U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report: 50-317/86-16 License: DPR-53
50-318/86-16 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: September 1 - October 17, 1986

Inspector: T. Foley, Senior Resident Inspector

Approved: L. E. Tripp 11/6/86
L. E. Tripp, Chief, Reactor Projects Section 3A Date

Summary: September 1 - October 17, 1986: Inspection Report 50-317/86-16; 50-318/86-16

Areas Inspected: (1) facility activities, (2) licensee action on previous inspection findings, (3) operational events, (4) routine inspections, (5) outage preparations, (6) licensee initiatives relating to SALP, (7) events requiring NRC notification, (8) fuel integrity, (9) physical security, (10) Licensee Event Reports, (11) maintenance, (12) surveillance, (13) Region I Temporary Instruction 86-02, (14) radiological controls, (15) other NRC concerns, i.e., Emergency Diesel Generator problems, (16) IE Information Notice 86-53, and (17) reports to the NRC. Inspection hours totalled 206.

Results: Pursuit of a potential safety issue was demonstrated by attempts to resolve the gassing problem associated with No. 12 EDG (Detail 15). The results of corrective efforts were discouraging. Nevertheless, licensee initiatives demonstrated responsiveness to concerns identified in the previous SALP (Detail 6).

Four plant trips occurred which indicated a need for a more expeditious implementation of trip reduction task force recommendations (Detail 3). Observation of the Trip Evaluation and Review Group's performance demonstrated a thorough and comprehensive approach to feedwater pump problems leading to reactor trips (Detail 6).

One repetitive violation was identified: failure to follow Security Plan procedures for vehicle key control (Detail 9). The licensee's corrective actions to prevent recurrence has been discussed and appear to be comprehensive.

8611240229 861117
PDR ADOCK 05000317
Q PDR

DETAILS

Within this report period, interviews and discussions were conducted with various licensee personnel, including reactor operators, maintenance and surveillance technicians and the licensee's management staff.

1. Summary of Facility Activities

Unit Operating Experience

Unit 1: Commenced this period at full power and, except for preventive maintenance and surveillance testing, remained at full power until October 10 at 5:55 p.m. when an operator mispositioned a condenser off-gas discharge valve causing a loss of condenser vacuum and a turbine trip, resulting in a reactor trip. During the restart from this trip, the unit tripped again on October 11 at 9:35 a.m. from 15% power due to axial flux offset. The plant returned to power operations on October 11, 1986 and continued routine operation through the rest of the period.

Unit 2: Entered the period at a reduced load (95%) due to a damaged bearing on No. 24 Circulating Water Pump. The unit remained at nearly full power until September 5, at 11:58 p.m., when the unit tripped due to a failed surge capacitor on No. 21A Reactor Coolant Pump. The unit was returned to operation on September 7. Full power operation continued until September 12 when operators manually tripped the plant due to a loss of No. 21 Steam Generator Feed Pump (SGFP) and an impending low steam generator water level. The unit was returned to service on September 14; however, power level was maintained at 60% (capacity of a single feed pump) while the Trip Evaluation and Review Group (TERG) directed troubleshooting efforts on 21 SGFP control system. On September 18, the unit underwent a controlled shutdown anticipating the inability to meet a Technical Specification Limiting Condition for Operation Action Statement due to an inoperable Emergency Diesel Generator. With NRC concurrence, the unit was returned to 60% power until September 20 when repairs were completed. Full power operations were resumed and continued throughout the remainder of the period.

Facility Experience

On September 9, the licensee conducted the Annual Radiological Emergency Response Exercise. NRC and BG&E observers agreed that some significant objectives of the drill were not demonstrated and certain aspects of the exercise should be again performed as discussed further in Inspection Report Nos. 50-317/86-14; 50-318/86-14 and NRC Region I CAL 86-11 dated October 1, 1986.

Throughout much of the period, considerable time was devoted to resolving problems associated with No. 12 Emergency Diesel Generator Jacket Water Cooling pressure oscillations, apparently caused by carbon monoxide (CO) leaking into the cooling system. The licensee's investigation precipitated a vendor recommendation to pursue the problem immediately, to rule out a cracked cylinder wall liner which would lead to a catastrophic failure of the machine. These efforts extended from September 10 through October 7 and resulted in several changes to Technical Specifications; NRC/licensee meetings; an NRC request for the licensee to justify their continued operation; some hardware upgrades of the emergency diesel generator; considerable effort by the maintenance organization; and a failure to identify the root cause of the problem (see Section 15 for additional details). Further efforts will be extended during the upcoming outage.

The licensee commenced active refueling preparations for the Unit 1 ten-year inservice inspection. Approximately 400 contractors have been brought on site. The secondary steam line inspection program, utilizing x-ray techniques on back shifts, has been active. Partially fabricated piping is being placed in the Turbine Building. Outage preparation meetings are being held regularly.

To improve steam generator water chemistry control on Unit 1, the licensee instituted a morpholine addition pH and corrosion control program in lieu of ammonia. No major problems occurred during the transition.

On October 16, the licensee satisfactorily performed certain aspects of the Annual Emergency Preparedness Exercise in a remedial drill. Both regional and resident inspectors and NRC contractors observed the drill, details of which are included in Inspection Report 317/50-86-13; 318/50-86-13.

2. <u>Licensee Action on Previous Inspection Findings</u>

(Closed) Inspector Follow Item (317/83-03-04). Licensee to Evaluate Controlled Copies of Procedures. The licensee has since issued cover sheets to all copies of controlled procedures reflecting the title, copy number, revision and distribution of such procedures.

(Closed) Inspector Follow Item (317/83-03-05). Licensee to Evaluate Numbering Controlled Manual Volumes. The licensee's Technical Library and administrative policies now require numbering controlled manuals and volumes.

(Closed) Unresolved Item (318/84-05-01). PASS Sample Tubing Exposed-Potential Scatter Contribution. The licensee has since abandoned the use of the previously installed PASS system. The exposed tubing will not be, or is no longer used.

(Closed) Unresolved Item (317/80-02-04). Ensure Facility Radiation Monitoring Devices are Repaired in a Timely Fashion. From observation of radiation monitors during routine tours of the facility the inspector has determined radiation monitors to be adequately functional, calibrated and maintained. This is no longer a concern.

(Closed) Inspector Follow Item (317/82-01-42). Technical Manual Controls Not Implemented Per CCI-122A. The licensee has instituted a program which numbers each technical manual and stamps the manual "controlled" after a page check and revision verification is completed. No inadequacies have been noted by the inspector relative to control of controlled documents during the past two years.

(Closed) Inspector Follow Item (317/84-19-02). Region I Review of On-Site Burial of Non-Radioactive Waste Generated in Controlled Area. An inspection by Health Physics specialist of the on-site burial was conducted and no inadequacies were noted (see Inspection Report 317/86-05; 318/86-05).

3. Operational Events

a. Reactor Trip/Capacitor Failure - On September 5, 1986, at 11:58 p.m. Unit 2 was operating at 100% power when the reactor automatically tripped on a Low Reactor Coolant Flow Trip signal resulting from Reactor Coolant Pump 21A breaker opening.

Following the trip, the primary cool down rate was faster than normal due to the atmospheric steam dump valve for 22 Steam Generator being stuck open. The dump valve was manually isolated ten minutes later. While manually controlling steam generator level to limit the primary cooldown rate, an Auxiliary Feed Water Actuation signal was generated at -170 inches. The lowest level reached was -175 inches. The motor driven Auxiliary Feed Water Pump started automatically as designed and was secured when steam generator level was returned above -170 inches.

Post-trip review data showed the reactor protection system functioned properly and no Technical Specification limits were exceeded.

The differential and ground over current relays were found tripped on 21A RCP breaker. Investigation determined the cause to be an RCP surge capacitor internally shorted to ground.

There are three surge capacitors, one for each phase, installed for each RCP motor. Although not needed while the pump is operating, these surge capacitors were installed to provide protection to the stator insulation from the initial voltage surge seen by the windings when the feeder breaker is closed. The protection provided decreases as the surge capacitors distance from the motor increases. Consequently, the surge capacitors are mounted directly on the RCP motor.

Each surge capacitor consists of 54 capacitor "packets" electrically connected and stacked in series. Each "packet" is made of two thin metallic foil sheets, separated by a mylar dielectric, and wrapped in two more sheets of mylar. These are all enclosed in an insulating sheath (made of a glass filled polyester material) and housed in an airtight, helium-filled porcelain container with a metal base plate.

All Unit 2 RCP surge capacitors were checked. Three surge capacitors were replaced due to a 3% change in measured capacitance (from baseline data). Two surge capacitors had loose terminal lugs. Although electrical continuity was present and no degradation in capacitance material was found, these surge capacitors were also replaced.

The licensee has experienced similar events on April 2, 1976, October 26, 1977, September 7, 1979, June 6, 1983, April 15, 1984, and July 20, 1986 (Inspection Report 317/86-11;318/86-11 details the July 20 event). In each case, a low Reactor Coolant Flow Trip resulted from a RCP breaker opening due to a shorted surge capacitor. BG&E has noted several deficiencies in the design of surge capacitors and several improvements have been made by the manufacturer in their structural design. Surge capacitors presently used are the third modification to the original style surge capacitor. Until the July 20, trip all previous failures occurred at the edge of the capacitor "packets" (the capacitor/insulating sheath junction). This mode of failure was the basis for previous modifications. Unlike the previous failures, the July 20, 1986, failure appeared to be the result of an arc tracking along the mylar dielectric from one foil strip to the other foil strip on the other side of the mylar dielectric. BG&E is testing a good surge capacitor by subjecting it to high temperature (up to 100 degrees Celsius) and high humidity environments. Although only five test cycle have been completed to date, the capacitor has not yet shown signs of capacitance deterioration. An analysis will be done on all capacitors replaced as a result of the September 5, 1986, Unit 2 trip.

The manufacturer has recently notified all customers that they will cease production of surge capacitors and no further orders will be accepted as of December 31, 1986. BG&E has found no other manufacturer which produces radiation resistant capacitors of sufficient voltage rating and capacitance.

As noted in Inspection Report 86-11, BG&E is determining the effectiveness of the surge capacitors in providing protection to winding insulation and possible alternatives to provide the same protection. The electrical system from breaker to RCP motor has been modeled by computer to show the voltage surge seen by the stator windings without any protection, with surge capacitors, and with inductors located at the RCP breaker switch gear. Additionally, a spare RCP motor has been used with an equivalent length of cabling and a pulse generator to experimentally obtain data to compare with the computer model. Based on preliminary results, the model and experimental data compare favorably and show that surge capacitors do provide a reduction in the voltage surge, and that inductors might be a viable alternative to surge capacitors.

Although there have been numerous instances of capacitor failures during the preceding years of operation, the licensee is now, in part due to the vendor termination of production, adequately allocating the resources and pursuing this technical issue with a viable approach.

The following corrective actions are currently planned or in progress:

-- Continued research to replace surge capacitors with an alternate system/device.

-- Investigate the possibility of a resonant vibration at the surge capacitor terminal box.

-- Continue environmental testing of surge capacitors with respect to temperature and humidity.

-- Investigate the possibility of providing more cooling to the surge capacitor terminal box.

-- Perform an analysis of the surge capacitors removed due to the September 5, 1986 Unit 2 trip.

The licensee reported this event to the NRC in LER 86-06.

b. Manual Reactor Trip/Loss of No. 21 Feed Pump

On September 12, 1986, at 100% power, operators observed a feed water flow transient, noting that No. 21 feed water pump had tripped and No. 21 steam generator water level was decreasing rapidly. Operators attempted to reset 21 steam generator feed pump but were unable to do so before steam generator level approached the automatic trip set point; therefore, they then manually tripped Unit 2 reactor anticipating an automatic reactor trip on steam generator water level low. Operators responded appropriately, and all safety systems functioned as designed. The cause of the trip initially appeared obvious in that a technician stated that while troubleshooting an inoperable remote alarm (in the Control Room) for the steam generator feed pump No. 21 A orifice D/P (in the Turbine Building) the unit tripped momentarily after he applied a jumper across terminals 7 and 8 of the "Love Joy" Steam Generator Turbine Driven Feed Pump Control System. The technician had permission from the shift supervisor and was utilizing Love Joy schematics, while attempting to simulate closure of the "orifice D/P" alarm contact. When the expected alarm response was not observed the technician assumed that he may have inadvertently placed the jumper across other terminals and possibly caused the feed pump/reactor trip.

During the post trip review, it was determined that immediately before the trip, operators were alerted by the following alarms: 21 Steam Generator Feed Pump Turbine Speed, Condensate Demineralization System and 21 Condensate Booster Pump Start Alarm. Review of data showed that the Reactor Protective System was not challenged prior to the manual trip, the RPS functioned properly, and no Technical Specification limits were exceeded.

A Plant Operations and Safety Review Committee (POSRC) met and determined that since similar events had occurred on May 21 and 27, 1986, which determined the root cause to be grounds associated with the power supplies to the control systems, this event should be recreated to determine whether jumper terminals 7 and 8 would produce a signal to trip the steam generator feed pump, and to assure that the previous cause had been corrected. An attempt to recreate the feed pump trip was performed by jumpering terminals 7 and 8. The jumper across 7 and 8 actuated the remote alarm as designed and did not generate a signal which would lead to a steam generator feed pump trip, i.e., the trip was not reproduced. Based on this, it was postulated that terminals 6 and 7 were jumpered (vice 7 and 8). Review of the schematic showed neither combination of jumpering just 2 terminals alone would produce a steam generator feed pump turbine trip signal.

On September 14, the unit was returned to power, but limited to 60% power, in order that one feed pump be capable of sustaining the plant should the other feed pump trip. The unit remained at 60% for the duration of the troubleshooting efforts. The return to power was desirable in order to more closely simulate the actual conditions under which the feed pump trip occurred.

Subsequently, troubleshooting to identify the cause of the trip revealed some installed wiring differing from the vendor schematics; frayed connections at the speed probes; electrical splices with improper insulation; tachometer with grounded connections (as supplied by the vendor) vice designed ungrounded models as per the schematics; and intermittent grounds on one of the two speed probes on each pump. Troubleshooting also demonstrated that jumpering across terminals 6 and 7 completed a ground path. Using a simulated speed signal and a grounded tachometer and then jumpering terminals 6 and 7, the licensee was able to reproduce a signal that would cause the Love Joy control system output signal to cause the No. 21 steam generator feed pump to increase its speed and cause the pump to trip on either low suction pressure or overspeed.

The licensee believes that the combination of jumpering (causing a ground) and, together with the grounded tachometer, apparently affected the speed control system's feedback and caused 21 steam generator feed pump to increase speed and trip on either over speed or low suction pressure. These noted problems were corrected and the system was returned to full power operation on September 21.

The immediate corrective action included: rewiring all four steam generator feed pump turbine speed probes, replacing one of 21 steam generator feed pumps speed probes, installing ungrounded speed tachometers on each feed pump, and correcting the original problem with the remote alarm on the steam generator feed pump Turbine Speed Control System. Additionally, a thorough wiring check and calibration was made on the system electronics to assure system reliability. Long term corrective actions include installing a "Lock-In" in feed pump trip indication panel, and investigating providing independent power supplies for the steam generator feed pump speed feedback system.

Additionally, the licensee conducted a visual examination of each circuit for accuracy (replaced several potentially degraded circuit boards) and improving the quality of workmanship. Additional corrective actions consist of minimizing steam generator feed pump testing during power levels greater than 60% and evaluate a maintenance policy that requires performing ground checks prior to and after maintenance of electrical systems.

For this event, the licensee implemented the Trip Evaluation and Review Group (TERG). Their efforts were controlled and orderly and demonstrated a technically sound, thorough approach to resolving the problem. The group obtained Plant Operations safety reviews for its troubleshooting procedures and ensured that decision-making was consistently at an adequate management level. Plant management emphasized solving the root cause of the trip, provided the necessary resources, and demonstrated no evidence of hasty decisions. Vendor support was utilized on site to perform direct assistance in the troubleshooting and calibration. The licensee reported this event in LER 86-07.

c. On October 10, 1986, at 5:55 p.m. the Unit 1 reactor tripped due to a turbine trip on low condenser vacuum. The low vacuum condition resulted from operator error in altering the position of a combined off-gas discharge valve (1-CAR-155) in the condenser air removal system during a test for condenser air in-leakage. Plant systems performed as designed during the trip, and plant conditions were quickly stabilized.

The air inleakage test consisted of injecting sulfur hexafloride (SF_6) gas into the condenser circulating water system and then monitoring the condenser air removal (CAR) system discharge line, through a drain connection, for the presence of the test gas. This general type of testing had been done previously by the licensee using both SF_6 and helium gases. Due to the simplicity of the test, a written procedure had not been developed for its conduct; however, the sequence of steps was reviewed in advance with the shift supervisor.

During the test, the system line up was not supplying sufficient off-gas flow to the SF_6 monitoring device, so the turbine building operator, without consulting control room personnel, began throttling and eventually closed 1-CAR-155. He reasoned that, since the sample point was upstream of 1-CAR-155, shutting the valve would increase line pressure and, therefore, sample flow rate. His logic that shutting the valve would not create an operational problem was reinforced by the fact that, as part of another type of condenser air inleakage check, described in Section IV of Operating Instruction OI 13 (revision 8), 1-CAR-155 is shut once per shift. He did not recall, however, that, importantly, OI 13 first calls for repositioning additional CAR system valves prior to closing 1-CAR-155. Independent closure of 1-CAR-155 opened a flow path between the condenser and the atmosphere external to the condenser. This caused a rapid loss of condenser vacuum.

Licensee discussions with other watchstanders indicated a general weakness in operator understanding of how independent closure of 1-CAR-155 could lead to loss of condenser vacuum.

A Performance Improvement Report (PIR) was routed to all operators on October 10, 1986, to make them aware of the event and its causes. At the close of the inspection period, the licensee was considering additional corrective actions. These actions will be described in a 10 CFR 50.73 event report and will be reviewed by the NRC.

d. On October 11, 1986 at 9:35 a.m., Unit 1 automatically tripped from about 15% power due to an axial flux offset condition. The plant was being restarted following an October 10 reactor trip (low condenser vacuum). Unit 1 was near the end of its operating cycle and operators were not able to adequately limit an axial flux peak near the top of the core with available control rods. Plant systems functioned normally following the trip, and the plant was quickly stabilized. The plant returned to power operation at 5:25 p.m. on October 11.

During the October 11 startup the reactor was taken critical with additional rods (Group IV) inserted in the core to provide improved control of flux peaks.

At the close of the inspection period, the licensee was considering corrective actions to prevent recurrence. These actions will be described in a 10 CFR 50.73 event report and will be reviewed by the NRC.

No inadequacies were noted.

4. Routine Inspections

a. Daily Inspection

During routine facility tours, the following were checked: manning, access control, adherence to procedures and LCO's, instrumentation, recorder traces, protective systems, control rod positions, containment temperature and pressure, control room annunciators, radiation monitors, effluent monitoring, emergency power source operability, control room logs, shift supervisor logs, tagout logs, and operating orders.

No unacceptable conditions were identified.

b. System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions and status were examined. Power supply and breaker alignment was checked. Visual inspection of major components was performed. Operability of instruments essential to system performance was assessed. The following systems were checked:

-- Unit 1 and 2 Auxiliary Feed Water Systems

-- Nos. 11 and 21 Emergency Diesel Generator Systems*

*For this system, the following items were reviewed: The licensee's system lineup procedure(s); equipment conditions/items that might degrade system performance (hangers, supports, housekeeping, etc.); instrumentation lineup and operability; valve position/locking (where required) and position indication, and availability of valve operator power supply.

No unacceptable conditions were identified.

c. Biweekly and Other Inspections

During plant tours, the inspector observed shift turnovers; boric acid tank samples and tank levels which were compared to the Technical Specifications. The use of radiation work permits and Health Physics procedures were reviewed. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated. Verification of tag outs indicated the action was properly conducted.

No unacceptable conditions were identified.

5. Outage Preparations

The inspector attended a sample of the routine outage preparation and coordination meetings, and held discussions with the Outage Director.

The outage organization consists of an Outage Director, two Outage Coordinators, a Lead Planner, two Containment Coordinators, an SRO Operations Outage Coordinator/Planner and several responsible engineers as critical path engineers for specific critical path work items.

The schedules vary for different work groups but primarily adhere to 7 days a week, 20 hours per day, 2-shift coverage. A total of 1,567 personnel will be on site, (410 contractor personnel) involved in 3,500 work activities. More than 600 valves will be repacked with "Chesterton" packing, and about 2,000 feet of extraction steam line piping will be replaced.

The 1986 ten-year Inservice Inspection and refueling outage is planned to last 57 days commencing October 25, 1986. The goals are to complete the following: (1) major job paths, i.e., reactor work, moisture separator reheater tube bundle replacement, main turbine and condenser work, intake structure work, extraction steam line work, and main steam isolation valve replacement; (2) complete all priority A, B, and C Maintenance Requests; (3) complete 15 priority A modifications and 53 priority B modifications; (4) keep exposure to less than 280 person-rem; and (5) complete the outage within 57 days.

The critical path for the outage is the reactor path. Critical evolutions for scheduling purposes are:

-- Salt Water Header work: involving 100% replacement of all tubes in the Component Cooling and Service Water Heat Exchangers. Additionally, a vulcanizing rubber will be affixed to the Component Cooling Heat Exchanger channel heads to reduce marine fouling and corrosion.

-- No. 11 and 12 Emergency Diesel Generator work: involving disassembly, inspection, and replacement of worn parts, including all cylinder liners, adapters, and seals.

-- In-Core Instrumentation (ICI): removal of 26 of 30 in-core instruments and installation of new detectors. This evolution has significant potential for radiological over-exposures and requires added control and supervision. The inspector expressed this concern to the Supervisor Radiological Safety. More "Hot" ICI's will be moved than ever before.

-- No. 12 Reactor Coolant Pump Overhaul and Inspection: involving total replacement of the main impeller, the auxiliary impeller, the shaft and motor and other auxiliary parts.

-- Reactor Vessel Inspection: including the ten year in service inspection "code inspections" of vessel belt line welds. Program includes nearly 100% inspection of belt line welds utilizing the Ultrasonic Data Recording and Processing System (UDRPS). Portions of this will be utilized for code requirements. The additional percentage of inspection is thought to be necessary to provide additional confidence in reactor vessel welds and provides a base line justification for possible extension of vessel/plant life, and relates to pressurized thermal shock concerns.

-- Inspection of both Steam Generators: involving a visual inspection of secondary components, and Eddy Current Testing of various percentages of each steam generator's tubes. The licensee will not do 100% Eddy Current Testing as has been past practice. Instead, four tubes will be pulled from No. 11 steam generator for destructive examination at Southwest Research Institute. The licensee perceives, based on previous eddy current examinations, that a corrosion problem exists, currently to a minor extent that is either pitting, intragranular attack or small volume defects.

-- Fuel Inspections: total core off-load of Cycle 8 fuel is necessary during the outage; 100% ultrasonic testing of the fuel will be performed utilizing the Babcock Wilcox "Echo 330" technique, and reconstitution as necessary. Eddy current testing will be performed on the control element assemblies. Removal and disassembly of the experimental "Scout", batch

"F", and 4 "Prototype" batch "G", assemblies will be performed for evaluation; the prototype assemblies will be returned for one additional cycle of operation.

In an effort to reduce exposure, the licensee has, or is in the process of installing, 10 video cameras with remote controls, several with two-way audio capability. Health Physics outage coordination and job supervisors plan to utilize these to minimize time in high radiation areas.

6. Licensee Initiatives Relating to SALP

During a meeting held on July 18, 1986, NRC discussed with BG&E the overall performance of the licensee during the period from October 1984 through April 1986. One concern regarded overall performance related to the licensee's perception of what constituted "good performance." NRC's response suggested that various utilities demonstrated good performance in various areas and that inspections by INPO, NRC, and other available industry documents should be sought to specifically answer the concern.

During the subsequent period, numerous personnel from each department have been sponsored in formal groups to visit various utilities who have been noted as having good performance in the particular area of concern. Each group has written trip reports about the pros and cons of the utility. Each visit appears to have had specific beneficial effects and an overall broadening of the licensee's perception of how BG&E can improve. A sampling of plant visits are:

Plant Visited	Comments
St. Lucie	3 BG&E personnel to observe maintenance planning procedures in preparation for ISI reactor vessel inspection.
Salem St. Lucie Millstone Oconee	Numerous BG&E personnel including General and Assistant General Supervisors to observe maintenance practices, planning, valve packing programs, "MOVATS", "Trevitest", and other programs.
St. Lucie Farley Connecticut Yankee Kewaunee	Numerous Health Physics personnel who have brought back several ideas which are already in place or in process of being implemented.

These visits to other utilities are viewed to be a positive characteristic of licensee performance.

Additionally, during the SALP discussion, NRC was concerned about the effectiveness of the Quality Assurance organization. Recent licensee initiatives have been noted in more in-depth audits, audits providing recommended solutions and displaying a less adversarial tone. Efforts are manifested which indicate an effort to improve the area being audited rather than citing trivial items for correction. QA management is exploring innovative techniques of assessing their own managers' performance. Although these techniques are yet to be developed, they are in consonance with the perceived weaknesses identified in the SALP.

In the area of maintenance, recurring SALP comments indicated deficiencies in training of maintenance personnel and inadequate orchestration of multidisciplined tasks pursuant to major modifications. The licensee has sent 16 personnel from Procedures Development, Engineering, Operations, Mechanical Maintenance, Electrical and Instrument Maintenance, and Planning to Raleigh, North Carolina, to be trained on the new main steam isolation valves from Rockwell International that will be installed this outage. The training lasted three days. Discussions with several attendees indicated that training was exactly what they desired, and they feel very positive about the installation, testing and operation of the valves. The General Supervisor Operations is committed to not returning the plant to operation until all aspects of every major modification are complete, including completed operating, testing and training procedures, post maintenance testing (totally satisfactory), and spare parts available. This type of approach, dedication of resources, and commitment, is also characteristic of good performance.

The SALP indicated weaknesses regarding the timeliness in which potential safety issues are recognized. The licensee clearly demonstrated a conscientious effort to pursue a potential cracked cylinder liner on the Emergency Diesel Generator No. 12. A crack left undetected could cause a catastrophic failure of the Emergency Diesel Generator. Although the results were not as definitive as desired, the licensee's efforts and intentions are recognized. Continuing this pursuit of potential safety issues is encouraged.

One licensee initiative appears lacking in effect. In an effort to consolidate the Nuclear Division, numerous engineering groups and other supporting groups, have moved from the corporate office to a new Nuclear Engineering Facility (NEF) immediately outside the Protected Area (PA). Additionally, several engineering groups previously within the PA are also integrated with the engineering department "out" in the NEF. The inspector has noticed considerably fewer personnel within the PA, apparently, a net loss of personnel inside the PA. This could contribute to less overall familiarity with current operations, design and operational problems; inhibit access; and certainly lead to no more familiarity with plant systems than prior to the move.

Relating to operational problems, plant trips, and root cause identification: although the licensee has not been successful at reducing plant trips, the plant events which have occurred recently appear to be thoroughly analyzed before returning to a condition which would subject the plant to a similar trip. The recent feed pump trip troubleshooting effort demonstrates the type of analysis and investigation, resources and dedication warranted in pursuit of root cause identification. We acknowledge that the specific cause was not unequivocally identified; however, because of the extensiveness and completeness of the investigation and corrective action, there is a high degree of confidence that the specific cause was corrected.

The licensee developed recommendations based on the Trip Reduction Task Force efforts. The implementation of these recommendations are only in their infancy. Based on the recent rash of plant trips, the licensee is encouraged to expedite these recommendations.

In summary, the licensee's initiatives are characteristic of those facilities which demonstrate a high level of performance. However,effective implementation of these initiatives must be demonstrated with positive results.

7. Events Requiring NRC Notification

The circumstances surrounding the following events requiring prompt NRC notification pursuant to 10CFR50.72 were reviewed. For those events resulting in a plant trip, the inspectors reviewed plant parameters, chart recorders, logs, computer printouts and discussed the event with cognizant licensee personnel to ascertain that the cause of the event had been thoroughly investigated for root cause identification.

-- On September 5, 1986, at 11:58 p.m., a scram occurred due to a low reactor coolant flow. All Reactor Protection System features functioned as designed. The cause of the low flow was due to a trip of Reactor Coolant Pump (RCP) 21A which tripped from an under voltage condition subsequently identified as being caused by a ground fault in one of the surge capacitors associated with the RCP (3 capacitors/pump).

-- On September 16, 1986, at 3:45 p.m., the NRC dedicated phone was declared out of service. Appropriate notification was made by the licensee to the NRC at 3:55 p.m.

-- On September 18, 1986, at 12:10 p.m., a "courtesy" notification was made by the licensee to the NRC concerning the unplanned shutdown due to the No. 12 Emergency Diesel Generator (EDG) being declared out of service. The shutdown was made anticipating the inability to meet the EDG Limiting Condition for Operation (LCO).

No unacceptable conditions were identified.

8. Fuel Integrity

During the period several plant trips occurred on both units which resulted in Iodine-131 Dose Equivalent (IDE) values being temporarily greater than the Technical Specification limit of 1.0 uci/cc. Both Chemistry and Fuel Management Departments have been monitoring and trending these and other radionuclides for several cycles. This iodine spiking is typical to some degree after plant trips and the degree or concentration is often used in the determination of the amount, if any, of fuel damage (i.e. pin holes, loosened or broken end caps, blisters, etc.). Analysis by Fuel Management indicates that the extent of Unit 1 fuel degradation is no worse than Unit 2 Cycle 5 by isotopic comparison. Chemistry, however, trends several other isotopes and various radionuclides in the liquid waste system. These trends have noted increases in Xenon-135 and -138 noble gases. Xe-133, the most predominate isotope, has also increased. Cesiums (Cs-134 and Cs-137) are higher than normal, yet not as high as during Cycle 5. A comparison of radionuclides in the liquid waste shows a shift from the typically predominate corrosion product Cobalt 58 to increased fission products.

Both Chemistry and Fuel Management agree that some fuel damage exists, however, it appears to be less significant than that of Unit 2 Cycle 5 if it is the same mechanism of failure. A suggested mechanism that would explain these parameters would be a crack or hole in the fuel gap region which would allow the more volatile nuclides to escape and restrict the non-volatiles.

Based on this, the licensee evaluated several negative effects possible and is attempting to determine the current extent of fuel damage.

In the final analysis, the licensee concluded that it was not cost beneficial to sip the fuel, however, this would result in:

-- more I-133 spikes above the TS limits, although not exceeding the permissible for 100 hrs;

-- increased radiation levels around radioactive systems;

-- increased radioactive waste;

-- increased dose to personnel both from airborne and direct radiation; and

-- less probability of meeting INPO's "Standard of Excellence".

This was discussed at a POSRC meeting which the inspector attended. This information was also sent to the Operations Manager from the Plant Chemist on July 23, 1986.

Subsequently, as described under the section titled Outage Preparations, the licensee plans to perform ultrasonic testing of all fuel and take corrective action to replace damaged pins where necessary. This is in consonance with good industry practices.

PAGES 16, 17, AND 18 CONTAINS
SAFEGUARDS INFORMATION AND ARE
NOT FOR PUBLIC DISCLOSURE.
THESE PAGES ARE INTENTIONALLY
LEFT BLANK.

10. Review of Licensee Event Reports (LERs)

LERs submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted on site follow up. The following LER's were reviewed.

LER No. Unit 2	Event Date	Report Date	Subject
86-06*	09/05/86	10/05/86	Reactor Trip Caused by Reactor Coolant Pump Surge Capacitor Failure
86-07*	09/12/86	10/10/86	Manual Reactor Trip Due to Partial Loss of Feed Water Flow to Steam Generator
85-11	10/19/85	08/15/86	Update of MSSV Set Point Problem

*Detailed examination of this event is documented in section 3 of this inspection report.

11. Plant Maintenance

Maintenance activities observed during this period consisted of troubleshooting Feed Water System per Engineering Test Procedure 86-8, "Feed System Troubleshooting", and, for most of the report period, maintenance associated with the No. 12 Emergency Diesel Generator as described under "Diesel Generator Problems" in Section 15 of this report.

No unacceptable conditions were identified.

12. Surveillance

The inspector observed parts of tests to assess performance in accordance with approved procedures and LCO's, test results (if completed), removal and restoration of equipment, and deficiency review and resolution. The following tests were reviewed:

-- STP-M-672-B-2, Pressurizer Relief Valve (ERV) Channel Functional Test.

-- STP-M-539-2, PORV/Safety Valve Acoustic Monitor Calibration.

-- STP-M-572-B-2, Pressurizer Relief Valve Channel Calibration.

- -- PMD-RCS-25, Electromatic Relief Valve Removal, Repair, and Re-installation.
- -- STP-O-90-1 & 2, Breaker Line Up Verification.
- -- STP-O-7-1 & 2, Engineering Safety Features Monthly Logic Test.
- -- STP-O-8-A-1, No. 11 Diesel Generator and 4 KV 11 Bus LOCI Sequencer Test.
- -- STP-O-8-B-1, No. 12 Diesel Generator and 4 KV 12 Bus LOCI Sequencer Test.
- -- STP-O-87-2, Borated Water Source Operability Verification.

No unacceptable conditions were identified.

13. Inspection of General Electric Type AK-F-2-25 Breakers (Region I Temporary Instruction RI 86-02)

Discussions with knowledgeable licensee representatives and review of facility breakers have indicated that the licensee does not use or maintain this type of breaker on site.

14. Radiological Controls

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of non-radiological points throughout the facility were taken by the inspector.

No unacceptable conditions were identified.

15. Other NRC Concerns

a. Emergency Diesel Generator Problems

Problem

Emergency Diesel Generator (EDG) Jacket Water Cooling (JWC) pressure perturbations and temperature fluctuations caused inoperability of No. 12 EDG on September 10, 1986. The EDG remained inoperable until September 30, 1986.

Diesel Generator Description

The emergency diesel generators are designed to provide a dependable, on site, power source capable of starting and supplying the essential loads necessary to safely shut down the plant and maintain it in a safe shutdown condition.

Three diesel generators are provided for the plant. However, each unit requires only one diesel generator to supply the minimum requirements for its engineered safety features equipment. Each emergency diesel generator is a 4160-volt, 3-phase, 60-cycle diesel with a nominal continuous rating of 2500 KW.

The engine is a turbo-charged, 12-cylinder, opposed piston, diesel engine with pistons arranged vertically driving two crankshafts (one upper and one lower). The crankshafts are connected together at the generator end by a vertical drive through which the power from the upper crankshaft is transmitted to the lower crankshaft.

The Jacket Coolant System is provided to remove heat due to combustion from the space around the cylinders and cylinder liners. When the engine is running, it drives the engine driven jacket coolant pump which circulates the coolant through the jacket water cooler. A three-way thermostatic control valve controls the amount of flow through the cooler (or the amount which bypasses the cooler) and thereby controls the temperature of the coolant coming from the engine. The cooler is cooled by the service water system.

b. Details

The following presents a chronological history of events leading to the inoperability and a detail of occurrences taken place during this report period.

Resident inspector discussion with operators reveal that, as early as 1984, Jacket Water Cooling (JWC) pressure would initiate low JWC pressure alarms in the Control Room. (Three low coolant pressure alarm and shutdown switches are connected to the jacket coolant discharge pipe from the engine. These switches are actuated at 12, 14 and 16 psi, respectively. The functioning of any one will sound an alarm in the Control Room, while functioning of any two will shut down the engine.) Maintenance Requests (MRs) were issued to correct the problem.

An investigation was conducted resulting in widening the set point and reset band, however, this did not resolve the low pressure alarms. In October 1985, a Maintenance Request (MR) was generated requesting investigation of the cause of the gaseous effluent which accompanied the JWC water during the venting of the system prior to operation. This resulted in the identification of carbon monoxide (CO) gas, however, carbon monoxide was also detected to a small degree in the 11 and 21 EDG's. No further action was taken at this time.

In January 1986, NRC Inspection Report 85-30 noted the following: "....numerous minor maintenance problems which taken together could significantly degrade the emergency system. These problems are generic to all three emergency diesels. The symptoms include several lubricating oil leaks, exhaust manifold leaks, fuel oil leaks, jacket cooling water leaks, and possible leakage between internal systems, i.e. exhaust to jacket cooling. Leakage of fuel and lubricating oil is continuously found on the sides (outside) of the diesel, in the sump, on exhaust lines, embedded in lagging, and a thin film of oil appears to have been deposited on all equipment, components and walls, floor, etc., within each EDG room...".

The licensee has since repaired the major oil leaks on each of the EDGs, cleaned and maintained the external appearance since the inspection report was issued, and assigned responsibility for maintaining each EDG.

In March 1986, the newly assigned system engineer (as a result of the January 1 organizational change), began efforts directly associated with resolving CO in the JWC system. Efforts included: research of past diesel generator operating parameters compared to present parameters; investigation of possible sources of CO; sampling other EDGs for CO; discussions with the vendor and other licensees regarding possible cracked liners and CO sources; and numerous meetings to develop a plan of action.

In June, the licensee determined repairs should be made even though the effluent had not yet caused inoperability, although the diesels' capabilities were not assured should the EDG be required to undergo a design capacity endurance test. Additionally, the licensee desired to investigate and preclude any possible conditions which could lead to a potential catastrophic failure. Discussions with the vendor also prompted an immediate concern.

A schedule was developed for the repairs assuming the worst case, that a cylinder liner and/or the turbo-charger blower were cracked. The schedule assumed 134 hours; however, a 72-hour run-in period would also be required. A plan was developed incorporating a potential need for a Technical Specification change to allow for a ten day outage. Existing Technical Specifications permit 72 hours out-of-service time. This was discussed with the NRC Licensing Project Manager on several occasions. A probabilistic risk assessment justification and a draft proposed Technical Specification change allowing for a ten-day Limiting Condition for Operation (LCO) were developed and approved by the on-site and off-site Safety Review Committees. However, simultaneously, Reactor Coolant Pump 21B had been displaying increasing vibration trends and plans were in process to shut down Unit 2 to repair the vibration (see Inspection Report 86-11). Unit 2 did shut down on July 25 and remained in Hot Standby for several days while plant staff evaluated vibration data. The licensee determined that no Technical Specification change would be necessary since a lengthy outage was likely to be imminent. However, vibration problems were resolved and the unit returned to full power on August 1. The licensee also submitted to the NRC on August 1 an Exigent License Amendment Request. The request highlighted (1) the current operability of the diesel in that operating parameters remain normal and only venting <u>after</u> operation departed from normal practice; (2) that the purpose was to investigate and repair, if necessary, a potential problem, and the ten-day extension was for only a "worst case" situation; and (3) that the repairs, if required, would be needed to prevent a potential catastrophic failure in the future.

On September 8, 1986, Amendment Nos. 121 and 103 were issued by the NRC to operating Licenses Nos. DPR-53 and 69 to temporarily change requirements affecting AC power sources. The change permitted the No. 12 EDG to be inoperable for 240 hours in order to only determine and correct the cause of the carbon monoxide leakage into the No. 12 diesel generator jacket water cooling system, and shall expire upon completion of the repairs or ten days after EDG 12 is removed from service. The change also required in lieu of the No. 12 emergency diesel generator which would be out of service, a Technical Specification limiting condition requiring a separate 69 KW SMECO off site power circuit as described in the licensee's Safety Evaluation dated January 14, 1977.

On September 9, 1986, both Nos. 11 and 21 EDGs were tested in accordance with STP-0-8A and B, (11 and 21 EDG, and 4KV Bus 11 and 24 LOCI sequencer test). Samples of No. 11 and 21 JWC systems were analyzed for CO with negative findings. Then at 0600 a.m. on September 10, 12 EDG was removed from service for maintenance. The maintenance consisted of (1) a hydrostatic test of the JWC system; (2) removal of 16 fuel injector port adaptors and replacement of the copper gaskets; (3) inspection of cylinder wall liners using boroscopes and fiberoptics; and (4) an additional hydrostatic test of JWC using a green dye and retorquing of all adaptors.

During the maintenance, an NRC representative with considerable industry experience on diesel generators, was present who also examined various aspects of the maintenance evolution. It was the consensus of all who examined the liners that they appeared satisfactory. On September 12, the EDG was reassembled and operationally tested. The gaseous effluent was reduced by about half. The licensee notified the resident inspector that they were declaring the EDG operable based on (1) examination of the cylinder liners revealed no cracking; (2) gaseous effluent was reduced and believed to originate from copper gasket leakage associated with the fuel injector adaptors, which are not causing operational problems that could not be repaired during the upcoming refueling outage; and (3) the diesel was satisfactorily tested pursuant to Technical Specifications and met the requirements for operability as defined therein. Licensee mechanics requested plant management to permit leaving the EDG out of service to repair the remaining leakage. The management response was "the intent of the Technical Specification was exigent in nature and there was no evidence of conditions that require exigence at this time". Permission was denied and the diesel was declared operable at 5:00 p.m. on September 12, 1986.

Also on September 12, at 1:24 p.m., Unit 2 tripped due to a feed water pump control problem described in paragraph 2 of this report. The unit was returned to 60% power operation on September 14.

After declaring the 12 EDG operable, the surveillance requirements of the September 8, 10-day exigent TS change (Amendment Nos. 121 and 103) were suspended and the surveillance requirements of the original Amendment No. 94 was reinstituted. On September 15, during routine surveillance testing of 12 EDG per STP-08, pressure perturbations occurred within the jacket water cooling system and, after 15 minutes of running the diesel, the engine tripped due to JWC low pressure. Some venting took place, then another attempt was made to run the diesel which also resulted in a low pressure trip. Another more thorough venting process took place, and an attempt was made to operate the EDG while venting the JWC system. This resulted in difficulty in maintaining JWC temperature within design limits. The licensee subsequently declared the 12 EDG inoperable on September 15 at 10:00 p.m. and entered TS Action Statement 3.8.1.1.B of the original Amendment No. 94.

Amendment No. 94, the original TS 3.8.1.1 "AC Sources", permits one diesel generator to be out of service for 72 hours after which the licensee must be in Hot Standby within six hours.

During the following three days, the licensee removed all adaptor fittings from each cylinder (2 fuel, 1 cooling water, and 1 relief valve adaptor for each cylinder). New copper gaskets and "O" rings were installed and the JWC system was hydrostatically tested at 50 psi. Leakage persisted and joints were tightened. One area around No. 12 cylinder appeared worse and could not be totally stopped (minute leakage of about one drop). Because of this, a hydrostatic test utilizing Freon was performed at the same pressure. This Freon test indicated severe leakage around No. 12 cylinder. Removal of adaptors for inspection of the cylinder revealed an indication of a scarcely visible hair line crack between two adaptor ports. The indication was then confirmed utilizing a dye check examination.

On September 18, a determination was made to replace the No. 12 cylinder wall liner and inspect the other combustion chambers of the diesel. Because of the estimated time to perform this evolution (approximately 7 days) and because most of the 72 hour action statement had expired, the licensee commenced an orderly shutdown of Unit 2 at 10:20 a.m., anticipating the inability to meet the required LCO conditions. Disassembly of the Emergency Diesel Generator was begun immediately. At 3:00 p.m., NRC regional management made a determination that the licensee could be considered to be still bound by the previously issued 10-day exigent Amendment Nos. 121 and 103. This consideration was afforded the licensee noting that TS surveillance 4.8.1.1.1 a. and b. of Amendment Nos. 121 and 103 (8 hour, 500 KV breaker alignment verification and 69 KV SMECO breaker alignment and power availability checks) were not performed because the diesel was apparently "operable". However, Amendment No. 94, TS surveillance 4.8.1.1.2(a) 1-7 were performed which verify operability of each EDG and TS surveillance 4.8.1.1.1, verification of 2 independent offsite power supplies were performed. This was discussed between the Licensing Project Manager, NRC lawyers, the Resident Inspector, and Region I staff. This action permitted continuation of operation under a previously issued TS which would expire on September 20 at 6:00 a.m. (240 hours after entering the action statement). The unit returned to operation at 11:00 p.m.

On September 19, the BG&E Vice President, Nuclear Division and Manager, Nuclear Engineering personally discussed and requested an Emergency Technical Specification change with the Director of PWR Project Directorate #8, NRC. As a result of this discussion, and appropriate justification and compensatory actions, a waiver of compliance with TS 3/4 8.1 "AC Sources" was issued by NRC suspending the required action statements "b" and "c" of TS 3.8.1.1 which stated, "restore (at least) two diesel generators to operable status within 240 hours (from the time of initial loss) or by 4:00 p.m. E.D.T. on September 23, 1986, whichever comes first, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours."

However, this waiver would expire at 6:00 p.m. on September 23, 1986, and was contingent upon the licensee conforming to all other aspects of TS 3/4 8.1, and all statements contained in the BG&E submittal dated September 19, 1986. (The inspector verified compliance with both the Technical Specifications and the submittal requirements.) This was done in order to provide sufficient time for NRC to process an Emergency Technical Specifications change request to permit an additional 240 hours of out-of-service time.

On September 23, an Emergency Technical Specification change, Amendments Nos. 122 and 104, was issued to permit, for one time only, continued at-power dual-unit operation of up to 240 hours with the swing diesel generator (No. 12) out of service. This extension of the allowed period of diesel generator inoperability was made contingent on the Action Statements of TS 3/4 8.1, and upon the continued operability of each unit's dedicated diesel generator, a 1000 KW portable diesel generator, and all three off site A.C. power supplies (including the "SMECO tie in"). The amendments were to be used only to determine and correct the cause of the carbon monoxide leakage into the No. 12 diesel generator jacket water coolant system. The extension would expire upon completion of repairs, post maintenance testing, and restoration to operability of the No. 12 diesel generator or by 6:00 a.m. September 30, 1986, whichever came first.

On September 24, the Emergency Diesel Generator was reassembled and commenced a "run-in" period in accordance with a Fairbanks Morse Service Information Letter. Results, components replaced, and the run-in schedule are included as Attachment A. During the run-in period, several inspections took place. During one inspection, No. 13 lower thrust bearing appeared to develop substantial wear between the inspection intervals (15 minutes of engine run time). On September 26, the bearing replacement was complete and run-in testing was resumed. After three hours of continuous running at 1250 KW, gas bubbles were noted to be accompanying the JWC during venting. This gassing continued and venting of the JWC heat exchanger became a necessary operator action to prevent the diesel from tripping off due to low JCW pressure. After several hours at various loads (up to 2500 KW for three hours) the licensee reduced load to 900 KW and noted significantly less gaseous effluent. Upon completion of the run-in, the diesel cylinder adapter gaskets were checked for leakage and then retorqued.

On September 28, the diesel was again run for two hours and checked for gassing. Gas was evident. The licensee's plans per the General Supervisor Operation's Night Orders were, should no gassing be evident, the diesel should be run for four hours to prove reliability. However, the adapter gaskets were again retorqued to 300 ft/lbs with vendor representative concurrence. Then, in accordance with the September 29th night orders, the EDG was to be run for one hour at 3000 KW with a dedicated operator standing by to vent (venting was necessary to maintain the emergency diesel generator operability). In accordance with the night orders, this was sufficient to consider the emergency diesel generator operational. However, should the diesel be unable to carry 3000 KW for one hour, an orderly shutdown would have had to be performed.

On September 29, a load test of 3,000 KW for one hour was conducted. Venting became necessary after 45 minutes of operation. A Plant Operations Safety Review Committee (POSRC) met and declared the Emergency Diesel Generator operable. The POSRC also determined that a dedicated operator was necessary to vent the diesel should it become necessary.

On September 30, the resident inspector questioned the adequacy of the determination of operability, alluding to the fact that, at one point between the repair periods, operator action could not adequately vent the JWC heat exchanger and gaseous products built into the system faster than they could be vented off which caused the diesel to trip off even with operator action/venting. The inspector requested the licensee to evaluate (1) demonstrating the long term reliability, (2) determining the amount and rate of gas building into the system, and (3) showing that operator action can continue to maintain the diesel functional over a 24-hour period.

Discussions with the Manager of Operations indicated that an endurance run of some period of time would be appropriate and that some compensatory measures could be made similar to those previously provided to satisfy the temporary Technical Specification changes if necessary. This was discussed between the NRC Licensing Project Manager and the Resident Inspector.

Subsequently, in an effort to formally approve and document these actions, a telephone conversation took place between NRC Resident Inspector, NRC Licensing, and BG&E Manager of Nuclear Engineering Services. During this discussion, licensee representatives maintained that the No. 12 emergency diesel generator was totally operable without any reservations; that no added or backup compensatory measures were warranted and, in fact, were going to be, or were in process of being removed. Consequently, NRC Licensing Division requested NRC regional management to access the operability of the emergency diesel generator in view of the conditions mentioned above, and with respect to the design requirements as stated in Chapter 8 of the "Final Safety Analysis Report": i.e.

"Each diesel generator is rated as follows:

2500 KW	Continuous
2700 KW	2000 HR
3000 KW	200 HR
3250 KW	168 HR

The predicted accident loads for large break LOCA, small break LOCA, and main steam line break are less than 3000 KW."

Again a telephone conference call was initiated between Region I management and BG&E Manager of Nuclear Engineering. Again, the licensee maintained the emergency diesel generator was fully functional, totally operable, even though an operator was necessary to vent the JWC system in order to prevent its tripping on low jacket water cooling pressure. The licensee did not consider it necessary to demonstrate that the gassing was not getting worse or that an operator would be able to adequately vent the JWC heat exchanger to maintain JWC pressure.

As a result, Region I management directed the licensee to submit a Justification for Continued Operation (JCO) specifically addressing the No. 12 emergency diesel generator operability. On October 1, 1986, the NRC received the JCO from the licensee which provided justification, including a statement that the vendor supports the licensee's assessment that the diesel will function as described in the FSAR as long as it is properly vented. The licensee also stated that a No. 12 emergency diesel generator reliability test consisting of a 24-hour run at 2500 KW while recording test data and recording the trend of venting operations, was in progress. Additionally, the JCO committed to maintain the compensatory power supplies (portable 1000 KW diesel and 13 KW SMECO tie-in) in place due to NRC concerns. The NRC requested the results of the 24-hour endurance run prior to assessing the emergency diesel generator operability.

Simultaneously, NRC's Division of Licensing requested a management meeting with the licensee to discuss the entire emergency diesel generator problem, specifically, the apparent symptoms prior to the corrective maintenance and the status of the diesel after repairs. The licensee was requested to have the vendor (Colt Fairbanks Morse) management representative present at this meeting.

On October 2, Fairbanks Morse notified the licensee that the emergency diesel generator performance in accordance with the FSAR could not be assured and that a catastrophic failure was possible since positive identification of the manner by which CO was leaking into the JWC system was not found. Additionally, the BG&E Metal Laboratory notified the plant that analysis of the No. 12 cylinder wall liner, which was previously identified to have had a cracked liner, did not have a through wall crack. A crack did exist that extended into the threads of one adaptor fitting which could have been the cause of some leakage.

Because of this, the Plant Operations Safety Review Committee (POSRC) met to discuss the operability of the emergency diesel generator in light of the new information. The POSRC declared the emergency diesel generator operable providing that a dedicated operator was available to vent the diesel should it become necessary. During this POSRC meeting, the Manager of Operations (Chairman of the POSRC), along with one other member and a non-voting member disagreed with the POSRC recommendation to declare the emergency diesel generator operable without reservation. The Chairman acted with the minority's decision to require special compensatory measures remain in place and seek concurrence from the NRC.

Pursuant to Technical Specification 6.5.1.7(c), the Manager notified the Vice President Nuclear Energy and the Off-Site Review Committee of this disagreement. Also, the licensee notified the NRC of the more recent information regarding the vendor's decision to no longer support the ability of the diesel to perform in accordance with the design requirements in the FSAR, and that the 12 emergency diesel generator cylinder liner was not a through-wall crack.

Subsequently, the 24-hour run of the No. 12 diesel was completed. The time between required venting operations averaged approximately two hours (time for JWC pressure to reduce from 35 psi to 30 psi and pressure start to become erratic). This data was transmitted to Region I specialists who later concurred with the licensee's decision to declare the diesel operable provided compensatory measures were in place. Following the 24-hour test of the No. 12 emergency diesel generator, a 4-hour test of No. 11 and 21 emergency diesel was performed without any unusual operator actions. Both emergency diesel generators were run without venting and all operating parameters remained within their designed limits.

During the above described events, the inspector observed the maintenance activity on a daily basis; held discussions with mechanics, supervisors, system engineers, vendor representatives and NRC technical representatives. The inspector attended technical licensee meetings, POSRC meetings, and NRC technical meetings regarding the No. 12 emergency diesel generator.

Each Amendment (Nos. 121 and 103, and 122 and 104) was reviewed and compliance was verified. Letters to the NRC dated August 1, 6, 25; September 5, 8, 19, 23; and October 1 and 3, 1986, regarding the diesel problem were reviewed for accuracy and completeness. Discussions between the resident inspector and the NRR Licensing Project Manager and the Region I Section Chief occurred daily during this period.

The inspector walked through the entire procedure, ETP 86-16 "Portable EDG Connection Procedure", and the procedure for energizing Bus 14A or 24A utilizing the portable 1000 KW diesel generator as stated in the General Supervisor Operations Night Orders. Training of operators and electricians, and load testing of the portable diesel was observed. Verification of the 13 KV SMECO breaker line up was performed by the inspector. Additionally, the inspector, along with vendor representatives and the NRC technical representative, examined the suspected failed parts as well as the replacement parts. Observation of diesel functional test and independent examination and evaluation of diesel operating parameters were performed.

The inspector conducted a review of the Technical Specifications of Emergency Power Supplies and the Final Safety Analysis Report and compared these with licensee Operating Procedures OI-21 and 27C and the previously stated surveillance test procedures. An independent walk-down of valves, piping and breaker line-up was conducted for the portable emergency power sources.

In summary, the licensee appeared to have made a conscientious attempt to solve a problem which had the apparent potential to cause a catastrophic failure. The effort was to demonstrate a proactive program which pursues potential problems and to rule out problems which could cause catastrophic failure.

The licensee demonstrated a technically sound approach to the resolution of problems and was responsive to NRC initiatives to identify root causes of problems in a timely manner. However, considerable NRC effort and repeated submittals were required to obtain acceptable resolutions.

The approach to the problem appeared somewhat limited in scope in that it concentrated on only the most probable cause. Vendor recommendations to replace additional components to increase the prospects of solving the problem were not implemented due to perceived regulatory time constraints. Because of the particular type of problem and circumstances involved, the licensee was unable to identify the cause of or solve the gassing problem.

16. IE Information Notice 86-53

IEN 86-53 alerted licensees to a potential generic safety problem involving improper installation of heat shrinkable tubing over electrical splices and terminations.

The inspector verified that training of technicians and Quality Control inspectors had recently been conducted by the vendor; that procedures have been implemented for heat shrink tubing installation; and that a 100% Quality Control inspection coverage had been instituted for installations. The licensee is developing a program to inspect and audit all EQ installations to assure correct installation and sizing heat shrinkable tubing. It was noted that the 2-inch minimum overlap deficiency identified in Temporary Instruction 2500/17 is reflected in a 1-inch minimum overlap required by the E-406 installation procedure.

17. Review of Periodic and Special Reports

Periodic and special reports submitted to the NRC pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. The review ascertained: inclusion of information required by the NRC; test results and/or supporting information; consistency with design predictions and performance specifications; adequacy of planned corrective action for resolution of problems; determination whether any information should be classified as an abnormal occurrence, and validity of reported information. The following periodic report was reviewed:

-- August Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated September 15, 1986.

No unacceptable conditions were identified.

18. Exit Interview

Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection.

ATTACHMENT A

Results

-- Apparent crack found in Number 12 Cylinder.

-- Found several main bearings slightly wiped.

-- Upper crankshaft journals needed lapping.

-- Upper connecting rod bearings scratched.

-- Two cylinders found with flashed chrome plating in combustion area.

-- Master link pin in timing chain worn.

-- Dye Penetrate Test (Pt) of combustion area of all liners completed with no indications.

-- Intake piping and intercooler found coated with soot. (Eventually determined this had no long term affect on air pressure.)

Components Replaced

-- All adapter seals and gaskets.

-- Cylinder liners Nos. 2, 8, and 12.

-- Pistons (upper and lower) Nos. 2, 8, and 12, and No. 4 upper.

-- No. 7 upper compression ring.

-- All connecting rod bearings.

-- No. 13 thrust bearing.

RUN-IN SCHEDULE

SPEED		TIME	LOAD	CHECKS
300	MIN	5 MIN	NO LOAD	B
350	500	15	NO LOAD	B
450	600	15	NO LOAD	
550	700	15	NO LOAD	
650	800	15	NO LOAD	
720	900	15	NO LOAD	A, B
720	900	1 HOUR	25%	A, B
720	900	1 HOUR	37.5%	A
720	900	2 HOURS	50%	A
720	900	3 HOURS	62.5%	A
720	900	3 HOURS	75%	A
720	900	3 HOURS	87.5%	A
720	900	3 HOURS	100%	A, B, C

A. Check pistons, rings and cylinder liners through the ports after the runs.

B. Check bearings for overheating after the runs.

C. If 110% overload run is required, this run will be scheduled after the 100% load is completed and necessary inspections made.