U.S. NUCLEAR REGULATORY COMMISSION

Region I

Docket/Report:	50-317/88-01 50-318/88-01
Licensee:	Baltimore Gas and Electric Company
Facility:	Calvert Cliffs Nuclear Power Plant, Units 1 and 2
Inspection At:	Lusby, Maryland
Dates:	January 19 - 29, 1988
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Approved By: James T Wiggins 3/11/88

James T. Wiggins, Chief — Date
Reactor Projects Branch No. 3 - Team Manager

Summary: January 19-29, 1988: Combined Inspection Report Nos. 50-317/88-01 and 50-318/88-01

Areas Inspected: (1) plant operations, (2) maintenance, (3) engineering support, (4) surveillance, (5) licensee overview activities (management coordination and control, quality assurance, plant operations safety review committee, offsite safety review committee, etc.), and (6) organization and interfaces.

Inspection hours totalled 619.

Results: The team's findings indicated generally good performance with positive findings regarding the performance of operators, safety overview provided by the onsite and offsite safety review committees, management initiatives to understand and improve performance and the amount of detail in completed maintenance work packages. One violation was identified in the Surveillance area concerning temporary procedure changes and their review and approval (Detail 5.e). One unresolved items was identified in the Engineering area concerning the precision of the inservice testing of the Salt Water Pumps (Detail 4.b). Weaknesses were identified in housekeeping in selected areas of the plant (Detail 2.b) and inadequate control and coordination of troubleshooting activities (Detail 3.d).

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Integrated Performance Assessment Inspection
at Calvert Cliffs Nuclear Power Plant
(Inspection Report 50-317/88-01; 50-318/88-01)

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DETAILS

1. Overview

As a result of Calvert Cliffs performance over the past 2-3 years, the recent Systematic Assessment of Licensee Performance (SALP) Board recommended an Integrated Performance Assessment (IPA) inspection be conducted to better understand licensee performance. The IPA focused on a number of functional areas with primary emphasis on interfaces between Operations, Maintenance and Engineering. Additionally, the team reviewed the effectiveness of available tools (i.e., trending/tracking mechanisms, management oversight activities) in identifying emerging plant problems, adequacy of resources in maintenance and engineering, effectiveness of surveillance testing program in assuring equipment reliability and procedural use and adherence.

2. Plant Operations

This area was reviewed during routine inspection by the team throughout the period and included around-the-clock shift observations by team members during the period January 20 through 25, 1988. Many of the inspection and monitoring activities were performed during windows of opportunity (e.g., shift turnovers, plant evolution, ongoing maintenance and surveillance, followup to events, etc.) as well as the normal daily activities performed by the on duty shift.

a. Plant Status

Units 1 and 2 were operating at 100 percent when the team arrived onsite. On January 21, 1988 Unit 1 power was reduced to 97 percent in order to remove the second stage Main Steam Reheater from service. Plant maneuvering was performed in a smooth, deliberate manner. Unit 1 remained at 97 percent power for the remainder of the inspection.

At 9:58 a.m. on January 22, 1988, Unit 2 tripped from 100% power due to low steam generator level. The initiator of the low level condition was a loss of power to both main feedwater pump and the moisture separator reheater (MSR) shell and MSR first and second stage drain tank level control systems. This caused the main feedwater pumps to hold at a constant speed. It also caused the MSR shell and drain tank inventories to dump to the main condenser instead of ultimately flowing to the heater drain tanks. Heater drain tank (HDT) levels lowered, resulting in HDT level control valves shutting, reducing flow to the main feedwater pump suctions. Less feedwater was then pumped to the steam generators (SG) and SG levels fell. Electrical

and Controls personnel performing a troubleshooting operation on the Unit 2 computer inverter introduced a phase-to-phase short on 120 VAC instrument power bus 2Y10 which caused two inverter supply fuses to blow and the feeder breaker for 2Y10 to open. The plant was quickly stabilized and plant systems performed as designed. The plant was returned to power operation at 11:15 p.m. on January 22, 1988 with the affected inverter disconnected from 2Y10.

Immediately prior to the trip, technicians had attempted to remove power factor correction capacitors from the circuit as a part of their inverter troubleshooting effort. The inverter was being powered from the AC backup power source (2Y10) at the time. Due to a combination of unclear communications between technicians and the vendor regarding the means of removal of the capacitors and an unclear vendor print, technicians installed jumpers around the capacitors which effectively created a short circuit path. More information concerning this troubleshooting is contained in Section 3.d of this report. Plant operators reacted swiftly to the loss of 2Y10 and were ready to crossconnect this bus prior to the trip. However, concerns over crossconnecting a normal bus to a bus that had a potential problem prevented taking this action. A manual trip was initiated, however, the automatic low level trip occurred first. Operator response to the plant trip was good in all areas reviewed.

Inspectors reviewed the preparations for plant restart. Unit 2 was taken critical at 11:10 p.m. on January 22, 1988 and returned to full power. Unit 2 remained at full power for the remainder of the inspection.

b. Plant Tours and Housekeeping

During the inspection period and specifically while observing shift crew activities from January 21 through 25, the inspectors conducted tours of all accessible plant areas. Several tours were taken with auxiliary operators. During the tours the inspectors evaluated routine activities conducted by auxiliary operators, general housekeeping and radiological controls and practices.

Auxiliary building operators were found to have a detailed understanding of the plant and were knowledgeable of existing plant conditions. Throughout their tours they generally maintained close communications with the control room, and responded to the reactor operators' requests.

Plant housekeeping appeared to be inconsistent with conditions ranging from very good in areas such as the ventilation equipment rooms to poor in areas such as the five foot elevation east penetration room for Unit 2. The following observations were made by the inspectors in the area of housekeeping:

- Switchgear rooms and cable spreading rooms located on the 27 foot elevation and switchgear rooms located on the 45 foot elevation of both units contained loose tool/test equipment carts and portable work benches on wheels, rolling lifting rig movable cabinets, and loose ladders. The extraneous equipment exposed both safety and non-safety related switchgear and electrical cabinets to potential hazards during a seismic event of being impacted by the movable equipment and causing damage.

- The Unit 2, 5 foot elevation east penetration area contained loose lagging materials, tools and debris. The area was also being used for storage of scaffolding materials randomly piled in open floor areas.

- The intake structure was also poorly maintained with debris stuffed into cable trays and in junction boxes and scaffolding placed in the circulating water pit.

The inspectors noted that metal scaffolding erected to facilitate maintenance and/or equipment operation is routinely left in place long after the conclusion of the maintenance activity. Scaffolding in the Emergency Core Cooling System (ECCS) pump room, charging pump room, ECCS ventilation rooms and the component cooling water pump room was erected between September and December 1987. According to the operators, scaffolding in the Unit 2 waste gas decay tanks area has been in place for several years. In all instances the scaffolding is next to or straddles safety related equipment. The inspector reviewed licensee procedures governing maintenance activities:

- CCI 200O, Nuclear Maintenance System
- CCI 200E, Maintenance Procedures

These procedures were found not to address the removal of scaffolding from work areas.

The inspector discussed the scaffolding-related problem with a civil engineer responsible for assessing seismic impact on plant equipment. The engineer stated that scaffolding is assumed to be removed immediately following maintenance, generally completed during plant outages. Therefore, seismic impact on safety related equipment located adjacent to scaffolding is not routinely evaluated by the licensee.

All of the above items were discussed with licensee management. While some corrective actions in the area of housekeeping have been initiated, long term programmatic improvements in all areas are needed.

The licensee's decontamination efforts appear to be minimal in the areas of the ECCS pumps. Thus routine access to the pumps is curtailed by roped off areas and requires the use of protective clothing. Since the pumps are inspected several times per shift, each inspection generates additional radioactive waste. Due to the lack of prompt removal, the trash was observed overflowing onto the floor around receptacles located at stepoff pads. Additional licensee attention appears warranted.

The unsatisfactory housekeeping and material conditions noted in several areas as discussed above are considered collectively to be indicative of a licensee weakness (50-317/88-01-01; 50-318/88-01-01).

c. Operator Performance

The day to day performance of the operators, both in the control room and in the plant, was very good. Shift turnovers appeared thorough. System knowledge level of the operators was good and the operating crews have a high level of experience at the plant. Contributing to the strong performance of on-shift personnel was the use of licensed and non-licensed operators in support functions including Operations Maintenance Coordinator, Surveillance Coordinators, Procedure Reviewers and tagging activities. The overall effect has been the minimizing of the number of control room interruptions and providing for communication flow to the operators. Additionally, administrative controls used to control the personnel who must enter the control room for approval of work packages appeared effective and resulted in minimizing the distraction of the operators' attention.

Operator's response to the initiating event and subsequent recovery activities for the Unit 2 trip on January 22, 1988 were very good. Operators responded to the initial loss of bus 2Y10 and were ready to crossconnect this bus and restore power. However, since the operators did not know the cause of the fault on bus 2Y10, they did not want to connect it to a different power supply. The plant tripped about one minute before the nature of the fault was identified. Immediate actions and recovery from the plant trip were good.

Procedure use and adherence by operators was observed to be good. During surveillance and routine watch activities, the operators used plant procedures. When questioned, operators were familiar with plant equipment and the intent of the procedures. Day to day performance of the operations staff was considered to be a strength.

d. Operations Interfaces

Routine maintenance is planned through the planners and results in a computer printout which includes major maintenance and surveillance items from outside the operations area. (Operations surveillances are scheduled through the Operations Surveillance Coordinator and a separate schedule is generated for control room use). Shop Planners and the Operations Maintenance Coordinator meet at 6:30 a.m. each morning to discuss possible schedule conflicts and prioritize maintenance and surveillance activities. At 8:00 a.m. the General Supervisors meet to discuss major job status. The General Supervisor of Operations leads this meeting and can focus additional attention when needed. At the end of each day the tagging group receives the tagging requests for the next day and the time when work will be ready to commence. Using this information, the tagging group prepares tagouts for the next day. Once the job is approved by the control room, the taggers will remove a system or component from service and tag out the equipment. Plant operators are generally not used to tag equipment out of service.

e. Summary

The Operations Department has a well qualified and knowledgeable staff. Support functions help reduce the interruptions in the control room to a minimum. Interface activities with other departments allow the General Supervisor of Operations to adjust the priority of other departments in support of operations activities as well as coordinate plant conditions for other departments. However, housekeeping and some radiologically contaminated areas need licensee attention.

3. Maintenance

The inspection team reviewed the maintenance program, associated procedures, work controls and equipment history, as well as the material condition for various areas in the plant.

The licensee preventive and corrective maintenance efforts for maintaining the reliability of plant equipment were reviewed with special emphasis on the interfaces between the maintenance organization and other departments.

a. Maintenance Program

Revision J to Calvert Cliffs procedure CCI-200 provides an overview of the actions necessary to implement and complete maintenance work using the "nuclear maintenance system". This system collects a detailed data base of active maintenance activities such as Maintenance Requests (MR's) and Maintenance Orders (MO's). Detailed information is retained for a period of two years, but for permanent

record retention, only abbreviated history data extracted from the Nuclear Information System (NIS), are retained for plant history. The data are recorded on reels and tapes and are retrievable by using the appropriate Record Set Identifier (RSI) numbers.

The inspector had the following observations during the review of the licensee overall work flow and work control:

(1) The licensee had no written detailed guidance for maintenance planners for post maintenance testing in CCI-200 J. As a result, post maintenance testing requirements are determined by individual planners based on their knowledge of the equipment or system. A procedure called "Operations Unit Administrative Policy 85-4 dated September 23, 1985" was used to provide further detail. However, their determination may be inconsistent as a result of the lack of guidance in this area. For major tasks such as equipment replacements, major refurbishments or overhauls, the design bases for such equipment might not be demonstrated and analyzed. This could diminish the capability or reliability of plant equipment, however, no instances were identified where this had occurred

(2) The Operations Department makes the final determination as to which maintenance orders (MO's) will require operations testing (OPTEST). The inspectors reviewed a number of completed MO packages and noticed that post maintenance testing, as recommeded by Maintenance, was sometimes waived by Operations without any documented justifications or analyses. Most OPTESTS were satisfied by using all or parts of certain Surveillance Test Procedures (STP's) and test results were sent to appropriate system engineers whereas OPTEST forms were forwarded to the Nuclear Plant Documentations Group for recordkeeping. Procedure CCI-200J does not specifically differentiate between post maintenance testing requirements and operations tests. The inspector further observed that the responsible system engineer was not involved in the review of the MO packages during planning, and therefore was not a party to the determination of what post maintenance activities were required. Currently, maintenance QC staffs are reviewing the MO packages in the mechanical area for information and if required, for additional hold points. However, QC was not involved in the reviewing of electrical or I/C packages for hold points.

(3) The inspector had the following additional observations in the I/C area:

- Licensee management indicated that the turnover rate in the I/C area was high during the past few years. This was due to a number of craft personnel that had left the company, or were moving to other positions in the plant for cross training or to secure a more stable non-shift working schedule.

- Interviews with operations staff and QC management indicated that the current QC inspectors have little or no prior plant I/C experience which would help assure meaningful QC coverage.

- Current craft supervisors (General and Assistant General Supervisor levels) were new in their positions and had little or no previous I/C experience.

- The inspection team noted a total of more than 150 deficiency tags posted in the two unit control room.

- Interviews with operations staff personnel revealed that a number of instruments in the control room had to be reworked in the recent past.

The inspection team noted that these concerns individually might not be significant. They indicate past problems with turnover and experience levels in the I/C department which appears to have affected performance. Collectively, the last two findings listed above might hinder the operators' ability to cope with plant transient conditions or other design basis events.

(4) The inspectors reviewed several completed Maintenance Order Packages (MOP's) and noted the following observed strength:

- The packages contained good work descriptions of what was completed in the field. The team concluded that this information should facilitate turnover between shifts, provide better communication among organizations that review the packages, and serve as good references for future work or equipment machinery history.

- The packages provided the inspection team with evidence of active QC involvement in establishing hold points and imposing stop work orders. The team reviewed QC inspection records and noted that NCR's were written as required. The inspector noted NCR-7296, Class A, which was used to document any observations where plant as built does not agree with the design. The licensee was in the process of development and implementation of a comprehensive plan to improve plant configuration management. This NCR was being used as the vehicle to resolve configuration discrepancies. This area will be monitored in future inspections.

b. Communications

The inspection team observed that the licensee had established a number of meetings to facilitate communications and work awareness among involved plant personnel. The following are descriptions of various meetings that were taking place during the time that the inspection team was onsite:

(1) The 6:30 a.m. daily meeting: the purpose of this meeting was to distribute MR's to the appropriate shops with the emphasis on priorities. This meeting was attended by the following plant staff:

- Assistant General Supervisors (AGS)
- Senior planners in different areas (disciplines)
- Supervisors from Radiation and Safety Protection
- Senior QC inspectors
- Operations Maintenance Coordinator (OMC)

(2) The 8 a.m. daily meeting: the purpose of this meeting was to provide briefings to craft General Supervisors (GS) and Department Managers on everyday problems. The following managers and their representatives attended this meeting:

- GS for Mechanical
- GS for Electrical/Instrumentation
- Lead Engineer - systems
- GS for Operations
- OMC Supervisor
- QC Supervisor
- Radiation and Safety Protection Supervisors
- Chemistry Supervisor
- All Department Managers

(3) The 11 a.m. (Project 2) scheduling meeting (M/W/F): this meeting was attended by planners to coordinate and schedule upcoming work planned for the next two weeks. It covered Preventive Maintenance, Corrective Maintenance, Surveillance Tests, Facilities Change Requests and other non-routine work that was needed. The following staffs attended this meeting:

- QC
- Radiation and Safety Protection
- Chemistry
- Water Treatment
- Safety Tagging

(4) The Forced Outage Work List (FOWL) meeting: this meeting was held every Thursday at 1 p.m. to develop and maintain a list of tasks that could be performed in the event of a forced outage. Personnel attending this meeting were mostly outage planners, senior planners of respective crafts and the Operations Maintenance Coordinator (OMC).

These meetings appeared to be effective in providing proper prioritization of activities and in resolving emerging plant problems.

c. Maintenance Work Order Backlog

The inspector reviewed the licensee monthly work that was completed and other information from the licensee's performance indicators. As of the end of the 4th quarter in 1987, the licensee had the following backlog of work (both PM and CM):

Mechanical Maintenance	5 weeks without delay 6 weeks with delay
Electrical Maintenance	2 weeks without delay 3 weeks with delay
I/C Maintenance	2 weeks without delay 5 weeks with delay

Delays were typically due to the awaiting of engineering resolution or to material unavailability because of required lead and processing time. Interviews with planners indicated that the final processing organization for material procurement is located at the licensee corporate headquarters in Baltimore. This office may not be cognizant of the plant priorities possibly due to the lack of a formal feedback mechanism in the procurement process (See Attachment 2, Pages 8-10).

d. Troubleshooting Process and Management Control

At the time of this inspection, the licensee had no formalized procedure to provide detailed guidance for craft personnel to perform troubleshooting. Craft management indicated to the inspector that if maintenance problems were identified, they would use the FAS Teams (Find Answers and Solutions) for quick response to problems. The licensee also used the "System Quality Circle Experts" team concept to solve difficult maintenance problems. In these cases, technical experts from Nuclear Engineering Services Division (NESD), Nuclear Maintenance Division (NMD) and Nuclear Operations Division (NOD) staffs and the appropriate system engineer would form a team to find solutions and provide solutions to the Maintenance Department for implementation.

Because there were no formalized troubleshooting procedures, craft personnel were left with little guidance in the field. On January 22, while the team was onsite, the Unit 2 reactor tripped as a result of troubleshooting activities for a non-safety-related electrical inverter that powered the Unit 2 plant computer. Subsequent to this trip, the inspection team interviewed the involved craft personnel, their supervisors, and the responsible engineer. The team noted the following weakness (50-317/88-01-02; 50-318/88-01-02) with the licensee's troubleshooting practices:

- Craft workers were provided with a General Maintenance Order (MO) and little other guidance.

- No precautions or specific control of parameters and bounds during troubleshooting were specified in the MO's.

- The licensee did not appear to have performed a detailed investigation of the job documented in the MO as required by CCI-117 prior to work.

- Conservative steps such as checking for grounds or sneak circuits were not used.

- There were communication and interface problems with the vendor in the interpretation of vendor supplied information.

- There were communication problems between Operations and Maintenance personnel (Operations indicated that they did not know much about the nature of the troubleshooting efforts being pursued on the morning of January 22).

In addition to the above weakness, the inspector also noted that schematic wiring diagram (Dwg 82-871-E) for inverters 2Y05 A, B and C (used by the electrician during troubleshooting) was not in agreement with the actual wiring in the inverter cubicle.

The inspectors also noted the licensee fusing and fuse replacement practices. The licensee investigation of the January 22 Unit 2 trip showed that out of the three fuses (A, B and C) on the inverters, only two of the fuses (B and C) were blown. It was later determined that the B and C fuses were of type fusetron, dual element time delay, Class K5 fuse type FRN-100, whereas the A fuse was of type NON-100, a one time fuse. It was not clear how and when the fuses were replaced. It appears that the licensee had no procedures or formal documents to administratively control the replacement of fuses by type (only by rating) at Calvert Cliffs for this type of application.

e. <u>Preventive Maintenance Program</u>

Procedure CCI-211E described the administrative requirements for the Preventive Maintenance (PM) program. This procedure was revised on January 26, 1988 during the course of this inspection. The inspector reviewed the procedure and interviewed licensee maintenance staff involved with the PM program. The inspector had the following observations based on previous implementation of the PM program:

(1) <u>Trending Analysis</u>

Section V.E of the procedure specified that "Supervisors should be alert for indications of conditions which may be detrimental to equipment performance..." However, no other detailed descriptions were given on how the PM data were to be evaluated and what feedback mechanisms were utilized to inform the supervisors of the evaluation results. From interviews with maintenance staff involved with the PM program and the document control staff, the inspector determined that:

- Section C of the procedure addresses evaluation and trending of data. The senior engineer responsible for the trending program demonstrated to the inspector the computer software utilized to store and analyze data. The current equipment monitoring program is based on the correlation of vibration data and oil sample analysis results taken from all ASME rotating equipment in the plant. A weekly summary of equipment with suspect mechanical condition is submitted to the General Supervisor of Operations, General Supervisor of Maintenance and the System Engineer. The System Engineer has the responsibility for the followup and the resolution of all abnormal equipment conditions.

  The inspector noted that while all vibration data are analyzed onsite, oil sample analyses are conducted by a local laboratory. The laboratory's responsibility for conducting the analyses in a timely manner was not formalized. Prompt notification by the laboratory upon identifying a potentially serious abnormal condition was left to the initiative of the laboratory. It was noted that the licensee needs to develop time requirements for conducting oil sample analyses and instructions for prompt notification upon the identification of abnormal findings.

- Other PM data were collected, but there was no systematic method of storing such data and therefore only minimum PM data were evaluated. The licensee was in the process of loading PM data in a PC computer, however, a systematic trending of these data was not evident at the time of the inspection.

- Completed MOs, however, are kept on reels and tapes. Data can only be retrieved by MO numbers, and not by equipment and system identification numbers. This recordkeeping system did not provide the licensee maintenance staff with a readily accessible path to obtain past maintenance history for trending purposes.

(2) Scheduling and Performance Evaluation

There was no dedicated staff assigned to oversee and integrate the PM program. Scheduling was manually tracked quarterly. The inspector observed that certain PM tasks were missed and others were deferred, however, there were no records to document that evaluations were performed for those missed and deferred PMs to include operability of the equipment involved (if appropriate).

(3) Preventive Maintenance for Manual Valves

The inspector reviewed procedures for maintenance of manual valves and found that the licensee had established PM procedures for general valves located in the following buildings.

Turbine building (PM 1, 2-102-M-A-2, R-1)
Auxiliary building (PM 1, 2-102-M-A2)
Containment building (PM 1, 2-102-M-R2)

The following generic steps were required for PM tasks on these valves:

-- Grease all valves equipped with grease fittings
-- Check and adjust packing as necessary
-- Visually inspect valves and note problems
-- Grease all sway struts.

The inspector expressed the concerns that the procedures contained no detailed list(s) of valves to keep track of job progress. As a result:

-- Personnel performing PM activities might do PM on the wrong valves or miss the PM requirements on certain v lves.

-- The use of a general PM procedure may provide the potential for overgreasing of the valves or the use of incompatible material.

-- Also, the general procedure would not control the exercising of valves or the maintenance of required valve positions. Valves might be exercised or required valve positions might be altered.

The licensee needs to review other PM procedures that might be too general in this respect.

(4) PM Program Redirection

On January 26, 1988, the licensee issued a new PM procedure CCI-211F, which incorporated the following major changes:

-- Overall responsibility of the PM program was assigned to the Manager of the Nuclear Engineering Services Department.

-- A defined process for evaluating, trending and reporting PM program results was stated and responsibility for this process was assigned to the Performance Engineering Unit.

-- A requirement for System Engineers to be notified of PM tasks that will not be completed as scheduled.

The inspector reviewed the above revised procedure CCI-221F and had the following observations:

-- The procedure states that: "The General Supervisor (GS) of the responsible craft group reviews and determines the reason for the missed PM tasks", however, there was no requirement that the GS evaluate and document the operability and reliability of equipment that had missed or deferred PM tasks.

-- PM tasks are currently processed as low priority work and therefore may not receive adequate management attention. Future achievement of good completion rates may be difficult.

-- There was no defined process to correlate the PM data and CM data for PM program optimization and re-adjustment.

(5) Summary

The licensee's preventive maintenance program was generally not systematic and lacked formality. Trending was being performed, but data were difficult to use as information was not readily accessible. Although PM was scheduled and tracked, the impact of missed and deferred PMs on equipment operability was not being evaluated. Some PM procedures needed additional detail or clarification. The licensee appeared to be aware of the need to strengthen this program and was in the process of program redirection at the time of the inspection.

f. Overall Maintenance Summary

The amount of detail contained in completed maintenance work packages showed good recording of the maintenance performed and good QC oversight. Coordination meetings provide the proper prioritization of plant activities. However, troubleshooting and post maintenance testing guidance needed improvement in order to prevent adverse impact on plant operations and assure that retesting sufficiently verifies operability of a component prior to returning it to service. The PM program was comprehensive, however, its non-systematic, informal approach in some areas potentially limits its usefulness.

4. Engineering Support Activities

The inspectors performed a review of the engineering support provided by the Nuclear Engineering Services Division (NESD) to the Nuclear Operations Division (NOD) and to the Nuclear Maintenance Division (NMD) and of the interfaces that exist between NESD and NOD and between NESD and NMD to extend this engineering support and to garner any appropriate feedback regarding this support.

a. Engineering Support

During the December 1985 reorganization, the licensee established the position of system engineer. The function of the system engineer was to become the expert with regards to the system's design basis, function, operation, maintenance, modification, testing and regulatory compliance.

The expertise was to be developed through a formalized training program that was under development at the time of the inspection, and through the system engineer's familiarization with the system. Part of this familiarization process included obtaining a knowledge of applicable surveillances, maintenance and modifications planned and through documentation reviews. An overall familiarity with the system's layout and current operating status was to be obtained through system walkdowns.

Discussions with several operators and system engineers indicated that many of the system engineers did not routinely walk down their assigned systems. The walkdown frequency appeared to vary from weekly to quarterly, or longer. It was difficult to ascertain how the system engineers maintain a current level of knowledge of the condition of their assigned systems without routinely walking down their entire systems. The inspectors found that apparently no guidelines have been promulgated to the system engineers concerning system walkdown requirements or periodicity.

b. <u>Engineering-Operations Interface</u>

The inspectors examined the engineering support provided by NESD to NOD and the feedback provided by NOD through discussions with several operators and system engineers and through reviewing portions of the operations surveillance procedures and test results, including post maintenance tests, that were applicable to the Units 1 and 2 salt water systems in 1987. The surveillances reviewed included the following:

STP-O-56A-2, Revision 9, "ESFAS Equipment Response Time"

STP-O-65-1, Revision 30, "Quarterly Valve Operability Verification - Operating"

STP-O-65-2, Revision 30, "Quarterly Valve Operabiltiy Verification - Operating"

STP-O-66-1, Revision 18, "Quarterly Valve Operability Verification, Shutdown"

STP-O-66-2, Revision 23, "Quarterly Valve Operability Verification, Shutdown"

STP-O-73-1, Revision 24, "ESF Equipment Performance Test."

The inspectors found that the NESD/NOD interface with regard to the development, revision, performance and review of operations surveillances were generally minimal, though sometimes dependent upon the system engineer involved.

System engineers do not directly revise or review operations surveillance procedures that affect or test their systems. Rather, they must request the procedures group of NOD to make any necessary changes. [illegible] system engineers do not review these modified procedures [illegible] required changes were properly incorporated.

An instance in which this methodology led to discrepancies in the programmatic and the procedural changes required was the development of the second 10-year inservice testing (IST) program for pumps and valves including their associated surveillance procedures necessary to conduct the IST program. The second 10-year IST interval started on April 1, 1987 and June 30, 1987 for Units 1 and 2, respectively. 10 CFR 50.55a(g)(4) and (5) required the licensee to update the IST program on April 1, 1987 to the 1983 Edition of the ASME Boiler and Pressure Vessel Code and to submit to the NRC any IST programmatic relief requests within twelve months of the end of the previous 10-year IST interval. The licensee submitted the second 10-year IST program with all requested reliefs on February 26, 1987.

The second 10-year IST program was developed under contract for NOD by the General Physics Corporation. Though NOD apparently has no significant ASME Code expertise, this program was not reviewed by NESD though significant ASME Code expertise can be found in Design Engineering and in Performance Engineering. NESD interface with NOD concerning the IST program was limited to NOD's use of the licensing unit of NESD as a conduit to submit the IST program to the NRC for review.

The inspectors found the following problems while reviewing the IST surveillance procedures provided to test the salt water system:

(1) Article IWP-3210 of the 1983 Edition of the ASME Code specifies that the allowable upper limits (alert and action limits) for the ranges for pump flow rate and pump differential pressure, as measured during the IST surveillances of ASME Code Class 1,2 and 3 pumps shall be 102 percent and 103 percent, respectively, of their applicable flow rate and differential pressure reference values. Without requesting ASME Code relief, the licensee had been utilizing less conservative alert and action limits of 105 percent and 107 percent respectively.

    The licensee had stated in the February 26, 1987 IST program submittal that they were using these values and that this use reflected "the approved relief request from the first ten year program [NRC Safety Evaluation dated February 8, 1982] and meets with ASME Code requirements per IWP-3210." However, the relief approved for the first 10-year interval dealt only with pump differential pressure and did not consider flow rate. Furthermore, reliefs granted for a previous 10-year interval do not extend into the following 10-year interval, but must be again requested and approved to still be applicable. Lastly, these increases in the alert and action range upper limits for flow

rate and differential pressure apparently did not comply with the requirements of Article IWP-3210 of the 1983 Edition of the ASME Code, thus, if these values were to be used after April 1, 1988 without a Code relief previously requested from the NRC, the licensee would be in apparent noncomplicance with the provisions of 10 CFR 50.55a(g)(5)(iv). The inspectors requested the licensee to submit the appropriate Code relief request before April 1, 1988 if they intend the continued use of these alert and action range upper limits.

(2) The IST of the # 11, 12 and 13 salt water pumps (Unit 1) is performed through the use of the surveillance test procedure STP-0-73-1, Revision 24, "ESF Equipment Performance Test." Pump performance is evaluated by either setting the pump flow rate to its reference value and determining differential pressure or by establishing the differential pressure at its reference value and measuring flow rate. In either case, the lack of precision in the installed pump discharge pressure gauge (2 psi increments, thus a ±1 psi error) is significant enough (a change of 1 psi corresponds to a flow rate change of 700 to 1000 gpm) that the error inherent in reading this pressure gauge spans a large portion of the entire action range. Thus, acceptable IST pump performance readily could be judged as unacceptable or unacceptable performance could be found to be acceptable. This is unresolved item 50-317/88-01-03; 50-318/88-01-03).

To reduce the precision error in this differential pressure determination, it appears that some surveillance procedural modifications may be necessary, such as:

(a) the use of a more precise pressure gauge for this test, or

(b) replacement of the graph in STP-0-73 of bay level versus pump suction pressure with a table of bay levels, in tenth of a foot increments, with their corresponding pump suction pressure values. Bay level provides the value for the pump suction pressure used to calculate the pump differential pressure. The values of suction pressure used in previous performances of this surveillance have varied by as much as 0.2 psi, approximately 400 gpm flow rate, for identical bay levels.

If NESD had been involved with the development or review of the IST program and of its applicable surveillances or the system engineer had conducted a thorough walkdown of the system and the applicable surveillance procedures, difficulties created in this surveillance due to the lack of pressure gauge precision could have been identified and averted.

Besides not reviewing the changes to operations surveillance test procedures, many of the system engineers do not review all of the surveillance test results that are applicable to their systems. Without this information trending of component and system performance by the system engineer is difficult to accomplish. However, the Operations Surveillance Coordinator (OSC) has established a policy of notifying the system engineer by memorandum of out-of-specification conditions or equipment failures that were discovered during the performance of operations surveillances. This notification is an improvement by the OSC over prior feedback practices between NOD and NESD.

In addition to the above examples, further items concerning NESD/NOD interface and support reviewed by the inspectors included the lack of lists of electrical loads powered from non-vital instruments buses and the reduction in the required value for salt water pump flow rate.

(1) In reviewing the January 22, 1988 Unit 2 trip that occurred following the inadvertent deenergization of the #22 instrument bus, the inspectors found that NESD had not developed lists of loads powered from the non-vital instrument buses. These lists were previously requested by NOD personnel to facilitate the development of abnormal operating procedures. NOD was informed that they could not be provided until late 1988 at the earliest. Thus, the plant operators are placed in the disadvantageous position of not knowing what components or systems (i.e., main feed) would be lost if one of these buses was deenergized due to a casualty or to maintenance.

(2) To comply with the new IST requirements of Article IWP-3210 of the 1983 Edition of the ASME Code for pump flow rate and differential pressure comparisons, NOD temporarily changed STP-0-73-1, "ESF Equipment Performance Test" and performed these modified Unit 1 surveillances on June 22 and July 3, 1987. The licensee determined that the flow rates for their reference differential pressures were lower than anticipated. Section 9.5.2.3, "Salt Water System," of the Updated Final Safety Analysis Report (UFSAR) states that the required flow is approximately 20,000 gpm for a loss of coolant accident (LOCA). The flow rates measured were considerably below this value with the lowest flow rate measured at 16899 gpm for #13 salt water pump on July 3.

The UFSAR flow rate of approximately 20,000 gpm was based on Bechtel's original design evaluation calculations for Calvert Cliffs for salt water system flow to the service water heat exchangers during a LOCA prior to the initiation of recirculation. In these calculations, Bechtel assumed a salt water flow of 20,000 gpm.

In response to these lower salt water flow rates, the licensee requested Bechtel to recalculate the minimum salt water flow rate required through removing assumed conservatisms. The result was 17730 gpm. This value is said to include an instrument error of 900 gpm.

On August 19, 1987, the general results of these calculations were presented to the POSRC (Meeting # 87-84). POSRC authorized the immediate use of these values by NOD in STP-O-73 and apparently directed NESD to institute a Facility Change Request (FCR # 87-83) to revise the salt water flow rate specified in the UFSAR. The licensee has incorporated and used these latter flow rate values in subsequent performances of STP-O-73 though no work has occurred on FCR # 87-83 and no additional evaluations, such as an unreviewed safety question determination or a comparison to the flow rates measured during pre-operational testing, apparently have been performed.

The mechanism of this change as used by the licensee appears to indicate that USFAR system descriptions, such as flow requirements for design basis events, can be altered without the performance of a formal unreviewed safety question determination. This concern was identified to licensee engineering management. Further, the reduction in the salt water flow requirements will be considered for further review and action by the Office of Nuclear Reactor Regulation through the normal performance of its licensing and facility design safety functions.

c. Engineering-Maintenance Interface

The inspectors examined the interfaces between NESD and NMD through discussions with several maintenance technicians and system engineers.

The inspectors found that the system engineers have a general familiarity with planned maintenance (PM) procedures for their associated systems. In addition, changes to PMs, though written by NMD, are now reviewed by the system engineers to determine if these changes must be submitted to POSRC for approval. This is a recent policy change that was implemented through a January 11, 1988 Plant and Project Engineering memorandum to all system engineers written to reflect a recent NESD/NMD agreement.

With regards to non-routine maintenance and repairs, the inspectors determined that generally the system engineers were not knowledgeable of these items with the exception of high priority issues about which they were specifically notified by NMD. The system engineers are not routinely routed nor routinely review maintenance orders (MOs). Many of the system engineers do not routinely review the computerized MO lists for their assigned systems. The frequency of review often varied from quarterly to semi-annually. This listing

is readily available from a computer with terminals located inside the protected area and inside the engineering facility. When requested for a listing of all MOs worked on the Unit 1 salt water system in 1987, several NESD personnel were unable to produce this listing until the last day of the inspection due to an unfamiliarity with the computer program. This precluded the inspectors from examining the NESD/NMD interfaces demonstrated in 1987 in response to equipment malfunctions in the Unit 1 salt water system.

Nuclear Engineering Services provides overall technical support to site operations and maintenance. The engineering department consists of Design Engineering, Plant and Project Engineering and Technical Services Engineering. Each group is headed up by a General Supervisor. While the engineering department went through a major reorganization approximately two years ago, changes in the organizational work load continue to be implemented in order to achieve optimum work load distribution, especially in the plant projects engineering and major projects engineering.

Based on discussions with principal engineers, the licensee identified two areas of concern:

1. Excessive work load assigned to system engineers. This problem is being addressed by the reassignment of responsibility for major facility change requests from the system engineer to the project engineers.

2. Backlog in updating critical drawings (P&ID's are considered critical and are updated within 72 hours of the issuance of a drawing change request (DCR)). All other drawings are being updated by twenty two contractor draftsmen as a part of a special program to be concluded by March 31, 1988. There are no long term plans to continue with the update program to address future DCR's. The licensee will rely on existing staff to change and update drawings as work is accomplished.

d. Processing of Facility Change Requests

The inspector noted that the successful development of completed plant modification packages, identified as Facility Change Requests (FCR's) by the licensee is based on a close working relationship amongst all engineering services and interfacing with operations and maintenance departments. The governing procedure in this area, CCI-126 H, Administrative Control of Facility Change Requests, reviewed by the inspector in draft format, has been issued for final comment. The procedure details responsibilities for the design, installation, testing, and turnover of FCR's based on a team building concept, requiring close working relationships between engineering, maintenance and operations departments.

The inspector reviewed selected sections of the following work packages:

- FCR 80-1010, Reactor Vessel Level Indication
- FCR 85-1048, Main Steam Isolation Valve Changeout

These modifications were accomplished in accordance with a previous revision of proceedure CCI-126, in which responsibilities for managing the project were not clearly defined. While no problems concerning the above FCR's were noted by the inspector, the final status for installation and close out of FCR 80-1010 was not clear from the modification package.

e. Control of Technical Manuals

Technical Manuals were controlled by the Technical Librarian in accordance with licensee procedure CCI 122D. The inspector verified through interviews of systems engineers that the requirements of the subject procedure were generally met and technical manuals were properly reviewed for accuracy upon receipt from the vendors.

f. Independent Design Reviews

The inspector verified that the Design Engineering Section Procedures DESP-6, Calculations and DESP-7, Design and Design Review, met the intent of ANSI N45.11 and established the requirements for the performance of design reviews by the use of alternate calculative methods. The checking process was being implemented by three qualified engineers. The inspector reviewed the calculation review records for the following design verifications or design changes.

- M87-21, High Pressure Safety Injection Pumps Flow, to determine if sufficient NPSH was available at the suction of the HPSI pumps,

- M87-17, Component Cooling Water Pumps, to calculate shaft stresses based on loading conditions, and

- FCR-87-45, Low Pressure Safety Injection Pump, to verify vent line rigidity requirements.

The inspector concluded that the independent design review program was effectively implemented by the licensee.

g. Summary

The System Engineer's position as the key person for system knowledge did not yet appear to be functioning as intended as evidenced by their limited review of surveillance test results and ongoing maintenance work as well as non-standard walkdown practices. There was insufficient Engineering involvement in surveillance testing and IST program changes for pumps and valves, particularly for the salt water system. Although the independent design review process appeared effective, one change involving decreased salt water system flow rate may have insufficient evaluation of whether it involved an unreviewed safety question and comparison with original pre-operational testing data.

5. Surveillance Testing

The surveillance test program was reviewed to verify that the licensee had developed, maintained, and implemented written procedures and administrative policies necessary to ensure the operability of safety-related systems. Approved Surveillance Test Procedures (STPs) were reviewed for technical adequacy and to verify that test acceptance criteria included specific Technical Specifications (TS) and Inservice Inspection and Testing requirements. Several surveillance tests were witnessed to verify proper conduct, documentation, and resolution of identified problems. Discussions were held with operators, technicians, engineers, planning personnel, and first-line supervisors to determine their understanding of and involvement in the test program.

a. Surveillance Test Program Implementation

Implementation of the Surveillance Test Program is described by Calvert Cliffs Instruction (CCI) 104H, Surveillance Test Program. Additional guidance associated with implementation of this program is contained in CCI 101J, Review And Approval Procedures For Proposed Calvert Cliffs Procedures, and GSO Standing Instruction 86-1, Surveillance Testing.

CCI 104H outlines the administration of the program and station personnel responsible for ensuring that the program is implemented effectively and correctly. This instruction also describes the preparation, review and approval, scheduling, performance, and results review of Surveillance Test Procedures (STPs). Details for processing changes and revisions to STPs are described in CCI 101J.

The inspector discussed the implementation of this program with the Surveillance Test Coordinators and Scheduling Coordinators for Operations/Inservice Inspection, Maintenance, Electrical and Controls, Fire Protection, and Engineering. The STP schedules for several months were reviewed to verify TS required frequencies were met.

Through interviews of station personnel and review of the STP program and several STPs, the inspectors identified two concerns. These are: a lack of specific guidance on a formal method to ensure that temporary changes to procedures are incorporated into future test performances and revisions and, the distinctions between intent and non-intent changes to procedures.

When temporary changes need to be made to an STP they are written into the body of the procedure. CCI 104H provides a PM/STP Feedback Sheet which is attached to all Maintenance and Electrical and Controls (E&C) STPs. The information required on this sheet includes any temporary changes which were made and suggestions to improve the procedure. These feedback sheets are forwarded to the Maintenance and E&C Scheduling Coordinators who must ensure that the changes, if permanent, are made to the test copy of any subsequent performances before a revision is issued. They also must ensure that these changes are incorporated into the next procedure revision. This has been accomplished by putting a copy of the feedback sheet into the master test file. Operations/ISI and Fire Protection STPs, however, have no feedback sheets or other formal method of assuring that changes are carried into future performances and revisions.

An example of this was identified during reviews of several sequential performances of STP O-73-1, ESF Equipment Performance. During the period between September 21, 1987 and December 23, 1987, substantial changes were made to the portions of the procedure which tested the Salt Water pumps. These changes were inconsistently and in some cases incompletely carried in the body of the procedure through this period. The memory of the Surveillance Test Coordinator has been relied upon to verify that any changes are included. During discussions of this matter with operations personnel, the inspector was informed that other operations procedure changes are tracked by the use of CCOM Change Reports. CCI 300H, Calvert Cliffs Operating Manual (CCOM), describes the use of Plant Operating Procedures, Operating Instructions, Emergency Operating Procedures, and Abnormal Operating Procedures. When changes are necessary to these procedures, a CCOM Change Report Form is completed. These changes are numerically identified and are therefore traceable. The form also provides a space for specifying if the change is permanent or one time only. The inspector found the use of this form to be an effective control of changes to operations procedures.

The inspector also noted that CCI 104H provides a brief description of changes to procedures, specifically, those that alter the procedure intent and those that do not. No guidance is given for determining if a change changes the intent of the procedure. During discussions with several shift supervisors, the inspector questioned the instructions given to determine procedure intent. Personnel expressed

varying opinions of what constitutes an intent change and how to determine procedure intent. This situation is complicated by the fact that, in general, STPs do not contain an objective or purpose paragraph in the beginning of the procedure. Shift Supervisors generally rely on a detailed review of the procedure and the applicable TS requirement to determine procedure intent.

b. Surveillance Test Observations

During the inspection period, the inspectors observed performance of several STPs. The inspectors verified procedure adherence, complete and accurate documentation, and adequate resolution of problems encountered during test performance. Personnel were found to have adequately reviewed the tests, to be knowledgeable of systems tested and procedural requirements. No concerns were identified.

Surveillance tests witnessed included:

- STP-0-05, Auxiliary Feedwater System Test
- STP-0-6-2, Reactor Protective System - Startup Test
- STP-0-8-0, No. 11 Diesel Generator Testing
- STP-0-29-2, Control Element Assembly Partial Movement
- STP-0-33-1, Radiation Monitoring System Functional Test
- STP-0-47-1, Main Steam Isolation Valve Partial Stroke Test
- STP-0-71-1, Staggered Test of 'B' Train Components

c. Review of Completed Surveillance Test Procedures

Several completed STPs were reviewed from each discipline. The inspector verified that the tests were conducted in conformance with TS, ISI, and procedural requirements; had received the proper reviews; were performed at the required frequencies; and that appropriate action was taken for deficiencies identified. The following concerns were identified.

STP-0-7-1, Engineering Safety Features Logic Test, performed on October 8, 1987, contained steps which could not be performed due to plant configuration. At this time, the #13 Salt Water Pump and two Hydrogen Purge motor-operated valves were out of service. Steps involving this equipment were inconsistently marked to indicate that they were not performed. Some were left blank, some marked N/A (Not Applicable), others marked T/O (Tagged Out). In several other procedures it was noted that temporary procedure changes were processed. Similar inconsistencies were found in STP-0-65-2, Quarterly Valve Operability Verification, performed on June 30, 1987 and STP-0-73-1, ESF Equipment Performance Test, performed on December 23, 1987. CCI 104H and 101J do not contain instructions on actions to be taken when plant configuration precludes test step performance. When questioned, station personnel cited the above mentioned alternatives when it is impossible to perform a step.

STP-0-5-1, Auxiliary Feedwater System, performed on October 30, 1987, is the monthly verification of Auxiliary Feedwater System (AFW) operability. During performance of this test, it was identified that the 11 and 12 AFW pumps were not putting out the required flow. It was determined that a check valve (1-AFW-202) on the 13 AFW recirculation line was leaking by and causing the flow readings for the 11 and 12 pumps to be low. The licensee elected to isolate this leak for the test by closing a normally locked open valve (1-AFW-186) upstream of this leaking check valve. This alignment had the potential for degrading No. 13 AFW pump operability in that, in certain accident and transient situations, this pump operates in the recirculation mode in standby. With valve 1-AFW-186 closed, there might not be sufficient capacity in the pump minimum flow line to prevent overheating during extended operation in this mode. This evolution was performed and the required data obtained without processing a temporary change. Technical Specifications 6.8.3.b. and CCI 101J, Review and Approval Procedures for Proposed Calvert Cliffs Procedures, Section V.B.2 requires that when a temporary procedure change is necessary that, before the evolution is performed, the changes be written into the procedure and reviewed by two members of station management, one of whom must hold a Senior Reactor Operator's License on the affected unit. This review is to be documented next to the applicable steps with the reviewing personnel's initials and date. In this example, procedure steps for closing the locked valve were not added to the procedure and did not receive the required reviews. This is a Violation (50-317/88-01-04 and 50-318/88-01-04).

The inspector reviewed the turbine building operators' logs for the day of this test to determine if the 1-AFW-186 was returned to its normal position. No entries relating to this valve were found. Also, a locked valve deviation sheet was not filled out prior to changing the valve position. However, STP-0-93-1, Locked Valve Verification, was performed on November 5, 1987. This valve was verified to be locked open on this date.

Additional examples of inadequate temporary changes to procedures were identified in the June 30, 1987 and September 23, 1987 performances of STP-0-65-2, Quarterly Valve Operability Verification. Many changes were made to the procedures, including addition and deletion of steps, which did not receive the second review until after the test had been completed. These are additional examples of the above violation.

TS 6.8.3.a and CCI 101J also require that these temporary changes made to procedures be reviewed by the Plant Operations Safety Review Committee (POSRC) within fourteen days. The inspector noted that these reviews have indeed been completed as required. However, it is station practice to have the STP with changes orally presented to

POSRC instead of distributing copies of the completed procedures with changes. Because of this practice, it is possible for procedures with inadequate or inappropriate changes to be reviewed and approved by POSRC without being aware of such changes.

Finally, the inspectors were concerned over the amount of iterations necessary until the correct baseline flow values for the AFW pumps were determined. The original baseline data for the AFW pumps was taken in June 1987 using the monthly STP-O-5-1 and O-5-2 with added steps to measure flow on the common recirculation line back to the Condensate Storage Tank (CST). System configuration for the turbine driven AFW pumps during this test had one pump running and the other pump idling. Through a series of iterations with tripping the idling turbine driven pump and closing 1-AFW-186, it was discovered in October 1987 that the initial baseline flow data were incorrect. This scenario indicates poor initial system configuration control and test data evaluation.

d. Summary

The Surveillance Test Program was generally found to be adequate. STPs were technically sound and were scheduled and performed adequately. However, there is a need for more attention to details in the documentation, changes, and review of the completed surveillances. Also, more detailed guidance needs to be provided for personnel to more adequately and uniformly fulfill the requirements and intent of the test program.

6. Licensee Overview Activities

a. Plant Operations and Safety Review Committee (POSRC)

(1) The inspector reviewed administrative procedures and guidance to verify that the POSRC was in conformance with regulatory requirement with respect to composition, duties and responsibilies. A sample of POSRC meeting minutes was reviewed to verify meetings were conducted per administrative and regulatory requirements. The number of meetings held by POSRC in 1986 and 1987 was verified to satisfy regulatory requirements. POSRC met 112 times in 1986 and 119 times in 1987.

Inspectors attended three POSRC meetings, 88-03, 88-04, and 88-05. Two of these meetings were scheduled to conduct normal POSRC business and the third was to perform a Post Trip Review. The inspector interviewed the POSRC chairman and several POSRC members. Documents reviewed during this inspection are listed in Attachment 3.

(2) Findings

Based upon the above review the following observations were made:

- The Manager - Nuclear Operations is the chairman of the POSRC per Technical Specifications (T.S.). The POSRC function is to advise the Manager-Nuclear Operations on all matters related to nuclear safety. These two T.S. requirements may conflict if the POSRC Chairman directs the meeting to the extent that POSRC recommendations to the Manager - Nuclear Operations simply reflect his/her own point of view. To alleviate this concern, Calvert Cliffs Nuclear Power Plant (CCNPP) POSRC rotates among the members the role of facilitator, who conducts the meetings. The Chairman acts only as an observer to the meeting, offering casual comments. POSRC started using a facilitator to conduct its meetings at the beginning of 1988. This is viewed as a potential strength by helping to assure that an independent assessment on matters related to nuclear safety is provided to the Manager-Nuclear Operations.

- The POSRC was observed to provide detailed interdisciplinary reviews of various safety concerns brought to its attention. Included in this observation were POSRC reviews of the proposed Licensee Event Report (LER) for the loss of load trip for Unit 2 on December 21, 1987; the temporary modification of the Auxiliary Feedwater (AFW) Logic Cabinet; and the Post Trip Review following the January 22, 1988 Unit 2 trip. The POSRC review of these subjects appeared comprehensive and thorough.

- The POSRC has implemented a good program for assigning responsibility and following up on action items it identifies. Due dates were observed, actions were complete and thorough and POSRC involvement was evident.

- The POSRC meetings observed by the inspector were well attended with representatives from all major disciplines. In addition to the required membership, it was noted that the General Supervisor - Quality Assurance took an active part in the meetings. The licensee was planning to formally increase the size of the POSRC by two members, one of which will by the General Supervisor - Quality Assurance.

It appeared that some items were not as well researched and coordinated as they could have been. Two examples where better preparation and coordination by the resonsible individual were needed, were with the proposed LER for Loss of Load for Unit 2 and the AFW temporary modification procedure. Because the POSRC does a thorough review of subjects brought to its attention, these subjects were reviewed in sufficient detail during the meetings observed by the inspector.

b. Off Site Safety Review Committee (OSSRC)

(1) Program Review and Implementation

The inspector reviewed the administrative program which defined the composition, functions and duties of the OSSRC for conformance with regulatory requirements. The previous two years of OSSRC meeting minutes were reviewed to verify and evaluate:

- The adequacy of OSSRC reviews of all audits, LER's, regulatory violations, Technical Specifications (T.S.) changes, proposed modifications, tests or experiments, design deficiencies and POSRC minutes and reports.

- The committee's composition with respect to the disciplines and expertise required by T.S., as well as meeting the quorum requirements of the T.S.

A sample of audits conducted under the auspices of the OSSRC was reviewed in order to evaluate the quality and depth of the audits and their conformance with T.S. requirements. OSSRC members, including the past and present OSSRC Chairmen and the Vice President - Nuclear Energy, were interviewed to determine the effectiveness of the OSSRC in meeting its responsibilities. The documents reviewed are listed in Attachment 4.

(2) Findings

The OSSRC has recently made some changes to the way they are organized and conduct business. Most of these changes and proposed changes appear to be positive, however, at the time of this inspection it was to premature to assess their effectiveness. Those changes or proposed changes which appear positive are:

- The present OSSRC chairman is an offsite member. Until his appointment, it was planned to rotate the chairmanship among the onsite members.

- All QA audits are performed under OSSRC approval. An OSSRC member is assigned responsibility for monitoring each audit performed. Prior to the audit, the audit team contacts the responsible OSSRC member to discuss the audit and obtain any additional guidance the member may have to offer. At the conclusion of the audit, the OSSRC member is briefed on the audit findings. In addition, the OSSRC member prepares an audit summary evaluation of the completed audit report. It was noted that some OSSRC members do a more thorough review than other members. The mixed performance of OSSRC members in this oversight function potentially can affect the overall quality of the auditing activity.

- The audits reviewed showed a marked improvement over the past two years in the quality of the audit and the explicitness of the findings. The audit findings noted by the inspector focused on safety significance. This was a result of OSSRC challenging the QA group to be more direct in their audits.

- OSSRC recommended that an independent Safety System Functional Inspection (SSFI) of the Auxiliary Feedwater System be performed. This was completed in 1987 and based on the results, the OSSRC recommended a second SSFI be performed in 1988. (See Section 6.c below for further details).

- The OSSRC met six times in 1986 and eight times in 1987. Four meetings are scheduled each year, the rest of the meetings were on a "as required" basis. The new OSSRC Chairman plans on having six scheduled meetings per year to allow a more thorough review of the items and provide more training to the offsite members. All scheduled meetings were well attended.

- The new OSSRC Chairman has proposed adding two new offsite members to the committee - one of the new members would be a member of another nuclear power plant.

c. Safety System Functional Inspection (SSFI)

In the fall of 1987, the licensee conducted an independent SSFI of the Auxiliary Feedwater System. This was a joint inspection, consisting of eight licensee and three contractor personnel, which took ten weeks to complete. The inspection resulted in 44 observations which were reduced to 17 Findings and 11 Recommendation. Results of the inspection were presented at the POSRC, the OSSRC and the Vice President - Nuclear Energy. POSRC identified six open items requiring immediate attention.

The SSFI activity was considered to be a strength for the following reasons:

- It demonstrated good licensee initiative.

- It was a systematic and well planned effort. The applied inspection resources were extensive and resulted in a detailed review of the AFW system.

- Licensee personnel worked in a joint team with an experienced contractor as a learning exercise to develop in-house capabilities for future SSFI efforts.

- Findings with potential immediate safety significance were promptly considered by POSRC to determine their impact on operability.

- Licensee management and design engineers were thoroughly briefed on findings.

Although the SSFI had been handled well at the time of the inspection, it was too early to assess long term followup and closeout of findings. Because of the insights into system design/modification/testing interface problems and inconsistencies identified by the SSFI, the licensee was planning on performing a second SSFI in 1988.

d. Quality Audit Unit (QAU)

The QAU has responsibility for generating the audit schedule, coordinating each audit with the OSSRC, performing the audit, and presenting audit findings to the appropriate Department Manager and the OSSRC. During the past year the QAU had initiated an evaluation program. These were voluntary independent audits performed at the request of the Department's Manager for his Department. Findings were written as recommendations and sent to the Manager. The Manager had the option of accepting or rejecting the recommendations. The Vice President - Nuclear Energy received copies of all recommendations.

The inspector reviewed several audits, audit findings, evaluation and recommendations (listed in Attachment 5) and found them to be thorough and well written. The findings and recommendations were clearly stated and meaningful. One problem noted was the lack of an automated tracking system to monitor commitments made on open items. The QAU has begun trending audit results. These trends are periodically presented to the OSSRC.

e. Communications Meeting

Approximately four to five times a year the licensee holds meetings with all of the upper level plant staff including engineers. At these meetings topics of current interest to the employees are presented by upper licensee management. The inspector monitored the meeting held on January 29, 1988. Presentations were made by the President, Vice President - Nuclear Energy, the Managers of Operations and Nuclear Engineering and a specialist. The subjects were current, candid and open to discussion.

f. Summary

The POSRC activities observed were considered to be effective based on the level of detail of the reviews conducted, membership attendance at meetings and the tracking system for action items. Recent initiatives to strengthen the OSSRC and improve its independence were considered to be positive. The voluntary independent audit function and the Safety System Functional Inspection both appeared to be good licensee initiatives.

7. Organization and Interfaces

The inspector examined two aspects related to the management of CCNPP. The inspector considered the structural components of the organization and the interfaces those components have with each other. The inspector utilized a model or framework for viewing the organization. This model considered six structural components as follows:

1. Communication system
2. Decision Making system
3. Accountability system
4. Reward/Recognition system
5. Reporting Relationship system
6. Cultural/Behavioral Norms system

Attachment 2 goes into some depth in discussing management structure and interfaces, presenting several examples found during the inspection. Below is a brief summary of some of the highlights found in that Attachment.

a. Communication System

The managers, supervisors, and key employees utilize both formal and informal communication systems. Such dual communication systems are entirely appropriate and are found in all organizations. Of importance to NRC is that the formal communication systems work well, especially as they relate to safety of plant operation, and that the informal systems do not interfere with effective operations and do not hinder the accountability tracking system so important to determining root cause of safety related problems. There is some evidence that due to the managerial structural design of the organization

(interface between Departments) communications is not always as efficient or effective as employees or management desire. In addition, due to the physical design of the plant (inside vs. outside the fence) certain organizational components (System and Design Engineers) have experienced difficulty meeting with other plant personnel and hence effectively communicating. Licensee management recognizes some of these problems and was implementing programs to improve communications. They included several efforts such as the following:

(1) The 1987 Opinion Survey was an illustration of management desire to learn about employee concerns in an effort to improve relationships.

(2) Team building and conflict/hostility resolution training for managers/supervisors was an example of positive interest and effort to deal with issues brought out in the Opinion Survey, i.e., more collaborative decision making.

(3) Establishment of various regular formal meeting opportunities among key staff from the different Departments and work units, i.e., maintenance management meeting at 6:30 AM, the daily 8 AM staff meeting, etc.

(4) A plan to move certain System Engineering functions "inside the fence" so they will be closer to the customers they service.

b. Decison Making System

The inspector found that licensee management was attempting to bring about a culture of collaborative decision making to the lowest levels of the organization. Such a culture appeared appropriate for operation within a matrix organization and within an industry concerned with operating a technology with a large variety of interrelated systems, as that found at CCNPP. Examples of such collaborative decision making were found in the following:

(1) Formalization of the Project Management/Matrix Management system in the Department of Engineering.

(2) The restructuring of the "Work Planning Committee" from top management to mid-level management.

(3) The POSRC group which makes its recommendations for a decision to the Manager, Nuclear Operations rather than having the Manager make the decision as "part" of the group.

c. Accountability System

The Nuclear Division utilized specific performance objectives for each manager/supervisor based upon the goals outlined in the Nuclear Program Plan (NPP). These performance objectives, in conjunction with the Performance Appraisal system, hold individuals accountable for implementing the goals of the Nuclear Division. Review of Managers' Performance Objectives indicated a positive relationship between objectives and the NPP. Interviews with managers and supervisors indicated that they were indeed held accountable for accomplishing their objectives.

d Reward/Recognition Systems

Licensee management seems to utilize both formal as well as informal positive rewards as methods of recognizing performance. Some of the formal approaches utilized are employee of the month, various safety awards, positive feedback notices on bulletin boards, training plaques, cash bonuses, etc.

The inspectors noted that informal recognition was used freely by both the Managers and General Supervisors. At various meetings, inspectors noted a good use of positive public recognition between participants for work efforts. An example was that of a supervisor publicly thanking another for some special effort. Such recognition was noted at several meetings. Non-public recognition was also noted when the Manager, Nuclear Operations privately and personally recognized one of the key members of the POSRC meeting after a discussion and analysis of a plant trip.

e. Reporting Relationship System

Although the licensee organization does have a formal organization chart indicating formal lines of reporting, the inspector noted that the Division works in a matrix environment. Such an environment can leave unclear lines of reporting and responsibility. The inspector found this to be true in particular areas such as in the Engineering and Maintenance Departments. The inspector noted that the current draft of the matrix management structure and responsibility description of those participating (engineers, etc.) seemed to create confusing reporting relationships.

Project management program charts were found to be excellent communication tools. The printed reports clearly communicated responsibilities, time constraints, and demands on resources. The charted schedules reassured those involved in the project of their roles and when they were expected to execute them.

The inspector noted some confusion in understanding work roles among various groups of employees, namely among groups in the Engineering Department, Procurement Unit, and Maintenance Department. This confusion resulted in difficulty in establishing meaningful priorities and getting certain work accomplished. Additional clarification of work role perception by the individuals serving in a position and by those he/she interfaces with is needed. The inspector also reviewed the draft "Working Relationship Policy." It was considered to be a positive effort. However, it did not clearly indicate specific delegation of authority of the VP, although in interviews with Managers and General Supervisors there was general recognition that the Manager, Operations was in charge when the VP was absent.

Some clarification of the above issues appears to be needed.

f. Cultural/Behavioral Norm System

The inspector noted the effort of licensee management to enhance the work culture of CCNPP. It appeared that a positive work ethic prevails and that employees have a strong desire to improve the Nuclear Division. Collaborative management, as a desired behavior style, was beginning to be accepted and was considered desirable by supervisors and staff. The emphasis on effective equipment operation rather than generation goals appeared to be accepted as desirable by employees.

g. Summary

Collectively, several positive management activities were considered to be licensee strength. These included the following actions recently completed or in progress.

- Use of an opinion survey to assist in identifying potential problems and perceptions.

- Team building/conflict resolution training and exercises.

- The number and diverse types of meetings that were being utilized to enhance communications.

- Measures taken to implement collaborative decision making thereby involving more staff members at lower levels in decision making.

- An effective accountability system in combination with a good formal and informal reward/recognition system.

- Recent management emphasis on improving plant material conditions with some corresponding deemphasis on generation.

8. Exit Meeting

Meetings were held with senior facility management personnel periodically during the course of the inspection to discuss the inspection scope and findings. Key supervisory and management personnel contacted during this inspection and present at the exit meeting are listed in Attachment 1. A summary of inspection findings was further discussed with the licensee at the conclusion of the inspection on January 29, 1988.

ATTACHMENT 1

Persons Contacted

The following is a list of key supervisory or management personnel contacted during this inspection and present at the exit meeting. There were other technical and administrative personnel who were also contacted.

Baltimore Gas and Electric Representatives

E. A. Crooke, President and Chief Operating Officer
J. A. Tiernan, Vice President, Nuclear Energy
J. R. Lemons, Manager, Nuclear Operations
W. J. Lippold, Manager, Nuclear Engineering Services
R. M. Douglass, Manager, Quality Assurance and Staff Services
L. B. Russell, Manager, Nuclear Maintenance
R. P. Heibel, General Supervisor, Nuclear Operations
N. I. Millis, General Supervisor, Radiation Safety, Nuclear Operations
L. A. Sundquist, General Supervisor, Quality Control and Support, Nuclear Operations
P. E. Katz, General Supervisor, Design Engineering, Nuclear Engineering Services
M. E. Bowman, General Supervisor, Technical Services Engineering
J. T. Carroll, General Supervisor, Quality Assurance
S. E. Jones, Jr., General Supervisor, Planning and Support, Quality Assurance
W. J. Whitaker, General Supervisor, Mechanical Maintenance
M. F. Roberson, General Supervisor, Quality Control and Support Services, Nuclear Maintenance
R. L. Wenderlich, General Supervisor, Electrical and Controls, Nuclear Maintenance
R. P. Sheranko, Project Manager
R. J. Smialek, Assistant General Supervisor, Radiation Control and Support, Nuclear Operations
J. R. Hill, Operations Training Supervisor, Quality Assurance and Staff Services
J. R. Lohr, Assistant General Supervisor, Nuclear Operations
C. R. Mahon, Principal Engineer, Primary Systems Engineering, Nuclear Engineering
R. R. Allen, Principal Engineer, Performance Engineering, Nuclear Engineering
A. B. Anuje, Supervisor, Quality Audits, Quality Assurance and Staff Services
W. R. Cartwright, Engineer, Nuclear Operations
R. M. Somers, Assistant to the Vice President
S. R. Cowne, Senior Licensing Engineer
K. M. Romney, Senior Engineer, Audit Unit, OASD

ATTACHMENT 2

Additional Details Regarding Review of Organization and Interfaces

The inspector examined two aspects of the Calvert Cliffs Nuclear Power Plant (CCNPP), the organizational structural components and the interfaces of these structural components. An assessment of effectiveness of management was considered but a thorough evaluation of this aspect of the operation of the Division was not made.

In January 1986, BG&E underwent a major reorganization. The CCNPP was reorganized into the Nuclear Division (NED) led by a Vice President. Under the VP, four Managers of major departments Operations (OP), Nuclear Engineering Services, (NES), Quality Assurance and Staff Services (QA & SS), and Nuclear Maintenance (NM)) were established. Reporting to each of these Department Managers were General Supervisors responsible for particular areas.

This change placed stress on the new organization. Examples of stress areas were:

a. Relocation of an engineering group from Baltimore to the Calvert Cliffs area.

b. The establishment of new work roles and work relationships among the newly constituted work groups.

c. The establishment of new or modified policies/procedures for various work groups as well as the Division.

d. Equipment outages and other plant problems which occurred during the early period of reorganization.

During the first eighteen months of NED's operation, management (VP and Department Manager level) concentrated on formalizing the new organizational structure and resolving the technical problems associated with the plant.

1. CCNPP Opinion Survey

In an effort to sense the "pulse" of employee perceptions of Division operations, an "All Employees Opinion Survey" was conducted in August 1987, by the Psychological Services Department located at the corporate level. This comprehensive survey designed specifically for CCNPP elicited candid opinions from all employees about their personal perceptions of management, plant operations, etc. The survey was analyzed and results sent to

management in the beginning of October 1987. The results were issued in the form of statistical data as well as antitotal data for individual units and the Division as a whole. The results of this survey were viewed in the context of the "environmental" conditions at the time the survey was administered. At that time, the plant was experiencing a major outage and a major maintenance work and overhaul. In addition, the Nuclear Division had recently received negative reports from NRC regarding EQ violations.

The major views expressed in this opinion survey were as follows:

- Employees would like to see an increase in coordination between various functions. They generally felt that work group members did not plan or schedule work well together. The Engineering Group specifically indicated dissatisfaction with integrated priority setting systems between groups. (The other departments did not feel as strongly about this issue as Engineering.)

- Employees indicated a strong desire for increasing their technical skill and knowledge, and a strong desire for advancement possibility. Employees generally perceived that their job did not provide chances for advancement, that they did not have influence over their jobs, and that work life was controlled behind closed doors. Employees indicated a strong motivation for improvement of their skill and knowledge but perceived that the company did not place enough emphasis on training and development and that the company did not help keep technical skills current. These perceptions were not universally shared as the Engineering Group felt the strongest about a lack of training and development.

- Employees expressed their feelings about the recent reorganization of the NED. They felt management should explain it better -- the purpose and how it will work. Employees saw the organization under increased stress compared to the previous organization. Employees were concerned and wanted to improve operations, they saw a need for increased concern for operational substance and less concern for outside "image" making. The survey generally indicated that the NED employees were a group of positively committed highly motivated and interested employees who wanted to perform their tasks well, had a strong desire for professional advancement, and an interest in improving the operations of the plant.

  Management has utilized the results of this survey to improve human resource as well as plant operational conditions in the Nuclear Division. The company is making a concerted effort to involve people in a more collaborative approach to management and decision making in all areas of the plant, beginning with the Department Managers. An

example of this was the reformatting of the "Work Management Committee" from that of VP and the four Department Managers to one made up of the General Supervisor level of management [Operations, Design Engineering, Plant and Projects Engineering, Planning and Support, Mechanical Maintenance, and Electrical and Controls.] This newly constituted (January 1988) committee will be given the responsibility and authority to make decisions related to priorities of work in the plant. The inspector understood that the committee will also be held accountable for the decisions it makes.

The following lists several other major activities management has instituted to improve the human resource and plant operations:

a. The VP revised and issued Power Availability Goals for CY 88. These goals did not specify the amount of power to be generated. The VP and other managers explained that the reason for this was to emphasize improvement of plant material conditions. This goal has become part of the Division's Nuclear Program Plan and has been translated into specific Performance Objectives for Managers and Supervisors. This goal has established the "philosophy" of the organization, that being to provide safe plant operation and to maintain equipment so the plant will be able to reliability produce power in the 1990's and beyond. To this end the plant planned an outage during February/March 1988. At that time, maintenance work was to be performed on several of the major systems. Such goals and related actions indicated a proactive approach in regard to safety and optimal plant operation on the part of management.

b. The VP and Departmental Managers recognized the need to improve interdisciplinary collaboration among themselves as well as all levels below. To this end a variety of formal and informal management structures have been established as well as training activities. Among these were:

- Reconstituting the Work Management Committee as described above.

- Establishing quarterly planning and problem solving meetings of the VP and Department Managers.

- Defining and formalizing the matrix management (Project Management) structure in the Nuclear Engineering Services area. This includes the creation of an expanded role definition of the system engineer, the development and implementation of a Project Management training course, and the responsibility charting of key interface groups.

- Establishment of a daily general staff meeting (8 AM Meeting) led by the GS Operations. The purpose of this meeting is to overview plant operations among and between the General Supervisory management level so that daily activities are coordinated. Several of these meetings were attended by the inspector who observed a significant amount of preparation and discussion by participants.

- Establishment of a maintenance scheduling meeting three days per week (11 AM meeting Mon., Wed., Fri.) at which time OP, NES, QA, and Maintenance discuss current work schedules and status of maintenance projects. Again the individuals involved appeared prepared for the discussion/decisions required.

- Establishment of the Thursday PM General Management Meeting at which time there is an updating of key activities, review of major projects in progress, discussion of budget, goals and objectives, schedule review and status up date. Participants were well prepared, a printed agenda was distributed and open cross discussion was held.

2. Delegation of Authority

During a previous inspection by NRC, some question was raised by NRC relative to who has delegated authority for CCNPP's effective functioning in the absence of the Vice President. Interviews with all Department Managers indicated unanimous agreement that the Manager, Nuclear Operations is in control (control seems to mean that of "operations" but, it was not clear from these interviews, if the Manager, Nuclear Operations has full delegated authority for all the functions of the VP. Does he assume general authority over the other Department Managers?) during the absence of the VP. CCNPP has addressed this question by revising its "Working Relations Policy - CCNPP" (Corporate Study 11-82-A, Draft Revision #4, January 1987). The inspector found that the document did not clearly describe the VP's delegation of authority to the Manager, Nuclear Operations. The document, furthermore, did not indicate specific delegation of authority for the other Department Managers. The inspector pointed out that CCNPP should consider specifying delegation of authority for the VP as well as the Department Managers in this document.

3. Establishing Performance Goals

BG&E utilizes a modified Management by Objectives system. BG&E has an annually developed Corporate strategic plan. The CCNPP has translated this plan into a Nuclear Program Plan. The Nuclear Program Plan (NPP)is broken into two parts -- a yearly plan and a long range plan.

The NPP is revised each year and developed by the VP and Department Managers with input from sub-units as well as the Corporate level. A comparison of the Corporate plan and the NPP indicates a direct correlation. The yearly plan for 1988 had five major goal areas each consisting of numerous specific sub-goals.

From the NPP, specific Performance Objectives are developed for the VP, each Department Manager, and each General Supervisor. These Performance Objectives become one of the major factors in an employees' yearly Performance Appraisal. Beginning in January of each year, all managers and supervisors develop Performance Objectives which they will be held responsible for completing that year.

Individual supervisors and managers appeared to take their Performance Objective plans seriously, thus the NPP is also taken seriously. Meeting their goals was one of the important factors in earning a reward/bonus at the end of the year. Thus, BG&E rewards managers for performance. A spot check of each of the Department Managers and several of the General Supervisors and supervisors showed that they were currently developing their Performance Objective plans. Of those plans reviewed, there was a direct correlation of Performance Objectives with the NPP. According to the proper functioning of a Management By Objectives System, CCNPP appears to be utilizing the most effective method for "getting" work accomplished.

4. Communications and Planning Interfaces

Planning and attending meetings is an important time consuming activity at CCNPP. Various groups of managers, supervisors, professionals and support personnel gather periodically during the day/week at a variety of meetings to conduct planning/scheduling activities. These meetings provided opportunities for various functional groups to interface and "workout" common problems. Management recently created several of these "meetings" in an effort to bring about more coordination and to encourage more collaborative decision making. Such interface is conducted on a formal as well as informal basis. Generally, CCNPP utilizes a combination of two formal approaches, formal reports and meetings.

The inspector attended numerous meetings and observed a good flow of information. Participants were encouraged to communicate, although there was not too much cross talk. Meetings were run efficiently, were usually short and to the point. Support personnel were usually prepared with appropriate schedules, data and reports. There was a positive attitude among those in attendance. After meetings adjourned participants usually continued informal discussion of issues. This might cause a potential problem in that these "private" discussions did not become matters of awareness for other group members.

Planning was also carried out within specific departments which have established specific planning units. These planning units must interface with their counterparts in other departments as well as with line employees (i.e., Maintenance Planning with System Engineers). One of the major issues of concern regarding interfacing between various work units was that of establishment of priorities between and in some cases within Departments. Inspectors found that what might be a high priority for Maintenance might be considered a lower priority for Engineering. The various planning meetings referred to above attempt to clarify and ameliorate such differences, but these meetings may not be sufficient, may only satisfy particular concerns associated with the charter of the meeting group, or may be the inappropriate communication vehicle for setting priorities. Several examples of conflicting priority setting are pointed out in this report (the procurement process is one example, preventive maintenance may be another).

Another example was between the Maintenance and Engineering units. One of the major results of the January 1986 Reorganization was the removal of the Maintenance function from Operations to a new Maintenance Department. To coordinate maintenance activities with the OP Department, a Maintenance Coordination function was established within OP. The OP/MC group reports to the GS of Operations. This group sets its maintenance priorities by scheduling daily maintenance meetings with other departments (at the 6:30 AM meeting and other meetings), chairs monthly review group meetings, plans future work, prepares FCR's, etc. The reorganization also established within the Maintenance Department a Planning Coordination unit whose role was to interface with OP and Engineering. Most safety related maintenance jobs must be approved by Engineering, specifically the Plant and Project Engineering Unit (Systems Engineers a new unit formed at the time of reorganization). Systems Engineers usually must coordinate with the Design Engineering unit. This arrangement may cause delays in accomplishing maintenance work due to inter and intra group coordination problems. This may occur because these various groups have different reporting relationships as well as differing priorities. Furthermore, each group has its own particular technical discipline/background. Because of these conditions, each group perceived their role differently. It is understandable, then, that a complaint generally heard was that "engineering does not fully understand the special problems associated with maintenance."

Management appears to be aware of some of these problems and was taking action to improve conditions. The Engineering Department was defining and formalizing the matrix management (Project Management) structure in the Nuclear Engineering Services area. This included the creation of an expanded role definition of the system engineer, the development and implementation of a Project Management training course, and the responsibility charting of key interface groups.

This program was just getting underway. This effort appeared to be a positive initiative although the "Expanded Job Description of the System Engineer" and the responsibility charting in the Project Management Course appeared confusing and bureaucratic. Management was aware problems did exist in their approach and were working at improvements. Management had provided team building training among the VP and Departmental Management group, and was providing conflict resolution training (Hostility Training Program) with lower level supervisors. The company was also conducting a training course for the eighty key individuals involved in project management.

5. Procurement Interface Problems

During interviews with Department Managers, General Supervisors, and other employees, a consistent complaint was heard concerning ordering and receiving parts. Most of the complaints came from either the OP or Maintenance functions.

Complainants indicated that parts were often not received in a timely fashion, thus holding up repair and maintenance work. A review of the Daily Maintenance Scheduling Log indicated some delay in repairs due to parts on order. The "Managers Key Operations and Maintenance Project List" (1/21/88) indicated, for example, that material for seismic support structure was not usable, and new material was ordered with a tight delivery schedule for pre-outage work. However, no purchase order had been cut as of January 22, 1988 (several days after this situation was identified). The requisition appeared to be waiting for approval by the Design Engineering unit. The required delivery date was February 10, 1988. The Procurement Manager did not expect the material to be delivered by February 10, 1988. The data from this example indicated a potential problem.

Inspection was made of the procurement process as it relates to safety related items. A functional review was made of the "Process and Contracts Coordination Unit" (PCCU) and the interface this function has with the Engineering Department and other appropriate units.

The PCCU has three major functions:

- Buy items it is allowed to buy (some of the procurement function is controlled out of the Corporate level office in Baltimore).

- Coordinate with other organizational units items PCCU cannot buy. These are generally safety related items.

- Coordinate service contracts.

The Manager of PCCU perceived he had several major roles. Among these were to communicate CCNPP procurement concerns with Baltimore, to follow-up on Baltimore concerns, to communicate to the end user the status of requests, and to communicate priorities to Engineering. Below is a description of the procurement process related to safety related items. (See diagram).

Safety related items may be purchased under either of three routes.

a. Blanket procurement -- pre-established blanket orders with pre-certified/bid vendors. The Design Engineering unit pre-approves safety related items to be purchased under the blanket order. Generally blanket requests are converted into purchase orders by the PCCU.

b. Other safety related orders are either procured through "local procurements" or through "requisitions". Such orders must be reviewed and approved by a Design Engineer first and then by the Purchase Quality Unit (PQU). After review by the PQU, the request is sent to Purchasing in Baltimore who cuts the purchase order and buys the item requested.

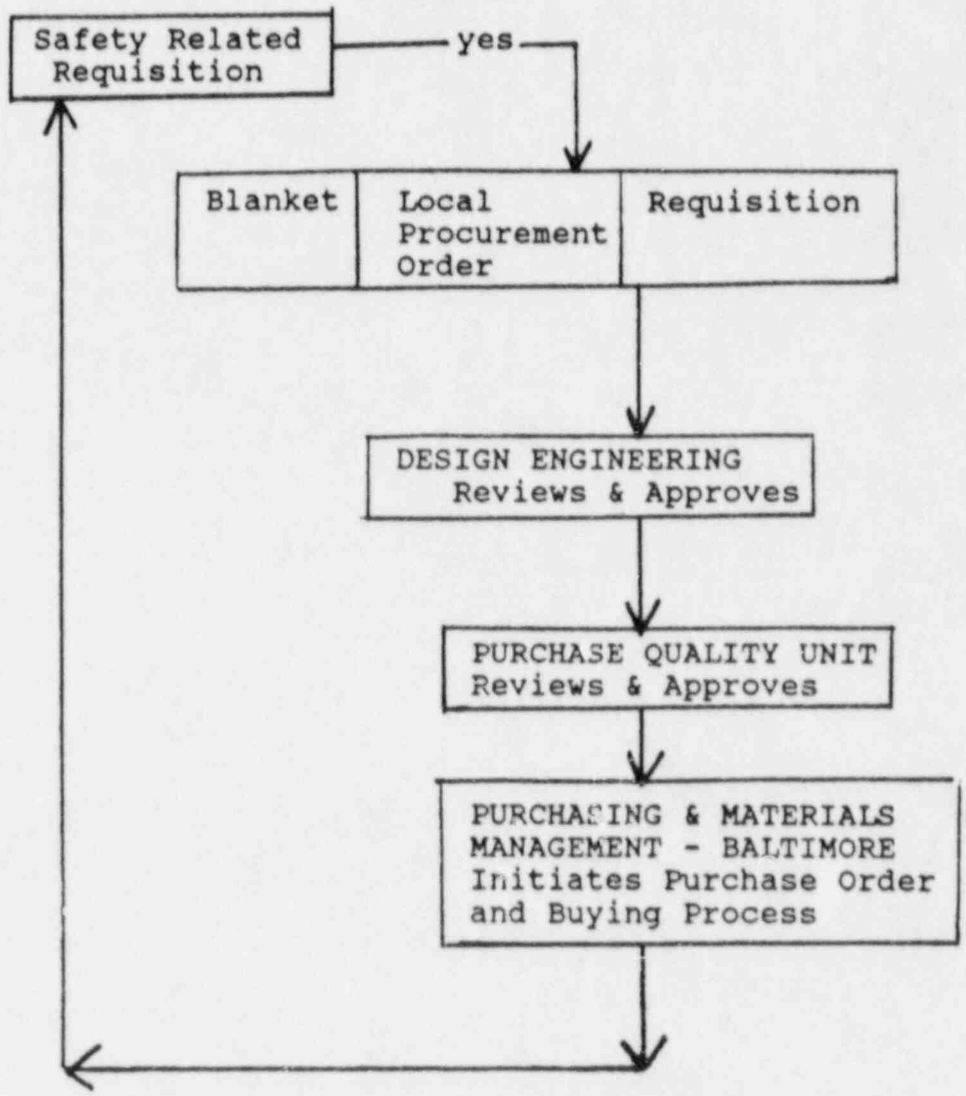
   When the Design Engineer Unit receives the requisition, the Engineering Procurement Coordinator (EPC) (there are two such coordinators who service the entire plant) reviews the work and sends it to the appropriate Design Engineer for review and approval. After the Design Engineer complete his task the request is returned to the EPC. The Engineering Procurement Coordinator then sends the request to the Purchasing Quality Unit (PQU) which reviews, approves, and sends the request directly to the Baltimore procurement office where it is converted into a purchase order.

   A feedback communication interface problem exits. The EPC does not communicate the status of the requisition to the PCCU. The PQU does not communicate the status of the requisition to the EPC or PCCU. The PCCU learns of the requisition status only after Baltimore cuts a purchase order. This process may take several weeks. (See diagram).

   Thus this procurement process does not appear to be functioning well for the following reasons:

   (1) The PCCU and in turn the original requester do not know the status of the requisition after it leaves PCCU's control until the final purchase order is made. This process can take several weeks to complete. The Design Engineer and the PQU both do not supply feedback data to the level above -- PQU to DE; DE to PCCU. When feedback is supplied it is done on an informal

SAFETY RELATED ITEMS PROCUREMENT PROCESS



basis. No formal system is in place in which feedback data goes to the level above. Tho PCCU learns of the completion of the DE and PQU review/approval only after the request is made into a purchase order by Baltimore. Baltimore sends a Purchase order summary report listing to PCCU monthly. This frustrates the PCCU manager as he perceives his role as a communicator to the customer of the status of the requisition.

(2) The Engineering Procurement Coordinators are required to interface with the various Design Engineers, requesting them to review and approve requisitions. There are two Coordinators handling all requests. As of 12/15/87 there was a backlog of 352 requests in Engineering. (See diagram) The Design Engineer considers the review and approval of purchase requests as a "collateral duty" which "interrupts the normal" duties of work. The Design Engineer is also requested to review and approve work requests from others, such as, System Engineers and Draftsmen. Each of the engineering disciplines -- mechanical, electrical, I&C, civil, etc -- does not have dedicated design engineers responsible for the processing/review of purchase requests. Currently an informal relationship exists between and among the various coordinators and engineers. Hence, when the service time to review and approve requests was extended beyond reasonable time frames, many routine requisitions became high priority items.

The organizational interfacing associated with this aspect of the procurement process appears to be inefficient and ineffective. Each group feels ineffective and blames another for their problems. Procurement Coordinators are frustrated over the lack of formal feedback systems and their inability to service their customers. Design Engineers do not perceive their role as giving high priority attention to safety related procurement requests; furthermore Design Engineers consider such requests as taking time away from other duties. Thus they have a nigh backlog. The Maintenance Department is unable to make repairs for lack of parts. In effect the Maintenance Department is considered ineffective by their customers, because they cannot make timely repairs. The Procurement unit is considered a "black hole" by Maintenance, the Engineering unit considers themselves over worked and unappreciated for the many demands placed upon them. All this results in Operations being hindered for lack of well maintained equipment.

Although this is merely one example of poor organizational interface caused by an inadequate communication system, it may not be the only example within the CCNPP. There is some evidence that the Maintenance Request and Maintenance Order process also does not adequately provide, for example, feedback of results by Operations to those performing maintenance. The relationship between Maintenance and the System Engineer units may not adequately provide for effective communication as indicated elsewhere in this report.

As a result of lack of certain formal communication systems, individuals involved have created a network of informal communication patterns. As a survival technique such informal systems appear to have been effective until now, but BG&E should not continue to rely on such informal networks especially, since accountability should be required.

It should be noted that management was implementing a project management system as well as communication training programs. These initiatives are tangential to the direct problem cited here but could have an indirect positive impact on this problem. (See Systems Engineer section for further discussion).

6. Systems Engineers

As a result of the 1986 reorganization, a Systems Engineer group within the Engineering Department was created. Many of these engineers were brought to the CCNPP from the Corporate office in Baltimore.

The term System Engineer seems to offer some confusion. "Systems Engineers" are made of small work teams or units of professionals consisting of a Principle Senior Engineer, an Engineer, an Assistant, Technical Assistant, and support staff. This team is responsible for engineering related work for one or more systems within the plant. They are considered "jack of all trades" being responsible for mechanical, electrical, controls, etc. related to daily operations and overall engineering. Thus, when staff refer to the Systems Engineer they appear to refer to this team. To clarify the job of a system engineer, on January 19, 1988 an "Expanded Job Description of the System Engineer" was issued in draft form by the Engineering Department. (This job description was concurred in by the VP and other Department Managers). According to this job description the definition of a system engineer is:

A graduate engineer or equivalent or an engineering analyst in Plant and Project Engineering who is assigned responsibility for maintaining expertise in assigned systems, and for serving as a focal point and team leader for system problem resolution and system improvement. The System Engineer may also be assigned similar responsibilities for components or other areas of responsibility which cross system lines.

The inspector did not find any specific position descriptions for a "systems engineer" except for the general job description referred to above.

Interviews with Management indicated that in the early period of reorganization, a few systems engineers were dissatisfied with moving to CCNPP and left the company. During the first two years of operation, system engineer units spent time defining their work roles and relationships as well as learning about the systems for which they are responsible.

Interviews with individuals in the maintenance area indicated dissatisfaction with systems engineers knowledge of plant systems in that system engineers did not have knowledge of the system for which they are responsible. Several systems engineers confirmed this impression. System engineers have received little inhouse and outside training on internal systems and project management.

Company management previously indicated to the NRC that they were aware of the systems engineer problem and would develop a training program designed to improve their understanding of plant systems and project management. The Technical Training Staff was in the process of developing this program and had implemented several parts. They completed a task analysis of the job which had been translated into an "expanded job description for systems engineers."

The training plan recommendation were to be brought to management for approval in February 1988. It consisted of a three part program as follows:

a. Orientation -- utilizing a series of self-study guides designed to familiarize participants with plant systems. This orientation was planned to be two weeks in length.

b. Initial Training -- consisting of classroom instruction modules, qualification manual guide instruction, etc. This part was to consist of 12 weeks of training in one year and 564 hours of training over an 18 month period. Training was to be performed by both inhouse and vendor trainers. As part of these efforts, a Project Management course had been designed, the pilot session was held during the second week of January 1988. Five more sessions of this course were scheduled for CY 88.

c. Continuing Training. Continuing Training in technical and administrative subjects was to be provided on an as needed basis to ensure that the technical staff is well maintained and improves their job proficiency. Such training was to be performed onsite/offsite by BG&E and vendor personnel. This training was to also consist of required reading/self study materials.

The licensee's staff proposed to fully implement the System Engineer training program on September 1, 1988. This would be the first consolidated training program for system engineers for CCNPP.

7. Management Information System

Management had recognized a need to create an integrated Management Information System for the entire Division. The concept of this MIS is to consolidate all information under one computerized data based system. This system is to provide for a comprehensive integrated computerized information processing network that will support the CCNPP. Such a system would provide the various sub-components within the organization with access to data. The VP was creating a new Project Manager position, reporting directly to him, which will have lead in creating the system. By February 1988, a project team was to be selected consisting of key representatives from OP, Maintenance, Engineering, QA, Information Systems and an outside consultant. This group was to speak for their respective departments to ensure department needs were considered in the system. By June 1988, Phase II was planned to begin which will consist of implementing the Plan over a 5 year phase in period.

Although this activity was in the early planning stages, the system was to be based upon an Equipment Identification Number (EIN). Creating standard names/language for equipment was to be established. The EIN was to be tied to engineering data to create a technical/data base. The system data base is to also include various administrative services -- training, procurement, personnel, etc. Thus, a complete tracking of equipment, work, people and dollars is to be accomplished.

This project appears to be an important initiative. NRC will continue to monitor progress of this project.

8. Turnover in I&C Section

The I&C and Electrical sections report to the Manager, Nuclear Maintenance. I&C Technicians in this group have historically experienced higher than usual employee turnover rates. This has resulted in a certain amount of lower productivity in the I&C group -- I&C work not being performed in a timely fashion -- and a low average experience level of I&C employees.

According to information supplied by the licensee's Personnel Department, the attrition rate of Control Technicians - Nuclear during the first six months of 1987 shows an overall rate of 7%. Of the 30 employees in this group, two transferred within the CCNPP, none of those who left I&C left the company. Although the data were not reviewed by the inspector, licensee management indicated the 7% rate was lower than past years and that a larger percent of past turnover reflected individuals leaving the firm.

Some I&C Technicians expressed dissatisfaction with their previous General Supervisor. (Management has recently employed a new General Supervisor apparently more acceptable to the employees concerned.) Everyone interviewed accepted the fact that a problem does exist in this area. The problem appeared to be related to a perceived lack of career paths by individuals currently hired (many of these were ex-Navy). Management was aware of this problem and had implemented several steps to improve the situation as outlined below.

Management had conducted exit interviews with I&C personnel as well as others in the plant. Data indicated that the plant hired highly intelligent high potential individuals in the I&C area, but they had not completed an undergraduate degree. Most were recent ex-Navy I&C technicians having been trained by the Navy. Many of those who left CCNPP cited a desire for a college education leading to a technical college/engineering degree. Such an undergraduate degree program was not available in the Calvert Cliffs geographic area, conducted in the evening, except for one at Johns Hopkins University.

As a solution to the problem of high turnover in the these sections, management had planned and/or implemented several activities. (Some of these activities are also an attempt to improve the general educational level of employees within CCNPP and provide general career growth.)

a. Formal Degree Programs

BG&E established an educational program with U of Maryland, and other utilities (Louisiana Power and Light, S. Carolina Gas and Electric, and Wisconsin Power) and other colleges in the area. The program leads to a BS degree in Nuclear Science. The original objective was to train CP employees to meet Shift Technical Advisor standards but was changed to meet all aspects of Engineering -- I&C, radiation safety, etc. Nine courses, three currently developed and implemented and six under development, provided a technical and scientific core curriculum totaling 120 semester hours. Courses are taught using CAI/CMI (Computer Assisted Instruction/Computer Managed Instruction) in conjunction with a textbook and instructor tutoring. Additional

courses are taught through the U. of Maryland's Open University program in a "seminar" format -- requiring readings, projects, and live instructors. Lower level courses (first two years of college) are provided by Charles County Community College. These consist of math, science, physics, chemistry, etc. These courses lead to an AA degree. Employees not desiring to enter the Nuclear Science B.S. degree program may complete their college studies at this time.

The above two programs are paid through the company's Educational Assistance Program. The EAP is specified in BG&E policy. The policy is extremely liberal, paying for full course tuition if the employee passes the course. Books and incidental expenses are the employees responsibility.

The above program relates to the I&C turnover issue as it 1) offers employees an opportunity to receive a degree, and 2) offers them an opportunity to move into the engineering career field.

b. Inhouse Technical Program

CCNPP has developed an inhouse INPO approved training program for technicians, including I&C. Graduates of this program are given recognition with a plaque mounted in the shop area. For one to move to an engineering position, they must complete the college programs described above and the inhouse technical training program. The Training Department's plan is to get the Engineering Department to recognize that the combination of the degree program and inhouse technical program is equivalent to an engineering degree. Getting acceptance for these programs is an issue. The Training Manager indicated that there is precedent for this in the Nuclear Division as company "policy" indicates that anyone going through the Nuclear Navy Power Officer Training Program is equal to an engineer for employment purposes. The Navy program does not require a degree.

c. Journeyman and Apprentice Programs

A journeyman program is also in existence designed especially to satisfy the Navy trained individuals on board. This two year program utilizes three months of formal training/lab training and OJT, eventually leading to a fully qualified technician position.

The company also was developing and/or has an INPO approved apprentice training program and Job Qualification Card program for electrical and controls Technicians as well as other maintenance disciplines. This program will encourage local high school graduates and new recruits to enter into the electrical and controls technician career field. The development of the apprentice program was one of the Performance Objectives for CY 88 of the Training Manager.

d. Other Local Programs

BG&E was trying to encourage local citizens to become employed as I&C Technicians. In this way, they feel that there will be more likelihood the I&C Technician will remain in the geographic area. To this end management indicated that CCNPP was designing a program with the local high school. This program will present graduating local high school students scholarships to New River Community College, Dublin, Va. Scholarships will be offered to those local high school students who may be developed into good I&C technicians and eventually employed by CCNPP. Participants would receive a two year degree in the Electrical Technical Program (AA degree in Applied Science Electrical/Electronics Technician). Upon completion of this program they would be eligible for the U of Md self study program offered by the company leading to a BS degree. Participants would take the inhouse technical training program in electrical and controls.

Another effort was the development of a work study program with local high schools in which the public schools would set up, within their vocational curriculum, a course of study in electrical and controls. CCNPP would in turn cooperate with the schools by offering job opportunities, thus students will gain practical experience by working at CCNPP.

To help lessen the problem of relocation of ex-Navy families the company in conjunction with the "spouses club" had established an orientation program. During employment interviews the Club takes the spouse on a tour of the Calvert Cliffs area and provides some orientation and settlement assistance. The club also provided social activities, etc. for all personnel. All personnel in the plant may join.

From the above, it is evident that BG&E is making a concerted effort to improve the high turnover situation as well as provide specific inhouse training for employees.

ATTACHMENT 3

POSRC DOCUMENTS REVIEWED

- CCI-103I, 7/8/87, Organization and Operation of the Plant Operations and Safety Review Committee

- Calvert Cliffs Nuclear Power Plant Plant Operations and Safety Review Manual, March 27, 1986

- The following - POSRC Meeting Minutes

86-99	12/01/86	86-109	12/19/86
86-100	12/03/86	86-110	12/22/86
86-101	12/05/86	86-111	12/24/86
86-102	12/08/86	86-112	12/29/86
86-103	12/08/86	87-116	12/16/87
86-104	12/10/86	87-117	12/21/87
86-105	12/10/86	87-118	12/23/87
86-106	12/12/86	87-119	12/30/87
86-107	12/15/86	88-01	1/06/88
86-108	12/17/86	88-02	1/13/88

- LER; Loss of Main Generator Permanent Magnet Generator; Calvert Cliffs, Unit 2; 12/21/87.

ATTACHMENT 4

OSSRC DOCUMENTS REVIEWED

- List of Principal and Alternative Off-Site Safety Review Committee, 8/29/86
- Memorandum 11/27/85, from Vice President - Supply to OSSRC Principal and Alternative Members
- OSSRC Manual
- The following OSSRC Meeting Minutes

86-01	3/27/86	87-01	2/06/87
86-02	6/26/86	87-02	4/06/87
86-03	7/25/86	87-03	5/08/87
86-04	9/19/86	87-04	5/12/87
86-05	9/25/86	87-05	6/21/87
86-06	11/21/86	87-06	6/25/87
86-07	12/18/86	87-07	9/24/87

ATTACHMENT 5

QAU DOCUMENTS REVIEWED

- QAP 20, Rev. 18, Training
- QAP 26, Rev. 38, Control of Conditions Adverse to Quality
- QAP 28, Rev. 24, Control of Items Covered by the Quality Assurance Program
    - "1988 Evaluations" Schedule
    - Evaluation, 11/21/86, Supervisory Review of Maintenance Orders
    - Evaluation, 7/22/86, Wide Range Noble Gas and Main Steam Radiation Monitor Operability
    - Audit 86-38, 12/03/86, Offsite Safety Review Committee Activities Audit
    - Audit 87-03, 3/27/87, Surveillance Testing
    - Audit 87-20, 10/14/87, Audit of POSRC Activities
    - Audit 87-09, 5/22/87, Nuclear Engineering Services Training
    - Audit 87-35, Draft, Offsite Safety Review Committee Activities Audit
    - Quality Audits Units Recommendation Sheet, 86-38-R01
    - Quality Audits Unit Recommendation Sheet, 86-38-R03
    - Quality Audits Unit Finding Sheet, 87-35-01
    - Quality Audits Unit Recommendation Sheet, 87-18-R01
    - Audit 86-01, 3/6/86, Corrective Action Systems
    - Audit 86-28, 10/31/86, Corrective Action Systems
    - Audit 87-01, 7/17/87, Corrective Action Systems
    - Audit 87-27, 10/29/87, Corrective Action Systems