U.S.NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	50-317/96-01; 50-318/96-01
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:	December 31, 1995, through February 10, 1996
Inspectors:	J. Scott Stewart, Senior Resident Inspector Carl F. Lyon, Resident Inspector Henry K. Lathrop, Resident Inspector

Approved by: Lawrence T. Doerflein 3/8/96
Lawrence T. Doerflein, Chief — Date
Reactor Projects Branch 1
Division of Reactor Projects

Inspection Summary:

Core and reactive inspections performed by the resident inspectors during plant activities are documented in the areas of plant operations, maintenance, engineering, and plant support.

Results:

See Executive Summary.

EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2
Inspection Report Nos. 50-317/96-01 and 50-318/96-01

Plant Operations:
Plant operations were performed in a very good manner and with a high regard for safety. There were no significant operating events during the period.

BGE implemented the emergency response plan procedure for severe weather on January 7-8 due to blizzard conditions. Among the actions taken, a double complement of essential personnel was maintained at the plant for watch relief and contingencies. BGE preparation and response to the severe weather was effective in ensuring continued safe operation of the facility.

On January 12, 1996, during the performance of the B train engineered safety features actuation system (ESFAS) logic test, a failed step led to the identification that a breaker was open rather than shut. Ensuring that the breakers on p-panels supplying safety related systems are properly aligned warrants BGE management attention.

BGE started trending unplanned starts, stops, or actuations of trip sensitive plant equipment in an effort to assess event near misses. The trending is a very good initiative in the continuing trip prevention effort.

A steam generator feedwater pump trip, caused by operator error, was an occurrence that should have been prevented by procedural controls, training, and adequate supervisory oversight. However, the event was of minor safety significance, partly due to the rapid and appropriate response of the operators.

Maintenance:
Overall, the licensee actions were good in identifying and repairing a degraded saltwater pump breaker. Followup actions on the failure were good, including identification of the root cause, scoping of other potentially degraded breakers, and elevation of the corrective maintenance to high priority work.

The lifting of the wrong slidelinks during a surveillance test was an example of poor work practice that may have been prevented by additional work control. Immediate identification of the error by alert reactor operators prevented a possible reactor transient and minimized the safety impact of the error.

Main steam isolation valve problems required 32 maintenance orders since August 1995 and numerous reactor operator compensatory actions. Additional engineering and maintenance management attention appear to be needed in this part of BGE's system performance improvement initiative.

Throughout on-line maintenance on the unit 1 saltwater and emergency diesel generator systems, plant safety was maintained and risk was minimized by

availability of redundant systems. However, the maintenance was poorly performed and required rework on both systems. Further, planning for the maintenance did not allow for rework and resulted in an outage time that substantially depleted the allowed outage time and presented a challenge to the plant operators. Afterwards, BGE management promptly initiated a formal review of the entire maintenance effort to identify areas for improvement.

BGE had made good progress in reducing the number of events caused by inadequate self-checking, inattention to detail, and inadequate independent verification during electrical and I&C maintenance.

Engineering:
Preoperational testing of the 1A emergency diesel generator (EDG) resulted in engine damage and the test program was halted for root cause determination. The Unit 1 outage was delayed to allow time to restore the EDG to service. The diesel problem identification and resolution had received a high level of management attention and BGE appropriately placed problem resolution and plant safety ahead of outage scheduling.

BGE identified that the service water heat exchangers may be fouling at a greater rate than predicted, and established an interim operability limit for Chesapeake Bay intake temperature for service water system operability. Extensive effort was being taken to resolve the issue before system operability would be degraded by increasing bay temperatures.

Plant Support:
The inspectors observed training provided to plant staff regarding foreign material exclusion controls and management expectations regarding foreign material exclusion areas. Overall, the training was considered an excellent initiative in BGE's ongoing effort to eliminate foreign material exclusion problems.

Security force response to severe weather challenges was excellent in ensuring continued plant and public safety.

Safety Assessment/Quality Verification:
As part of the effort to identify event precursors, BGE trended unplanned plant transients, such as unplanned starts, stops, or actuations of trip sensitive, engineered safety features, or major power train equipment, and other significant event near misses. BGE's trending was a good initiative that provides an additional indication of where to focus trip prevention efforts.

BGE limited the reactor power to 70% (limit for operation on one SGFP) following a feedwater pump trip, until the preliminary investigation results were reviewed by management. After concluding that the cause for the pump trip had been adequately explained and that there were no safety concerns with the pump, BGE returned the unit to full power.

TABLE OF CONTENTS

ATTACHMENT

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the period at full power. On February 10, power was reduced to 32% to replace the main generator stator liquid cooling system strainer. During the downpower, the 12 steam generator feedwater pump tripped unexpectedly. Following strainer replacement, power was raised and held at 70% on February 12 until the preliminary investigation of the feed pump trip was completed. The unit returned to full power on February 13.

Unit 2 began the period at full power. On January 20, power was reduced to 85% for water box cleaning and main turbine valve testing. The unit returned to full power the same day and remained at full power for the rest of the period.

Due to problems that had developed with the 1A Emergency Diesel Generator during pre-operational testing, the start date of the unit 1 outage was delayed to allow for troubleshooting and repair.

Several BGE senior management changes became effective this period. Mr. G. Creel, formerly the Senior Vice President-Generation, became Executive Vice President and Acting Chief Operating Officer of BGE. Mr. R. Denton, formerly the Vice President-Nuclear Energy Division, became Senior Vice President-Generation. Mr. C. Cruse, formerly the Plant General Manager of Calvert Cliffs, became Vice President-Nuclear Energy Division. Mr. P. Katz, formerly Manager-Nuclear Engineering Department, became Plant General Manager. Mr. P. Chabot, formerly Superintendent-Technical Support, became Manager-Nuclear Engineering Department. The Superintendent-Technical Support position was eliminated and the Technical Support units were transferred to other departments.

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

The inspectors observed plant operation and verified that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. During the inspection period, the inspectors provided onsite coverage of routine evolutions and made daily observations of the conduct of control room activities. Overall, the plant was operated in a very good manner and the operators performed with a high regard for public safety. There were no significant operating events during the period.

2.1 Operations Observations

a. Severe Weather

BGE implemented the emergency response plan procedure for severe weather on January 7-8 due to blizzard conditions. The company's severe storm policy (Personnel Services Unit Guideline 11) was also implemented on those days and again on February 2 due to heavy snowfall. In addition to securing the site

---

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

for the storms, a double complement of essential personnel was maintained at the plant for watch relief and contingencies. The inspectors noted good coordination between operations and maintenance personnel in keeping the intake structure travelling screens free of ice, which could have impacted unit operation. No notable problems were encountered from the weather, except that the automatic telephone ring down feature to the Dorchester and St. Mary's County emergency management agencies was lost for about six hours on January 8. However, other phone circuits to those agencies were available for use. The NRC was informed of the telephone problem in accordance with 10 CFR 50.72. The inspectors concluded that BGE preparation and response to the severe weather was effective in ensuring continued safe operation of the facility.

b. Breaker Found Out-of-Position on Unit 2

On January 12, 1996, during the performance of the B train engineered safety features actuation system (ESFAS) logic test, surveillance test procedure (STP) O-7B-2, an ESFAS timer light failed to illuminate and a control room air conditioning damper failed to shut as required by the test. Plant operators halted the test and conducted an investigation. The operators identified that the breaker for the ESFAS logic was open rather than shut. The surveillance had been completed satisfactorily in December 1995 and BGE concluded that the mispositioning had occurred in the interim.

BGE was unable to determine the cause of the mispositioning. The breaker was on a p-panel that housed a number of breakers in close proximity, with some breakers normally open. The subject breaker was not labelled and a plant drawing was needed to determine the significance of the breaker. The open position disabled the automatic actuation of control room air recirculation on a safety injection actuation system (SIAS) signal. Maintenance had been performed in the vicinity of the breaker on January 8, 1996, and it was suspected that the mispositioning inadvertently occurred during this maintenance.

The normal actuation of control room air recirculation due to high radiation was not affected. As corrective action, BGE evaluated the failure and determined that because of recent increase in diesel generator rating, the ESFAS system would have met its design requirements with the breaker in the open rather than shut position.

As followup action, the NRC inspectors walked down a number of safety-related p-panels and verified that safety system breakers were in the correct (shut) position. During the walkdown, the inspectors identified that a number of p-panels contained breakers that were neither labelled nor numbered for identification. Included in this category were breakers on panel 14 of motor control center 104R, which provided power to the low pressure safety injection (LPSI) pump motor space heaters. The inspectors considered the material condition of some of the p-panel labelling to be a weakness, that may have contributed to the mispositioning occurrence. Further, ensuring that the breakers on p-panels supplying safety related systems are properly aligned warrants BGE management attention. BGE acknowledged this concern.

c. Trending of Trip Near Misses

BGE began trending reactor trip "near misses" in May 1995 as part of the trip prevention effort. The goal was to reduce the severity of events as part of the overall effort to eliminate them entirely. Trending precursors to significant events, such as trips, was one step in identifying and correcting problems before they escalated to a severe level.

The trending criteria has undergone some modification since inception; BGE currently trends "automatic trip near misses," that include instances of (1) actions required by operators (including manual trip) to prevent an automatic trip, and (2) valid reactor protection system trip or pre-trip alarms due to a plant transient. Since trending began in May 1995, there were 17 automatic trip near misses, of which 4 were manual trips. Four of the trip near misses were attributed to operator error, one to maintenance error, and 12 to equipment malfunction. Of the 12 equipment malfunctions, 3 were attributed to the MSIVs (see section 3.2.b) and 5 to the main feedwater system. One of the operator errors also involved an MSIV.

As part of the effort to identify event precursors, BGE also began trending unplanned plant transients, such as unplanned starts, stops, or actuations of trip sensitive, engineered safety features, or major power train equipment, and other significant event near misses. The inspectors concluded that BGE's trending was a very good initiative that provides an additional indication of where to focus trip prevention efforts.

d. Unit 1 Feedwater Pump Trip

On February 11, while reducing reactor power to perform corrective maintenance on the main generator stator liquid cooling system strainer, the 12 steam generator feedwater pump (SGFP) tripped due to high feedwater header discharge pressure. Unit 1 was at about 50% power and operators had lowered the speed on 11 SGFP to place it in standby. The 12 SGFP tripped as the 11 SGFP minimum flow valve opened. Prompt operator action was taken to raise the speed on 11 SGFP and put it back in service to maintain steam generator levels and to avoid a reactor trip.

BGE's preliminary investigation, identified that the pump tripped due to operator error. The investigation included operator interviews and analysis of instrument data, and found no mechanical or electrical equipment problems with the 12 SGFP. Instrumentation installed on the 12 SGFP confirmed that no control oil transient had occurred, such as the one that resulted in a reactor trip in November 1995.

The BGE evaluation determined that the operation was conducted in accordance with procedure. As the operator adjusted the bias on the 12 SGFP controller to increase pump speed, action was also taken to reduce speed of the 11 SGFP, to minimize the effect on steam generator level during the transition from two pump to single pump operation. As 12 SGFP speed increased, its steam supply automatically shifted from reheat to main steam. As the operator increased the bias adjustment, a large difference developed between actual pump speed and the speed demand signal. This difference caused 12 SGFP speed to increase

rapidly as the main steam supply valve opened. Header pressure increased significantly and the pump tripped on high discharge pressure.

As immediate corrective action, operators were provided with additional information on how to operate the feed pump bias controls including which instrumentation should be monitored when the bias is being adjusted. BGE initiated a root cause analysis to determine additional corrective actions and lessons learned. BGE stated that this analysis will include potential contributing factors such as training and simulator modeling.

The inspectors considered the trip of the 12 SGFP to be an occurrence that should be prevented by procedural controls, training, and adequate supervisory oversight of operations. However, this occurrence was of minor safety significance, partly due to the rapid and appropriate response of the operators to the loss of the running feedwater pump. Additionally, BGE management limited the reactor power to 70% (limit for operation on one SGFP) following the strainer maintenance until the preliminary investigation results were reviewed by management and the onsite safety committee. After concluding that the cause for the 12 SGFP trip had been adequately explained and that there were no safety concerns with the pump, BGE returned the unit to full power.

The inspectors concluded that the BGE response to the feed pump trip was good. The preliminary investigation was thorough and critically reviewed by the on-site safety committee. The decision to hold the unit at 70% power until the root cause of the pump trip was adequately determined indicated due regard for nuclear safety.

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 the inspection details attachment.

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.

The surveillance testing was performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the testing depending on its sensitivity and difficulty. Reviewed surveillance activities are listed in the inspection details attachment.

a. Lifting of Incorrect Slidelinks During Testing

During the performance of surveillance test procedure (STP) M-212D-2, "RPS (Reactor Protection System) Functional Test, Channel D," on January 17, an instrument technician opened the slidelinks for 21 steam generator pressure channel "A" instead of channel "D." This action inserted trip signals on the corresponding "A" channels of RPS, engineered safety features actuation system, and auxiliary feedwater actuation system. The test was immediately halted by plant reactor operators, the slidelinks were closed, and the channel was reset. The operability of the channel was not affected and no equipment started as a result of the error because two channels are required to trip for a safety system actuation.

The NRC inspectors discussed the event with the Instrument & Controls (I&C) section general supervisor and examined the work site. The channels were properly labeled and color-coded. BGE management stated that the cause of the error was failure of the technician to self-verify the correct channel before opening the slidelinks. As immediate corrective action, I&C work was stopped until the issue could be reviewed and discussed with I&C personnel. The testing was resumed and completed satisfactorily on January 19 after an extensive briefing and with direct supervisory and quality assurance oversight.

The inspectors noted that the procedure step did not contain either an independent verification or a "STAR," (stop, think act, review) supervisory caution, as verification that the correct channel was removed from service. The inspectors concluded that the lifting of the wrong slidelinks was an example of poor work performance that may have been prevented had additional work control been used. Immediate identification of the error by alert reactor operators, prevented a possible reactor transient if the testing had continued and minimized the safety impact of the error.

b. Closed (Violation 94-29/28-01); Maintenance Performance

The inspectors reviewed maintenance performance problems BGE had experienced due to inadequate self-checking, inattention to detail, and inadequate independent verification. Examples of those errors were cited as a violation of NRC requirements in October 1994 (VIO 50-317/94-29-01 and 318/94-28-01).

Electrical & Controls (E&C) maintenance staff established an action plan in December 1994 based on STAR (stop, think, act, review) principles to improve the quality of E&C maintenance. The plan included promulgation of clear management expectations with regard to E&C maintenance, establishment of a STAR mock-up trainer, establishment of supervisory hold points in work packages, more emphasis on supervisory presence/coaching in the field, and use of peer assessments, such as the event-free program (the gold card program) in use in the Operations Department. The inspectors reviewed aspects of the plan, issue reports, and trends, and discussed the issue with E&C staff to assess the plan's effectiveness.

Performance indicators over the past year showed improvement in STAR-related maintenance problems. The number of program deficiency reports (PDRs) was

down from 5 to 2, and the number and severity of issue reports related to STAR were down. The total E&C maintenance rework average was down from 0.73% in 1994 to 0.36% in 1995. There was only one E&C significant event in 1995 (May 24 reactor trip). The January 17, 1996 occurrence (last section), was an example where the performance improvements have not been effective.

Overall, BGE had made good progress in reducing the number of events caused by inadequate self-checking, inattention to detail, and inadequate independent verification during electrical and I&C maintenance. Part of the improvement was an increased level of supervisory involvement in day-to-day surveillance activities. Continued attention to the program improvements by maintenance personnel will be required for continued effectiveness. The inspectors concluded that BGE has an adequate management program in place to minimize future occurrences. Accordingly, VIOLATION 94-29/28-01 is closed.

c. Main Steam Isolation Valve Issues

On January 23, the 12 main steam isolation valve (MSIV) continued to go past the expected 10% shut position during the performance of surveillance test procedure (STP) O-47A-1, "A Circuit MSIV Partial Stroke Test." Hydraulic fluid was apparently leaking by the solenoid valves used for partial stroke testing of the MSIVs. The pre-evolution brief for the STP included a contingency for the problem and when the valve continued to shut, operators promptly shut the "A" train hydraulic drain manifold isolation valve, which re-opened the valve. The MSIV closed about 30% before re-opening. Because the MSIV has both an A and B train isolation circuit, the MSIV remained operable. The "A" train hydraulic dump solenoid valve and the test circuit solenoid valve on 12 MSIV were subsequently replaced to restore the "A" train to service. No problems were noted on the "B" train.

In addition to the problems on 12 MSIV, the 22 MSIV "A" train solenoid test valve timer module failed on January 20. This caused a "22 MSIV test valve closed" alarm in the control room until the "A" hydraulic path was isolated and the timer module was replaced.

BGE classified the 12 MSIV event as an automatic reactor trip "near miss," because a reactor trip would have occurred if the MSIV had shut. It was the fourth trip near miss involving the MSIVs (out of 17 total trip near misses) since BGE began trending near misses in May 1995. MSIV equipment problems have resulted in 32 maintenance orders since August 1995, requiring numerous operator compensatory actions. Many were recurring or similar issues. As a result, BGE created program deficiency report (PDR) 96005 on January 31 to document the MSIV problems as a "significant condition adverse to quality" and to initiate a root cause analysis of the problems. To aid in their investigation, BGE has initiated an independent assessment of MSIV problems.

The inspectors determined that the plant operators responded well to the challenges presented by MSIV equipment problems. However, recurring problems with the MSIVs indicate that additional engineering and maintenance effort and management attention are needed in this part of BGE's system performance improvement initiative.

d. On Line Maintenance

On February 7, 1996, Unit 1 commenced a series of on-line maintenance evolutions that included replacement of saltwater inlet and outlet piping to the 11 component cooling heat exchanger and preventive maintenance of the 11 emergency diesel generator. A series of technical specification action statements were entered concurrently with the removal from service of the 11 saltwater header, the 11 emergency diesel generator, 11 service water header, 11 containment spray pump, 11 and 12 containment air coolers, and the 11 component cooling heat exchanger. The maintenance was planned to be completed within a 49 hour window, below the limiting 72 hour technical specification limiting condition for operation.

A number of complications extended the maintenance beyond the planning window. The saltwater piping replacement took longer than expected and on refill of the saltwater header, a piping flange leaked excessively. Rework of the header required redraining, and repair of the affected piping connection. This extension delayed restoration of service water cooling to the emergency diesel generator, and thereby delayed post-maintenance testing of the diesel. When the saltwater and service water headers were returned to service mid-day on February 9, testing of the 11 emergency diesel was conducted. The initial test failed when the indicated lube oil pressure failed to respond to increasing engine speed during a slow-speed start. Troubleshooting of the engine identified that the lube oil sensing line had disconnected during the work. Completion of the diesel rework and satisfactory testing of the engine was then completed in the 71st hour of the 72 hour limiting condition for operation (LCO).

Throughout the on-line maintenance evolution, plant safety was maintained and risk was minimized by availability of redundant systems. However, the maintenance was poorly performed and rework was required to restore the systems to service. Further, planning for the maintenance did not provide adequate LCO margin for either the saltwater header rework or sequential delay of the diesel rework. The result was an outage time that substantially depleted the allowed outage time and presented a challenge to the plant operators, who were tasked with the decision to continue operation of the unit. The extent of maintenance rework and the sequential nature of the problems were examples of poor maintenance planning for the complex on-line maintenance task. The inspectors noted that BGE management promptly initiated a formal review of the entire maintenance effort to identify areas for improvement.

e. Failure of 12 Saltwater Pump Breaker to Shut

On December 22, 1995, during surveillance testing of the saltwater system, saltwater pump number 12 failed to start when its handswitch was taken out of pull-to-lock during a testing sequence that should have caused pump start. When the test step was repeated, the breaker shut as designed. Plant operators noted the failure to start in the surveillance test paperwork and wrote an issue report to document and ensure evaluation of the problem.

Operators suspected the failure to start on the first try was due to a loose handswitch aggravated by possibly dirty contacts. Maintenance personnel could not identify the cause of the problem. Because the switch failure appeared to be limited to the pull-to-lock to operate transition, pump operability was not considered degraded and on January 2, 1996, the handswitch was replaced.

During the post-maintenance testing of the new handswitch, the pump again failed to start and was immediately declared inoperable. Subsequent troubleshooting identified occasional binding of the lower operating mechanism of the breaker. Subsequent evaluation identified the binding to be due to inadequate/improper lubrication. The breaker was cleaned, properly lubricated, repeatedly cycled to verify freedom of movement, and restored to service after successful surveillance testing.

The affected switchgear was a General Electric 4 kV, horizontal drawout, metal clad, magna-blast type AMH 4.76-250 circuit breaker. The facility had been notified by General Electric of the susceptibility of the affected breakers to binding due to lack of lubrication and the preventive maintenance procedure had been revised on March 8, 1995, to provide more guidance for lubrication along the bearings and pivot points that had bound in the affected breaker. The affected breaker had not been through the preventive maintenance process since the revision.

As further corrective action, a complete list of related switchgear was compiled and evaluated as to whether or not the updated preventive maintenance, including lubrication of the lower operating mechanism, had been performed. Twenty-one susceptible breakers were identified from the compiled list and each was inspected and tested on a high priority basis. The testing included an as-found functional evaluation, lubrication of the lower mechanisms as specified in the preventive maintenance procedure, and repeat testing. In each case, the breakers operated as designed, with less than one-second cycle times both before and after the maintenance.

Overall, the inspectors determined that the licensee actions were good in identifying and repairing the affected breaker and ensuring that other susceptible breakers were not affected. Although the apparent cause of the initial breaker failure to shut was limited to a suspected loose handswitch, actions to replace the handswitch and the operability evaluation at the time were adequate for the observed malfunction. Followup actions on the subsequent failure were good, including identification of the root cause of the failure, scoping of other susceptible breakers and elevation of the preventive maintenance to high priority work.

4.0 ENGINEERING (IPs 92903, 37551, 37550)

4.1 SACM Diesel Generator Cylinder Liner/Piston Damage

In mid-December, 1995, while performing a series of pre-operational acceptance tests on the new safety-related (1A) diesel generator, BGE test engineers noted sporadic instances of increased crankcase pressure in the 1A2 engine. All other monitored parameters remained within normal operating limits, and crankcase pressures on the 1A1 engine were also normal. The two new diesel

generators (the OC diesel provides station blackout emergency power) have tandem units with the generator located between two engines and were manufactured by Societie Alsacienne de Constructions Mechaniques (SACM) with a nominal rating of 5400 KW. BGE inspected the 1A2 engine and noted that cylinder 1A2-B7 exhibited evidence of scuffing of the cylinder liner and excessive carbon-like buildup on the piston and piston rings. BGE replaced the cylinder liner, piston and rings. BGE continued testing into January, 1996, when BGE test personnel noted increasing crankcase pressure in the 1A1 engine and lube oil leaking past the crank shaft seals. The 1A diesel was shut down following a 24-hour endurance run to investigate these anomalies. BGE found that five cylinder linings exhibited scuffing and their associated pistons contained deposits of carbon-like material. On January 18, based on the damage found on the 1A diesel, BGE restricted the use of the OC diesel to emergency only. A boroscopic inspection of the OC diesel cylinders on January 26 revealed that one (of 32) cylinder liner exhibited the same symptoms as the damaged 1A diesel cylinders.

BGE assembled a root cause analysis team, composed of personnel from BGE, several engineering/fault analysis firms, SACM and the lubricating oil manufacturer (Mobile Oil), to determine the cause(s) of the scuffing and carbon buildup. Three potential factors were identified:

- BGE's method of starting and loading the diesel generators,
- piston ring composition/dimensions, and
- lubricating oil and/or its additive package.

The manufacturer of the piston rings determined that the material composition and tolerances of the rings were as specified. Mobil Oil sampled the lubricating oil and determined by analysis that the oil apparently met the specifications supplied by SACM. However, an independent analyst noted that the concentration of the additive package in the lube oil was substantially higher than expected.

The inspectors noted that BGE had taken a conservative approach to the determination of the possible causes of the damage and had contracted recognized industry expertise to provide an independent assessment of both the root cause methodology and results, as well as a review of the entire diesel generator project for generic implications and common threads.

Operability of the diesel generators was an integral part of the planned unit 1 refueling outage because of the extensive electrical work required to tie-in both the 1A and OC diesels to the plant electrical systems and the realignment of the existing diesels to different safety busses. As result of the emergent diesel repair, the start of the planned refueling outage was delayed until March 29, 1996.

The diesel problem identification and resolution had received a high level of management attention. The inspectors concluded that BGE had established effective controls to identify and resolve the operational problems with the emergency diesel engines and had appropriately placed problem resolution and

plant safety ahead of outage scheduling. Resolution of the diesel issues as well as preoperational readiness testing warrants a continued high level of BGE management attention.

4.2 Service Water Heat Exchanger Design Calculation Deficiencies

As part of their followup activities resulting from a detailed design review of the safety-related service water system in 1993, BGE initiated an on-line test program for the service water heat exchangers (SRWHXs) in June, 1995. The program was designed to quantify and evaluate, over a one year period, the amount of microbiological fouling of the SRWHX tubes and subsequent effect on SRWHX operability. BGE designed and installed a model of the tube side of a SRWHX, called a side stream monitor (SSM), to operate in parallel with the full-size unit, and which would be subjected to the same conditions experienced by the SRWHXs during operation. The SSM was physically located in the Unit 2 intake structure.

The current design basis assumed a maximum allowable fouling factor of 0.0012Hr-Ft^2-°F/BTU. (0.0007Hr-Ft^2-°F/BTU baseline fouling factor for a clean SRWHX + 0.0005Hr-Ft^2-°F/BTU assumed maximum equilibrium fouling factor for a "dirty" SRWHX. The latter value was derived from a qualitative study performed in 1989, whereas the former was developed from actual plant testing.) Using this maximum allowable fouling factor, BGE engineering staff calculated a maximum allowed Chesapeake Bay water temperature of 87.4°F to assure the SRWHXs could perform their design safety function.

In January, 1996, while reviewing preliminary data gathered from the SSM, BGE determined that the equilibrium fouling factor assumed in their calculation may have been non-conservative (0.001Hr-Ft^2-°F/BTU), resulting in SRWHX operation outside their design basis for a number of periods over the past several years. The microfouling appeared to be about twice the assumed value and equilibrium was reached in a substantially shorter time. BGE made the appropriate notification to the NRC on January 18. An operability evaluation, accepted by operations management on February 7, indicated that the SRWHXs remained operable with Chesapeake Bay temperatures below 70°F. Operation above 70°F could be acceptable as long as each SRWHX was cleaned once every two weeks. Currently, the SRWHXs are cleaned ("bulleted") once per three months.

BGE assembled a team comprised of engineering, design, chemistry, maintenance and testing personnel to validate the data being provided by the SSM and to determine both short and long term corrective actions. At the close of the inspection period, BGE was evaluating several alternatives, including accelerating the SRWHX replacement scheduled for 1998/1999, more frequent SRWHX cleaning, use of chemicals to reduce/slow down the microfouling, and variable flow controls for selected service water safety-related loads.

The inspectors reviewed BGE's issue report and supporting analysis, as well as the operability determination, and determined that the analyses appeared thorough and reasonably supported the operability conclusions. Although extensive effort will be required to resolve the service water operability issue before Chesapeake Bay water temperature exceed 70 °F, BGE had in place

effective measures to identify and resolve the issue before plant safety would be challenged. The inspectors concluded that BGE's efforts to further refine the design envelope for the SRWHXs, beyond what was called for in Generic Letter 89-13, were notable. NRC Inspection Reports 50-317 & 318/94-80 and 95-06 provided additional information on this issue.

4.3 SACM Diesel Generator Filter Housing Potential Quality Problem

In February, 1996, the State of Maryland informed BGE of a potential quality problem with the filter housings manufactured by AMER Industrial Technologies, Inc. The housings were used in the fuel oil transfer system for BGE's new safety-related 1A diesel generator, currently undergoing preoperational testing. BGE verified that they were installed and also that only the 1A diesel was affected. The other new diesel generator, designated OC, while generally identical physically to the 1A machine, was not safety-related and had filter housings provided by a different vendor.

An inspection of AMER's facilities performed recently by a representative of the American Society of Mechanical Engineers (ASME) noted that process controls for the procurement of materials for the manufacture of safety-related parts were, in some cases, inadequate, and could render the parts' quality indeterminant. Parts in this category included the filter housings supplied to BGE.

BGE documented the issue on a startup problem report (SPR) and indicated to the inspectors that the issue was to be resolved by Bechtel, the architect/engineer and constructor for the new diesel project, prior to declaring the 1A diesel operable. The inspectors noted that the 1A diesel had not yet completed its test program and was not turned over to BGE for operation; therefore, there was no actual safety consequence because of the use of the AMER filters.

5.0 PLANT SUPPORT (IPs 92904, 71750)

5.1 Emergency Preparedness

The inspectors conducted a review of the emergency preparedness facilities and found that functional readiness was being maintained. The review included a walkdown of the Technical Support Center, Operational Support Center, Operational Support staffing areas, Media Center, and Emergency Offsite Facility as well as a check of control room capabilities. A number of emergency supply and procedures inventories were checked and no inventory discrepancies were identified. The inspectors were informed that BGE had considered relocation of the Media Center to a new location. The final action had not been approved during the inspection period.

5.2 Security

The inspectors reviewed the response of the security organization to challenges presented by severe weather. When required, appropriate and timely actions had been taken to ensure continued security effectiveness. Security

force response to severe weather challenges was excellent in ensuring continued plant and public safety.

5.2 Housekeeping and Foreign Material Exclusion Controls

General plant cleanliness was good throughout the period. The 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.

During the inspection period, the inspectors observed training provided to plant staff regarding foreign material exclusion controls and management expectations regarding foreign material exclusion areas. The training was detailed and included a review of foreign material intrusion events at Calvert Cliffs and other nuclear sites. Additionally, a practical demonstration of foreign material controls processes was required of each staff attending the training. Overall, the inspectors considered the training an excellent initiative in BGE's ongoing effort in eliminating foreign material exclusion problems.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

6.1 Integrated Assessment Team Program

On January 1, BGE began a six month pilot program with an Integrated Assessment Team inspection of the Operations functional area. BGE's objectives are to reduce duplication of oversight within the Nuclear Quality Assurance Department (NQAD) and to improve overall assessment capabilities and sharing of results to provide a more integrated assessment of performance.

The team consists of four BGE evaluators: one from the ISEG (Independent Safety Evaluation Group) section, two from the quality verification (QV) section, and one from the quality audits (QA) unit. The team has responsibility for all inspections carried out in the Operations area, from audits and surveillances required by regulations to performance-based assessment.

Following evaluation of the integrated team approach similar teams with inspection responsibility in other functional areas, such as maintenance and engineering, may be established. The inspectors reviewed the team overview and assessment plan and discussed the objectives with NQAD management and staff. They also discussed measures to assure that evaluators who performed QA inspections or audits required by regulations were qualified in accordance with required standards.

6.2 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. Overall, the inspectors determined the level of review and member participation to be satisfactory in fulfilling the POSRC responsibilities.

6.3 Offsite Safety Review Committee

Portions of the Offsite Safety Review Committee (OSSRC) meeting on January 25 were attended by the inspectors. The OSSRC composition and agenda were in compliance with the requirements of TS 6.5.4. The agenda included a review of plant status and significant safety issues and proposed changes to the operating license. A good questioning attitude and safety perspective were noted. particularly regarding service water heat exchanger operability, misdiagnoses of root causes, and foreign material management issues. Several items were referred to the plant staff for additional information and were therefore not resolved. Overall, The inspectors found the level of review to be satisfactory to fulfill the OSSRC responsibilities.

7.0 REVIEW OF UFSAR COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions.

During a portion of the inspection period (February 1-10, 1996) the inspectors reviewed the applicable sections of the UFSAR that related to selected inspection areas discussed in this report. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

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. BGE management acknowledged the inspection findings.

INSPECTION DETAILS ATTACHMENT

Routine Maintenance and Surveillance Observations

MO 2199504306	Clean 22 SRW Heat Exchanger Tubes
MO 2199504316	Clean 22 CC Heat Exchanger Tubes
MO 2199500790	Replace 22 CC Heat Exchanger RV-3825
MO 2199505053	Inspect 22 ECCS Pump Room Air Cooler
MO 1199600205	Lubricate and check trip latch on breaker 152-1112
MO 1199600206	Lubricate and check trip latch on breaker 152-1412
MO 1199600262	Replace 1-SV-4047A and 4050A on 12 MSIV
MO 0199600129	Inspect and Replace Cylinder Liners and Pistons, OC Diesel
MO 0199403006	11 EDG lube oil sensing line replacement
MO 0199600107	Inspect OC Diesel Engines for Carbon Buildup in Piston Rings
MO 1199505085	Clean 11 ECCS pump room strainer
MO 1199503473	Replace four 11 CC heat exchanger spool pieces
MO 1199505874	Inspect 11 ECCS pump room air cooler channel head
MO 2199504364	Clean No. 21 Component Cooling Heat Exchanger
STP O-73I-2	HPSI Pump Performance Test
STP O-65J-2	SI Check Valve Quarterly Operability Test
STP O-5-1	Aux Feedwater System Monthly Surveillance Test
STP M-200-2	Reactor Trip Breaker Testing