpoint (735 psig) was below the acceptance limit but above the TS-allowed value. The setpoint was adjusted within acceptance criteria limits. The instrument loop was left in an operable condition and returned to service.

- WR NI-125280, Troubleshooting of Source Range Neutron Flux Channel 31.

  WR NI-125280 was performed by I&C technicians on Source Range Nuclear Instrument Channel I (Channel 31). The source range meter was reading an erroneous value while the plant was at 100 percent power. The work consisted of testing the instrument channel per 2PSP05-NI-0031, Revision 2, "Source Range Neutron Flux Channel I Calibration." This channel was returned to service prior to the Unit 2 startup on September 18, 1990. This condition was apparently corrected when the operators returned the electrical system lineup to its normal configuration. However, the exact cause of the problem was never determined.

  Procedure 2PSP05-NI-0031 was performed in its entirety on Channel 31. Several setpoints were found slightly out of tolerance, including the

neutron flux level indicator and loss of detector voltage bistable. These setpoints were properly adjusted and tested. Two procedural observations were reported to the licensee. Step 7.17.19 of 2PSP05-NI-0031 provided instructions to plot count rate versus voltage on a graph. The technicians did not plot the data exactly as required by the procedure (X axis was too short), but this had no effect on the final test results. Step 7.17.33 provided instructions to transfer values from the graph to a data sheet. The original readings could have been recorded directly to the data sheet to insure the precision of the data recorded.

The licensee's maintenance program was implemented in accordance with the approved procedures in a manner similar to previous performance. Personnel were cognizant and deliberate of the activities they performed.

9. Monthly Surveillance Observations (61726)

Selected surveillance activities were observed to ascertain whether the surveillance of safety significant systems and components had been conducted in accordance with TS and other requirements.

The following surveillance tests were observed and the documents reviewed:

- OPSP02-NI-0032, Revision 0, "Source Range Neutron Flux Channel II Analog Channel Operational Test (ACOT).

- OPSP02-NI-0035, Revision 0, "Intermediate Range Neutron Flux Channel I ACOT."

- 1PSP02-SY-0002, Revision 2, "Triaxial Time-History Seismic Instrumentation Channel Check."

  Procedure 1PSP02-SY-0002 was performed by I&C personnel on the Unit 1 seismic monitors. During the performance of the surveillance, two problems were identified and corrected. The pen stylus for Channel 3 of the SMR-102 plotter was broken and was replaced by WR SY-104804. The Channel 2 accelerometer was replaced by WR SY-104805. Part of the surveillance test was performed in the tendon gallery. This area contained trash, including empty food containers.

- 2PSP06-NZ-0001, Revision 2, "13.8KV Relay Channel Calibration."

  Procedure 2PSP06-NZ-0001 was performed by electrical technicians on the 13.8KV Switchgear 2G, Cubicle 11, relays. Two relays failed the "minimum pick-up test." The relays were subsequently adjusted by the technicians and then passed the tests. No personnel or procedure concerns were identified.

- 2PSP03-SP-0006S, Revision 0, "Train S Reactor Trip Breaker Trip Actuating Device Operational Test (TADOT)."

Procedure 2PSP03-SP-0006S was performed by Unit 2 operations personnel on the Train S automatic trip and automatic actuation logic circuitry. This was the second attempt by the operators to perform the TADOT. The last time the procedure was performed, Step 7.7.22 of the procedure was incorrectly performed, resulting in an unanticipated Unit 2 trip on September 17, 1990. The procedure was correctly performed the second time.

- 1PSP03-SB0001, Revision 5, "Steam Generator Blowdown System Valve Operability Test."

  Procedure 1PSP03-SB-0001 was performed by Unit 1 operations personnel on three steam generator blowdown system valves. The valves tested were 1-SB-FV-4151, -4152, and -4153. The testing frequency had been increased because of "ASME Section XI" valve trending requirements. All three valves passed the surveillance test.

- 2PSP03-MS-0002, Revision 1, "Main Steam System Cold Shutdown Valve Operability Test."

Licensee personnel performed well in this area while being observed by the inspectors. The persons who performed the activities appeared knowledgeable and competent, used the correct test equipment, adhered to approved procedures, and were careful while performing the assigned tasks.

10. Preparation for Refueling (60705)

A review was conducted of the Unit 2 first refueling outage preparations. The outage began on September 29, 1990. The review assessed the adequacy of the licensee's administrative requirements for control of refueling operations and for control of plant conditions during refueling activities.

The scope of the outage was reviewed and found to include the following:

- Refueling

  - Full core off-load and fuel reload.

  - Fuel ultrasonic testing to ensure integrity of fuel rods.

  - Control rod change out to Silver-Indium-Cadmium material.

- Steam Generator Activities

  - Hot leg shot peening to prevent corrosion cracking in the steam generator tubes.

  - Sludge lancing to remove corrosion products.

- Eddy current inspection to evaluate condition of tubes in the steam generators.

° Main Turbine

- Warranty inspection and repair to improve reliability of turbine generator.

° General Maintenance

- Diagnostic testing of motor operated valves (MOVs) in support of a commitment to test all MOVs in the plant over a 5-year period.

- Disassembly and inspection of the emergency diesel generators to maintain their reliability.

- Approximately 500 surveillance tests, 1100 preventive maintenance tasks, and 1200 maintenance WRs are scheduled to be performed to maintain and improve equipment reliability.

° Perform routine in-service inspection/testing.

° Implement approximately 50 design changes to improve overall plant operation.

The outage scope and actual work performed will be evaluated and the results documented in a subsequent inspection report.

11. Spent Fuel Pool Activities Unit 2 (86700)

Selected Unit 2 spent fuel pool activities were inspected to ascertain whether the activities were in conformance with TS requirements and approved procedures. The inspection included verification that key spent fuel pool parameters were within the required limits and support systems were correctly aligned to maintain the fuel pool level and temperature.

Prior to the Unit 2 first refueling outage, the spent fuel pool systems were inspected to ensure that the pool was ready for a full core off-load. Key pool parameters inspected included (the source documents for the parameter limits are listed in parenthesis):

° The spent fuel pool water level was at the 66-foot elevation. The lower TS limit had been designated at the 61-foot, 10-inch elevation (TS 3.9.11.1).

° The spent fuel pool water boron concentration was at 2629 parts per million (ppm). The TS lower limit was 2500 ppm (TS 3.9.1 interpretation and Procedure OPGP03-ZO-0012, "Primary System Chemistry Specifications," Revision 4).

- The spent fuel pool temperature was at 90°F. The TS upper limit was 140°F FSAR Table 9.1-1).

- Other pool parameters, including chlorides, fluorides, and specific activity, were also below the upper allowed limits (FSAR Section 9.4-1 and Procedure OPGP03-ZO-0012).

The FHB ventilation system was inspected to ensure that the system will maintain the building at the specified negative pressure. The inspection consisted of a comparison of as-found switch, damper, and power supply positions to those required by Operating Procedure 2POP02-HF-0001, Revision 4, "FHB Heating, Ventilation, and Air Conditioning (HVAC)." The system consisted of two subsystems, the nonsafety-related supply system and the safety-related exhaust system. During the inspection, the system was noted to be in an off-normal lineup because of an inoperative exhaust system bypass damper. In this mode, the supply subsystem was inoperative, outside air was being bypassed around the supply system filters, and the FHB air was being discharged through the B train exhaust filter units (emergency mode of operation).

Section 5.2 of Procedure 2POP02-HF-0001 provided instructions on how to place FHB exhaust filter trains in service. Step 5.2.7 provided instructions to close the inlet isolation dampers for the supply fans stopped in the previous step. Inlet Isolation Dampers FV-9510 and -9530 were noted to be open with the associated fans off. These two nonsafety-related dampers were out of position per Procedure 2POP02-HF-0001, Step 5.2.7 requirements. The unit supervisor directed the plant operator to shut the dampers when informed of the misalignment. The out-of-position dampers would not have prevented the FHB exhaust filtration trains from functioning, as designed.

Four system controllers were found at incorrect setpoints. The exhaust Air Flow Controllers 2-HIC-9507 and -9507A at Panel 2-CP022 were set at 28,500 cubic feet per minute (CFM) but should have been set at 29,000 CFM per procedure Step 7.7 and Switch Lineup 2POP02-HF-0001-4 instructions. The value "28.5" was handwritten on the panel adjacent to the controllers. The established 28,500 CFM setting was within the TS-allowed tolerance of plus or minus 10 percent. The FHB Temperature Controller TIC-9502 (nonsafety-related) was found set at 50°F at local Panel ZLP-108 but should have been set at 60°F per the licensee's instrument setpoint index. Area thermostat N2-HF-TSHH-9537A was found set at 125°F but should have been set at 101°F per Lineup 2POP02-HF-0001-2. This thermostat was nonsafety-related and the dial settings of similar thermostats have been known to be inaccurate. Finally, nonsafety-related FHB Differential Pressure Controller PDIC-9548 was found set at 0.3 inches water column but should have been set at 0.2 inches water column per the instrument setpoint index. The inspector notified the licensee of these setpoint discrepancies, and the licensee took action to correct the controller setpoints.

Several other minor deficiencies were noted during the walkdown. None of the items noted during the walkdown of the FHB HVAC system appeared to have any effect, on safety-related operation. The system was already in the emergency mode of operation and the building differential pressure was being maintained at a higher than required value.

The spent fuel pool cooling and cleanup system was inspected to determine if the system was in operation to support the spent fuel pool. Specific attributes inspected included valve, control switch, and electrical switch lineup, equipment condition, and operation of support system. As-found switch, valve, and power supply positions were compared to positions established by Operating Procedure 2POP02-FC-0001, Revision 2, "Spent Fuel Pool Cooling and Cleanup System." All components were found in the correct positions to support system and plant operation. However, the following discrepancies were noted and reported to plant personnel:

- Procedure 2POP02-FC-0001, Step 6.3.5, provided instructions to throttle Valve 2-FC-0042 to maintain refueling water purification flow between 190-200 gpm, however, the actual flow was noted to be 185 gpm;

- Step 8.6 provided instructions to verify that differential pressure (dP) across the spent fuel pool skimmer pump discharge filter was between 5-20 psid. The actual dP was noted to be 1 psid. The licensee subsequently determined that the procedure was determined to be incorrect and that no lower setpoint value was applicable;

- Valve 2-FC-0071 was listed in Valve Checklist 2POP02-FC-0001-1 as a drain valve but was actually a vent valve; and

- Valve 2-FC-0073 was listed as a vent valve in the valve checklist but was drawn as a drain valve on the P&ID.

Additionally, several discrepancies were noted between valve positions listed in the procedure lineup and shown on system P&IDs. The discrepancies were attributed to P&ID errors.

The spent fuel pool cooling and cleanup system was properly aligned to ensure the integrity of spent fuel moved to the spent fuel pool. The FHB HVAC system would have ensured that a negative pressure would be maintained in the building. The potential release paths were monitored and the emergency filtration system was available if needed.

12. Refueling Activities (60710)

Licensee compliance with Mode 6 TS was verified. This included verifying that adequate borated water sources and flow paths, ESF instrumentation and activation systems, electrical power supplies, source range channels, and other support systems were available. The high head safety injection pumps and charging pumps were rendered inoperable as required by the TS.

The inspector observed the reactor head removal, reactor vessel stud hole plug installation, and initial reactor cavity flooding. All observed activities were performed in accordance with OPMP04-RX-0018, Revision 2, "Non-Rapid Refueling Mechanical Support."

All observed hand tools in the vicinity of the reactor cavity were restrained with lanyards. Cleanliness zones were established in the areas adjacent to the reactor cavity.

Appropriate radiological boundaries were established for areas that were potentially contaminated or that had a potential for becoming contaminated. A high level of cleanliness was maintained in the vicinity of the reactor cavity.

The inspector observed the movement of several new fuel assemblies from the new fuel storage area into the spent fuel pool. The equipment operators were proficient in their knowledge and use of the equipment.

13. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in paragraph 1) on October 12, 1990. The inspectors summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.