U.S.NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.:	50-317/91-10; 50-318/91-10
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:	March 31, 1991, through May 4, 1991
Inspectors:	Larry E. Nicholson, Senior Resident Inspector Allen G. Howe, Resident Inspector Melanie A. Miller, Operations Engineer Daniel G McDonald, NRR Project Manager Glenn M. Tracy, Resident Inspector Brian Hughes, Operations Engineer Pamela J. Monaco, Inspector Intern
Approved by:	Robert J. Summers Robert J. Summers, Acting Chief Reactor Projects Section 1A
	5-21-91 Date

Inspection Summary:

This inspection report documents routine and reactive inspections during day and backshift hours of station activities including: plant operations; radiological protection; surveillance and maintenance; emergency preparedness; security; engineering and technical support; and safety assessment/quality verification.

Results:

See Executive Summary.

EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection Report Nos. 50-317/91-10 and 50-318/91-10

Plant Operations: (Modules 71707, 93702) Unit 1 operated at power throughout the period. Unit 2 was started up on April 28, 1991 after an extended outage. Operators performed well during startup and low power testing. Management oversight during this time was appropriate and effective. Unit 2 tripped on May 2, 1991 due to a feedwater pump malfunction and was restarted on May 3, 1991. An inadvertent auxiliary feedwater actuation occurred May 4, 1991, on Unit 2 during main turbine testing. Initial management response to both events was good and continued as the period ended. Before the initial Unit 2 startup, troubleshooting efforts caused an inadvertent reactor protective system actuation while shutdown. Informal controls of the troubleshooting efforts contributed to the event.

Radiological Protection: (Module 71707) Routine review in this area showed acceptable performance.

Surveillance and Maintenance: (Modules 61726, 62703) Emergency diesel generator test inadequacies were identified by BG&E and effective corrective actions were initiated. Maintenance errors resulted in damage to two service water valves and delayed the Unit 2 startup. A preventative maintenance program review found that the backlog of past due work had been reduced but many of the overdue preventative maintenance procedures were inadequately deferred.

Emergency Preparedness: (Module 71707) Routine review in this area showed acceptable performance.

Security: (Module 71707) Routine review in this area showed acceptable performance.

Engineering and Technical Support: (Modules 71707, 90712, 92700)
Problems in program implementation were identified during reviews of vender technical manuals and engineering staff overtime. BG&E actions in response to these issues has been appropriate. Significant weaknesses were found in the inservice pump testing program. BG&E response regarding this issue has been adequate.

Safety Assessment/Quality Verification: (Modules 71707, 30703)
The Performance Improvement Review Panel provided a disciplined approach to action plan closure. Good safety assessment was observed at various POSRC meetings.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the inspection period at power and continued for the remainder of the period.

Unit 2 began the inspection period in a continued shutdown for the 8th cycle refueling outage. The unit was taken to normal operating temperature and pressure on April 2, 1991, but a cooldown was performed to repair leaking check valves in the safety injection system. Repairs to correct excessive seat leakage were also made to the service water non-safety loop isolation valves. A delay in the outage resulted when these valves required rework to repair damage from improper maintenance. The chronology of significant events in the Unit 2 startup was as follows:

Date	Time	Event
April 25	1:00 a.m.	Entered Mode 4
April 25	7:20 a.m.	Entered Mode 3
April 28	3:25 p.m.	Criticality achieved
April 30	4:00 p.m.	Completed low power physics testing
May 1	11:23 p.m.	Paralleled to the grid

Unit 2 experienced an automatic reactor trip from approximately 8% power on May 2, 1991. The trip was caused by a malfunction in the main feed pump which resulted in a low steam generator level. After the problem was repaired, Unit 2 was restarted at 4:27 p.m. on May 3, 1991 and paralleled on May 4, 1991 at 1:40 a.m.

2.0 PLANT OPERATIONS

2.1 Operational Safety Verification

The inspectors observed plant operation and verified that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

- control room
- primary auxiliary building
- radiological control point
- electrical switchgear rooms
- auxiliary feedwater pump rooms
- security access point
- protected area fence
- intake structure
- diesel generator rooms
- turbine building

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources was verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Routine operations surveillance testing was also observed. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Plant radiation monitoring system indications and plant stack traces were reviewed for unexpected changes. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, the temporary modification log, and the jumper and lifted lead book. Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspector also examined the condition of various fire protection, meteorological, and seismic monitoring systems. Control room and shift manning were compared to regulatory requirements and portions of shift turnovers were observed. The inspectors found that control room access was properly controlled and that a professional atmosphere was maintained.

In addition to normal utility working hours, the review of plant operations was routinely conducted during portions backshifts (evening shifts) and deep backshifts (weekend and midnight shifts). Extended coverage was provided for 15 hours during backshifts and 23 hours during deep backshifts. Additionally, around the clock coverage was provided during startup activities from April 26 to May 5. Operators were alert and displayed no signs of inattention to duty or fatigue.

2.2 Followup of Events Occurring During Inspection Period

During the inspection period, the inspectors provided onsite coverage and followup of unplanned events. Plant parameters, performance of safety systems, and licensee actions were reviewed. The inspectors confirmed that the required notifications were made to the NRC. During event followup, the inspector reviewed the corresponding CCI-118N (Calvert Cliffs Instruction, "Nuclear Operations Section Initiated Reporting Requirements") documentation, including the event details, root cause analysis, and corrective actions taken to prevent recurrence. The following events were reviewed.

a. Reactor Protection System Actuation

The inspectors reviewed the circumstances involving the actuations of the Unit 2 reactor protection system (RPS) that occurred on April 7 and again on April 9, 1991. The unit was in mode 3 with control rod testing in progress when the actuations occurred. During the first event, operators were inside the containment manually adjusting the pressurizer spray by-pass flow when the channel "A" reactor coolant system (RCS) low flow pre-trip and the channel "D" pre-trip and trip were received. A pre-trip is an alarm that a trip setpoint is being approached. The trips were reset and the channel "A" low flow pre-trip and trips were again received. In

addition, the channel "B" low steam generator level pre-trip alarm was also received. These alarms were subsequently reset. No automatic actuations occurred since the 2 out of 4 trip logic was not satisfied.

The second event occurred at 1:57 a.m. on April 9. The Shift Supervisor and operators involved in the previous event had conjectured that the use of radios inside the Unit 2 containment could have caused the inadvertent trips. A decision was then made to have an operator enter the containment and key a radio in the vicinity of the applicable transmitters. While preparing for this evolution, the operator prematurely keyed his radio and caused a reactor trip. This action resulted in a RPS trip on all four channels for RCS low flow. Control rod testing was in progress at the time of the trip with the trip breakers closed and a rod withdrawn two steps out of the core. The trip breakers subsequently opened and the rod fully inserted as designed. The original intent was to secure from rod testing and fully insert all rods prior to initiating this troubleshooting. An entry in the Shift Supervisor's log indicated that this event was not reportable since it was a planned evolution. A problem report was initiated and a note was added to the Unit 2 operation shift turnover sheet to prohibit the use of radios in this vicinity of the containment.

Subsequent review by BG&E resulted in a determination that the event of April 9 was in fact unplanned and therefore reportable in accordance with 10 CFR 50.72.b.2.ii. A report was made to the NRC on April 19, 1991. The inspectors' assessment of the events was as follows:

1. The formality and extent of communications was not commensurate with the evolution. No procedure or written guidance was developed to prescribe a planned sequence of events and provide a means to capture the test results. The full RPS trip was not annotated in the applicable control room operator (CRO) log. The nuclear engineer who was directing the control rod testing was not included in the preliminary discussions and was not aware of the troubleshooting effort. The problem reports written to document the problems contained incorrect dates and omitted pertinent information.

2. The Shift Supervisor and crew displayed good resolve by continuing to evaluate the first event for possible causes. However, the data and pertinent facts from the subsequent troubleshooting effort were not captured in a manner to support a thorough evaluation.

3. The reactor trip that occurred on April 9 should have been reported in accordance with 10 CFR 50.72.b.2.ii. The RPS actuation was a result of an accidental radio transmission. No procedure was in place that recognized an RPS actuation and the CRO was not expecting a reactor trip at the time of occurrence. The Shift Supervisor had expected to secure control rod testing and fully insert all rods prior to commencing the troubleshooting.

The inspectors noted that the BG&E investigation into the events resulted in similar conclusions. Appropriate actions to assess the lessons learned and prevent recurrence of a similar problem were observed. No further questions or concerns were identified.

b. Temporary Waiver of Compliance Related to the Containment Purge Isolation Valves

On April 6, 1991, BG&E requested and was granted a Regional waiver of compliance from certain requirements of Technical Specification 3.6.1.7. This waiver allowed the operation of the containment purge supply and exhaust isolation valves with Unit 2 in modes 3 and 4 for the purpose of purging the containment. High levels of carbon monoxide developed in the Unit 2 containment during the heatup due to off-gassing from the new insulation and heatup of fluid residues. These levels required the use of self-contained breathing equipment during entry into the containment. The containment was successfully purged and normal entry conditions were reestablished.

c. Request for Relief from ASME Requirements

On April 20, 1991, BG&E requested and was granted verbal interim relief from the ASME Section IX requirements pertaining to a small through-wall flaw in the weld of a six-inch weld-o-let inspection port to a 30-inch Unit 1 saltwater system header. A branch connection was installed to encapsulate the flaw and therefore provide a pressure boundary replacement around the weld-o-let. The written request for this waiver was submitted via a letter from BG&E, dated April 25, 1991. The inspectors observed portions of the development and implementation of the corrective actions. No concerns were identified.

d. Unit 2 Reactor Trip

On May 2, 1991, at 10:50 a.m., Unit 2 experienced an automatic reactor trip from approximately 8% power. The cause of the trip was low steam generator level as a result of a malfunctioning main feedwater pump. The main turbine was off line at the time for balancing. The unit was placed in a stable condition after the transient with the auxiliary feedwater system used to supply cooling water makeup. The inspectors observed the execution of the applicable emergency procedures and recovery operations. Operator performance was acceptable. No concerns were identified.

e. Auxiliary Feedwater Actuation

On May 4, 1991, at 9:22 p.m., an auxiliary feedwater actuation system (AFAS) actuation occurred on Unit 2 which started the No. 23 auxiliary feedwater pump. The AFAS occurred when the governor and intermediate valves were cycled while preparing for a main turbine overspeed trip test. When the valves were opened, a steam generator level swell and high level turbine trip occurred. The turbine trip caused a level shrink and pressure transient. This produced an indicated low steam generator level and AFAS actuation. Operator actions to recover from the actuation were appropriate. BG&E review was ongoing as the period ended but no initial concerns were identified.

2.3 Failure to Disseminate Essential Information to Operators

BG&E recently completed modifications to the No. 21 and No. 22 steam driven auxiliary feedwater (AFW) pumps which included enlarging the overspeed trip devices. As a result of this modification, resetting the overspeed trip of the turbines now requires pulling the connecting rod rather than pushing up the manual trip lever, which is the method the operators are accustomed to. The inspectors noted that the procedure OI-32, "Auxiliary Feedwater System," was revised appropriately to reflect the above change on April 10, 1991; however, this information was not disseminated to the operators as of April 26, 1991. BG&E informed the inspectors that the changes to OI-32 were intended to be included in the "Required Reading" book for the operators but never materialized. The modifications to systems and changes to operating procedures are also covered during planned operator requalification training.

BG&E management agreed with the inspectors that the information was essential to operations and disseminated the information to operators through the "Required Reading" book as an immediate corrective action. The inspectors concluded that this error appeared to be an isolated case of inattention to detail for operator training.

2.4 Unit 2 Restart

a. Review of Startup Checklist

The inspectors routinely monitored the status of the operations startup checklist OP-6 to verify signoffs were complete and exceptions authorized prior to changing modes. The checklist is maintained by the shift supervisor and was routinely reviewed by operations management. The inspectors concluded that the checklist was effectively used to ensure readiness for plant mode changes. In addition, the inspectors routinely monitored system and component status during the mode changes to independently verify that proper equipment status was maintained. No problems or concerns were identified.

b. Extended Startup Observation

During the Unit 2 startup, the inspectors conducted extensive around-the-clock coverage of plant activities. The inspectors assessed control room activities, procedure use, communications, shift turnovers, surveillance and startup testing, and management oversight of activities.

Operators were observed to be professional and knowledgeable. Shift turnovers and pre-evolution briefings were thorough and detailed. Good crew interaction and communication were observed. Procedures were in use and questions or problems were resolved before proceeding. Testing was performed in a controlled manner with good interface between the cognizant test group and operations. Good management oversight of activities was observed. Problems were effectively addressed and activities were adequately controlled to avoid adverse impact to startup activities and Unit 1 operation.

The inspectors concluded that the overall Unit 2 startup was well controlled and managed. Problems were effectively and adequately addressed.

c. Reactor Physics Testing

The inspectors witnessed portions of the low power physics testing performed on Unit 2. Testing was conducted in a thorough and professional manner. Good communications were observed between the personnel involved. Test data was accurately captured and analyzed.

On April 30, 1991, during the performance of startup procedure PSTP-2 (Rev. 12), "Initial Approach to Criticality and Low Power Physics Testing," BG&E discovered the Control Element Assembly (CEA) Total Worth below the expected value by a margin of 10.44%. The acceptance criteria as specified in PSTP-2 and FSAR section 13.4.5 allows a maximum difference of 10% below the predicted value. Thus, the CEA Total Worth was 0.44% below the acceptance criteria.

Due to this finding, the reactor engineering staff reverified their previous calculations and data analysis. This action resulted in the determination of their values as accurate. In accordance with FSAR section 3.4.6, BG&E commenced an evaluation of the validity of their safety analyses for the entire upcoming operating cycle. This review required the consideration of the lower values' effect on the severity or consequences of accidents or anticipated operational occurrences. The licensee consulted the fuel and CEA vendor, Combustion Engineering (CE/ABB) for assistance in the technical evaluation and required analysis.

Upon completion of telephone discussions, CE/ABB completed an initial evaluation. The results of this evaluation were verbally transmitted to BG&E in the afternoon of April 30, 1991, and formally documented that evening in ABB letter dated April 30, 1991, Serial No. B-91-060. CE/ABB informed BG&E that the safety and startup data pertaining to early-in-cycle (up to 1,000 MWD/T, which is approximately 30 days of full power operation) remain valid. CE/ABB concluded that only Scram Worth and Shutdown Boron Concentration data would be adversely affected and sufficient margin existed for both of those items to retain validation. Evaluations were continuing on the balance of the cycle, but preliminary indications were that similar conclusions could be reached for the rest of the operating cycle.

All PSTP-2, low power physics testing data were presented to the Plant Operations Safety Committee (POSRC) in the late afternoon of April 30, 1991. POSRC accepted the initial analysis conducted by CE/ABB and decided to continue power escalation and startup testing. POSRC developed an open item to review the final evaluation and impact on the rest of the operating cycle within two weeks. Additionally, the plant was formally limited to operation up to 1,000 MWD/T.

BG&E was unable to determine the cause for the low CEA worth values. The reactor engineering staff did, however, point out that the individual CEA groups 1-4 (which were the major contributors to the low total worth value) were recently replaced during the outage. All other PSTP-2 physics testing data fell within the acceptable ranges.

The inspectors observed the performance of the Unit 2 startup and physics testing. Discussions were held with the rector engineering staff and plant management regarding the low CEA worth values. The inspectors observed the associated POSRC discussion and reviewed the CE/ABB letter with regional specialists. Additionally, the inspectors reviewed the completed PSTP-2 test procedure and its associated data. The shutdown margin calculation was reviewed and found acceptable.

The inspectors considered BG&E's actions acceptable and will continue to examine the forthcoming analysis and evaluation for the rest of the cycle as well as for root cause of the anomalous test result.

3.0 RADIOLOGICAL CONTROLS

During routine tours of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's Radiological Controls Program. The utilization and compliance with special work permits (SWPs) were reviewed to ensure detailed descriptions of radiological conditions were provided and that personnel adhered to SWP requirements. The inspectors observed controls of access to various radiologically controlled areas and use of personnel monitors and frisking methods upon exit from these areas. Posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were verified to be in accordance with licensee procedures. Health Physics technician control and monitoring of these activities were determined to be adequate. An acceptable level of performance was observed.

4.0 MAINTENANCE AND SURVEILLANCE

4.1 Maintenance

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, technical specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable, administrative controls were followed, tagouts were adequate, personnel were qualified, correct replacement parts were used, radiological controls were proper, fire protection was adequate, quality control hold points were adequate and observed, adequate post-maintenance testing was performed, and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee assigned appropriate priority to safety-related maintenance. The licensee's recently-instituted Quarterly System Schedule and preventive maintenance program were also evaluated.

4.1.1 Maintenance Observation

The inspectors observed/reviewed portions of the following maintenance activities.

a. Charging Pump Breaker Rebuilding

The inspectors observed segments of the rebuilding of a charging pump breaker performed under MO 201-063-302E. The breaker required rebuilding since components had been removed to be used on other breakers when this breaker was a spare. The task was accomplished utilizing E-15, "480V Westinghouse Circuit Breaker Pole Shaft Replacement," and FTE-53, "480V Load Center Breaker Disconnect Switch and Cubicle Inspection." Quality Verification involvement was evident. An acceptable level of performance was observed.

b. Cleaning of No. 21 Service Water Heat Exchanger

On April 4, 1991, the inspectors observed the cleaning of the No. 21 service water heat exchanger in accordance with PM No. 2-11-M-Q-2. Two maintenance personnel were performing the cleaning operation from the discharge end of the heat exchanger when a surge of water came out of the discharge pipe at 1:32 pm. The maintenance personnel responded appropriately by immediately alerting the control room. Over the next six minutes, six to eight surges of water exited the discharge pipe. In total, several hundred gallons of saltwater were discharged. This water fell through the floor grating and onto the No. 23 auxiliary feedwater pump and motor. BG&E began reinstallation of the heat exchanger endbell approximately six minutes after the water discharges began.

In assessing the cause of the event, the licensed operators and engineers present at the scene preliminarily determined that the startup of the circulating water pump had caused fluctuations of the saltwater system. To validate this determination, the operators decided to repeat the circulating water pump startup. When repeated, the water level in the discharge pipe increased. This increase occurred because the startup of the circulating water pump pulls water into the condenser from the discharge canal which is also the discharge point for the saltwater-side of the service water heat exchangers. During the heat exchanger cleaning, this discharge path had not been routinely isolated due to the need to allow drainage and as such the water pulled from the discharge canal had an unobstructed path to the service water heat exchanger. In order to prevent similar situations during future cleaning operations, BG&E has included the addition of caution tags to the water box priming pumps and the circulating water pumps. The No. 23 auxiliary feedwater pump and motor were subsequently tested satisfactorily. The inspectors considered the actions to resolve this problem acceptable.

c. Repair of Service Water Valves

On April 13, 1991, excessive valve seat leakage was identified on CV-1637 and CV-1639, the valves that isolate the non-safety related portion of the service water (SRW) system. On April 16 during post-assembly stroke testing, the operator linkage on both valves and the shaft on CV-1639 were damaged. The cause of the failure was improper valve reassembly. Additionally, two other SRW valves, CV-1600 and CV-1638, had excessive seat leakage and required repair.

The repairs to CV-1600, 1637, 1638, and 1639, and the rework of CV-1637 and 1639 after improper assembly directly impacted the end date for the Unit 2 outage. BG&E initiated a detailed review of the causes of the problems which was ongoing as the period ended. The inspectors concluded that these actions were appropriate.

4.1.2 Quarterly System Schedule

The licensee instituted a Quarterly System Schedule (QSS) for maintenance in October 1990 which assigns each system, subsystem, or train to a week in a 12-week sequence such that all plant systems are covered in the sequence. The process represents a positive initiative to more effectively control maintenance activities by establishing windows during which specific work is to be accomplished. Another positive aspect of QSS is system engineer involvement. In the planning week, the system engineer (SE) is responsible for preparing an initial work scope proposal.

The inspectors observed a sample of the planning process and concluded that the program was developing as expected. Specific observations, however, included minor inconsistencies in recommendations from the system engineers and an absence of work prioritization based on the age of the MO. These observations were discussed with appropriate members of the BG&E staff. No overall concerns were identified.

4.1.3 Preventive Maintenance

The licensee's preventive maintenance (PM) program is defined in CCI-211J, "Preventive Maintenance Program," dated September 4, 1990. The status of the program is currently tracked via a personal computer but the licensee plans to integrate the PM program, along with the rest of the maintenance program, into a state-of-the-art mainframe computer system scheduled for implementation in August of 1991. This conversion will continue the increased attention afforded the PM program since the summer of 1990. In the summer of 1990, about 40% of the roughly 5,000 PMs were considered past due because they had either not been performed within +25% of their scheduled date or they lacked sufficient documentation to establish the date of the last performance. Of these past due PM's, about 900 were on safety related equipment.

Since July 1990, extensive progress has been made to reduce the number of past due PM's by (a) performing the PMs, (b) identifying documentation to support performance of PMs, and (c) processing PM deferrals. Currently, the level of past due PMs is about 100, which is a significant improvement due to increased management attention toward the program. However, a continuing problem is the untimely processing of a PM deferral before the PM is overdue. In accordance with CCI 211J, Appendix 211.20, "Deferred or Missed Preventive Maintenance," the responsible maintenance assistant general supervisor is responsible for initiating a deferral for critical and safety-related PMs which may be missed. The inspector identified several examples where this provision had not been rigorously implemented for many of the past due PMs, including those missed over several cycles and/or not scheduled in the near future.

The inspectors questioned the fact that past due PMs were not being appropriately included in the QSS scheduling process. However, BG&E adequately demonstrated why certain PMs had not been included on QSS schedules. Overall, the inspectors concluded that the PM program had improved, yet program weaknesses regarding PM deferral were still evident. The inspectors noted in the previous resident inspector report (50-317/318/91-06) that a saltwater expansion joint had failed due to aging. The joint was six years beyond the vendor recommended life of 10 years. These concerns were discussed with BG&E and a program evaluation was initiated.

4.2 Surveillance Observation

The inspectors witnessed selected surveillance tests to determine whether properly approved procedures were in use, technical specification frequency and action statement requirements were satisfied, necessary equipment tagging was performed, test instrumentation was in calibration and properly used, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. Portions of the following activities and surveillance test procedures (STP) were reviewed.

a. STP Logic Test Observations

On April 1, 1991, the inspectors observed STP 0-7A-1, "Train A Engineered Safety Features Monthly Logic Test," Sections IV, V, VI, and XII, and portions of STP 0-9-2, "Auxiliary Feedwater Actuation System, Monthly Logic Test," in both the control room and cable spreading rooms. No problems were identified during the observations.

b. Engineered Safety Features Test

On April 2 and 3, 1991, the inspectors observed portions of STP 0-7-2, "Engineered Safety Features Logic Test." The inspectors observed a detailed prebrief that used a newly developed format for prebrief conduct and ascertained that the test was supervised by a dedicated senior reactor operator. The test was well executed and controlled. No concerns were noted during the observations.

c. Emergency Diesel Generator Surveillance Testing

From April 10, 1991 to April 11, 1991, non routine surveillance testing was required because the No. 11 emergency diesel generator (EDG) was inoperable while the No. 11 saltwater system was out of service for maintenance. The Technical Specification action statement for an inoperable EDG requires verification of operability of the remaining EDG and verification of the availability and alignment of offsite power supplies. These verifications were performed per STP 0-8-0, "11, 12, and 21 Diesel Generator Test" and STP 0-90-1, "Breaker Lineup Verification." Both tests were performed and were within the required frequency.

In reviewing STP 0-8-0, the inspectors noted that data was not explicitly required for EDG engine speed of at least 900 rpm as required by Technical Specification 4.8.1.1.2.a.4. The functional surveillance test coordinator (FSTC) informed the inspectors that this issue was a recently identified internal audit finding, described an appropriate alternate method to derive engine speed from generator frequency, and demonstrated that engine speed was acceptable for the test performed. The inspectors noted, however, that the test as written did not contain adequate acceptance criteria for frequency to confirm acceptable engine speed. The frequency criteria was 60 $\pm$ 1.2 Hz, but for engine speed to be satisfactory, a minimum frequency of 60 Hz is necessary.

On April 19, 1991, BG&E determined that the testing required by Technical Specification 4.8.1.1.2.c. to verify engine acceleration to 900 rpm within 10 seconds was also inadequate and issued a problem report. The test procedure was revised and the inspectors witnessed testing of the No. 11 and No. 21 EDGs that same day. The No. 12 EDG was tested on April 21, 1991 when the No. 12 saltwater header was returned to service. All EDGs performed satisfactorily when tested. The surveillance test had been using an "engine at speed" indicator light for the verification of this requirement. However, it was discovered that the "engine at speed" indication was set for a speed of 810 rpm and thus, the test did not verify acceleration to the required 900 rpm. Due to the discovery of these surveillance procedure inadequacies, BG&E reviewed past surveillance testing records and identified at least one instance of unsatisfactory EDG performance where the EDG was not appropriately declared inoperable and corrective actions were not taken. BG&E has determined that this event is reportable as a licensee event report.

The inspectors discussed the above issues with the FSTC, the system engineer, and BG&E Regulatory Compliance personnel. The issues were well understood and actions were in process to change the affected procedures. The inspectors concluded that testing was performed in a timely manner to verify the operability of the EDGs after the problems were identified and that adequate corrective actions were in process to address the problems noted.

d. Refueling Water Tank Level Switch Calibration

On April 18, 1991, the inspectors observed portions of STP M-220F-2 "Calibration Check of Refueling Water Tank Level Switch for Recirculation Actuation Signal." Personnel involved were knowledgeable and professional. Some minor problems with test equipment were corrected and the test was completed without any additional difficulties. The inspectors verified that locked valve controls were properly implemented. No concerns were noted.

e. Radiation Monitor Calibration

On April 29, 1991, the inspectors witnessed portions of test procedure STP-M-567-1, "Steam Generator Blowdown Recovery Radiation Monitor and Loop Flow Calibration". Good procedure compliance was observed. Very good technical knowledge was demonstrated by the technicians involved. Communications was appropriate. No deficiencies were noted.

5.0 EMERGENCY PREPAREDNESS

The inspectors routinely toured the onsite emergency response facilities and discussed program implementation with the applicable personnel. An acceptable level of performance was observed by the resident inspectors.

6.0 SECURITY

During routine inspection tours, the inspectors observed implementation of portions of the security plan. Areas observed included access point search equipment operation, condition of physical barriers, site access control, security force staffing, and response to system alarms and degraded conditions. These areas of program implementation were determined to be adequate. An acceptable level of performance was observed by the resident inspector.

7.0 ENGINEERING AND TECHNICAL SUPPORT

The inspectors reviewed selected design changes and modifications made to the facility which the licensee determined were not unreviewed safety questions and did not require prior NRC approval as described by 10 CFR 50.59. Particular attention was given to safety evaluations, Plant Operations Review Committee approval, procedural controls, post-modification testing, procedure changes resulting from this modification, operator training, and UFSAR and drawing revisions. The following activities were reviewed:

7.1 Vendor Manual Control

The inspectors identified three pieces of vendor technical information included in maintenance order (MO) 200-082-091A for replacement of the No. 12 saltwater pump which were not included in the Fairbanks Morse vendor technical manual No. 12-315-10 for these pumps. The inspectors were concerned that this information did not appear to be appropriately incorporated into the vendor manuals and that this information was not properly reviewed before inclusion into the MO. The information included a system engineer technical discussion, a memorandum from the vendor, and an August 17, 1989, letter from Fairbanks Morse to the system engineer. This information was in the possession of the system engineering unit and had not been appropriately inorporated into the vendor manual update process in accordance with CCI-122, "Control of Technical Manuals and Other Vendor Technical Information," dated January 22, 1991. Problem report No. 7592 was initiated to evaluate the apparent lack of required vendor manual update and corrective actions. The report identified an additional vendor letter dated July 18, 1989, which likewise had not been included in a technical manual update but did not include the August 17, 1989 letter.

In response to this issue, BG&E has completed a Technical Information Turnover Cover Sheet (Attachment 1 of CCI-122) to evaluate the above information for inclusion into the vendor technical manual. In addition, a memorandum dated April 25, 1991 was issued to each system engineer to reinforce the need to initiate reviews of vendor technical information and to request a review of system engineer files to identify such information. The inspectors reviewed the memorandum and consider the actions as outlined in the memorandum acceptable. BG&E management will assess system engineer response to the memorandum to determine if further actions are required.

BG&E also indicated that the vendor information had been appropriately reviewed prior to inclusion in the MO in accordance with Plant Engineering Guideline (PEG) 12, "Vendor Correspondence." An observed weakness with the program outlined in PEG-12 was that an assessment of the new information against that contained in the approved vendor manual was not required. BG&E stated that an inclusion of this assessment would be evaluated for a future revision to PEG-12. The inspector had no concern regarding the licensee's action on this issue. No additional concerns were identified.

7.2 Engineering Staff Overtime

The inspectors expressed concern regarding the apparent excessive overtime being expended by members of the system engineering staff. As a result, BG&E performed a review of the overtime and concluded that their performance in reviewing and assessing the impact of excessive overtime in the system engineering department had been weak. Specifically, the guidelines of administrative procedure CCI-159 which required that engineers conducting tests limit their overtime to within specified limits had not been routinely followed. A subsequent review of the specific tasks performed by the individuals working excessive overtime indicated that the

correct this problem by developing an established backshift rotation in lieu of holding people over. In addition, the importance of limiting overtime was reemphasized within the engineering staff. No additional concerns were identified.

7.3 In-service Testing of Pumps

An unresolved item was identified in the previous resident inspector report (50-317/91-06-02 and 50-318/91-06-02) regarding the in-service testing (IST) program for pumps as required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Code. Specifically, the issues concerned the establishment, control, and documentation of reference values for saltwater pumps as required by Articles IWP-3110, IWP-3111, and IWP-3112. In addition, a record of tests and corrective actions did not appear to be established and maintained in accordance with Articles IWP-6240 and IWP-6250, respectfully.

A review of the documentation of testing of the saltwater pumps indicated a weak IST pump program. Reference values were changed without a thorough assessment of the adequacy of the pump performance against the previous reference values and vendor pump curves. In addition, inappropriate techniques were used, such as averaging previous test data, to establish and justify new reference values. The review of this issue was made difficult by the absence of documented analysis and justification in many cases. Problem report No. 10554 was written to address the failure to establish the appropriate documentation. A review of the test results did indicate, however, that the saltwater pumps were maintained operable.

The inspectors questioned the generic implications of these program weaknesses to other pumps in the IST program. BG&E performed a review of the remaining pumps in the program and concluded that appropriate testing was performed with the exception of the component cooling (CC) pumps for both units. Problem report No. 10552 was initiated to document the discovery that the reference values for the CC pumps were significantly below the vendor's pump curves. The reference values for these pumps were last established in late 1987 (with the exception of the No. 23 pump whose reference value was changed after a pump overhaul in 1988) when testing was changed from measurements at shutoff head to flow conditions. At that time, BG&E did not evaluate the fact that pump performance had shifted from slightly below the vendor performance curve at shutoff head to as much as 20% below the vendor curve at flow conditions.

Since the existing reference values at flow conditions had not been adequately analyzed, BG&E calculated a new reference value by establishing the minimum pump performance required during an accident and deriving a corresponding set of reference and alert values. Using these new conservative values, a comparison of the test data indicated that the No. 13 CC pump had fallen below this new action level for differential pressure on August 21, 1989. Subsequent to this test, pump performance improved significantly without apparent cause, leading to the conclusion that the low measured differential was an anomaly. The alert level, requiring doubling of the test frequency, also would have been reached on CC pump No. 13 on tests conducted on March 20 and May 25, 1989, September 10, 1990, and February 7, 1991.

As a result of the above discrepancies, BG&E decided to perform tests on the CC pumps to determine whether the pumps were capable of performing within the new reference values. The tests were performed in April 1991, and determined that each pump was capable of passing the necessary accident-required flow rate. However, CC pump No. 13 fell below the IST action level on differential pressure and pumps Nos. 11 and 12 were in the alert range. As a result, pump Nos. 11 and 12 were placed in the increased testing program, and pump No. 13 was declared inoperable. Subsequent BG&E analysis of the test method and pump performance indicated, however, that the pumps were in fact performing within the acceptable range. Final review of the data was ongoing as the inspection period ended. A review of the operating history of Unit 1 and the status of the three CC pumps indicated that the required number of pumps were maintained operable.

BG&E management stated that their IST surveillance program has not performed at an acceptable level. Recent initiatives have included a reorganization to elevate the importance of the program with increased management attention. In addition, staffing has recently been increased to include an engineer with previous IST program experience. BG&E indicated that they plan to develop a reference value basis for the components included in the IST program and to revise administrative procedure CCI-104, "Surveillance Test Program," to include guidance on how to justify and accomplish a reference value change. The inspectors reviewed and agreed with the overall methodology applied for calculating the Unit 1 reference values as a result of the concerns. The NRC will continue to monitor the progress and effectiveness of these initiatives.

8.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

8.1 Plant Operations and Safety Review Committee

The inspector attended several Plant Operations and Safety Review Committee (POSRC) meetings. TS 6.5 requirements for required member attendance were verified. The meeting agendas included procedural changes, proposed changes to the TS, Facility Change Requests, and minutes from previous meetings. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. Overall, the level of review and member participation was adequate in fulfilling the POSRC responsibilities. No unacceptable conditions were identified.

8.2 Performance Improvement Review Panel

On April 16, 1991, the inspectors attended a meeting of the Performance Improvement Review Panel (PIRP) that was conducted to discuss the status of certain task action plans. This panel, consisting of the Vice President-Nuclear and the site managers, reviewed the status of selected Performance Improvement Plan (PIP) actions to decide whether final closure on the issues was appropriate. Discussions involved a review of the individual plan scope and objectives, as well as whether the plan had obtained the desired results relative to the original root causes. The specific PIP task action plans reviewed during this meeting were as follows:

- 4.2 Quality Verification
- 2.2 Communications
- 5.3.1 Procurement
- 3.9 Quality Circles
- 4.7 POSRC
- 2.3 Issues Based Planning
- 5.2.2 Surveillance Test Program

The panel reviewed the closeout documentation for each plan, including the various verification audits and vertical slice audits. All plans were recommended for closure with the exception of the surveillance test program action plan. The managers agreed that a recent program reorganization prevented an effective assessment of the program effectiveness. The inspectors concluded that this panel provided a disciplined approach to action plan closure. No concerns were identified.

9.0 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 inspector determined that corrective actions would prevent recurrence. Those items for which additional licensee action was warranted remained open. The following items were reviewed.

9.1 (Closed) UNR 50-317/89-18-04 and 50-318/89-19-01

This issue involved the discovery of errors in the calculations which determined that the fire suppression system for the containment iodine filters was not required to be environmentally qualified. As a result, solenoid valves, position switches, thermistors, and internal wiring in the fire suppression system were not environmentally qualified.

Subsequent analysis, completed in January 1991, concluded that the iodine filter fire suppression system is not required. However, improper operation of the components could cause inadvertent initiation of the fire suppression system which would prevent the containment iodine filters from performing their safety function. As a result, the containment iodine filter dousing system has been re-classified as nonsafety-related and the system has been manually isolated. The results of this analysis and details were contained in Licensee Event Report 89-015, Revision 1, dated April 3, 1991. The inspectors reviewed this LER and discussed the analysis with the appropriate staff. No further questions or concerns were identified.

9.2 (Closed) UNR 50-317/90-08-02 and 50-318/90-08-02

This issue concerns the adequacy of testing of the reactor protective system shunt trip relays to the trip breaker shunt trip coils. BG&E had identified a parallel current path through a trip breaker position indication light bulb that gave a "false" indication that the shunt trip relay was closed.

The inspectors reviewed modifications that corrected the indication problem and the surveillance test that demonstrated operability of the shunt trip relays. These actions were adequate to correct the equipment problems. Additionally, the inspectors reviewed actions to factor information learned from this problem into surveillance test reviews for technical adequacy. These reviews compare the test to the as-built configuration and appear to be adequately detailed to identify any similar problems.

9.3 (Closed) Violation 50-317/90-08-01 and 50-318/90-08-01

This issue concerns the unplanned release of a waste gas decay tank. The licensee's response, dated July 3, 1990, to the notice of violation and LER 90-16 submitted on May 21, 1990, documented the root cause analysis and proposed corrective actions. Inadequate communications between members of the operations staff and lack of a specific procedure were attributed by the licensee as the root causes of the event.

The inspectors verified that BG&E conducted training of all operators to specifically reinforce the need for proper communications and the use of the locked valve deviation log CCI-309C. CCI-309C was revised to clarify the requirements and accountability for proper documentation and verification when manipulating locked valves. BG&E also performed an evaluation of the operations department policy on verbal communications and determined that the policy was implemented effectively. The inspectors concluded that the corrective actions were adequate to address the identified root causes.

9.4 (Closed) UNR 50-317/90-23-01 and 50-318/90-23-01

This issue concerned inadequate control for fire doors. In a previous inspection period, BG&E had experienced repeated problems with fire doors found either blocked or taped open, indicating a weakness in management controls in this area. The inspectors had determined that the immediate corrective actions taken by BG&E and the proposed path for resolution appeared appropriate. This item was unresolved pending the licensee's complete implementation of the longer-term corrective actions with satisfactory results.

During this inspection period, the inspectors assessed the licensee's progress in this area. The inspectors determined that the licensee management, through a multi-disciplined task force, was effective in improving controls for fire doors. The task force conducted walkdowns of fire doors to identify needed improvements in maintenance and human factors (i.e., clear labelling). The

task force also conducted surveys and visits at other nuclear facilities to seek better controls of fire doors. Inspector review of the licensee-generated problem reports and non-conformance reports for the period September 1990 to April 1991 indicated only one documented incident of a blocked open fire door. The inspectors also noted that numerous problem reports, non-conformance reports, and maintenance requests were generated on maintenance improvements on fire doors, such as broken fusible links, painted fusible links, and fire doors not having a fire rating plate which indicated thorough walkdowns by the task force and overall heightened awareness on operability of fire doors.

The inspectors concluded that BG&E actions have been effective in improving controls for fire doors.

9.5 (Closed) UNR 50-317/91-06-02 and 50-318/91-06-02

This issue concerned the absence of well documented justifications for revising reference values as required in the ASME Section XI Code for pump testing. In addition, the inspectors were concerned that reference values have been inappropriately changed without adequate engineering justification. The results of the inspectors assessment are contained in section 7.3 of this report. This item is closed.

10.0 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.

On May 1, 1991, Mr. Thomas T. Martin, Regional Administrator, toured the site and met with various members of BG&E management. Mr. Curtis J. Cowgill, NRC Region I Section Chief, accompanied Mr. Martin on his visit.

10.1 Preliminary Inspection Findings

No open items were identified as a result of this inspection effort.

10.2 Attendance at Management Meetings Conducted by Region Based Inspectors

Date	Subject	Report No.	Inspector
4-5-91	S/G Testing	317/91-07 318/91-07	P. Patnia[illegible]
4-12-91	Operator Licensing Examination	317/91-05 318/91-05	L. Briggs

Date	Subject	Report No.	Inspector
4-12-91	Special Event Inspection	317/91-09 318/91-09	A. Howe
4-19-91	Health Physics	317/91-11 318/91-11	J. Furia
5-3-91	Security	317/91-12 318/91-12	R. Albert