U.S.NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	50-317/95-10; 50-318/95-10
License Nos.	DPR-53/DPR-69
Licensee:	Baltimore Gas and Electric Company Post Office Box 1475 Baltimore, Maryland 21203
Facility:	Calvert Cliffs Nuclear Power Plant, Units 1 and 2
Location:	Lusby, Maryland
Inspection conducted:	November 5, 1995, through December 30, 1995
Inspectors:	Carl F. Lyon, Acting Senior Resident Inspector Henry K. Lathrop, Resident Inspector Julian H. Williams, Senior Operations Engineer, DRS Suresh K. Chaudhary, Senior Reactor Engineer, DRS Cheryl Beardslee, Reactor Engineer, DRS
Approved by:	Lawrence T. Doerflein 1/26/96 Lawrence T. Doerflein, Chief Date Reactor Projects Branch 1 Division of Reactor Projects

Inspection Summary:

Core, regional initiative, and reactive inspections performed by the resident inspectors during plant activities are documented in the areas of plant operations, maintenance, engineering, and plant support. Additionally, inspections conducted by regional inspectors are documented in the areas of engineering and operator licensing.

Results:

See Executive Summary.

EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2
Inspection Report Nos. 50-317/95-10 and 50-318/95-10

Plant Operations: Operators manually tripped Unit 1 on two occasions when (1), a steam generator feed flow controller failed, and (2), when 12 steam generator feed pump tripped. Both trips were managed safely and professionally by the operators. A number of equipment problems complicated the first trip, resulting in an auxiliary feedwater actuation and requiring the operators to shut the main steam isolation valves to control plant cooldown. The resulting investigations of both trips were thorough and focused, and plant management was actively involved in issue problem identification and resolution.

The licensed operator requalification training (LORT) program was reviewed. Some weaknesses were noted in the LORT program. Two unresolved items were identified, one dealing with attendance at LORT and the other regarding individual evaluations on the dynamic simulator annual exams.

Maintenance: The root cause analysis for the seizure of 22 AFW pump shaft in August, 1995, was comprehensive, recommended reasonable corrective actions, and concluded that there were no generic implications for the other AFW pumps. However, the failure to provide and implement an adequate procedure for the pump overhaul was a Non-Cited Violation.

Operator error during the performance of a surveillance test resulted in the inadvertent start of an emergency diesel generator. Operator response and notification were proper. Operator error was also responsible for the trip of an emergency diesel generator during another surveillance test. The two procedural errors were a Non-Cited Violation.

Engineering: BGE's control of temporary alterations was satisfactory. Although there were a few temporary alterations that have been in place for more than a year, the reasons were acceptable. The internal communication system within the engineering department was effective in assuring dissemination of management expectations and performance indicators. The backlog in engineering work had increased; however, adequate management efforts have been placed on efficiently managing this increase. The management oversight and self-assessment program in the engineering department was effective.

Plant Support: BGE provided satisfactory interim guidance to operators for classifying emergencies caused by fire or explosion affecting safe shutdown equipment. BGE's request for a change to their Emergency Action Levels was being tracked by the Emergency Planning Unit.

BGE conducted a full participation security exercise with the Maryland State Police. The exercise met its drill objectives.

The designation of the reactor containment buildings as foreign material control areas was a good initiative in response to past problems with containment cleanliness. Containment foreign material control efforts will be assessed during the upcoming refueling outage.

TABLE OF CONTENTS

ATTACHMENT

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the period at full power. On November 9, the feed regulating valve (FRV) controller for the 11 steam generator failed, the FRV went to the full open position, and operators manually tripped the unit in anticipation of a high steam generator water level automatic trip. The unit returned to full power on November 13. On November 16, the 12 steam generator feed pump (SGFP) tripped, and operators manually tripped the unit due to lowering steam generator water levels. The root cause for the loss of 12 SGFP was not immediately determined, and on November 20 BGE restarted the unit on 11 SGFP. The unit was operated at 70% until repairs to 12 SGFP's control oil system were completed. The unit was returned to full power on December 4. Power was reduced to 70% on December 8 to inspect and modify 11 SGFP based on the results of the investigation of the November 16 trip. The unit returned to full power on December 11 and remained there through the rest of the period.

Unit 2 operated at full power without incident through the period.

2.0 PLANT OPERATIONS (INSPECTION PROCEDURES (IPs) 71707, 71001, 92901)[1]

The inspectors observed plant operation and verified that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. This review included tours of the accessible areas of the facility, verification of engineered safeguards features (ESF) system operability, verification of proper control room and shift staffing, verification the units were operated in conformance with technical specifications and that appropriate action statements for out-of-service equipment were implemented, and verification that logs and records were accurate and identified equipment status or deficiencies. During the inspection period, the inspectors provided onsite coverage and followup of unplanned events.

2.1 Followup of Events Occurring During the Inspection Period

2.1.1 Manual Trip of Unit 1 Due to Increasing Steam Generator Water Level

On November 9, operators noticed that the water level in 11 steam generator (SG) was increasing. Attempts to regain level control were unsuccessful and shift supervision ordered the Unit 1 reactor tripped at +37 inches, prior to reaching the automatic trip setpoint. The plant responded as designed, except as noted below, and operators stabilized the unit in Mode 3 (hot standby). The inspectors noted that the operators took appropriate and prudent actions in first responding to the increasing SG level, then manually tripping the unit when level control could not be re-established. The Plant General Manager directed the formation of a significant incident finding team (SIFT) to perform a root cause analysis of the event and determine appropriate corrective actions.

---

[1]The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

Discussion

The post-trip response of the unit was generally as designed; however, a number of equipment problems were experienced that challenged the operators.

- The event was initiated by the failure of controller 1-FIC-1111 for the 11 feedwater regulating valve (FWRV). The controller would not respond to automatic or manual signals. While the controller had "frozen", it was sending an increasing "open" demand signal to the FWRV, which resulted in the uncontrolled increase in 11 SG level until the reactor was tripped. The FWRV did go to its required "closed" position after the reactor trip.

- The second stage moisture separator reheater (MSR) steam source valves did not shut. The steam being drawn off the SGs caused the reactor coolant temperature to begin decreasing. Operators terminated the cooldown by closing the main steam isolation valves (MSIV).

- The two atmospheric dump valves (ADV) used to control reactor coolant temperature when the SGs were isolated (MSIVs shut) appeared to be controlling at different rates.

- 11 SG feed pump tripped on high discharge pressure following the reactor trip. Operators noted that 12 SG feed pump was running at about 1300 rpm and not injecting water into the SG, and tripped the pump. Water levels in the SGs were recovered using the auxiliary feedwater pumps.

- Control element assembly (CEA) 51's amber dropped rod light did not illuminate after the reactor was tripped. Operators verified that the CEA was fully inserted. BGE tightened the switch connector and the light operated properly.

- 11 FWRV bypass control valve opened to the required position following the trip, but its control room position indicator malfunctioned and indicated the valve was closed. Its position was verified locally.

- An auxiliary feedwater actuation system (AFAS) initiation signal was generated when 11 SG water level reached its low setpoint of -170 inches. Control room operators restored the water level to normal without further incident.

Assessment

The inspectors discussed the event with operations, maintenance, and engineering personnel and monitored BGE's post-trip activities, including the November 10 post-trip review by Operations and the preliminary findings of the SIFT. The inspectors assessed BGE's performance as follows:

- Control room operators acted conservatively in tripping the reactor after unsuccessfully attempting to regain control of 11 SG water level and prior to an automatic trip on high SG water level. The operators also responded appropriately and professionally to the various challenges posed by degraded and faulted equipment following the manual trip. However, the inspectors noted that the malfunctions apparently distracted the operators such that the dissimilar steaming rates of the two steam generators were not noticed until the 11 SG level decreased to the AFAS initiation setpoint. The inspectors discussed this issue with operations management and determined that operators had correctly followed their emergency procedure, EOP-0, which only required verification that at least one SG (12 SG, in this case) was available for decay heat removal.

- BGE determined that the failure mode of controller 1-FIC-1111 appeared to be unique following research in the industry's data base and discussions with controller's manufacturer, Fischer-Porter. The expected failure mode was to fail "as-is", at some constant output. BGE returned the controller to the vendor for investigation of the failure mechanism. BGE stated that if the root cause could not be determined there, further evaluation would be performed by an outside company specializing in failure analysis.

- A differential pressure switch providing the closing signal to the MSR second stage source valves had failed. A leaking bellows had caused a setpoint change and corrosion build-up within the switch mechanical internals. BGE replaced the switch and inspected other similar switches in the plant. No unacceptable conditions were found. The faulted switch had been in service for a number of years and was not included in BGE's preventive maintenance (PM) program. Based on these findings, BGE was considering its inclusion in the PM program.

- BGE performed calibrations on the ADV controllers and found #11's out-of-specification high and #12's in calibration but at the high end. Additionally, the valve mechanical positioners were found set slightly differently, such that #11 ADV opened more for the same input signal. BGE technicians realigned the ADV control circuits and stroked the valves to verify they opened to the same position. BGE was investigating the actual and potential effects of differing steaming rates on plant operation and control and intended to take corrective action as appropriate.

- BGE determined that 11 SGFP had tripped on high discharge pressure. After a similar occurrence in the June, 1995, trip of Unit 1, BGE had modified the opening time of the SGFP recirculation valves to allow slower stroke times, improving steam generator level control at low power levels. However, at full power, the valves could not open fast enough to prevent high discharge pressure trips. The inspectors concluded that the implementation of the modification was another example of the change management problem existing at Calvert Cliffs, as detailed in several recent inspection reports. While the slower stroke time at low power to improve SG level control appeared reasonable, BGE failed to consider the effect the slower stroke time would have on SGFP availability at higher power levels. BGE concluded that 12 SGFP had probably also tripped on high discharge pressure, but that the trip signal had existed for too short a time to be locked in by the circuitry.

The inspectors attended the post-trip review on November 10 and noted that the review was very thorough, well-conducted and provided detailed explanations for the equipment failures occurring during and after the trip. The final report of the SIFT had not yet been issued when the report period ended. However, preliminary findings and recommendations were documented in Licensee Event Report (LER) 50-317/95-005, dated December 11, 1995. The inspectors reviewed the LER and determined that it accurately documented the event, causal factors and safety significance. BGE indicated that a supplement to the LER would be submitted detailing the results of the root cause analysis of the controller failure and any additional corrective actions.

2.1.2 Manual Trip of Unit 1 Following the Los f 12 Steam Generator Feed Pump

On November 16, while operating at 100% power, the 12 steam generator feed pump (SGFP) tripped. Efforts to reset and restart the pump were unsuccessful and the operators manually tripped the Unit 1 reactor. The plant responded as designed except that 11 SGFP tripped on high discharge pressure. Steam generator water level was recovered using the auxiliary feedwater pumps. As in the November 9 trip, a significant incident finding team (SIFT) was formed to determine the root cause of the 12 SGFP trip and formulate corrective recommendations. The SIFT's final report had not been issued when the report period ended; however, preliminary findings and conclusions were documented in Licensee Event Report (LER) 50-317/95-006.

Discussion

Unit 1 responded as designed to the manual trip of the reactor with the exception of 11 SGFP. BGE indicated that the trip of 11 SGFP on high discharge pressure could be expected due to the feedwater regulating valves (FWRVs) being open more and 11 SGFP at maximum speed in response to lowering steam generator water levels when the unit was tripped. The reactor trip signal caused the FWRVs to rapidly shut. The resultant pressure surge exceeded the high discharge pressure trip setpoint of the SGFP. BGE had modified the control circuitry for the 12 SGFP such that the "mini-flow" (recirculation) isolation valve would open faster when the FWRV went shut, preventing an unnecessary high discharge pressure trip, but had not yet had an opportunity to similarly modify 11 SGFP. The inspectors noted that there were no significant equipment malfunctions as had occurred during the November 9th event.

Due in part to the protracted nature of the troubleshooting of 12 SGFP, BGE management decided to return Unit 1 to power operation using the 11 SGFP, which was verified to be operating satisfactorily. Reactor power was limited to 70% until 12 SGFP could be returned to service.

Preliminary results of the SIFT were presented by the team leader to the plant operations safety review committee (POSRC) on December 1. The team concluded that 12 SGFP had tripped due to low control oil pressure to the trip dump plunger, causing the plunger to actuate. The pressure drop was caused by a number of minor component oil leaks and relay block corrosion which prevented the back-up control oil pump from restoring pressure before the trip setpoint was reached. BGE could not positively identify the event which initiated the pressure decrease. The team was able to duplicate the trip of 12 SGFP, but could not produce the same trip on the 11 SGFP. The 11 SGFP control oil system was in somewhat better condition than the 12 SGFP system.

BGE's corrective actions for this event included the following:

- 12 SGFP's control oil system components were inspected and adjusted/repaired to within vendor specified tolerances. Deficiencies were found with the mechanical trip mechanism, relay block and thrust bearing.

- A check valve was added to the low pressure portion of the control oil system to maintain adequate control oil pressure to the dump plunger during momentary pressure transients to allow time for the back-up oil pump to restore control oil pressure. The check valve would have no effect on the protective trips for the SGFP.

- Temporary instrumentation was installed to better monitor control oil system performance and aid in determining the cause of the pressure perturbation which initiated the event.

- 11 SGFP was inspected, instrumented, tested and modified similar to 12 SGFP.

Assessment

The inspectors discussed the event with operations, engineering, management and SIFT personnel and observed portions of the troubleshooting and repair activities. The troubleshooting was rigorously controlled and performed in such a way as to preserve as-found data/equipment conditions. Component testing was very thorough. Communications between the various groups involved were extensive and demonstrated the close cooperation provided to the investigation and issue resolution. The SIFT briefing on the investigation's progress and preliminary results given to the POSRC on December 1, was comprehensive and demonstrated sound engineering analysis. The POSRC demonstrated a strong questioning attitude and safety perspective regarding continued operation of Unit 1 on one SGFP and the reliability of the feedwater system in general. Operations management was conservative in limiting the time plant operation would continue before implementing corrective actions on 11 SGFP to verify its continued reliability.

The inspectors also noted that, unlike the previous trip of Unit 1 on November 9, the operators were not challenged by equipment malfunctions following the manual reactor trip, indicating that the repairs made at that time were effective. The inspectors concluded that both trips were managed safely and professionally in accordance with procedures by the operators, that the investigations were thorough and focused, and that plant management was actively involved in issue investigation and resolution.

2.2 Plant Operations and Safety Review Committee

The inspectors attended several Plant Operations and Safety Review Committee (POSRC) meetings. TS 6.5.1 requirements for required member attendance were verified. The meeting agendas included safety significant issue reports, proposed tests that affected nuclear safety, 10 CFR 50.59 evaluations, reportable events, and proposed changes to plant equipment that affected nuclear safety. POSRC activities related to the two manual reactor trips which occurred during the period are noted above. Overall, the level of review and member participation was satisfactory in fulfilling the POSRC responsibilities.

2.3 Routine Operations Observations

On November 5, 2-SW-5208-CV, the 22 component cooling heat exchanger saltwater discharge valve, failed to stroke fully open. It would only open approximately 70%. Operators discovered the deficiency while investigating a higher than normal temperature across the heat exchanger. They immediately declared the valve inoperable. After stroking the valve several times, it opened fully and there was no further indication of binding. Troubleshooting failed to identify the root cause, and the problem did not recur. Design engineering staff prepared a functional evaluation to support returning the valve to operable status, including a recommendation to continue daily stroking of the valve to support reliability. The BGE root cause analysis for the irregular valve failure, including why previous actions to resolve the problem were apparently not effective, was still in progress at the end of the period.

Previous difficulties with 2-SW-5208 and weaknesses associated with BGE's response were described in NRC Inspection Report 50-317 and 318/95-06. Subsequently, on September 29, the valve actuator was replaced and the valve was returned to normal service. After the November 5 failure, inspectors noted a prompt response by operators, good communications with maintenance and engineering staff, and a technically sound functional evaluation to support returning the valve to service.

2.4 Offsite Safety Review Committee

The inspectors attended portions of the Offsite Safety Review Committee (OSSRC) meeting on November 30. The OSSRC composition and agenda were in compliance with the requirements of TS 6.5.4. The agenda included a review of plant status, significant safety issues and proposed changes to the operating license, as well as status reports on license renewal and improved Technical Specifications. A very good questioning attitude and safety perspective were noted, particularly regarding testing of the new emergency diesel generators and foreign material exclusion. Overall, the level of review and member participation was satisfactory to fulfill the OSSRC responsibilities.

2.5 Licensed Operator Requalification Training (LORT) Program

Written Examinations

The inspector determined BGE's sampling plan used to construct the biennial written exams provided the necessary guidance to ensure that subjects taught during the two-year period were appropriately examined.

The NRC inspectors reviewed the weekly quizzes and the biennial exams for content and repeatability of the questions. The questions were of satisfactory quality and difficulty. The inspectors noted that approximately 50% of the questions on the weekly quizzes were repeated from the previous week(s). Assuming that the two parts (A and B) of the biennial exam were added together the question repeatability was about 25%. However, Part A had at least 50% of the same questions on each exam. This allows a strong potential for exam compromise. Also, if an individual fails Part A of the exam he will be given another exam with 50% of the same questions. This problem of question repeatability was noted by an NRC inspector last year and documented in Inspection Report Nos. 50-317/94-33 and 50-318/94-32. Question repeatability on quizzes and exams is considered a weakness. Except for this weakness, the written exams were adequate. No failures were noted during the week of the inspection.

Job Performance Measures (JPMs)

The NRC inspectors observed the performance of JPMs in the plant and on the simulator. Performance was generally good, with only one JPM failure. The inspectors observed that operators were unfamiliar with the new emergency diesel operating procedures. Operations involving problems with the salt water system also indicated some unfamiliarity with the procedures. Performance on the simulator using emergency operating procedures (EOPs) was excellent, demonstrating that operators were familiar with the procedures as well as the expected plant response. No problems were noted with the in plant JPMs. The facility evaluators used proper techniques when administrating the JPMs. The JPM portion of the operating exam was satisfactory.

Dynamic Simulator Examination

The NRC inspectors observed scenarios given to operating and staff crews. The scenarios, crew performance, and crew evaluations were adequate. All crews implemented the EOPs well. The inspectors noted that the facility does not perform individual operator evaluations except when a failure occurs. The inspector also noted that NRC Information Notice 95-24 describes this as a common industry problem. The inspector discussed the requirement (10 CFR 55.59 (a)) with the facility and will review facility actions to address individual simulator evaluations at a later date. This is an unresolved item (URI 50-317 and 318/95-10-01).

The inspectors noted that the detailed results of the simulator exam are not given to the operating crews until all licensed operators have been examined and the write up has been reviewed by management. This long delay can reduce the effectiveness of the evaluations since the operators may not remember the scenario or their actions.

The inspectors noted that operations management was not involved in the evaluations of the simulator exams. In most cases, neither was training management. While NRC has no requirement that operations management be present during the exams, the guidance in the examiner standards, ES-604.D.1.a, states that operations management should be present. Industry practice is that operations management is present. This is considered a weakness.

Remediation Program

The remediation process is in place and appears to be working. The NRC inspectors reviewed several remediation plans for individuals. When an individual needs remediation in the short term, the instructor normally prepares a remediation plan. The individual may prepare the plan himself. For more extensive remediation, an action item tracking (AIT) form is prepared. The AIT is a facility document and utilizes the company tracking system for tracking remediation activities. All completed remediation plans are filed with the individuals training records. No problems were identified by the NRC inspectors with the remediation process.

Feedback

Opportunity for student feedback is provided at the end of each training session. These forms are reviewed by training and operations personnel. Based upon operator interviews, it appears that comment resolution does not always get back to the commentor. Without closing this loop the operators could lose interest in making comments. Facility management acknowledged this observation and indicated that they would look further at the feedback process.

All operators interviewed felt that they had received enough training to make them safe operators and were satisfied with their training. There was a strong feeling among the operators that more systems refresher training was needed. It appears that the facility has developed some self-study materials in response to this feedback.

The feedback system was satisfactory.

License Conditions

The NRC inspectors reviewed the facility program to ensure that only reactor operators and senior reactor operators with active licenses perform licensed duties. The program was well developed and managed. No problems were identified.

The inspectors reviewed the medical records of a sample of licensed operators to ensure that biennial medical exams were performed. The medical exams were given as required and the records were effectively maintained.

The NRC inspectors reviewed records of participation (by attendance) in the LORT program and discussed this area with licensee management. The Calvert Cliffs LORT program manual, Revision 0, dated February 28, 1995, requires each licensed individual to attend a minimum of 160 hours of requal training in each two-year cycle. The Systematic Approach to Training (SAT)-based LORT program includes many hours above this minimum. (280 hours - assuming 20 hours per session and 14 sessions in two years.) NRC requires all licensed operators to attend all SAT-based requal training to maintain their knowledge and skills at an acceptable level. The inspector noted that individuals frequently missed requal training in 1995 and a few individuals did not attend the minimum training required by the facility. Additional NRC review of the facility-LORT minimum-hour requirement and attendance is necessary. This item is unresolved (URI 50-317 and 318/95-10-02) pending further review.

Management Oversight

The inspectors found that operators were clear on what their management expected. Operations management observes and evaluates simulator training each week. Lack of operations management involvement in the simulator exams was discussed previously.

Conclusions

Several weaknesses were noted in the LORT program, including:

- A large number of questions repeated on quizzes and exams.
- Lack of individual evaluations on the dynamic simulator annual exams (Unresolved Item 50-317 and 318/95-10-01).
- Lack of operations management involvement on the annual operating exams.
- Not requiring attendance at all requal training and individuals missing training (Unresolved Item 50-317 and 318/95-10-02).

Observed operator performance on the exam during the exam week was satisfactory. BGE acknowledged the weaknesses and unresolved items and intends to review these to identify needed corrective actions.

3.0 MAINTENANCE (IPs 62703, 61726, 92902)

3.1 Routine Maintenance Observations

The inspector reviewed selected maintenance activities to assure that the work was performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty. Maintenance activities reviewed are listed in Attachment 1.

3.2 Routine Surveillance Observations

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. Surveillance testing activities reviewed are listed in Attachment 1. The surveillance testing was performed safely and in accordance with proper procedures, except as noted below.

During the performance of STP M-220B-2, "Engineered Safety Features Actuation System (ESFAS) Channel ZE Functional Test," a control room annunciator window did not alarm when the bistable trip setpoint was reacned. The bistable trip light did light at the proper setpoint. BGE suspected that the bypass circuit in use during testing was malfunctioning, because the system operated correctly during troubleshcoting when the circuitry was tested without bypass keys. Subsequent to the failure during STP M-220B-2, troubleshooting was performed and operability was confirmed.

The inspectors observed the performance of the STP and noted that the procedure was adhered to and bypass keys were properly used. The inspectors reviewed the associated Issue Report, IR0-040-330, troubleshooting control form, surveillance test procedures and recent procedure change forms. The inspectors also discussed the issue with cognizant BGE personnel and determined the following:

- STP M-220B-2 functionally tested ESFAS and reactor protection system (RPS) bistables.
- Until 1995, bypass keys were not utilized during surveillance testing. BGE began using bypass keys in the latter part of 1995 to minimize the chance of a plant trip while testing.
- Subsequent to the inspection, BGE completed testing on all of the modules equipped with the maintenance bypass keys. Three modules had annunicators that failed to properly actuate with the bypass keys in-place, but all worked properly without the keys. There were no operability concerns.

BGE was working with the vendor to resolve the problem in the bypass key circuitry.

On November 20, operators inadvertently started 21 emergency diesel generator (EDG) while performing STP O-7B-2, "B Train Engineered Safety Features (ESF) Logic Monthly Testing." The STP performs a channel functional test of modules of the ESF actuation system, including the safety injection actuation system (SIAS).

The order from the control room operator was to, "perform step 10, initiate SIAS B-7...," which was acknowledged by the senior reactor operator in the cable spreading room as, "perform step 10." However, he then transposed the numbers in his order to the panel operator, telling him to, "initiate SIAS B-10..." The panel operator verified the order and initiated the SIAS B-10 module, instead of the SIAS B-7 module required by the STP. The only equipment affected was the 21 EDG, which responded correctly for the SIAS B-10 signal. The operators immediately recognized their error and informed the control room. SIAS B-10 was reset and the STP was aborted. The EDG was run and secured in accordance with procedure. The event was reported to the NRC in accordance with 10 CFR 50.72.

On December 8, 21 EDG tripped during its slow speed start for performance of STP 0-8B-2, "21 DG and 4kV Bus 24 LOCI Sequencer Test." The EDG tripped because the diesel operator became distracted, lost his place in the operating instruction, and failed to reset the jacket cooling water pressure trip. After evaluation, the trip was reset and the STP was performed satisfactorily. As corrective action, BGE is in the process of revising the STPs to include all steps required to be performed, rather than referencing other procedures. A "placekeeper" column in the STP would then be available as an operator aid. They were also evaluating the need for additional independent verification.

Inspectors reviewed the November 20 and December 8 events and discussed them with operations staff. There were no safety consequences and BGE took appropriate corrective actions. Technical Specification (TS) 6.8.1.c requires that written procedures be established, implemented, and maintained for surveillance and test activities of safety-related equipment. Failure to implement the STPs properly was a violation of TS 6.8.1.c. However, this licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

3.3 22 Auxiliary Feed (AFW) Pump Shaft Seizure Update

BGE completed its root cause analysis (RCAR 95-25) of the seizure of 22 AFW pump shaft and presented the results to the plant operations and safety review committee (POSRC) on December 4. (See NRC Inspection Report 50-317 and 318/95-08 for a discussion of the event.) The root cause was determined to be an inadequate overhaul procedure which contained an unreliable method for radially aligning the pump shaft. There were several contributing factors, including less than optimal maintenance practices and failure to follow procedure.

The investigative team identified seventeen ineffective or broken barriers for the twelve actions contributing to the shaft seizure and recommended eleven corrective actions, including procedure revision, additional technical training, independent technical procedure review, and re-emphasis of the need for a questioning attitude and documentation of unexpected or unusual conditions.

The inspectors reviewed the root cause analysis and discussed the results with engineering personnel. The analysis was comprehensive and focused both on the technical and safety significance of the event. The analysis' conclusions were supported by the findings and the corrective actions recommended reasonably addressed the deficiencies. The report's conclusion that there were no generic implications (i.e., the other three AFW pumps were not similarly affected) was well-reasoned and supported by field testing.

Technical Specification (TS) 6.8.1.a requires that written procedures be established, implemented, and maintained for the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which includes maintenance that can affect the performance of safety-related equipment. Failure to provide and implement an adequate maintenance procedure for the overhaul of the AFW pump was a violation of TS 6.8.1.a. However, this licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

4.0 ENGINEERING (IPs 92903, 37551, 37550)

4.1 Temporary Alterations/Modifications

At Calvert Cliffs, temporary modifications are designated as "temporary alterations (TAs)". TAs are controlled by administrative procedure MD-1-100, Revision 3, which has been effective from June 28, 1995. Plant TAs include, but are not limited to, lifted electrical leads, electrical and/or mechanical jumpers, electrical or mechanical loads, disabled annunciators, computer software changes, and/or any temporary special setup involving intrusive test setup, leak repairs, addition or removal of components or parts thereof, or aligning systems or components in configuration which is not included in the plant design basis.

To assess the adequacy of procedural controls and technical validity of the TAs planned and/or implemented in the plant, the inspector reviewed a representative sample of TAs from both units.

A total of nine (9) TA packages (five from Unit 1, and four from Unit 2) were reviewed for technical adequacy and procedural controls, including the effectiveness of the new TA procedure MD-1-100, Revision 3. The reviewed TA packages included alterations designed for implementation during power operation and during outages. The inspector noted that the applicable procedure controlling the implementation of TAs was detailed and clear, and appeared effective in controlling the temporary alteration program at Calvert Cliffs. Although there were a few TAs which had been in the plant over several TA cycles (3 months), BGE was able to demonstrate that these were exceptions due to circumstances beyond the BGE's control, i.e., the original equipment vendor was out of business. The replacement components and/or parts had to be either commercially bought or custom manufactured and then dedicated for use in safety-related applications.

The inspector concluded that the initiation, implementation, and control of temporary alterations at the site was satisfactory. The reviewed packages included all necessary screenings, reviews, approvals. and safety evaluations, as required. The safety evaluations were technically acceptable, and the TA log was sufficiently detailed to make it clear and self-explanatory.

4.2 Engineering Communications

The Nuclear Engineering Department's (NED's) internal communication system was reviewed to assess the effectiveness of the system in controlling interface of various groups; communicating design and personnel performance expectations; dissemination of technical, engineering, and plant operating information; and the feedback in these areas from technical personnel to engineering management.

The inspector determined that the clear division of responsibility between the plant and design engineering group contributed to a clear line of communication for establishing responsibility and expected performance by each group. The Systems Engineering group in the plant engineering section is clearly recognized by all as the primary contact for engineering support to the plant, and for the safe and reliable operation of the assigned plant systems.

The use of the "issues report" system for documenting concerns/problems is an effective method, and the computer bulletin boards (24 in all) of the site-network are very effective methods of informal communications among the various departments at the plant site. Also, the morning meetings with operations and maintenance staff contribute to early problem/concern identification and resolution. The "System Summary and Improvement Plans" (Draft Procedure PEG-19) also provide administrative guidance to plant engineering personnel for the preparation, review, communications, and updating of system summary and improvement plans posted on the computer network.

Based on the above observations and review, the inspector concluded that the internal communication system (formal and informal) was effective in assuring dissemination of management expectations and performance standards.

4.3 Engineering Backlog

In reviewing the trend graphs of the performance indicators, the inspector noticed that the total engineering backlog for maintenance activities was trending up compared to early this year (January 1995). Further review and discussions with engineering management personnel indicated that the backlog had peaked around September 1995 and has since slightly declined. However, the inspector noted the modifications backlog had declined from 679 in January 1995, to 319 by December, 1995.

It is recognized that the engineering backlog is cyclic in nature, and is affected by the outage schedule; however, any sustained adverse trend in this area is of concern.

The NED management appears to have recognized the importance of this adverse trend, and has taken measures to control and reduce the backlog. The measures, such as using more technical (contractor) resources to reduce the volume and applying risk assessment techniques in establishing the safety significance of the delayed work, appeared effective in managing the engineering backlog.

The inspector concluded that although the maintenance order engineering backlog had recently increased, it was not yet unmanageable, and appropriate management emphasis had been placed on reduction and backlog management.

4.4 Management Oversight and Self-Assessment

The management oversight and self-assessment policy of the Nuclear Engineering Department (NED) is documented in a new engineering procedure (ES-033). The stated objective of this procedure is to promote continuous improvement in the performance of the NED, and to achieve this goal through the involvement of the entire staff of the department to assess and evaluate the quality and effectiveness of the NED products and services.

The inspector reviewed the procedure and found it to be comprehensive and clear in establishing the management philosophy, expectations, and the implementation goals.

The monthly trend analyses of the performance indicators established by the NED management is an effective measure to assess the performance trends in the department. The inspector reviewed the "NED Measures" memorandum dated November 13, 1995, which reported the analysis and assessment of the engineering backlog of the maintenance orders. Additionally, using senior personnel, the NED performs reviews at the completion of complex, difficult, or high risk modifications to assure the integrity of the modification implementation process and identify any applicable lessons learned. Also, a process called, "Customer Interview" is used to discuss and evaluate the quality and effectiveness of the NED performance. The inspector reviewed one such memorandum which documented the results of an interview with mechanical maintenance and the NED. This process appeared effective in identifying and establishing mutual expectations and goals.

Based on the above observations, the inspector concluded that the self-assessment and management oversight program in the design engineering area was effective.

5.0 PLANT SUPPORT (IPs 92904, 71750)

5.1 Emergency Preparedness

During BGE's emergency preparedness exercise in September 1995, inspectors noted that the emergency action level (EAL) for a fire or explosion affecting safe shutdown capability deviated from the Nuclear Management and Resources Council (NUMARC) EAL guidance. The NUMARC EAL did not require that the fire or explosion necessarily prevent the ability to establish or maintain safe shutdown in order to declare an Alert condition. BGE's EAL went a step further by requiring that the fire or explosion be shown to actually impair safe shutdown capability. The issue was of concern because the exercise crew did not declare the Alert expected by the scenario after a simulated explosion in an emergency diesel engine because they concluded that their ability to achieve or maintain safe shutdown was not affected. The issue was an Inspector Followup Item (IFI 50-317 and 318/95-07-01) pending BGE's evaluation and corrective actions.

Following evaluation, BGE concluded that a revision to their EALs was necessary to ensure that emergency classifications were consistent with the intent of the EAL scheme and with the guidance of NRC Regulatory Guide 1.101. Changes to the EALs require approval of the NRC and state authorities before implementation. In the interim, a memorandum from the Director-Emergency Planning was promulgated on October 19, 1995, to applicable site personnel providing additional guidance in categorizing fires or explosions in the Protected Area, and bringing the BGE EALs more in line with the NUMARC EALs.

Inspectors reviewed the interim guidance and verified its addition to the control room copy of the emergency response plan implementing procedures. They also discussed the issue with BGE emergency planning staff and reviewed BGE's Revision 2 to the EAL Technical Basis Document, which included an adequate clarification of the requirements for declaring an Alert condition. BGE intends to use the revision as a basis for requesting a change to their EALs from the NRC. The interim guidance and revision were satisfactory in clarifying the requirements for an Alert. BGE's request for a change to the EALs was being tracked by the Emergency Planning Unit. Inspectors assessed that BGE's response to the issue was adequate, based on their short-term corrective actions and the long-term corrective actions in progress. IFI 95-07-01 is closed.

5.2 Security

Inspectors observed portions of BGE's full participation security exercise with the Maryland State Police (MSP) on November 7. The objective was to exercise the full range of assets used in a hostage/terrorist/negotiating scenario. Certain aspects of the site security plan were waived for the drill, in accordance with NRC Regulatory Guide 5.65 and the site security plan. A critique was conducted after the drill, and officers involved in the exercise were given elements of site general orientation training and radiation worker training on November 8.
Inspectors reviewed the drill timeline and BGE's access control measures, including those suspended for drill purposes. BGE met the objectives of the exercise.

5.3 Housekeeping

General plant cleanliness was good throughout the period. Inspectors noted good equipment conditions during plant tours. Equipment problems were noted with deficiency tags where appropriate, and corrective maintenance was properly prioritized and performed to minimize system degradation.

Inspectors noted that BGE recently revised procedure MN-1-109, "Foreign Material Exclusion," to designate the containments as foreign material control areas. The change was in response to containment cleanliness problems noted in past outages. As a result, additional training has been required for personnel entering containment, including an overview of the Foreign Material

Management Program, containment cleanliness requirements, and management's expectations. Inspectors consider the additional controls to be a good initiative; however, their effectiveness will not be assessed until the upcoming refueling outage.

6.0 REVIEW OF WRITTEN REPORTS (IPs 90712, 92700)

The inspectors reviewed LERs and other reports submitted to the NRC to verify that the details of the events were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1:

LER 95-005: Manual Reactor Trip Due to Increasing SG 11 Water Level. The event was documented above in section 2.1.1.

LER 95-006: Manual Reactor Trip Due to Loss of 12 Steam Generator Feed Pump. The event was documented above in section 2.1.2.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations, and corrective actions.

10 CFR Part 21 Reports

BGE was informed via an Enertech letter dated April 21, 1995, of a 10 CFR Part 21 Notification with regard to a potential spring problem on Bettis actuator model NHD732-SR80. The affected springs failed in a high cycle commercial environment after two years of service (cycled every five minutes for twenty-four hours a day). BGE has one of the actuators installed in each unit on valve SRW-1640-CV, the service water supply to the blowdown heat exchanger. In the Calvert Cliffs application, the valves are cycled only about once a month for surveillance testing. Following engineering evaluation, BGE determined that there was no operability concern with the springs as used on the service water supply valves. However, they obtained replacement springs and intend to install them in accordance with routine priority maintenance.

7.0 FOLLOWUP OF PREVIOUS INSPECTION FINDINGS

Licensee actions taken in response to open items and findings from previous inspections were reviewed. The inspectors determined if corrective actions were appropriate and thorough and previous concerns were resolved. Items were closed where the inspectors determined that corrective actions would prevent recurrence. Those items for which additional licensee action was warranted remained open. The following items were reviewed.

7.1 Emergency Preparedness

(Closed) IFI 50-317 and 318/95-07-01: Intent of the Emergency Action Level for Fire or Explosion in an Area Affecting Safe Shutdown. The item was reviewed and closed in section 5.1.

8.0 MANAGEMENT MEETING

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held to summarize the conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.

8.1 Preliminary Inspection Findings

Two Unresolved Items were identified with regard to the Licensed Operator Requalification Training program, as described in section 2.6. A Non-Cited Violation was identified with regard to surveillance testing, as described in section 3.2. A Non-Cited Violation was identified with regard to an inadequate maintenance procedure, as described in section 3.3. An Inspector Followup Item regarding Alert condition criteria was closed, as discussed in section 5.1.

ATTACHMENT 1

Routine Maintenance and Surveillance Observations

MO 1199503810	Clean 11 Service Water Heat Exchanger Tubes
MO 1199304657	Install New Spring Support Assemblies on 11 EDG Control Panel
MO 0199501716	Repair Fuel Oil Leak on #8 OCS Injection Pump Fitting
MO 0199501744	Replace V-tubing Between #8 and #9 Cylinders of 11 EDG
MO 1199505677	Troubleshooting and Testing of 12 Steam Generator Feed Pump
MO 1199505945	Replace 1-CVC-234
STP O-8A-1	11 EDG & 4kV Bus 11 LOCI Sequencer Test
STP O-8-1	11 Diesel Generator Test
STP O-65-1	Quarterly Valve Operability Verification-Operating
STP O-65J-1	SI Check Valve Quarterly Operability Test
STP O-90-2	Breaker Line-up Verification
STP O-8B-1	12 EDG & 4kV Bus 14 LOCI Sequencer Test
STP M-200-2	Reactor Trip Breaker Functional Test
STP M-220F-2	Refueling Water Tank Low Level Bistable Setpoint Verification Test
STP M-220D-2	Engineered Safety Features Actuation System Channel ZG Functional Test
STP M-220B-2	Engineered Safety Features Actuation System Channel ZE Functional Test
STP M-213-2	Calibration of Power Range Nuclear Instrumentation by Comparison with Incore Nuclear Instrumentation