APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/90-29 Operating License: NPF-76
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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: October 9-18, 1990

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Approved: [signature] 11/21/90
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Inspection Summary

Inspection Conducted October 9-18, 1990 (Report 50-498/90-29; 50-499/90-29)

Areas Inspected: Nonroutine, announced, balance-of-plant (BOP) team inspection which included inspections of activities related to the operation and maintenance of BOP equipment and components.

Results: The inspectors determined that the licensee had developed and implemented appropriate programs and procedures to operate and maintain BOP equipment and systems effectively. The inspectors found no instances in which the material condition of BOP equipment or systems had adversely impacted the operators ability to operate the plant safely.

Within the areas inspected, no violations or deviations were identified, but the inspectors observed that the process for accomplishing maintenance was not always efficient in that instances were observed in which there were delays in completing maintenance because of inadequate work instructions, inadequate communications between groups (i.e., planning, maintenance, and operations), and the unavailability of repair parts. The inspectors also identified instances in which accomplishing some BOP activities appeared to require unsafe personnel work practices.

The inspectors further concluded that the various competing work pressures and impediments to work progress perceived by maintenance technicians and planners were having an eroding effect on their morale. The concerns relative to personnel safety appeared to contribute to the morale problems. In addition, it appeared to the inspectors that these factors were of a magnitude that presented a potential for adversely influencing personnel performance.

DETAILS

1. PERSONS CONTACTED

HL&P

*W. H. Kinsey, Vice President, Nuclear Generation
*S. L. Rosen, Vice President, Nuclear Engineering
*M. R. Wisenburg, Plant Manager
*A. C. McIntyre, Manager, Design Engineering
*C. A. Ayala, Supervising Licensing Engineer
*V. R. Albert, Systems Division Manager, Plant Engineering Department
*G. N. Midkiff, Director, Nuclear Plant Operations Department
*J. W. Loesch, Plant Operations Manager
*W. J. Jump, Maintenance Manager
*G. L. Parkey, Manager, Integrated Planning and Scheduling
*J. R. Lovell, Manager, Technical Services
*J. D. Bumgardner, Work Control Center Manager
*D. M. Chamberlain, Management Supervising Engineer
*M. K. Chakravorty, Executive Director, Nuclear Safety Review Board
*A. K. Khosla, Senior Engineer, Licensing
*D. R. Keating, Director, Independent Safety Engineering Group
*T. J. Jordan, General Manager, Nuclear Assurance
*R. R. McRae, Manager, Industrial Safety and Health
*M. A. Ludwig, Manager, Participant Services
*S. M. Shropshire, Central Power and Light
*C. A. Nance, Chemical Operations and Analysis Engineering Associate II
*K. J. Christian, Unit 1, Operations Manager
*L. G. Weldon, Manager, Operations Training
*M. A. McBurnett, Nuclear Licensing Manager

During the inspection, the inspectors also contacted other members of the licensee's staff to discuss issues and ongoing activities.

*Denotes those individuals attending the exit interview conducted on October 18, 1990.

2. BACKGROUND

During the period of August 7-10, 1990, Region IV conducted an assessment of licensee activities related to recent plant events, including plant trips and inadvertent safety system actuations. The findings of that assessment were reported in Section 3 of NRC Inspection Report 50-498/90-26; 50-499/90-26. The inspectors performing the assessment concluded that the licensee had not identified a common cause for the events, but had identified some potential causes which included the material condition of balance-of-plant (BOP) components and the backlog of maintenance (primarily BOP) items.

Based on the Region IV assessment and the continuing frequency of events at STP, Region IV initiated this BOP team inspection to verify that the BOP equipment conditions and BOP maintenance activities were not adversely impacting on the operators' ability to operate the plant safely. In addition, a human factors specialist was included on the team to provide human factors evaluations of selected BOP activities.

The inspection was conducted in accordance with the guidance delineated in NRC Inspection Procedure 71500, "Balance of Plant Inspection," dated September 30, 1988.

3. DETAILED INSPECTION FINDINGS

3.1 Maintenance

3.1.1 Scope

The inspectors conducted a review of the licensee's maintenance program in the area of balance-of-plant (BOP) systems to verify the effectiveness of preventive and corrective maintenance.

3.1.2 Detailed Findings

The licensee's ongoing evaluation of equipment failures in the BOP systems for the purpose of revising the preventive and corrective maintenance programs was reviewed. The two principal methods for reporting deficiencies and implementing corrective action were the maintenance work request (MWR) and station problem report (SPR) systems. The inspectors performed BOP walkdowns and identified a number of steam, water, and oil leaks. In all cases these items had been previously identified by the licensee and had been incorporated into the licensee's corrective action programs. There were no identified instances for which needed equipment repairs had been identified by the licensee and a work request or station problem report had not been issued. As noted in previous NRC inspection reports, a large backlog of maintenance work requests continued to exist at STP. The inspectors confirmed that the majority of these outstanding open work items were rated at Priority Level 3 and had no impact on plant safety. However, several plant operations personnel expressed disappointment because their expectations for lowering the backlog had not been met. This appeared to be having a negative impact on the licensees efforts in fostering a team concept between the operations and maintenance departments.

The plant reliability and statistics (PRS) group in the plant engineering department was charged with the responsibility for periodically determining the operating characteristics of the secondary plant systems and components to establish a trending database. These performance trends were used in detecting degraded performance which then resulted in the appropriate corrective measures. This performance trending was accomplished by calculating the performance monitoring parameters required for trending each plant component contained in the program as well as by implementing ultrasonic and thermography testing techniques. The PRS group also reviewed every work request issued on 10 secondary plant systems. The plant computer work management system (WMS) automatically flagged all associated work requests to the PRS group. A thermal performance work document report was then generated, which assigned priority codes to the work requests. Priority A was assigned to those MWRs which represented significant leakage and a loss of megawatts; Priority B was assigned to MWRs which did not represent significant leakage or a loss of megawatts and were not affecting the thermal performance calculations; and Priority C was assigned to those MWRs that were considered small, nuisance leaks. The majority of all leaks to the atmosphere were of the latter priority. The PRS group also generated a thermography action list, a vibration action list, and a lube oil action list; these resulted from the performance of periodic engineering test procedures, which were intended to identify equipment that was performing less than adequately. The items on these three lists were assigned priority codes. Priority A was assigned to those items that were critical to sustain plant operations; Priority B was assigned to those items for which component failure was imminent; and Priority C was assigned to those items which may have had an affect on component reliability. The information was sent to the work control center (WCC) on a weekly basis. At the WCC, the information resulted from the predictive and performance programs were incorporated into a 6-week "scoping schedule." From this schedule, items were then worked as available manpower allowed. Manpower availability was considered at weekly WCC meetings. The PRS group tracked the thermal performance items completed each work week and reported the results to appropriate levels of management for independent review. The PRS group was also in the process of generating a BOP critical surveillance program which was intended to further enhance the overall reliability of the BOP. This new program will involve a comprehensive review of secondary plant equipment for the adequacy of preventive maintenance and periodic surveillance testing.

The plant engineering department issued a document entitled "System Engineer Guidelines," on September 14, 1990. This document was intended to describe a program for using system engineers to improve overall plant performance and reliability. The document stated that system engineers were responsible for being thoroughly knowledgeable of their assigned system, including operating status, equipment condition, tests and surveillances, and equipment history. The system engineers were required to identify problems with systems and to initiate appropriate corrective action based on the performance of periodic system walkdowns. The licensee generated a system walkdown guideline to provide guidance to system engineers. The guide described areas of concern, items of importance, and suggested areas of emphasis to be considered when conducting system walkdowns. The inspector considered this program to be a positive approach in attempting to improve material condition of the plant.

The inspector reviewed the BOP preventive maintenance (PM) program in order to assess whether that program was adequate for ensuring system and component reliability. The process of providing periodic, planned, and predictive maintenance activities to maintain specifications and operability of permanent equipment did not differentiate between safety-related and BOP equipment. The program was described in Plant Procedure OPMP02-ZG-0008, "PM Development," Revision 0. This procedure was reviewed by the inspector and was found to provide instructions for the identification, development, and revision of PM activities. The procedure required that manufacturer's recommendations be evaluated for inclusion in the PM program and that all deviations from manufacturer's recommendations resulted in documented justifications. The resulting PMs were assigned a two-character importance factor code. The first character (1, 2, or 3) indicated equipment importance to the plant while the second character (A, B, C, or D) indicated PM activity importance to the equipment. The procedure also provided a typical PM feedback form which was intended to solicit information concerning problems encountered with performance of PM activity (tagouts, tools, parts, materials, delays, or changes). As of October 8, 1990, a total of 11,276 feedback forms have been closed out. This indicated a high incidence of feedback from the crafts performing the work. At the time of this inspection, 6,701 feedback forms were active.

The inspector reviewed the number of PMs that have been deferred or formally justified and authorize to be delinquent in accordance with the PM program. The PM deferral rate for the year-to-date was 9.6 percent in Unit 1 and 6.9 percent in Unit 2. The Unit 1 rate was higher because of the recently completed refueling outage. These deferral rates represented a marked improvement over the previous year's performance. The ratio of PM to total maintenance man-hours for a period from January to September 1990 was 49.1 percent, well above the 34.0 percent self-imposed goal. The corrective maintenance backlog was large, but 94 percent of the open items associated with the maintenance department's backlog were low priority items. The licensee had brought additional maintenance support personnel on-board to reduce the number of lower priority MWRs. This effort should reduce the backlog of MWRs and improve the material condition of the BOP systems.

Post-maintenance testing requirements for BOP system components were controlled and performed by the same process as safety-related items. The specific requirements were based on the type of equipment being serviced and not on the safety or nonsafety classification. Plant Procedure OPGO03-ZE-0020, Revision 1, "Postmaintenance Test Program," delineated the specific requirements in a referenced post-maintenance testing manual.

The preventive and corrective maintenance activities in the BOP have received increasing attention by management in HL&P. A station manager condition improvement plan had recently been initiated by the licensee, and it contained goals and action plans which upon completion would serve to further enhance the reliability of secondary plant systems.

3.1.3 Observation of Maintenance

The inspector observed maintenance accomplished in accordance with Work Request WR-NH102417. This job was written to replace a small diameter (1/2-3/4 inch) ball valve with a regulator (0-1000 psi) in the station nitrogen system. The following is the sequence of events to job completion and problems encountered.

° While hanging the clearance, licensee personnel determined that the affected valves were identified by new permanent green metal tags; however, the valve numbers on these tags did not match those on the clearance. There were also old temporary tags attached to the valves; the temporary logs matched the clearance valve identification numbers.

The yard operator contacted the unit supervisor and discussed the fact that valid source documentation supporting the new tag numbers could not be located. The solution to the problem that was selected was to cut the new ID tags off so the clearance would match the old tags.

- The test package did not specify a test pressure but required the newly installed regulator to be tested to 1.25 time system pressure. However, the nitrogen system being tested could not supply the necessary pressure. In addition, the original package did not require a specific leak detection test method (e.g., soap the connections). Consequently, the planner had to rewrite the package to hook up an external high pressure (6000 psi) nitrogen bottle to leak test the connections.

- The engineer/planner requested that operations support the test and they agreed to do so. When operations personnel arrived to support the test, the operator refused to do so without having a written valve lineup and test procedure.

  The engineering/planning groups went back to work and subsequently supplied a test procedure and valve lineup which the operations and maintenance departments supported to complete the test.

It appeared to the inspector that better planning, including prework walkdowns and briefings, would have eliminated most of the observed problems and delays.

3.1.4 Personnel Interviews

The team conducted interviews with a number of licensee, maintenance department personnel, as well as other licensee personnel who regularly interacted with the maintenance department.

Several concerns specific to the planning and implementation of MWRs were reported by interviewees. STP staff stated that there were frequent communication problems among the different working groups involved in the MWR process. For example, engineering personnel indicated that they were often unnecessarily consulted on minor decisions by maintenance staff. Reactor plant operators (RPOs) stated that MWRs were often returned to them by planners for additional information that should be found elsewhere. PM planners reported duplication of effort between PMs and MWRs. Difficulty in obtaining requisite spare parts and conflicts between operations department priorities and the performance of MWRs were also identified as common problems across the different departments.

Maintenance technicians and maintenance planners also reported conflicting pressures that interfered with their ability to perform work effectively. Technicians indicated that they were faced both with pressure to complete a certain quantity of work but were often unable to succeed as a result of numerous difficulties such as lack of spare parts, unavailable document control or warehouse support on backshifts, changing priorities, and incorrect or incomplete MWRs.

Planners also acknowledged facing pressure to complete a specific quantity of work within predetermined (and sometimes unrealistic in their view) schedules. They indicated that the ability to perform high quality work was often compromised by workload and work schedules. Planning staff also reported the same impediments to work completion as indicated by technicians. In addition, planners reported fatigue as a result of the workload and expressed concern regarding the lack of an effective review of their work.

The inspectors concluded that the various competing work pressures and impediments to work progress perceived by maintenance technicians and planners were having an eroding effect on their morale. In addition, it appeared to the inspectors that these factors were of a magnitude that presented a potential for adversely influencing personnel performance.

3.2 Modifications

3.2.1 Scope

This portion of the inspection focused on an evaluation of the overall process for the development and implementation of plant modifications. It was restricted to modifications associated with the plant systems covered in Attachment IP-2.10-01 to Plant Procedure IP-2.10, "Quality Program for Nonsafety-Related Equipment and Activities."

The timeliness of the modification process was assessed to determine whether delays in the implementation of plant modifications were having an adverse impact on plant operations or operational safety. To accomplish this, computer printouts detailing all engineering change notice packages (ECNPs) and modifications contained in the support engineering integrated document system (SEIDS) historical database were reviewed for the plant systems identified in Attachment IP-2.10-01.

During the inspection, the general quality and completeness of several BOP modification packages and their implementing work documents were reviewed.

3.2.2 Detailed Findings

Various administrative plant procedures governing the processes for the development and implementation of plant changes and modifications were examined. Discussions were conducted with a number of personnel involved in the implementation of these procedures. Although Procedures IP-3.1Q, "Plant Modifications," and IP-3.24Q, "Engineering Change Notice Package," were specifically examined, the evaluation of their application and usage was purposely restricted to the systems addressed in Attachment IP-2.10-01, "Table of Nonsafety-Related System and Program Elements," of Procedure IP-2.210. The inspector determined that the licensee's process for controlling and implementing plant changes and modifications was effective.

The licensee was using an integrated, living schedule (ILS) to gather information for modifications and engineering change notices (MOD/ECN) regarding the progress of each activity, scope identification, and resource allocations. The ILS was managed and maintained by the integrated planning and scheduling department.

Through the use of the ILS mechanism and periodic reports, a modifications review committee systematically evaluated potential MODs/ECNs for such things as overall priority and the available resources to perform the task. This information was then used to determine if and when a potential MOD/ECN would be designed and installed.

The status of the tracking ILS mechanism provided an avenue for determining whether any discrepancies, changes, or delays warranted notification or approval of the management review committee (MRC). The MRC was to be notified whenever the current schedule was 20 days behind schedule for "Outage MODs/ECNs," 40 days behind schedule for "Licensing Commitments," and 60 days behind schedule for "other MODs/ECNs."

An assessment was conducted of the status of all MOD/ECN packages associated with the BOP systems covered by Attachment IP-2.10-01 and listed in the SEIDS historical database. Based on an evaluation of "Status Code," the following results were noted for MODs/ECNs:

Status Code	Total
Preliminary Assessment 7H (PA on Hold) (1)	63
Evaluation 10 (MEP Working)	16
Evaluation 10H (MEP on Hold) (2)	8
Design 15 (MDP Working) (3)	54
Design 15H (MDP on Hold)	224
Design 17 (At PM for Approval) (4)	9
Installation (Issued to PDC) (5)	132
Operable	37
Engineer Closed	191
Hold	2
Superseded	62
Canceled	128
Void	124

(1) PA - Preliminary Assessment
(2) MEP - Modification Evaluation Package
(3) MDP - Modification Design Package
(4) PM - Plant Manager
(5) PDC - Plant Document Control

As a result of the proportionately larger number of "Design 15H" status code modifications, the inspector assessed whether this condition represented an adverse impact on plant operations. The inspector reviewed each of the Status Code 15H items with the Unit 1 Operations Manager and determined that the conditions addressed by the design changes in this status code fell in the category of operational inconvenience rather than an impact on operational safety.

Examples of these were:

88-J-0117 Install a time delay to bypass annunciator when diesel engine starts.

88-J-0126 Change feed pump turbine oil reservoir level setpoints for Level Switches N1LP-LSHL-7463, 7464, and 7465.

89-J-0107 Provide 30 second time delay pickup on Annunciator Windows 5M3A3 and 5M3B3 to prevent spurious alarms.

On the general subject of BOP problems and their relationship to the plant modifications processes, licensee personnel stated that they essentially treated BOP modifications no differently than the modifications on safety-related systems. The practice appeared to be causing unnecessary delays and an increase in the MODs/ECNPs backlog. An example was related to the need for repeated repairs of steam leaks on level columns because of threaded fittings. Seal welding these level columns appeared to be a better long-term fix, but doing so would require going through the lengthy formal modifications process.

The team noted that in the "Material Condition Plan Task Force Action Item List" the design engineering department (DED) had been assigned action items to streamline the modifications processes and reduce the effort required to issue design changes, especially for nonsafety/minor changes. They were tasked to review and identify methods of recognizing a less cumbersome level of control on nonsafety-related design changes. Under this task force action item list, the plant engineering department (PED) had been assigned the responsibility for developing a plan to ensure that design change packages were closed out in a timely manner.

Timeliness of the incorporation of vendor identified issues into the MODs/ECNs process was reviewed with no adverse findings.

Various modification work packages being worked during the present Unit 2 refueling outage were examined for adequacy and completeness. Samples were selected from work packages prepared/implemented by the maintenance and support services (M&SS) group and by other maintenance department divisions. Also, selected portions of modifications being worked were observed by the inspector in the field. No adverse findings were identified.

As a result of the the various plant events associated with the malfunctions of the feedwater system isolation valves (FWIV), the inspectors reviewed the licensee's actions in the area of design changes. The following ECNPs were currently being developed by DED to address problems associated with the FWIVs:

90-J-0147/8 "Install Two Single Pole Switch Terminals in the FWIV Relay Panels"
MOD 90-021/2 "FWIV Hydraulic System Upgrades"
MOD 90-071/2 "Clean-Up and Recirculation Skid for FWIV Hydraulic Fluid,"

3.2.3 Conclusions

The licensee had developed and implemented adequate programs and procedures to effectively control and implement design changes to plant BOP systems.

These programs and procedures were being effectively implemented, as evidenced by the reviews conducted by the inspector in the following areas:

- engineering tracking and development of identified design changes,
- modification work package planning and scheduling by the responsible groups,
- management involvement in the task of overall process improvement (Station Material Condition Improvement Plan), and
- plant awareness of the "Plant Modifications and ECNP Status" via the incorporation of this parameter as a "Management Performance Indicator" in the monthly station report.

3.3 Operations

3.3.1 Scope

This area of the inspection assessed the quality of the BOP operations procedures, the operators ability to execute the procedures, the general condition of BOP equipment, the extent of delays in BOP corrective maintenance, and any impact these delays may have had on plant operations. The inspector also reviewed the impact that equipment unavailability, because of needed maintenance, had on the operator's ability to operate the plant safely.

3.3.2 Detailed Findings

3.3.2.1 BOP Operations Procedures

The inspector reviewed BOP procedures for secondary plant startup, plant startup to 100 percent power, and selected system operating procedures. Performance of procedures executed in the control room was observed. All procedures reviewed contained administrative performance instructions about sequence of steps and requirements for omission of procedure steps. Secondary plant startup was covered by two procedures, one of which was used, depending on the availability of steam from the other unit or the auxiliary boiler. The general operating procedures contained numerous exits or breakouts to other procedures for the operation of specific systems or components. However, the control room operators were able to transition into and out of procedures easily.

The inspector observed the transfer of 13.8 kV buses from the auxiliary transformers to the standby transformers. The applicable procedure required the operator to fill out a checklist that ensured the electrical breakers were operated in the correct sequence. This checklist was completed and the desired electrical lineup was obtained.

There appeared to be some inconsistency in the use of "note" and "caution" steps in the body of procedures. A good example of this inconsistency was found when comparing the secondary plant startup procedure to the plant heatup procedure. Procedure 1POP03-26-0003, "Secondary Plant Startup," cautioned the operator to not allow the steam generator feed pumps (SGFPs) to idle with the turbine latched to prevent excessive pump bearing wear. However, Procedure 1POP03-ZG-0001, "Plant Heatup," did not contain a "note" or "caution" to remind the operator that all high-head safety injection (HHSI) pumps must be operable within 4 hours of exceeding 350°F RCS temperature, or before exceeding 375°F RCS temperature. The situation with the inoperable HHSI pump was more of a safety concern than the feed pump bearing wear. Licensee representatives agreed that a review in this area of "caution" and "note" usage in system operating procedures should be done to significantly enhance the procedures.

It was the conclusion of the inspectors that current procedures used to operate the BOP were sufficient in scope and detail to safely operate the two units at STP.

3.3.2.2 Condition of BOP Equipment

The inspector accompanied the Unit 1 turbine building reactor plant operator (RPO) on his rounds during the power escalation phase of Unit 1 startup. There were numerous steam, water, and oil leaks observed. All of the deficiencies observed had been entered into the corrective action system (work request initiated). There was no ongoing corrective action noted because most fluid leaks were unisolable for repair at power, or because resources were being used to support the ongoing Unit 2 outage. Several temporary scaffolds were found to be erected in the grade level and sublevel of the turbine building. The scaffolds were constructed and supported securely, but several of the scaffolds required precise body control and maneuvering to safely reach the working platform from the access ladder. A number of tripping hazards existed because of several temporary hoses being utilized to support a condenser waterbox outage for leakage sniffing.

The inspector observed operations activities in the Unit 1 control room during startup and the subsequent power escalation. A delay of at least 24 hours resulted from a modification work package that was not appropriately planned or implemented. The modification replaced pressure switches on the EHC system and was partially implemented during a forced outage. The partial installation replaced double acting switches with single acting switches which did not complete the proper interlock logic of the circuit. The delay was caused because the entire package had to be reviewed, rewritten, and reworked by system engineering to obtain the desired results.

All deficiencies on control room controls, equipment, or instrumentation appeared to be documented. The deficiencies on the control boards were identified by affixing the work request tag to or near the component, control, instrument, or annunciator. A small tag was used to preclude the obstruction of other controls or instruments, while identifying the affected component in most instances. However, several tags on the control boards and annunicator panels were the full size tags, which increased the risk of undesirable obstruction.

It was noted that a No. 12 emergency diesel generator trouble alarm was illuminated as was a result of a faulty oil sump level instrument. A work request had been initiated in March 1990. There were other examples of long standing work requests that had been initiated but not completed. None of these outstanding corrective maintenance items could be considered as an impediment to safety systems performing their design function or having an impact on safety in general.

The licensee's backlog of balance-of-plant corrective maintenance was large, and the number of minor, outstanding maintenance items and secondary systems leaks appeared to be more than that normally encountered at other facilities. Although these conditions were bothersome, and at times frustrating to the plant operating staff, there was no evidence that they were a challenge to plant safety.

3.3.2.3 Observation of BOP Operations Activities

The inspector observed licensed and nonlicensed operators execute BOP procedures in the control room and in the plant. It was determined that current BOP operating procedures were staged in the control room and at local stations where they could be utilized. Multiple copies of procedures were generally available because they also served as task performance check lists.

During transfer of the 13.8 kV busses from auxiliary to standby transformers, the procedure to be used was verbally authorized by the unit supervisor. Prior to execution, the panel operator walked the procedure down by actually touching those controls that he intended to operate. The unit supervisor directly supervised the evolution. During the evaluation when the operator positioned the control switch to separate the auxiliary transformer, both breaker indicating lights extinguished. The operator immediately allowed the control switch to return to normal and the breaker closed indication light came on, indicating two feeders closed to the electrical bus (an undesired parallel condition). The operator removed his hand from the controls and waited for the breaker to trip automatically, establishing the desired electrical lineup. A work request was prepared and troubleshooting revealed that the breaker control switch was faulty. The control switch was replaced, tested, and found to work as designed.

During power escalation, the control room called the turbine building operator and told him that condensate dissolved oxygen concentration was increasing rapidly and ordered him to "look for leaks." The control room operator also stated to the operator that this condition could force the unit to be shutdown.

A procedure to "find air leaks" was not evident. The system engineer discovered that the sampler/analyzer was lined up incorrectly and was in fact sampling an air stream. At the time of this inspection, a reason for the incorrect lineup had not been determined.

The inspector observed the 18-month required calibration of Nuclear Instrument Channel 43 (NI-63) in Unit 2. The following were observed during the perfo mance of the calibration.

(1) Two technicians were assigned to perform the task, a journeyman and an apprentice instrumentation and control technician (I&C).

(2) The work package procedure was separated into a body and a data logging section, which served to streamline the effort.

(3) The I&C shop foreman visited the jobsite twice during the observation.

(4) The test equipment (various meters) was hooked to a service power outlet located within the NI cabinet. This practice was questioned by the inspectors, but was later determined to be acceptable because the service outlet power supply was separated from cabinet instrumentation and control power, and the grounded test equipment would not have affected the NI instrument itself.

(5) The calibration procedure did not check the percent meter against the bistable trip setpoints. Only voltage or current were checked. The journeyman technician stated that this action was previously required by the procedure, but it had been discontinued because of the difficulty of matching up the data from the power meter, bistable setpoint and test equipment indication. This was not considered to be of any consequence because any discrepancy between bistable setpoint and percent power indication would be found in other required surveillances performed on the channel.

(6) The NI-46 recorder was determined to be out-of-tolerance for reproducing channel output. The technician was able to adjust recorder gain to attain the proper tolerance.

(7) Verification signatures were required for the procedure steps that were performed prior to restoring the system to normal. The observed practice was for the journeyman to perform the step and the apprentice to verify correct performance.

(8) At the completion of the calibration, each technician reviewed the entire package ensuring that each step had been completed and that all data had been obtained. At this time the journeyman reported to the reactor operator (RO) that the calibration was complete, signed the package completion signature, and asked the RO to enter restoration in his log. When this was done, the technician submitted the package to the shift supervisor (SS) for his review. The SS reviewed and signed the package. The observed interface between the operations and maintenance personnel was cordial and professional.

(9) The last step performed by the technicians was to fill out and sign a test completion notification form. This multiple form took 10 minutes for each technician to complete, review, and sign. The signatures were for compliance with several Technical Specifications associated with Nuclear Instrument Power Range Channel 43. The technicians stated that they did not know the purpose of the form. When the foreman was asked why the technicians were required to sign that the instrument met or complied with facility license requirements, he stated that the form was merely a scheduling tool so that surveillance planning and tracking personnel would not overlook or miss required surveillances.

The inspector determined that licensed and nonlicensed operators had received the appropriate training and were capable of efficiently and safely executing BOP procedures.

3.3.2.4 The Corrective Action Maintenance Program Impact on Plant Operations

The inspector observed that there appeared to be unnecessary maintenance delays for several reasons, including a lack of material or repair parts, incomplete planning, and poor communication among various groups involved in the maintenance process. These groups included maintenance, operations, and engineering. Quality assurance, quality control, and health physics did not appear to be causing unnecessary delays. An example of a maitenance delay stemming from incomplete planning is provided in Section 3.1.3 of this report.

The inspectors talked with several individuals in operations to determine if backlogged maintenance was impacting safe plant operation. Operators appeared to accept the fact that material was not readily available, or that some corrective maintenance must be deferred because of plant conditions. However, oprators were vocal about backlogged maintenance contributing to conditions of poor lighting, difficult access, and personnel safety.

Most of the operators that the inspectors interviewed were aware of the method to report perceived personnel safety issues. They stated that they were generally discouraged from using the program because of a lack of results and feedback. Operators generally were not aware of other programs in place to solve problems, such as the station problem report procedure. Several operators and craft personnel were aware of the "speak out" program, but characterized it as a "whistle blower" program which they did not want to use.

The inspectors concluded that the operating staff was being affected by the maintenance backlog, but the affect was on the collective morale level and operational safety was not being impacted directly by this condition.

3.3.2.5 Personnel Interviews

The team interviewed a number of STP operations department staff about their specific concerns. In addition to the issues identified in this section, operations department personnel also contributed a number of general concerns about STP that are detailed in Section 3.4, "Management Support."

Specific to working conditions within the operations department, interviewees expressed strong concern about personnel safety issues. Specific examples of working conditions considered unsafe by operations department staff are detailed in Section 3.5, "Human Factors."

In addition, operations department staff reported low morale, particularly among reactor plant operations (RPO). The operators interviewed cited the following as conditions contributing to low morale: (1) heavy workload resulting from inadequate RPO staffing and (2) fatigue resulting from overtime. In addition, operations department staff indicated that there was a common perception in their department that management was unconcerned about personnel safety.

3.3.2.6 Malfunctioning Equipment Impact on Plant Operators and Operations

It was determined that operators were having to compensate for system, equipment, or components that were not functioning properly in Unit 1. Examples of this included:

° The lube oil conditioning system heaters did not cycle automatically, requiring extra operator effort to maintain the system within the proper operating range.

° Stator Cooling Water Head Tank N_2 regulator did not function to maintain the required system pressure. This condition required operator intervention to maintain system pressure, thereby avoiding a main generator trip (and resulting reactor trip).

° The Number 11 south condenser water box inlet isolation valve did not work in the power (electric motor) mode and had to be operated by the handwheel.

° The motor for Feedwater Valve (FW) MOV 107, 11B FW HTR outlet, would not operate. On at least one occasion in the past, it was necessary for the turbine building operator to manually shut this valve following a reactor trip.

° During startup, the operators transferred the 13.8 kV buses from the auxiliary to the standby transformers during main generator synchronization to the grid. The buses were then placed back on the auxiliary transformers after the generator was on line. This was done in response to a 13.8 kv bus black out that occurred about 2-3 months prior to the inspection while operators were loading the main generator with the auxiliary transformer supplying the 13.8 kv buses. This step had not been proceduralized in the startup procedure, nor was there any apparent effort ongoing to determine why the auxiliary transformer was lost when the main generator was synchronized to the grid.

The inspector also observed the following instance in which a worker had to perform what appeared to be arduous exercises in order to accomplish a relatively simple task. The instance involved the turbine building RPO adding lubricating oil to the upper motor bearing reservoirs for Heater Drain Pumps 11 and 13. To access these reservoir bubblers, the operator had to climb around and sometimes stand on conduit cable trays and small diameter (1-2 inches O.D.) piping.

The team concluded that some equipment deficiencies in the BOP, such as those discussed in the above exammples, create a necessity for operator intervention to assure safety at all times. For the cases observed, the inspectors noted that potential risks were mitigated by the communications equipment provided to the operators and by the system knowledge and plant condition awareness on the part of the operators.

3.4 Management Support

Licensee management was involved in determining ways to reduce the maintenance backlog and the number of events that had recently occurred at STP. For example, additional maintenance personnel have been hired and trained to specifically work on backlog items.

The licensee was actively assessing events and attempting to identify a root cause or common thread for recent events that in some instances caused reactor trips, and in others, challenged safety systems.

In addition to assessing the event causes, the licensee recently implemented a self-checking/self-verification program aimed at reducing the number of personnel errors and plant events by emphasizing attention to detail work practices. The self-checking/self-verification program encouraged workers to perform seven steps prior to performing an activity.

(1) STOP - think about task
(2) LOCATE - find device to be operated
(3) TOUCH - place hand on device - do not operate
(4) VERIFY - compare label to work document
(5) ANTICIPATE - consider expected results of action
(6) MANIPULATE - perform action
(7) OBSERVE - be alert for unexpected response

The licensee also had implemented programs designed to retain key personnel (i.e., reactor operators) and provided morale boosting incentives to others. These programs included:

° A reactor operator incentive pay program which provided a bonus to operators who stay with STP for a specified number of years.

° A lead operator and a lead journeyman program which made additional advancement positions available to reactor plant operators (nonlicensed) and craft personnel.

However, comments made by licensee personnel in the interviews discussed below indicated that these programs had not been completely successful in improving morale in some groups. The interviews conducted with STP personnel yielded a number of common concerns across department lines regarding staff perception of the adequacy of management support. Despite numerous comments that were critical of action or lack of action by STP management, a large majority of the personnel staff interviewed indicated that they were aware of overall improvement in areas of concern. With regard to the future, personnel expressed a "wait and see" approach.

The primary concern of the personnel interviewed was a reported lack of management responsiveness to previously identified personnel safety issues (see also Section 3.5, "Human Factors"). The personnel interviewed were particularly concerned that, in their view, the industrial safety program at STP was ineffective.

Personnel interviewed stated that budget constraints were widely used by management as an explanation for not being responsive to concerns, but noted that much budget waste resulted from poor management planning.

The personnel interviewed reported that a lack of coordination among shifts and shift organizations reduced their ability to effectively complete work assignments (i.e., RPOs vs. maintenance vs. health physics vs. warehouse vs. document control vs. medical staff). As an example of the impact of the nonparallel shift structures, it was reported that the full maintenance crew on backshifts was unable to complete some work because of inadequate backshift support from document control and the warehouse. In addition, a concern related to personnel safety was expressed in that full maintenance and operations staffing on weekends was not supported by medical staff.

In response to recent management actions, the personnel interviewed reported that the meetings held with management were not particularly useful for morale improvement and that many people were reluctant to express their concerns in that setting. Personnel reported that management's message to the staff to be careful and not make mistakes was not useful. They acknowledged that people do not intentionally make mistakes; however, the conditions at STP were reducing effectiveness of staff performance resulting in mistakes. In addition, a number of the staff stated that they did not believe the self-verification training was particularly useful because most people already essentially follow the approach as part of doing a good job.

The team concluded that a number of concerns expressed by STP staff relative to management support and specific job conditions contributed directly to the low morale level, especially for RPOs, I&C technicians, and maintenance planners. It was the opinion of the team that these morale problems, along with reactions to job pressures such as concern about individual safety, fatigue as a result of overtime, and heavy workload caused by limited staffing, were of the magnitude to have the potential for degrading performance and contributing to personnel error. The team further concluded that these potential effects on performance may have played a role in recent operational events at STP.

With respect to recent and future management action on STP organizational issues, the team expressed concern that current efforts appeared to focus on direct issues rather than the overall process and generic issues.

Based on the perceptions of STP personnel regarding recent improvement, the inspection team concluded that evidence of management concern and awareness regarding personnel working conditions could significantly improve morale. The failure to correct the morale problems has a potential for further degrading performance and increasing personnel error.

3.5 Human Factors

The team identified a human factors concern in the area of personnel safety. As a result of interview comments received from representatives of all STP departments the team conducted a walkdown of selected examples provided by STP personnel.

From these walkdowns, the inspectors identified the following are examples of plant equipment for which access and operation lead to substantial risk to personnel safety.

(1) Isolation valves for main steam pressure control valves were located outside of the rail enclosure on top of the deaerator (DA) storage tanks in both units 55 feet above the turbine deck (88-foot level). One of the isolation valves (MS 298) was manipulated during every plant shutdown and startup. The job required two operators and over 1 hour to complete. Access to MS 298 required an operator to stand on main steam piping. Neither a platform on which the operator could stand nor a rail enclosure was provided. Use of a safety belt attached to the rail enclosure was the only protection available to the operator.

Isolation Valve MS 563 for PV-7174 and Isolation Valve MS 566 for PV-7174A, were also located outside of the rail enclosure on top of the deaerator storage tanks. Neither platform nor railing were provided for these valves; however, they were used less frequently than MS 298.

(2) The DA tank drain valve was manipulated during every plant shutdown and startup. The valve was located in the overhead on the 55-foot level of the turbine generator building (only Unit 1 was inspected). To access the valve, an operator had to step first on a conduit, then climb several hot, heater drip pipes to a cable tray. The operator had to then climb the cable tray, stepping on wiring, to a piece of overhead bracing that led to the valve. While standing on the bracing to operate the valve, the operator could only attach his safety belt below where he was standing, which could have resulted in a longer fall than if it were possible to attach the belt above the operator. If an operator fell while wearing a safety belt in this location, there would be no structure within reach and the individual would therefore dangle from the overhead until help arrived. Although this situation was a difficult one to correct, even a permanently installed ladder would reduce the difficulty of operator access.

(3) In the Unit 1 turbine generator building 55-foot mezzanine, near the steam generator blowdown flash tank, a number of valves in the steam generator blowdown system which operators had to manipulate were located under the

floor grating. To access these valves, operators had to climb on hot main steam pipes under the floor grating. Steam leaks in this area were common. In addition, SB 225 was operated by a handwheel that was turned downwards and, therefore, more difficult to reach and manipulate. Extensions through the floor grating could have been easily installed on all of these valves.

(4) In the Unit 1 turbine generator building condenser pit (approximately the 20-foot level), approximately 75 vent valves in the condensate and feedwater systems were located in the overhead, approximately 30 feet above the floor. For example, CR 0053, CR 0054, CR 0055, CR 0056, CR 0057, and CR 0058, used for condenser air removal, were found in this location. To access these valves, operators had to climb an I-beam onto pipes that were often hot and vibrating during plant operation. These valves were operated every time a water box was taken out of or placed into service, and during every outage when operators had to enter water boxes to check for tube leaks. An operator reported that these valves have been operated approximately 30-40 times in the last few weeks.

(5) Although ladder storage racks were found throughout the Unit 1 turbine generator building, most storage racks were found to be empty during a walkdown on October 13, 1990.

(6) Lighting on the Unit 1 turbine generator building 55 foot level was limited in a number of areas inspected. Although RPOs were required to carry flashlights, the standard issue flashlight was a "mini-mag" which may not have provided adequate supplemental lighting.

(7) Access to the controllers for four moisture separator drip tanks and four reheater drip tanks on the 55-foot level of the turbine generator building required personnel to climb an approximately 20-foot ladder. The platforms were of limited size. During plant operation, the metal ladders were hot and the temperature on the platform was elevated because of the close proximity of steam pipes. Unit 2 platforms appeared to be smaller than those in Unit 1 and pipes were placed close to the top of the access ladder. Operators reported that steam leaks were common and that high temperatures had been measured on the Unit 1 platforms of approximately 138°F on the platform metal and over 400°F on the steam pipes. Personnel interviewed stated that additional insulation, extended platforms, or relocation of the level controllers would reduce or eliminate this problem.

(8) The gauge for essential cooling water pump seal water flow had to be read approximately three times each day for each pump. Access to this gauge was restricted, which required operators to step over pipes and walk through a crowded area. Personnel interviewed stated that numerous cuts, scrapes, and twisted ankles have resulted from the difficulties in accessing the gauge. The easiest access required personnel to walk on the screen wash booster pump supply pipe. Wear on the pipes indicated that this had in

fact been occurring. A clear path to the gauge was found through another area in the ECW pump room. Removal of a small portion of handrail and the addition of two steps would provide easy and safe access for personnel.

The inspectors concluded that these examples constituted risks to personnel safety. These specific examples were discussed with licensee management verified that these situations had been previously brought to their attention and that they may have reacted more slowly than they should. The inspectors, therefore, concluded that the STP personnel perceptions that management had not been responsive to concerns about personnel safety appeared justified. In addition, the inspectors noted that the effect on personnel of working under these conditions could contribute to the morale problems identified previously in this report.

3.6 Root Cause

The inspectors reviewed the STP approach to root cause analysis. Root cause analysis was addressed as part of Procedure IP-1.45Q, "Station Problem Reporting," Revision 6, dated July 9, 1990. The procedure described in detail a process for reporting, investigating, analysing, and correcting problems which were not appropriate to other STP deficiency reporting mechanisms such as WRs, DRs, or RFAs. It should be noted that the inspectors did not conduct a review of any completed records of root cause analysis. Therefore, this review addressed the root cause analysis program and not its implementation.

The team noted that, although use of a method of root cause analysis is commonly found at nuclear power plants, the methods used are rarely proceduralized. The STP procedure appeared to be thorough and complete. Of particular note was the level of detail found in human performance cause codes. A common flaw in the analysis of human error was a lack of consideration of the many factors that can cause human error. The level of detail in the human performance cause codes in IP-1.45Q included numerous factors that could impact human performance, as well as distinctions between several categories of human error for which external root causes cannot be easily determined. In addition, STP provided detailed training in the use of IP-1.45Q to relevant individuals.

The inspectors concluded that the proceduralization, level of detailed guidance for analysis, and training provided the user of IP-1.45Q appeared to be adequate for a exceptable method of root cause analysis.

4. EXIT MEETING

On October 18, 1990, the inspection team and other NRC representatives met with Mr. W. H. Kinsey and other licensee personnel to discuss the scope and findings of the inspection. Mr. L. J. Callan, Director, Division of Reactor Safety, Region IV represented NRC management at the exit meeting. At the exit meeting, none of the information discussed was identified as proprietary. Licensee personnel who attended the exit meeting are identified in Section 1.