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Facility: Calvert Cliffs Nuclear Power Plant, Units 1 and 2
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EXECUTIVE SUMMARY

1 OBJECTIVES

The team was chartered with three objectives for its inspection of the Calvert Cliffs Nuclear Power Plant (CCNPP): (1) to perform a broad-based inspection of licensee performance in the functional areas of operations, maintenance and surveillance, engineering and technical support, and safety assessment; (2) to compare the observed level of performance with that characterized in the last Systematic Assessment of Licensee Performance (SALP) report; and (3) to evaluate the effectiveness of the licensee's Performance Improvement Plan (PIP). The team mainly observed performance of activities, supplementing their observations by reviews of the licensee's programs and procedures.

2 OVERALL CONCLUSIONS

The team concluded that CCNPP is being operated and maintained in a safe manner. Baltimore Gas & Electric Power Company (BG&E) has made substantial progress in correcting past performance problems through its PIP and other programs and procedures. BG&E has continued performance improvements noted in the most recent NRC SALP Report for CCNPP. Although BG&E has significantly strengthened the process for identifying and evaluating issues, BG&E has yet to clearly demonstrate that they can promptly and effectively resolve them. Weaknesses were also identified in BG&E followup of some unexpected or deficient plant conditions and in 10 CFR 50.59 implementation.

3 CONCLUSIONS FOR EACH AREA

3.1 Operations

Operators were knowledgeable and professional and usually used and adhered to procedures. The licensee is improving operating procedures at an appropriate pace through its Procedures Upgrade Program (PUP). Communications within the Operations organization were good. Managers clearly conveyed their expectations to the operations staff and, in turn, operators promptly conveyed any concerns to the managers. Effective shift turnover briefings ensured that each incoming crew was aware of plant status. Communications by control room staff were clear and concise. The operations staff also interfaced well with other groups on site; for example, maintenance staff served in the operations work control group.

3.2 Maintenance and Surveillance

The licensee uses an appropriate threshold for identifying hardware deficiencies, but needs to continue to identify and correct deficient conditions throughout the plant. The licensee had strengthened the maintenance planning and documentation processes. Although recent maintenance packages exhibited excellent quality, inefficiencies in the process contributed to a less than fully effective implementation of maintenance activities. Maintenance craft were knowledgeable about their work and used appropriate procedures. Their supervisors effectively oversaw their work. Post-Maintenance Testing (PMT) was improved but PMT guidance was inconsistently used and did not address minor maintenance. The licensee needs to better define emergency maintenance and evaluate and trend rework and significant equipment failures.

By centralizing the Surveillance Test (ST) Program and assigning responsible individuals, BG&E effectively resolved previous problems with ST scheduling. Generally, the staff is knowledgeable about ST procedures and use and adhere to them. Since the team identified two technical adequacy concerns within the relatively small sample of ST procedures reviewed, an overall conclusion could not be reached on ST procedure adequacy. The licensee will need to assess the broader implications of this finding.

3.3 Engineering and Technical Support

System engineering functioned acceptably and made meaningful contributions to improved overall performance. System engineers generally provided appropriate identification and followup of plant issues, although the team identified some instances where they failed to identify and pursue deficiencies. The quality and completeness of Design Engineering products were generally good. The team was concerned with BG&E's consistency, timeliness, and rigor in evaluating the operability impact of unexpected or degraded conditions and the lack of detailed guidance to process and document them, especially those that need additional information or expanded engineering analysis. For example, several individuals in various parts of the BG&E organization were aware of the service water heat exchanger support lamination, but they did not initiate an Issue Report or question and evaluate component operability. The licensee staff did not fully understand the difference between operability and reportability and their associated time constraints. However, items that clearly have an impact on operability are aggressively pursued, raised to plant managers, and promptly and thoroughly corrected. The team also noted several concerns with the licensee's program for implementing 10 CFR 50.59. These issues warrant licensee management attention and corrective action.

3.4 Safety Assessment and Quality Verification

BG&E management and staff generally had a sound safety perspective. The Issue Report (IR) process effectively identifies issues and categorizes them based on safety significance, and quickly and effectively elevates issues to appropriate managers. However, its overall effectiveness is reduced by its inability to promptly and consistently bring issues to a timely resolution, and requires significant managerial attention. The Operating Experience Review (OER) Organization is well staffed and their performance is a notable strength. Site review committee performance was generally good except that some modifications to safety-related equipment were not reviewed by the Plant Operations and Safety Review Committee (POSRC), which highlighted a weakness in the licensee's implementation of TS requirements.

3.5 Performance Improvement Plan and Implementation Program (PIP-IP)

BG&E's PIP-IP is helping to correct past performance problems at the Calvert Cliffs Nuclear Power Plant. The Nuclear Program Plan contains initiatives started under the PIP along with several new initiatives, and appears to be effective in tracking the remaining open PIP-IP action plans.

DETAILS

1 INTRODUCTION

1.1 BACKGROUND

During the last several years the licensee and the U.S. Nuclear Regulatory Commission (NRC) identified a series of performance problems at the Calvert Cliffs Nuclear Power Plant (CCNPP). In an attempt to resolve the programmatic and managerial weaknesses associated with these problems, the licensee undertook an extensive effort to evaluate the problems, identify their underlying root causes, and correct the problems. The licensee developed the Performance Improvement Plan (PIP) to facilitate management and monitoring of this effort. The actions specified in the PIP are largely complete. The licensee has successfully returned both units to operation.

1.2 SCOPE

To improve NRC managers' understanding of the current status of CCNPP performance and to evaluate the licensee's success in resolving past performance problems, NRC chartered an Integrated Performance Assessment Team (IPAT) with three objectives: (1) to perform a broad-based inspection of licensee performance in the functional areas of operations, maintenance and surveillance, engineering and technical support and safety assessment; (2) to compare the observed level of performance with that characterized in the last Systematic Assessment of Licensee Performance (SALP) report; and (3) to evaluate the effectiveness of the licensee's PIP. The team focused on performance-based observation of ongoing activities, supplementing this observation by reviewing programs and procedures.

1.3 METHODOLOGY

Operations

To assess the overall effectiveness of plant operations, the team monitored operator activities in the control room and in the field and reviewed operator logs, tagouts, shift turnovers, and other practices. They interviewed managers and operators to assess the effect of the Operational Improvement Plan. They attended the licensee's morning status meetings, shift turnover meetings, and Plant Operations and Safety Review Committee (POSRC) meetings to assess communication effectiveness. The team interviewed the staff and observed control room activities to determine the results of management initiatives to improve operation of the plant and monitored pre-evolution briefs to assess their effectiveness in ensuring that the staff understood maintenance and surveillance activities.

Maintenance and Surveillance

To assess the performance of the maintenance and surveillance testing programs, the team observed ongoing field activities, and reviewed the control of maintenance work, the quality of maintenance procedures, and whether the staff used and adhered to them. They assessed how surveillance tests were scheduled and coordinated. The team also assessed whether managers were adequately involved in the program and effectively interacted with other station surveillance staff to identify and appropriately resolve deficiencies identified during field activities.

Engineering and Technical Support

To assess the effectiveness of engineering and technical support at CCNPP, the team reviewed various aspects of the engineering programs, including system engineering, design engineering, modifications, and engineering problems affecting plant operation. The team reviewed several contemporary plant problems and regulatory issues the system engineers had identified or processed to assess their: (1) responsiveness to safety significance, (2) rigor for the ensuing engineering activities, (3) interaction with other organizations, (4) technical adequacy of conclusions and recommendations. The team also evaluated Plant Engineering Section (PES) interaction with the Issue Report (IR) process, and their response to performance-based observations made by the team during plant tours.

Safety Assessment and Quality Verification

To assess the effectiveness of safety assessment and quality verification, the team reviewed IRs and how BG&E staff identify, process, and resolve issues. They also reviewed Independent Safety Engineering Unit (ISEU), Plant Operating Experience Review (POER), and Industry Operating Experience Review (IOER) products and interviewed the staffs of these groups. The team observed POSRC meetings, reviewed open item data and trends, and POSRC modification screening processes. Finally, the team assessed Quality Assurance Department performance, audits, and training.

Performance Improvement Plan and Implementation Program (PIP-IP)

The team selected six action plans to inspect from over forty action plans in BG&E's PIP-IP. The team assessed whether these action plans were effective in initiating an improvement in performance, and whether they accomplished the expected results. The team's inspection approach included (1) review of the purpose and scope of the selected action plans, (2) assessment of the licensee's activities to verify effectiveness, (3) assessment of action plan effectiveness through inspection of current program performance, and (4) verification of whether the six action plans were effectively transferred to the Nuclear Program Plan (NPP).

2 FINDINGS

2.1 Operations

The team observed and evaluated the Operations Department performance in the areas of operations effectiveness, communications, and procedures to assess overall operator performance and to identify strengths and weaknesses in the conduct of operations.

2.1.1 Effectiveness

From the team's observations, interviews, and reviews, the team determined that --

- The Control Room Supervisor used a checklist to ensure that the shift was manned as required.

- The operators in the control room were attentive to plant conditions, and the licensee kept their distractions to a minimum.

- Effective shift briefings ensured that each incoming crew was aware of plant status. The operator's used shift turnover information sheets and watch station relief checklists. The organizations that interacted with the operations staff were represented at shift turnover meetings and included departmental representatives from radiological controls, tagging, chemistry, and fire and safety. Watchstanders provided equipment status at the meeting for their assigned station. The team considers the licensee's shift turnover process a strength because it ensures a thorough review and understanding of plant conditions.

- Several control room alarm functions for operating equipment were out of service; this could affect the operator's ability to monitor plant conditions. However, the operators had backup means to monitor these parameters. Inhibiting alarm functions were controlled by a procedure, and the Shift Supervisor reviewed each function to ensure that safety was not affected. The licensee's process to control out-of-service alarm functions for operating equipment was determined to be acceptable.

- Operator logs were being effectively maintained. The operators had clearly marked when they entered and exited Technical Specification (TS) action statements in the margins of the logs, as applicable.

- The tagout log and observations of several tagouts in progress showed that tagout clearance practices were effective in ensuring that plant configuration was maintained.

- Several observed pre-evolution briefs for surveillance and maintenance activities effectively ensured that the staff adequately understood plant conditions and evolution objectives.

- With one exception, the licensee appropriately interpreted and entered TS during maintenance and surveillance activities. The exception concerned the removal of hydraulic snubbers at power, which is discussed in Section 2.3 of this report.

2.1.2 Communications

The team interviewed operations managers to determine their expectations and discussed their expectations with several members of the operations staff. Licensee managers have several programs to improve communications with the operations staff. These programs include the General Supervisor-Nuclear Plant Operations (GS-NPO) Book, electronic voice mail, and safety audit tours performed by managers and supervisors. The team reviewed the GS-NPO Book and determined that when this book promulgated operating guidance, appropriate changes were made to standing orders or procedures to include this guidance. The licensee frequently used the GS-NPO book to communicate management's operating philosophy, including its philosophy about safety and quality and event-free operations. Electronic voice mail was extensively used for timely communication with the operations staff. Managers and supervisors conducted safety audit tours to observe watchstanding practices and whether the staff complied with procedures. In addition, the Superintendent of Operations frequently visited the control room.

The team monitored control room activities to assess the quality of routine communications. Managers expect control room communications to be concise and the staff to repeat each order given to ensure they understand it. This expectation is promulgated in Calvert Cliffs Instruction (CCI) 140, "Conduct of Operations," and is amplified in the GS-NPO Book. Operator communications in the control room were effective and the staff repeated each order. In addition, all plant operators were equipped with portable radios to ensure timely communication with the control room.

The licensee had several methods to enhance communication between departments: shift turnover information sheets; various plant meetings, including the turnover, daily management, and operations/maintenance interface meetings; and pre-evolution briefs. The licensee recently established a program for operators to temporarily rotate to other departments to expand their understanding of interrelationships among departments. Many of the Operations Department managers have participated in visits to other utilities and industry-sponsored seminars.

The team reviewed several License Event Reports (LERs) and determined that ineffective communication was a contributing cause for two of the events: LER 91-001, "Reactor Coolant Inadvertently Drained Through Containment Spray Header," and LER 91-006, "Failure to Follow Technical Specification Action Statement." Licensee corrective actions implemented in response to these events addressed the communication discrepancies. The licensee recognized that events of this type indicate the need to continually emphasize communications.

2.1.3 Adequacy and Use of Procedures

The licensee has reviewed 62 percent of Abnormal and Emergency Operating Procedures and

Surveillance Test Procedures through its Procedures Upgrade Program (PUP) and estimates it will complete all of them by December 1992. Of the remaining site technical and administrative procedures, 44 percent have been upgraded and the rest are scheduled to be completed by December 1994. Overall, the licensee has upgraded 49 percent of its procedures, 14 percent more than it had completed by July 1, 1991. The Procedure Review Committee (PRC) reviews and approves technical procedures as described in the TS and its function is clearly described in CCI-103, "Organization and Operations of the Plant Operations and Safety Review Committee (POSRC)." The team noted that the PRC reviews procedures before each meeting. At the meeting, the technical staff presents information about procedure changes to the committee. Presentations observed were detailed, and the committee exhibited a questioning attitude. The team compared several procedures that had been through the PUP with previous revisions; the revised procedures were improved.

The licensee took several actions to ensure that the staff adhered to procedures. These actions included communications to the staff through the GS-N[illegible] and discussions at shift turnover meetings of events that have resulted from poorly [illegible] procedures. The licensee developed procedure adherence guidance within each de[illegible] developing a site-wide policy. POSRC Action Item 91-75-03, "Develop and Clarify [illegible] Policies Defining Expectations For Procedure Usage, Pre-evolution Briefings, and Proper Supervisory Involvement," was being used to track development of the site policy. The staff used and properly followed procedures during the team's observation of surveillance tests and routine evolutions in the control room.

The team reviewed several LERs, which were attributed in part to either poor procedures or not adhering to them. These LERs included: 91-01, " Unit 2 Reactor Coolant Inadvertently Drained Through Containment Spray," 91-02, "Unit 1 Emergency Diesel Generator Slow Start Times Allowed," and 91-02, "Unit 2 Engineered Safety Features Actuation System Initiation." The licensee implemented adequate measures to correct the problems identified in these LERs.

The team noted that the POSRC does not review TS Interpretations. TS Interpretations are controlled by CCI-311, "Technical Specification Interpretations," which only requires that the GS-NPO and the Superintendent of Operations review them. The licensee stated that since TS Interpretations are not procedures, in that they only clarify existing documents, they need not be approved by the POSRC. The team considered this approach to review and approval of TS Interpretations to be weak, in that it did not take full advantage of the insights potentially available through multi-disciplinary review by POSRC.

The team identified that the POSRC had not reviewed and approved CCI-308, "Temporary Notes, Operator Aids, and Permanent Labels." The licensee believed that during a previous meeting, POSRC considered the need to approve this procedure and elected to not review it. The licensee could not find documentation to support this assertion. After additional consideration, the licensee concluded that the POSRC should have reviewed this procedure and agreed to have them complete it. The team did not identify any other CCIs that had not received the appropriate review.

2.1.4 Conclusion

The team concluded that operations effectiveness, procedures, and communications are consistent with that described in the last SALP Report, and the licensee continues to complete previously initiated performance improvements. The licensee conducted plant operating activities in a safe and well controlled manner. Operators were cognizant of plant and equipment status and demonstrated a professional approach.

The managers effectively communicated with the operations staff and demonstrated good involvement in day-to-day plant operations. Communication between departments and face-to-face operator communications were good. Radios were effectively used by plant operators to ensure timely and clear communication between the control room and the field. Managers continue to emphasize communication quality to help reduce operating events.

The team concluded that the PUP was producing good quality procedures at an appropriate pace. Although not using and adhering to procedures contributed to several past events, the licensee's corrective actions appear to have been effective. Operators were aware of requirements to adhere to procedures and were observed following procedures.

2.2 Maintenance and Surveillance

For the maintenance program, the team evaluated how effectively the licensee planned and performed maintenance and evaluated the effectiveness of their troubleshooting and post-maintenance testing (PMT) processes.

For the surveillance program, the team evaluated how well the licensee oversaw, scheduled, and implemented the program and evaluated the quality of the surveillance test procedures.

2.2.1 Maintenance Program

2.2.1.1 Planning Effectiveness

In August 1991, the licensee consolidated the maintenance planning function under one plant work group in an attempt to provide a standard and efficient work control process. In addition, the licensee issued a detailed Maintenance Order Planning Guideline and implemented a new computerized system called NUCLEIS for planning and controlling work.

The introduction of NUCLEIS resulted in an anticipated increase in the planning backlog, which in turn contributed to an increase in the maintenance backlog. Despite these increases, the licensee reduced these backlogs somewhat because it assigned additional planners who became familiar with NUCLEIS. Nevertheless, on several days during the inspection, the team noted that a sufficient number of planned tasks had not been developed to keep the mechanical maintenance staff busy. This lag in planning inhibited further backlog reduction and gave the maintenance supervisor minimal time to review work packages before implementation.

Supervisors said they needed the work packages more than a day before the work was scheduled. While the planning group was working toward providing supervisors these packages five days before the scheduled work date, this goal was not being consistently achieved. The licensee was aware of this planning productivity problem, and arranged to provide five additional backup planners, beginning January 1, 1992. To further increase the supervisors' review time, the licensee recently added production coordinators to the work groups and was filling two planning supervisory positions.

Non-emergency, high priority tasks were planned effectively. For example, the diesel generator maintenance performed during the weekend of December 7, 1991, indicated that adequate provisions exist for performing maintenance during off-normal hours.

The quality of planned routine maintenance packages was good. Review of a sample of packages prepared over the last six months indicated that improvement in this area has continued. The licensee intended that users of the routine packages give planners feedback. However, the team identified that this feedback system was informal, was not very effective, and did not satisfy the licensee's expectations. Therefore, the licensee plans to establish a formal feedback program.

To further enhance the planning and maintenance process, the licensee implemented a Quarterly System Schedule (QSS), a rolling 12-week schedule, which provides a systematic process for scheduling system maintenance. The planning for this system appeared to be up to date.

2.2.1.2 Implementation

The maintenance staff were familiar with their tasks and procedures and used and adhered to them very well. Both the maintenance supervisors and the work force were technically competent and conscientious. Pre-job briefings were a part of each maintenance task. Maintenance supervisors and the quality verification staff were in the field too, and the supervisors considered field observation of work performance an important aspect of their job. Both the planner and the system engineer were identified on each maintenance order to help resolve questions that could arise while working.

The licensee recently implemented the rover maintenance program to control and document minor maintenance without generating individual maintenance orders (MOs). Although this program was adequately implemented, in several instances, the associated documentation was not sufficiently detailed. The team brought this inadequacy to the licensee's attention.

Discussions with mechanical maintenance workers and supervisors indicated that maintenance training is very good, training facilities are adequate, and managers strongly support the training program.

Several specific examples of minor undocumented deficient hardware conditions existed. These included unsecured transient equipment, support hangers abandoned in place, plugged floor drains, and component fasteners that might have inadequate thread engagement. Certain deficiencies also existed in areas adjacent to completed work sites. These examples indicate that licensee managers need to continue to emphasize the need to identify and document material deficiencies.

The team observed that Station staff were confused about what constitutes emergency maintenance and when it should be used. The licensee used the emergency maintenance process for removing inadequately supported flow instrumentation in the component cooling water system. In this instance, the licensee determined that the condition did not affect system operability, did not involve a TS Action Statement, or constitute an urgent safety concern. However, the licensee processed this task as emergency maintenance and bypassed some of the normal planning and documentation applied to high priority and routine maintenance. Licensee managers indicated they would take steps to clearly define emergency maintenance.

Currently, no program or procedure for tracking and evaluating rework or recurring maintenance exists, but the licensee indicated it initiated development of such a procedure. Also, root-cause followup of significant component failures was not formalized through the MO process. BG&E managers stated that they plan to address this concern by expanding the IR process to include MOs (see Section 2.4 for additional details concerning the IR process).

2.2.1.3 Troubleshooting and Post-Maintenance Testing (PMT)

Administrative Procedure CCI-117, "Temporary Modification Control," describes the maintenance troubleshooting process for failed or degraded equipment. Each troubleshooting activity requires a specific and documented action plan as well as an associated risk assessment. One concern identified was that certain actions performed during troubleshooting, such as a circuit card removal and subsequent reinstallation, may not require a specific post-maintenance test (PMT) or functional test.

BG&E previously developed a PMT Guide in response to identified PMT weaknesses. PMT designation and documentation in MOs was generally very good, although the staff inconsistently used the guide. For example, specific PMT was not included in the MO following maintenance to the Unit 2 No. 24 vital inverter, and the planner did not use the PMT Guide in developing the associated MO. Review of the actual PMT performed indicated that it satisfactorily verified system operability. BG&E plans to address these inconsistencies and provide additional guidance for PMT following minor maintenance activities (e.g., small breaker or fuse replacement), and troubleshooting.

2.2.2 Surveillance Testing Program

2.2.2.1 Scheduling and Oversight

A site surveillance test program manager administered the surveillance test program, and specific functional surveillance test coordinators (FSTCs) coordinated it. The licensee previously centralized the program because of its performance weaknesses. The requirements of the surveillance test program were integrated into a single Administrative Procedure, CCI-104, "Surveillance Test Program." Since these improvements were implemented, the number of missed surveillance test procedures (STP) has significantly decreased, and the percentage of STPs begun on time has improved. The licensee also developed a TS Surveillance Matrix to ensure adequate translation of TS into the STP. These actions appeared to have effectively improved overall surveillance test program performance. The POSRC reviewed all failed surveillance tests, which provided additional independent and diverse assessment and appeared to effectively re-enforce the plant staff's safety perspective.

2.2.2.2 Procedure Quality

The licensee initiated a procedure upgrade program (PUP), which included a technical adequacy review. Overall, STP clarity and quality was adequate and those processed through the PUP were improved. However, the technical adequacy of two procedures reviewed by the team was questionable. STP 0-10-1, "Spent Fuel Pool (SFP) Ventilation System Monthly Test," did not effectively verify flow through each of the redundant parallel charcoal filter trains. The common header and only one of the two charcoal filter trains is instrumented. The charcoal filter trains cannot be separately isolated from the common header. However, the licensee infers no blockage of the non-instrumented charcoal filter train based on common differential pressure readings and data taken during the 18 month test when the non-instrumented charcoal filter train is temporarily instrumented. The team interpreted the relevant TS to require verification that system redundancy be maintained. BG&E initiated an IR to investigate the concern and took immediate steps to provide reasonable assurance that the equipment was performing satisfactorily.

The second procedure, Operating Instruction (OI) 3B, "Shutdown Cooling - Unit 1"), is an 18-month stroke test and is part of the Inservice Testing (IST) Program for manually operated shutdown cooling valves SI-319, SI-329 and SI-452. A similar procedure exists for Unit 2. These valves included reach rods some of which use multiple gear boxes and universal joints. The test procedure did not ensure that the valves were operated by using their reach rods from the remote handwheel as would be required during an emergency. In response to the team's concern, the licensee initiated a review of this procedure.

In the past, numerous pen and ink changes to surveillance test procedures made them difficult to follow. The licensee's administrative changes to eliminate this concern were generally effective. However, the team found temporary changes to CCI-104, "Surveillance Test Program," were not incorporated into the procedure as required, making this procedure extremely difficult to use. In one instance, the licensee failed to identify two temporary changes to a controlled copy of the procedure. The licensee immediately initiated an IR and short-term corrective actions. The licensee's corrective actions for this problem were prompt.

2.2.2.3 Implementation

The quality of in-field surveillance activities observed was good. The testing activities were well planned and the procedures carefully followed. When deficiencies were noted, the licensee's staff prepared IRs to initiate evaluation and corrective action. During observation of auxiliary feed pump surveillance testing, the licensee's inspections of the equipment exceeded the requirements of the test procedure and the maintenance staff participated in these inspections.

The staff acceptably used and adhered to STPs with one exception. During performance of the periodic diesel-driven fire pump surveillance test (STP-F-77-0, "Staggered Test of Diesel Fire Pump"), the licensee started the pump locally instead of from the control room. This method was not in accordance with the procedure and failed to test the control room start function. When pointed out by the inspector, the licensee initiated immediate actions to properly perform the test, and an IR was issued. The structure of the licensee's test procedures appeared to contribute to this incident. Some fire pump functions are tested weekly and others monthly. The weekly test starts the pump from the remote station, while the monthly test starts the pump from the control room. The monthly test procedure was not written to encompass those features requiring weekly testing, therefore periodic conduct of both the weekly and monthly tests in close succession was required. This may have contributed to confusion about the test sequence. The team discussed with the licensee the need to evaluate the human factors and procedure adherence issues raised by this incident during the IR followup.

2.2.3 Conclusion

The licensee established adequate administrative controls for maintenance activities. These controls ensured that groups such as quality verification and health physics were appropriately involved. The quality of completed MOs improved during the last six months. Plans and risk assessments for completed troubleshooting activities were thorough and well documented. The PMT Guide provides a good framework for conducting PMT, but was inconsistently used and lacked guidance for minor maintenance. Preventive and corrective maintenance procedures and the documentation of work performed was good. The team concluded that non-emergency high priority maintenance tasks were planned effectively and in a timely fashion.

Although several minor undocumented hardware deficiencies existed, the team concluded that BG&E's threshold for identifying hardware deficiencies is appropriate and station personnel were generally aggressive in identifying and documenting deficiencies. However, the licensee needs to (1) better define emergency maintenance, (2) improve planning productivity, (3) ensure that PMT are consistent and sufficiently detailed, and (4) evaluate and analyze for trends, rework and significant equipment failures.

The licensee has implemented effective actions to resolve its previous problems with surveillance test scheduling. The current centralized ST program and clear assignment of responsibility to FSTCs provided sufficient oversight and accountability to ensure consistent surveillance test scheduling. Generally, the staff is knowledgeable about test procedures and uses and adheres to them. On the basis of the team's identification of two technical adequacy concerns in the small sample of STPs reviewed, the team could not reach an overall conclusion on procedure adequacy. The licensee will need to assess the broader implications of this finding.

2.3 Engineering and Technical Support

The Plant Engineering Section (PES) and the corporate Design Engineering (DE) Department share the engineering and technical support function. Both organizations are located on the CCNPP site. The PES is staffed by system engineers who provide day-to-day plant engineering support. DE provides short-term design support to plant operations. In addition, DE supports nuclear fuel management, the long-term modification program, life extension planning, design basis consolidation, and other traditional corporate engineering functions.

2.3.1 Plant Engineering Section

The PES staff consisted of 90 persons with 40 assigned as system engineers. System engineers were further assigned to a primary, secondary, electrical and instrument, or auxiliary system work group. Plant-level Calvert Cliffs Instructions (CCIs) and section-level Plant Engineering Guidelines (PEGs) and Directives controlled the PES functions. System engineers attended an INPO-accredited, 14-week Engineering and Technical Staff Training Program, and completed on-the-job system qualification in accordance with the PEGs. Specific observations about the performance of the PES are discussed in the rest of this section.

2.3.1.1 Response to Technical Issues

The team reviewed the following PES activities:

- Plans and actions to improve the operating lifetime and performance of reciprocating charging pump plunger packing;
- Plans and actions to reduce the accumulation of noble radioactive gasses in the auxiliary building;
- Evaluation of elevated auxiliary building room temperatures on safety-related equipment;
- Resolution of emergency diesel generator (EDG) fuel oil consumption, storage capacity, and system design problems identified during a licensee performed electrical distribution system functional inspection (EDSFI);
- Correction of service water (SW) heat exchanger foundation installation deficiencies;

In general, PES performed well on the EDG fuel, charging pump packing, noble gas accumulation, and room temperature issues. System engineers also effectively handled several aspects of the SW heat exchanger problem. The SW system engineer initially recognized the lack of foundation anchors in September 1991 and aggressively pursued the issue, initiating an IR. However, several additional issues that involved system engineers and PES supervisors that could have affected system performance were not handled as well. These issues are discussed in Section 2.3.3.

2.3.1.2 System Engineer Plant Walkdowns

System engineers routinely identified problems during plant tours and structured walkdowns conducted in accordance with PEG 7, "System Walkdowns," Revision 1, or via Maintenance Requests and Deficiency Tags. However, during the team's plant tours, inspectors found easily recognizable problems that the system engineers had not previously identified or processed as deficiencies. Examples included leaking equipment, loose fasteners and parts, an unauthorized temporary modification and unsecured rolling equipment. The quality and completeness of PEG-7 System Walkdown Reports varied widely with respect to the type and number of deficiencies identified and the documentation of responses to the deficiencies. Further, PEG-7 did not specify system engineer walkdown frequency and did not provide measures to assure that supervisors and managers monitored walkdown performance. Records contained in The System Walkdown Reports File indicated that the frequency and effectiveness of walkdowns were inconsistent, and the licensee needs to ensure that their frequency and effectiveness become consistent.

2.3.1.3 Contractor Oversight

The PES used contractors to augment their permanent staff. The contractors fill temporary vacancies destined for permanent BG&E employees and frequently had specialized qualifications not otherwise available. Informal PES oversight practices limited authority for independent contractor's actions, such as unilateral initiation of maintenance actions or publication of technical dispositions. However, these practices were not captured in PES procedures. No safety-significant problems were observed with respect to contractor oversight. The licensee should evaluate the need for written contractor oversight guidance or instructions.

2.2.2 Design Engineering Department

2.3.2.1 Modification Change Requests (Minor Modifications)

The team reviewed more than a dozen Modification Change Requests (MCRs). The quality of engineering analyses were generally good. The documentation of the justifications for 10 CFR 50.59 screening determinations, however, was frequently inadequate or superficial. A typical justification for a determination of a "no Unreviewed Safety Question" included a statement that the modification was to a system or component not specifically described in the Updated Final Safety Analysis Report (UFSAR), or the justification simply consisted of the screening-form questions reformed as statements. In most cases, however, the inspectors could glean appropriate technical information from associated engineering evaluations to reach a conclusion that no safety-significant impact had resulted.

During a facility tour, the team found that the continuous automatic testing function of the engineered safety features actuation system (ESFAS) cabinets at both units had been placed in the standby mode. In this mode, the automatic testing function was bypassed. When questioned, the licensee stated that it was placed in standby to prevent unnecessary and spurious engineered safety features actuations. The team found that UFSAR Section 7.3.7 documented the use of the continuous testing function of ESFAS and asked whether BG&E completed a 10 CFR 50.59 safety evaluation and UFSAR change. BG&E subsequently located a 10 CFR 50.59 draft evaluation that had previously been initiated in response to facility change request (FCR) 89-126. However, the evaluation had not been completed and the UFSAR had not been changed. Licensee managers informed the team that it will complete the evaluation expeditiously and change the UFSAR.

CCI-704, "Design Change and Modification Process," that the staff uses to prepare and review 10 CFR 50.59 evaluations contained inadequate guidance on preparing 10 CFR 50.59 safety evaluation screens and very limited instructions for preparing adequate safety evaluations. In addition, training on 10 CFR 50.59 conducted in 1990, which was based on NRC Manual Part 9800 guidance, differed significantly from the training conducted in 1989, which was based on NSAC 125, "Guidelines for 10 CFR 50.59 Safety Evaluations." Managers stated that their engineers were instructed to use the NSAC 125 guidelines; however, the large number of evaluation screens that contained inadequate or inappropriate justification was evidence to the team that the engineers had not followed NSAC 125 guidelines. In addition, the scope of POSRC review of modifications to safety-related systems, performed under 10 CFR 50.59, had been inappropriately limited (described in detail in Section 2.4 of this report). The team is concerned that these collective issues may jeopardize the effectiveness of the licensee's program for implementing 10 CFR 50.59. In response to this concern, the licensee issued a memorandum outlining its expectations and interim guidance about the quality of evaluation and documentation required for 10 CFR 50.59 screens and safety evaluations. The licensee plans to review the present procedural guidance and appropriately revise and use it.

2.3.2.2 Facility Change Requests (Major Modifications)

The team attempted to assess the quality of supporting engineering analyses and documentation for major modifications. The team reviewed in FCR 90-105, "Removal of the ECCS Pump Room Motor Operated Dampers, Units 1 and 2," and evaluated the following analyses and documentation:

- Special FCR Instructions
- Operational Description of Facility Change
- Design Input Requirements List (ANSI N45.2.11, Section 3)
- Design Review Form (ANSI N45.2.11, Section 6.3)
- Design Screening Document
- 10 CFR 50.59 Evaluation Log No. 91-1-032-054-R0

- ALARA Review
- Q-List Change Review, Classification Form, and Data Input Form
- FSAR Document Change
- Seismic Qualification Calculation for Control Room Panel 1C24B (#C-91-162)
- Design Checklists for Civil, Mechanical, Electrical, and Fire Protection

The team also reviewed in less detail a dozen other FCRs, all of which Bechtel developed. Licensee engineering managers initiated a program to reduce reliance on contractors, but in-house engineers have developed no complete FCR packages.

2.3.2.3 Contractor Oversight

During the June 1991 SALP, the NRC found that the licensee's success in controlling engineering contractors was inconsistent and required attention. The licensee was implementing a number of new initiatives such as augmented project meetings, development of contractor performance indicators, BG&E/Contractor team building and quality task circles, and development of new BG&E internal standards and performance measurement methods. The team reviewed the scope and status of these initiatives. The traditional (QA and contractual) controls were effective and several innovative activities were either being planned or developed. The measures implemented and planned by the licensee were responsive to the oversight needs and previous problems.

2.3.2.4 Performance Improvement Program

The team reviewed the scope and status of portions of BG&E's Performance Improvement Program in conjunction with the evaluation of DE activities, including the Drawing Improvement Program (DIP), the Design Basis Consolidation Program, the Engineering Planning Unit, and the CCI-700 design procedure portion of the Procedures Upgrade Program.

Drawing Improvement Program

The DIP is a long-range program directed at correcting long-standing drawing errors and their root causes, and complementing the BG&E configuration management program by providing a higher integrity drawing control system. Actions to ensure the quality of critical drawings needed for operational support were successfully being used. Longer term initiatives such as completing updates for lower priority drawings, drawing database implementation, and completing conversion to computer-assisted drafting were in various stages of development. The DIP was not complete, but had been assigned a priority, and was meeting operational needs.

Design Basis Consolidation Program

The design-basis consolidation activities were reviewed by inspecting the BG&E response, particularly for design-basis discrepancies found during licensee-performed safety system functional inspections and system engineering functions. The program was being developed, using available pilot design-basis document matrices and with strategic planning in process. Although output to date has been limited, the program was contributing to resolution of real time design-basis discrepancies and appeared to be properly directed for long-term success.

Engineering Planning Unit

The Engineering Planning Unit of the DE Department was chartered to schedule and allocate resources for all design functions, including FCRs, Nonconformance Reports (NCRs), IR, and other plant engineering work loads. The licensee was staffing the unit and finishing its long-term planning. Several months ago, the licensee assigned a unit supervisor, and began using the site computer-based project management system to schedule and measure performance and to control backlogs of engineering workloads. Although full scale implementation of all planning and scheduling tools was not complete, the team considered this unit's activity a strength.

CCI-700 Series Procedures and Management Tools (NORMS)

Recently developed CCI 700 series procedures provided control of engineering activities at the plant. The procedures were of generally good technical quality, although somewhat difficult to follow. Plant managers approved the 700 series procedures for use in September 1991, but the engineering managers recognized they needed to continue to improve them.

The inspectors also sampled the contents of the NORMS database used to track data associated with modifications which the engineering staff introduced in August 1991. Basic information for over 700 modifications had been entered into the database, but only four records contained complete information for its associated modification; these were completed as part of the pilot program. Engineering managers indicated that, if BG&E approves funding of the program, the remaining records could be completed within a year. The team observed that NORMs has extensive search and sorting capability, however, the team could not accurately assess its usefulness as a management tool because it is not complete.

2.3.3 Operability Evaluations

The team identified weaknesses in the thoroughness, timeliness, and rigor with which the licensee's technical staff approaches evaluating the operability impact of unexpected or degraded conditions, particularly for those cases that needed expanded engineering analysis to support an operability decision. Several examples indicative of this concern are discussed in Sections 2.3.3.1 through 2.3.3.5.

2.3.3.1 Service Water Support Bolting Deficiency

On September 13, 1991, system engineers discovered that the SW heat exchanger supports had not been installed as designed, that is they were not bolted down as required. On September 16, the plant staff initiated an IR. The Issues Assessment Unit (IAU) determined that the lack of anchoring was nuclear safety-significant, affected design, and constituted a Significant Condition

Adverse to Quality. The Quality Verification Section initiated a Plant Deficiency Report (PDR) requiring that DE perform an analysis and root-cause determination by November 29, 1991. Design Engineering preliminarily determined that the SW heat exchangers were operable, based on qualitative analysis. Seismic experts from Bechtel and BG&E collaborated on the analysis. On the basis of this analysis, DE had confidence that the subsequent quantitative analysis would demonstrate operability. The initial response to this issue by engineering and other plant personnel was timely and appropriate to the potential safety-significance.

On September 17, DE issued a memorandum summarizing the bases for the preliminary operability determination and requested that Bechtel complete a stress analysis. On September 20, Bechtel reported that the initial analysis produced unacceptably high stresses for the SW piping connected to the heat exchanger. Design Engineering concluded that continued analysis would generate favorable results and requested that Bechtel perform additional analyses incorporating damping factors for building motion and accounting for friction between the heat exchanger supports and the concrete floor. Bechtel informed DE on September 29 that new calculations resulted in lower SW pipe stresses, although the new values remained greater than acceptable. Design Engineering concluded that the trend of the results was in the right direction. All parties remained confident that an analysis would ultimately verify that the actual stresses were acceptable. On November 25, DE extended the deadline for response to the PDR until January 31, 1992, to allow time for a more sophisticated analysis.

In parallel with the analysis, DE developed a modification to place the SW heat exchanger supports in a configuration equivalent to the original design. This modification was completed in early December and eliminated any ongoing operability concern. At the close of the inspection, the licensee continued to pursue refined analyses to demonstrate component operability in the as-found condition.

Although the licensee promptly initiated action to restore the system to its original design configuration, the team was concerned with the extended period BG&E allowed for the evaluation, its lack of documented quantitative analysis, and the absence of a justification to continue operation in this condition during the intervening three months.

In February 1990, the licensee identified anchoring deficiencies in the Component Cooling Water (CCW) heat exchanger, which was a second anchoring deficiency. The team observed that as of December 10, 1991, the licensee did not have an action plan to address the potential for other problems similar to these identified on the SW and the CCW systems.

2.3.3.2 Service Water Heat Exchanger Support Lamination

As previously discussed, the licensee implemented portions of a modification to the supports for the SW heat exchangers, but considered the components operable while modifying them. In mid-November, the responsible maintenance engineer found that one of the required welds could not be made because of a visible indication on the end of the support plate. On November 15, 1991, the licensee's Materials Engineering and Analysis (MEA) Section performed nondestructive examination (NDE) of the plate and confirmed the presence of a lamination on the end of the plate. The licensee attempted to remove a portion of the lamination by excavating the area without success. The MEA did not escalate the unacceptable NDE results to levels appropriate for further characterization and engineering disposition. Instead, MEA put an administrative hold on closure of the modification package, pending resolution of the condition. While this approach is acceptable for modifications being implemented on out-of-service equipment, it does not ensure timely evaluation when an operable safety-related component is potentially affected.

Although MEA, maintenance engineers, and PES supervisors knew of the condition, the licensee did not promptly initiate an IR or fully characterize the lamination. Instead, maintenance engineers requested a change to the modification to relocate the weld away from the lamination so that implementation could proceed. The DE Department approved and issued this change without characterizing the severity of the lamination and without evaluating its impact on the system. Interviews with DE personnel indicate that they assumed the lamination was shallow.

On December 2, 1991, when the NRC questioned the operability of the heat exchanger, the SW system engineer became aware of the problem and raised it to licensee managers as a potential operability concern. Once brought to the manager's attention, they acted promptly. The licensee performed extensive ultrasonic testing (UT) of the plate and found that the lamination extended the entire height and width of the plate. Preliminary engineering assessment indicated that this degree of lamination would render the component unable to withstand a seismic event, and the licensee declared the heat exchanger inoperable. Followup UT on the other heat exchangers identified less severe lamination problems. The licensee completed additional repairs and analyses and declared the heat exchanger operable. Near the close of the inspection, the licensee stated that preliminary analyses indicated that the heat exchanger was operable even in the as-found condition.

Once the managers were aware of this problem, they took aggressive action. Although several individuals, representing various parts of the organization were aware of it two weeks earlier, they did not initiate an IR or question and evaluate the potential impact on component operability.

2.3.3.3 Unacceptable Annubar Sensing Element Installation

On December 2, the team identified flow test sensing elements (annubars) installed in the CCW and SW piping that did not appear to be properly supported. Although the team informed PES supervisors immediately, the licensee did not initiate an IR until late on December 4. DE subsequently determined that the annubars would stress the system piping beyond code-allowable limits during a seismic event, but the stress would not result in piping failure. Plant managers imposed the appropriate TS Action Statements and the annubars were removed. This operability determination and the corrective actions were completed on December 6. In this case, the PES staff and supervisors recognized that the adequacy of the equipment installation was questionable. The team believes that the delay in initiating and processing the IR was inappropriate, given the potential inoperability of the CCW and SW systems and their respective allowable outage times provided in the TS.

2.3.3.4 Pressure Instrument Mounting

During a tour of the auxiliary building, pressure switch 2-PC-224ZA (low suction pressure trip for the #23 charging pump) was not secured to its mounting plate and did not have an attached deficiency tag. Other similar instruments were mounted, using welded steel angle iron. Apparently, the licensee installed diaphragm seals on the chemical volume control system (CVCS) pressure instruments during the 1980s to meet original design drawing details. After the installation, the instruments could not be remounted because of the added height. The instruments remained unsupported for some unknown period.

In 1990, the licensee issued a minor modification to mount the instruments, using welded angle iron. Craftsmen could not remount pressure switch 224ZA because of an interference between the angle iron and a fitting on the diaphragm. The team asked if the licensee had evaluated the acceptability of leaving the instrument in this configuration. Apparently, the licensee did not perform a seismic analysis to support operability. In response to the concerns raised by the team, the licensee walked-down the installation, performed a seismic analysis, and verified that the condition was acceptable. The licensee should have analyzed the acceptability of leaving the instrument in this configuration before returning it to service.

2.3.3.5 Snubber Removal at Power

On December 4, the plant maintenance staff were installing snubber 2-52-5A which had been removed for preventive maintenance and testing, on the unit 2 safety injection pump suction line. The team asked the operators if TS permitted snubber removal at power. Operators determined that TS 3.7.8.1 allowed 72 hours to replace the snubber, as long as an engineering evaluation showed that the inoperable snubber did not render the system inoperable. Operators did not have an engineering evaluation for the snubber or system involved, but stated that they had always considered the removal of one snubber at a time acceptable. The licensee produced copies of internal NRC memoranda that they interpreted as allowing them to remove snubbers with the unit at power without performing an engineering evaluation. The removal of snubbers without prior completion of an engineering evaluation to assure continued system operability was a routine licensee practice. The team did not agree with the licensee's interpretation of the internal NRC memoranda. Further, the team considered the practice of placing safety-related piping systems in an indeterminate condition for the purpose of performing elective maintenance and testing unacceptable. Licensee plant managers acknowledged the team's concern, concurred with the need to evaluate the acceptability of snubber removal before performing the task, and stopped all removal of snubbers until an engineering evaluation could be performed.

Additionally, the team questioned the licensee's practice of replacing snubbers before the functional test required by TS. This practice appears to skew the results of the TS-required sampling surveillance by replacing previously in-service snubbers with new ones. This concern was discussed with the licensee.

The team believes that the licensee's practice does not agree with the TS requirements. Additionally, the team was concerned that the licensee was comfortable making safety decisions based on internal NRC memoranda without safety committee review or approval.

2.3.4 Temporary Modification Program

The temporary modification program, as described in CCI-117, "Temporary Modification Control," is basically sound. The licensee is reducing the overall number and age of existing temporary modifications. Since March 1990, the number has been reduced from over 100 to approximately 41. This number is still higher than the licensee would like and the licensee is continuing to try to reduce it. During plant walkdowns, the team identified an unauthorized temporary modification to the CVCS tank in which a chemistry sample line and isolation valves were installed several years ago but, not captured as a temporary modification. When informed by the team, the licensee initiated action to remove this modification. The team did not identify any other unauthorized modifications. This example appears to have been installed before the recent program improvements, and the team did not view it as indicative of current performance. The team did point out that installations of this type should be identified and resolved by the system engineers.

The team's review of CCI-117 revealed that other administrative programs that temporarily modify configuration are not controlled as temporary modifications, noting several semi-permanent installations of ASME Section XI flow instrumentation that were not considered temporary modifications since they were considered as non-intrusive test equipment. Additionally, several of the control room annunciators were deactivated by removing the annunciator cards at the racks and installing a "Blue Dot" on the annunciator window. This was not considered a temporary modification since it was controlled by another administrative control program.

Although no specific deficiencies were identified, the team believes that the examples described (i.e., multiple programs that alter plant configuration) may dilute the effort to maintain configuration status in that plant drawings and other support documents would not be annotated. The temporary modification program, if used, will ensure that plant drawings are annotated to reflect the actual plant configuration.

2.3.5 Conclusion

Overall, the licensee's engineering and technical support staff and programs adequately supported safe plant operations and maintenance. System engineering functioned acceptably and made meaningful contributions to improved overall performance. The system engineers' credibility with the operations staff and involvement in operations and maintenance activities has improved. The system engineers generally provided appropriate identification and followup of plant problems and contributed to plant safety and reliability. However, in some instances system engineers failed to identify and pursue obvious plant deficiencies. The team concluded that while PES effectively supported operational activities, PES needs to perform more consistently.

The quality and completeness of DE products was good; completed engineering studies, MCRs, and FCRs were thorough and generally well supported. However, the licensee's procedures governing the 10 CFR 50.59 program provided little guidance on preparation of screening and safety evaluations. Screening evaluations used to support MCRs had poor justifications, and many were not reviewed by the POSRC. In response to these concerns licensee managers issued interim guidance for preparing and processing evaluations, and are developing additional long-term corrective actions.

Licensee managers introduced several programs, such as the Engineering Planing Unit, to address previously identified weaknesses. These initiatives were well scoped and were making progress, but in most cases the team could not determine their effectiveness since the programs were still in the early stages of implementation.

The team concluded that the technical staff aggressively pursues deficiencies that clearly have an impact on operability. In addition, when operability issues are framed and raised to senior plant managers, they implement prompt and thorough corrective actions. However, the team was concerned that the staff may not be consistently addressing those cases in which additional information or expanded engineering analysis is needed to support an operability decision in a timely manner. Interviews with PES and DE personnel, and review of written material, indicated confusion about the difference between operability and reportability determinations and the time constraints on each. In partial response to these team concerns, the engineering department conducted retraining to address this issue for all technical personnel during the week of December 9, 1991. The licensee also planned to publish additional guidance and processing instructions.

2.4 Safety Assessment and Quality Verification

For the area of safety assessment and quality verification, the team assessed key contributors to assuring safety and quality: (1) BG&E's issues management system; (2) the quality and scope of self-assessments; (3) the performance of the station review committees; (4) managerial oversight of plant activities; and, (5) the performance of the Quality Assurance and Quality Verification organization.

2.4.1 Issues Management System

Previous NRC inspection reports identified the lack of a cohesive licensee approach to identifying, assessing, prioritizing, and resolving plant issues potentially adverse to safety or quality. In response to this concern, the licensee began to centralize existing issue identification processes and gradually replace the existing nonconformance report (NCR) system with a new system that required extensive development and station-wide training. On August 19, 1991, the licensee implemented the Issue Report (IR) system. The system established a single administrative process, the IR, with the capability to identify, review, and prioritize issues and designate responsible resolution action organizations. Additionally, the IR process allows the designated action organization to internally assign estimated closure dates for resolving each issue, approve extensions, and assure quality technical issue resolution internally. These resolution aspects of the IR process differed significantly from the previous nonconformance report (NCR) process, in that the Quality Assurance Department (QAD) no longer had to concur with a closure date or independently review a resolution. Station managers intentionally limited the QAD oversight of IR resolution to enforce the philosophy of making the appropriate technical discipline responsible for resolving the issue.

The team's assessment of the IR process was divided into three segments: (1) issue identification effectiveness, (2) review and prioritization effectiveness, and (3) issue resolution effectiveness.

2.4.1.1 Identifying Issues

The IR process is implemented in accordance with procedure CCI-169, "Issue Report Initiation, Review, and Processing," Revision 3. The procedure enables any individual to identify an actual or suspected plant issue of any magnitude by initiating an IR. The IR is a user-friendly one-page form with comprehensive instructions on the reverse side. The forms were readily available throughout the facility. Review of IRs indicated that through ease of use, process accessibility, and extensive staff training, the licensee had established an effective mechanism for plant personnel to identify and send issues to managers.

The IR requires the initiator to answer three basic questions, to the best of the individual's knowledge. Does the issue present (1) an immediate personnel or equipment safety concern, (2) an operability concern, or (3) a reportability concern? If any of these questions are answered affirmatively, the initiator is required to immediately contact a reviewing supervisor, preferably the direct supervisor, who in turn answers the same three questions. Again, if any of the questions are answered affirmatively, the reviewing supervisor is required to immediately notify the Shift Supervisor to ensure that appropriate safety and license conditions are satisfied. Team review of a sample population of IRs indicated that the licensee's process for identifying and expeditiously elevating issues of potential immediate personnel or equipment safety concern, or issues with potential operability or reportability concerns to the Shift Supervisor's attention was effective.

Notwithstanding, the team identified that the IR implementing procedure did not specify how much time could elapse before the initiator gave the IR to the reviewing supervisor, when the screening questions are answered negatively. The team noted instances in which several days to more than a week elapsed between IR initiation, supervisory review, and receipt by the Issue Assessment Unit (IAU). The team did not identify any instance of adverse safety consequence caused by the processing delays. At the conclusion of the inspection, the licensee was evaluating this observation and was considering enhanced guidance for handling IRs initiated during periods of reduced staffing such as backshifts, weekends, and holidays.

2.4.1.2 Assessing and Prioritizing Issues

After an IR is initiated and reviewed, it is sent to the IAU. The IAU is an independent section responsible for reviewing, screening, classifying, prioritizing and processing IRs. The unit conducts these activities in accordance with instruction IAU-02, "Issue Report Processing by the Issues Assessment Unit," Revision 6. The unit supervisor briefs the Issue Report Review Group (IRRG) daily on the status and classification of all IRs received since the previous briefing. The IRRG is a multi-disciplinary body that assesses an IR before it is sent to the action organization to resolve the issue.

The IAU and IRRG functions were clear strengths of the IR process. The IAU implementing procedure was highly effective and included comprehensive screening, significance, and prioritization criteria. The team observed that the IAU expeditiously and accurately processed incoming IRs. Additionally, the IRRG oversight of IAU activities was effective. However, a potential weakness existed in the IRRG composition. Specifically, although the group was responsible for reviewing issues that could affect facility license conditions for operation, it lacked current licensed senior reactor operator knowledge and expertise. However, the team found no IR deficiencies resulting from the IRRG's composition. Although several IRRG members were previously licensed at the facility, the individuals were not required to be versed on TS Amendments and operational parameter changes since their licenses had been retired. The licensee promptly responded to this observation by requiring a currently licensed senior reactor operator to be present when the IRRG meetings are convened.

2.4.1.3 Resolving Issues

Since the IR process began on August 19, 1991, more than 800 reports have been initiated. Of these, the IAU and IRRG determined that 34 were significant and classified them as L-1. At the conclusion of the inspection, all IRs classified as L-1 remained open. Although many aspects of each open L-1 issue remained unresolved, initial safety evaluations indicated no immediate safety concerns. However, several of these outstanding issues involved potential FSAR deviations and questions about safety system design bases assumptions. For example, an issue originally identified by an NCR in 1989, and by an L-1 IR, questioned the appropriateness of not testing CVCS letdown line excess flow check valves. The UFSAR stated that the valves are tested. Additionally, L-1 issues remained unresolved for the design adequacy of the charging pump room ventilation systems and the technical adequacy of a temporary main vent radiation monitoring system installation.

Organizations appear to routinely grant multiple extensions for completing reviews and corrective actions. For example, the licensee identified issues during the Emergency Diesel Generator Fuel Oil Engineering Design System Functional Inspection (EDSFI) and granted up to five extensions totaling a year or more. In each case, the eventual disposition determined negligible safety impact although the lack of safety significance was not known at the time the extensions were granted.

With respect to the IR process, the licensee had not demonstrated that it had established the necessary managerial controls and oversight to ensure that the responsible organization was accountable for resolving identified issues in a timely fashion. Specifically, the IR process allows the responsible organization to establish initial estimated closure dates and authorize extensions. Additionally, independent quality review of resolution adequacy is limited. The QAD reviews nonsignificant IRs on a limited and random basis only. Although QAD reviews the adequacy of all L-1 IRs, it has little authority established in procedures to affect the timeliness of resolution. While QAD could issue a Corrective Action Request (CAR) to evaluate L-1 IR resolution concerns, no CARS had been issued. Individual action organization supervisors were generally not fully aware of the status of IRs for which they were responsible, rather they deferred to IAU reports of trends, which showed a clearly increasing IR backlog.

A draft licensee QAD surveillance report and an Independent Safety Engineering Unit (ISEU) report had independently identified similar weaknesses in the issue resolution aspects of the IR process. Senior station managers acknowledged these concerns and initiated actions to evaluate them.

2.4.2 Self-Assessments

The Operating Experience Review (OER) Organization performed a major portion of Calvert Cliffs self-assessments, while various line organizations such as Operations, Maintenance, and Engineering performed a few. The OER was divided into three units: the ISEU, the Plant Operating Experience Review (POER) Unit, and the Industry Operating Experience Review (IOER) Unit. A discussion of their performance is as follows.

Independent Safety Evaluation Unit

The ISEU was to perform real-time independent assessments, to review quarterly trends of plant performance, to observe activities in the line organization, and to perform other reviews and assessments as requested. They gave the results of the IR activities to BG&E managers and included recommended corrective actions.

The team interviewed ISEU staff members and reviewed three quarterly ISEU Trend Reports (Evaluation 91-04, "Investigation of 10 Events Caused by Operator Error;" the Operations Activities Reports for August [illegible] October, 1991; and Evaluation 91-13, "Investigation of the shipment of an extra fuel pin to Chalk River, Canada") and two significant event reports. One of the latter was related to the inadequate isolation of main feedwater flow instruments and the other involved unexpected Unit 1 reactor vessel level indications caused by an air bubble. The ISEU was diligently performing broad-based comprehensive and thorough investigations, including human factors considerations and detailed root-cause analyses. The assessments were timely and of high quality.

Plant Operating Experience Review

The POER was to analyze in detail Calvert Cliffs plant operating events to determine root-causes and trends and to recommend corrective actions to prevent or minimize the likelihood of event recurrence.

From interviewing POER staff members and reviewing several root-cause analyses reports (RCARs) (RCAR-9114, "Seismic Monitor Actuation During Maintenance" and RCAR-9118, "Unapproved Non-Safety Related Air Regulator Installed in Safety Related Application"), a shutdown and outage risks investigation report and the Unit 2 fall 1991 outage report, the team found that the POER performed detailed root-cause analysis which addressed human performance, causal factors, and corrective actions.

The shutdown and outage risk investigation report assessed the safety functions required in cold shutdown and identified plant systems that needed to be ready to operate so that an active single failure would neither challenge a safety feature nor cause the loss of the ability to mitigate a shutdown event. The investigation was thorough; however, the team did not assess the effectiveness of the corrective actions.

Industry Operating Experience Review

The IOER was to review industry experiences to see if any applied to CCNPP. These reviews included NRC Bulletins, Information Notices, Generic Letters (GL), and other related industry information. The team interviewed IOER staff members and reviewed several examples of industry experience correspondence it got from the IOER, including: NRC Bulletin 88-08 GL 91-13, Information Notices 91-43, 52, 60, 61 and 63, and a Combustion Engineering Tech Note.

The IOER had appropriately screened the industry information and provided timely recommended actions when they determined the information applied to CCNPP. The IOER issued a weekly newsletter, "Industry Briefs," to disseminate industry information, which was a good initiative.

2.4.3 Plant Operations Safety Review Committee

2.4.3.1 Meetings

During four Plant Operations and Safety Review Committee (POSRC) meetings, the committee reviewed 10 CFR 50.59 Safety Evaluations, requests to extend dates for completing POSRC Outstanding Items, Significant Issue Reports, surveillance test failures, and POSRC meeting minutes.

POSRC performance was generally good. At each meeting, they met appropriate procedural and TS requirements. The POSRC Chairman effectively elicited full discussions of the issues brought before the committee in which all members participated. A few members seemed unprepared for a meeting, for example, the Chairman had to delay while some members reviewed a safety evaluation they had received before the meeting.

At the conclusion of each POSRC meeting, the committee members rated and commented on the quality of the presentations given during the meeting. Any criticisms were subsequently communicated to the POSRC presenter. The practice of providing feedback to POSRC presenters was a good initiative that appeared to help communicate committee expectations and reinforce licensee staff safety perspective.

2.4.3.2 Outstanding Items

POSRC Outstanding Items (OI) were created by the committee when additional information was required to assess safety significance or to evaluate how a concern was resolved. The POSRC Chairman tracked and developed trends for these OIs. Some issues were several years old in the significant backlog of 73 OIs; the oldest item was dated 1987. No OIs involved an immediate safety concern, but the POSRC had granted multiple extensions of completion dates for some items.

The team asked what controls could effectively reduce the backlog of OIs. Unlike open IRs, extensions of OI completion dates had to be granted by POSRC and approved by the Plant General Manager. An OI trend showed that the licensee had significantly reduced the number of POSRC OIs from 200 in January 1991 to 73 in December 1991. The trend also showed a significant decrease in the number of OI extensions granted.

2.4.3.3 Modifications

The POSRC had not reviewed a significant number of modifications to safety-related components, as required by the plant TS as a result of two processes created by BG&E to screen out certain modifications from POSRC review.

POSRC-required reviews and assessments of modifications were specified in Calvert Cliff TS 6.5.1.7. It stated the POSRC was to review all proposed changes or modifications to plant systems or equipment that affect nuclear safety, and all 10 CFR 50.59 safety evaluations that support changes or modifications that affect nuclear safety, to determine whether the changes or modifications constituted an unreviewed safety question.

The first procedural mechanism used by BG&E to screen proposed modifications from POSRC review involved a "Safety Significance" assessment by the initiating site group. The group (Design or Plant Engineering) completed a form, answering a series of "yes" or "no" questions intended to determine if the modification would <u>adversely</u> affect nuclear safety. If all the questions were answered, "no," then the engineers did not submit the modification package to the POSRC for review, unless a detailed 10 CFR 50.59 safety evaluation had been prepared as part of the modification.

The second procedural mechanism served to reduce the number of 10 CFR 50.59 safety evaluations associated with proposed modifications. The initiating group completed a form, answering a series of "yes" or "no" questions intended to determine if a 10 CFR 50.59 safety evaluation was required for the proposed modification. If all the questions were answered, "no," then no detailed safety evaluation was performed.

These two mechanisms prevented all modifications for which all questions were answered "no" from being submitted to the POSRC for review, as required by the TS. The team reviewed 16 recently completed permanent and temporary modifications for safety-related equipment and found that the POSRC had not reviewed 11 of them, but that these 11 were of minor safety significance and did not appear to involve an unreviewed safety question. BG&G informed the team that approximately 800 modifications had been made to safety-related equipment without POSRC review since the beginning of 1991.

BG&E issued instructions at the close of the inspection to require that the POSRC review all proposed modifications to safety-related equipment and modifications that could potentially affect nuclear safety. In addition, the licensee said it would conduct a review of a sample of the modifications completed in 1991. NRC was assessing the corrective actions as the inspection ended.

Although not inspected in detail, the team noted that BG&E used the same procedural mechanisms to screen proposed new procedures from the review committees, another potential weakness in BG&E's safety oversight. The purpose of the POSRC was to provide BG&E managers with an independent multidisciplined review of proposed changes to determine their effect on nuclear safety and whether they involved an unreviewed safety question. The two screening mechanisms abrogated this review function and allowed single-discipline site organization reviews to replace the POSRC reviews required by the TS.

2.4.4 Quality Assurance and Quality Verification

Quality Assurance

The team assessed the effectiveness of the Quality Assurance Department (QAD) by reviewing several recently completed audits and surveillances, including a draft surveillance report of the IR system. The audit reports were generally thorough and performance-based, presenting well developed observations and findings. The conduct of an electrical distribution system functional inspection (EDSFI) audit was especially noteworthy. The QAD utilized highly knowledgeable consultant support and obtained available industry information from other recently completed EDSFIs to enhance their audit. Issues identified during the audit which presented clear operational concern were promptly addressed. The licensee has established an EDSFI project team with responsibility for resolving the remaining audit issues. Approximately half of the 13 audit findings have been closed. All audit report and issue followup documentation has been meticulously maintained. Other noteworthy audits included two annual corrective action program audits (91-02, 91-11) and a preventive maintenance audit (91-15).

A recently completed QAD surveillance of the IR system was very detailed and comprehensive. The report expressed several strong concerns about the current performance of this system, the same concerns the NRC team raised about IR resolution, accountability, and timeliness. The draft report results reflected sound auditor perspectives and effectively developed issues of concern. The audits and surveillances performed by the QAD were effective, and the auditors interviewed were very knowledgeable within their assigned areas of expertise.

Quality Verification

Previously, the NRC Special Team Inspection Report (50-317,318/89-200) identified significant deficiencies in the quality control program, specifically, the lack of quality control (QC) procedures, generally weak QC department technical expertise, and a resultant line organization lack of respect for QC processes. Upon being informed of the Special Report conclusions regarding QC performance, the licensee assigned a project director who had consultant support to initiate a QC improvement program.

Since then, the licensee has made significant progress in resolving these weaknesses. The organizational title was changed from QC to Quality Verification (QV) in recognition that the line organization is responsible for controlling quality within production and that non-line organizations only verify quality. The QV organization has adopted formal implementing procedures which were developed consistent with a standardized procedure writers guide, and contain sound technical content. The licensee also effectively recruited individuals for the QV organization who had technical discipline experience, which served to improve station perceptions of QV processes as well as to enhance QV performance. Many specialized technical training sessions previously provided to line personnel only are now available to the QV staff, which has improved training for the QV technicians.

QV management established a performance indicator program with critical elements that effectively identified organizational performance. Additionally, a trending program was recently developed which utilized risk analysis, task complexity and frequency, and previous task performance data to establish the priorities for QV involvement in plant activities. Team observations of field activities indicated the presence of QV technicians during conduct of safety-related activities. The technicians were prepared, involved, and aware of critical task elements.

2.4.5 Conclusion

The team concluded overall, that BG&E management and staff had a sound safety perspective. Management safety oversight was generally effective, but exhibited several weaknesses that were of concern to the team. The IR process was an effective mechanism for identifying issues and quickly elevating immediate issues to appropriate managers. However, the overall effectiveness of the IR process is reduced by its inability to promptly and consistently bring issues to a timely resolution. This weakness appeared to be the result of a lack of process controls for senior managers to establish accountability and to monitor action organization effectiveness in resolving issues. Lacking effective issue resolution, the IR process may not be capable of accepting the incorporation of the maintenance request process, which is currently scheduled to occur in January 1992.

The team found that the OER was well staffed with diverse educational expertise and experience. The staff had all received formal training in investigative techniques, root-cause analyses, and human performance evaluation processes. Their performance was a notable strength. The performance of the QV Organization was much improved. The performance of the site review committees was generally good, however, failure of POSRC to review all required modifications to safety-related equipment is a weakness in the licensee's implementation of TS requirements.

2.5 Performance Improvement Plan and Implementation Program

During 1989, BG&E developed a long-term Performance Improvement Plan (PIP) and PIP Implementation Program (PIP-IP) to address the overall decline in performance at the Calvert Cliffs Nuclear Power Plant. The PIP-IP contained over 40 action plans to address the underlying root causes that led to the performance deficiencies. More recently, BG&E established the Nuclear Program Plan (NPP), to continue the initiatives started under the PIP, to implement new initiatives as they are defined, and to ensure remaining open PIP-IP action plans are completed. The team evaluated six of these plans.

2.5.1 Communications Plan

The Communications Plan was developed to improve communications at all levels of the organization and includes both written and verbal communication methods. This action plan included assignment of a full-time communications expert to Calvert Cliffs who is responsible for making communications more effective with employees, the local community, and the press. To maintain this action plan as an ongoing program, various meetings, bulletin boards, newsletters, and announcements were created.

On January 28, 1991, the BG&E QA Organization concluded from its verification of this action plan that all milestones were complete and all deliverables were available. After interviewing the Senior Nuclear Public Information Representative, reviewing the Comprehensive Communications Program for Calvert Cliffs, and questioning BG&E employees concerning communications effectiveness at Calvert Cliffs, the team agreed with BG&E's conclusion. BG&E currently has four specific communications programs in place as part of the Communication Plan: Media Relations, Employee Communications, the Community Information, and Emergency Preparedness Communication. The four programs continue to address the intent of this action plan, and the licensee designated appropriate completion schedules and responsible individuals for these programs. Feedback verification is also occurring through periodic, formal surveys.

2.5.2 Site Integrated Scheduling Process

The licensee established the Site Integrated Scheduling Process (SISP) to identify, plan, prioritize, schedule, approve, and implement projects at Calvert Cliffs. The five primary scheduling functions will be (1) long-range planning and scheduling, (2) project scheduling, (3) engineering scheduling, (4) outage scheduling, and (5) quarterly systems (Maintenance) scheduling. SISP will establish an overall philosophy to govern the flow and transfer of information among the site scheduling functions.

The SISP action plan was originally scheduled to be completed in late 1991. However in August 1991, BG&E determined that the action plan needed to be revised. BG&E wanted to decentralize scheduling functions into various departments rather than keep them centralized in one group. The change was approved by the Vice President, Nuclear Engineering Division. The team concurred with the change and determined that the change did not affect the original intent of the action plan. Completion of this action plan is now scheduled for mid to late 1992.

The team determined that the milestones and deliverables associated with the action plan are generally on schedule. The five processes are currently functioning and some procedures have been drafted that cover the processes. By reviewing the scheduling programs and through interviews with the Action Plan Manager, the team determined that BG&E is appropriately improving planning and scheduling capabilities and the transfer of information among the different scheduling functions.

2.5.3 Quality Assurance Internal Assessment Improvements

The licensee initiated an effort to improve the QA function at CCNPP. Specific improvement initiatives included increasing manager and general supervisor awareness and participation in the audit process, increasing auditor knowledge and experience, and increasing the technical quality of audits.

On January 16, 1990, the QA organization conducted an independent verification and concluded that all milestones were complete and deliverables were available. The Quality Audits Unit (QAU) performs monthly trending of the number of new, open and late audit findings, and their average time open. QAU also records attendance by manager and general supervisors at pre- and post-audit meetings. Both of the latter areas are reviewed periodically reviewed by the Off-Site Safety Review Committee (OSSRC)

Team review of QA activities indicated that this action plan successfully improved and sustained QA performance effectiveness. QA audits were generally thorough and performance-based, and presented well developed observations and findings. Auditors interviewed by the team were very knowledgeable within their areas of expertise.

2.5.4 Issues Management System

The licensee established an action plan to develop a single process by which issues would be identified, evaluated, and resolved. Initially this action item was limited to revising the non-conformance report process, however it was expanded to address and replace all issue processing systems. The licensee ultimately developed the IR system which provided a single process to disposition issues of any magnitude.

The IR process has several strengths with respect to identification and initial assessment of issues. However, the team identified several areas of weakness in the licensee's ability to resolve these issues in a timely and consistent manner. Potential improvements to the IR system were being evaluated at the conclusion of the inspection. See Section 2.4.1 for a detailed evaluation of the IR process.

2.5.5 Maintenance Work Control

The Maintenance Work Control action plan was developed to improve the overall quality of maintenance. The action plan was expected to improve the work control process through better job planning, resulting in decreased rework and improved allocation of maintenance resources. In addition, the maintenance backlog was also expected to be reduced and better controlled, and the preventive maintenance program was expected to be consolidated and formalized.

This action plan is currently in the licensee's verification process. The team interviewed key maintenance staff and managers and verified that the stated maintenance work control deliverables were completed. These included the development of a maintenance planner guideline and training and qualification program, a maintenance strategy and goals document, and a work control group method for planning maintenance orders.

Many aspects of this action plan have been incorporated into the maintenance strategy and goals document. The team observed a monthly strategy and goals status meeting and determined that specific goals were realistic and achievable that the maintenance organization strongly supported them. Appropriate feedback also occurred during the periodic status meeting.

2.5.6 Operations Improvement Area

The Operations Improvement Area action plan addresses a number of activities that are designed to improve performance of the Operations Section, principally to improve coordination between the Operations and Maintenance Sections. However, it also addresses the need to improve safety tagging and work control programs, strengthen operating crews and operations support staffing, and enhance computer capabilities.

This action plan is scheduled for completion in the second quarter of 1993. The team assessed the completed items and milestones and whether BG&E is making adequate progress toward their intended goals. BG&E implemented an automated safety tagging program and developed the Plant Work Control Group. The team assessed the safety tagging and work control process by reviewing several safety tagouts and associated procedures, and held discussions with appropriate staff. The team determined that the safety tagging and work control process was effective.

To strengthen operating crews and operations support staffing, the licensee added several positions. The operations department established an operations maintenance coordinator position and added several positions to support post-maintenance testing. In addition, the operations department was staffed with additional personnel to increase the number of qualified operators. Although the original intent was to establish a six-shift rotation for operating crews, managers are reevaluating that objective.

The team determined that this action plan, although not fully implemented, is contributing to better operator performance. Adequate progress was noted in achieving the milestones.

2.5.7 Conclusion

The team concluded that BG&E's Performance Improvement Plan and Implementation Program have resulted in substantial progress in correcting past performance problems at the Calvert Cliffs Nuclear Power Plant. The Nuclear Program Plan contains initiatives started under the PIP along with several new initiatives, and appears to be effective in tracking the remaining open PIP-IP action plans.

3 MANAGEMENT MEETINGS

The lead inspectors in each of the five functional areas met daily with their assigned licensee technical and management contacts to ensure open communications. In addition, the Team Manager, Team Leader, and Assistant Team Leader met daily with the Plant General Manager to discuss developing issues and outstanding requests. After the inspection on December 13, 1991, the team conducted an exit meeting to summarize their significant findings and conclusions. NRC Region I and Headquarters managers and licensee senior managers participated in this exit meeting, which was held in the licensee's visitor center and was open for public observation.

ATTACHMENT

UNRESOLVED ITEMS FROM THE CALVERT CLIFFS IPAT INSPECTION

Unresolved Item 91-82-01, "10 CFR 50.59 Evaluations."

- CCI-704, "Design Change and Modification Process," does not contain adequate guidance on preparing 10 CFR 50.59 safety evaluation screens and contains very limited instructions for preparing adequate safety evaluations. A large number of evaluation screens contained inadequate or inappropriate justification. (See Section 2.3.2.1)

- The POSRC did not review a significant number of modifications to safety-related components as required by TS as a result of two processes created by BG&E to screen certain modifications from POSRC review. BG&E also used the same two processes to screen proposed new procedures from POSRC review. (See Section 2.4.3.3)

Unresolved Item 91-82-02, "Operability Evaluations."

- The licensee's technical staff was weak in their thoroughness, timeliness, and rigor in evaluating the operability impact of unexpected or degraded conditions, particulary for those cases that needed expanded engineering analysis to support an operability decision. The five examples were (1) service water support bolting, (2) service water heat exchanger support lamination, (3) annubar sensing element installation, (4) pressure instrument mounting, and (5) snubber removal at power. (See Section 2.3.3)

Unresolved Item 91-82-03, "Issue Report Resolution."

- The licensee did not demonstrate that necessary managerial controls and oversight were in place to ensure that the responsible organization was accountable for resolving their IRs in a timely fashion. QAD has limited authority to affect IR resolution timeliness and they perform limited reviews of IR resolution adequacy. As a result, the IR backlog is increasing. (See Section 2.4.1.3)

Unresolved Item 91-82-04, "Technical adequacy of Test Procedures."

- STP 0-10-1, "Spent Fuel Pool (SFP) Ventilation System Monthly Test," did not effectively verify flow through each of the redundant parallel charcoal filter trains. OI 3B, "Shutdown Cooling - Unit 1," which is part of the licensee's IST Program, did not ensure that certain valves were operated using their reach rods from their remote handwheel as would be required during an emergency. (See Section 2.2.2.2)

Unresolved Item 91-82-05, "Surveillance Test Procedure Adherence."

- During performance of STP-F-77-0, "Staggered Test of Diesel Fire Pump," personnel started the diesel-driven fire pump locally rather than from the control room as stated in the procedure. (See Section 2.2.2.3)