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LICENSEE: Baltimore Gas and Electric Company
MD Rts 2&4, P.O.Box 1535
Lusby, Maryland 20657

FACILITY NAME: Calvert Cliffs Units 1 and 2

INSPECTION DATES: March 2- April 3,1992

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Areas Inspected: Announced team inspection by regional and contract personnel to review the functionality of the electrical distribution system.

Results: Details can be found in the Executive Summary.

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EXECUTIVE SUMMARY

During the period between March 2 and April 3, 1992, a Nuclear Regulatory Commission (NRC) inspection team conducted an electrical distribution system functional inspection (EDSFI) at Calvert Cliffs Units 1 and 2. The inspection was performed to determine if the electrical distribution system (EDS) was capable of performing its intended safety functions as designed, installed, and configured. The team also assessed the licensee's engineering and technical support of EDS activities. For these purposes, the team performed plant walkdowns and technical reviews of studies, calculations and design drawings pertaining to the EDS, and conducted interviews of corporate and plant personnel.

Based upon the sample of design drawings, studies and calculations reviewed and equipment inspected, the team concluded that the electrical distribution systems at Calvert Cliffs Units 1 and 2 are capable of performing their intended functions, taking into consideration the latest modifications to resolve the load sequencer design deficiencies. In addition, the team concluded that the engineering and technical support staff at Calvert Cliffs provide adequate support for the safe operation of the EDS at the plant. The inspection also identified several apparent violations, twelve unresolved items and seven observations as discussed in this inspection report. Some of the significant concerns identified by the team that required expedited review and resolution include: establishing adequate Diesel Generator loading and its capabilities; establishing adequate load flow analysis and degraded relay settings; swing diesel operation without cooling water; and potential single failure of switchgear room heating ventilation air-conditioning (HVAC) particularly with respect to Appendix R requirements.

Based upon the sample of equipment surveillance, testing, maintenance and the documentation reviewed, the team concluded that in several cases, the licensee failed to perform a thorough technical review of design requirements to establish the acceptability of test results or failed to adequately incorporate instrument inaccuracies or tolerances in test procedure acceptance criteria. The team identified that the emergency diesel generators (EDG) could fail and also could jeopardize emergency core cooling if sequenced loads are started concurrently with the permissive loads during loss of off site power (LOOP) or LOOP/loss-of-coolant accident (LOCA) due to the Calvert Cliffs Units 1 and 2 process-controlled load sequencer design. The NRC was concerned that the safety and regulatory significance of this issue was not recognized by the licensee's safety review committees when it was initially identified to them in 1987, and no appropriate corrective actions were taken until this issue was identified by the NRC EDSFI team. Instead, the licensee concluded from a probabilistic risk assessment study that the contributions to core melt frequency was insignificant, the event was not reportable, and no further action was required. The team determined that this activity appeared to be apparent violations of NRC requirements. The licensee took prompt corrective actions after the NRC raised the issue.

Three other licensee activities were identified as potential violations of NRC requirements. These were inadequate testing of the EDGs and undervoltage relays; inadequate design control measures to assure that assumptions used in the calculations are verified properly; and inadequate procedures to include instrument inaccuracies and tolerances. Generally, the licensee had implemented controls to maintain electrical system configuration for all safety-related EDS components and were found acceptable. However, the team noted from the above that the thoroughness of technical reviews and attention to detail could be improved.

The team found a number of significant deficiencies in reviewing the mechanical systems supporting the Electrical Distribution System. The EDGs are heavily loaded with very little operating margin. Both the loading calculations and the results of the surveillance tests led the team to the conclusion that additional analysis was required to demonstrate that the EDGs would serve their safety-related function for all design basis events under limiting operating conditions. The licensee had self identified the fuel oil system deficiencies and created a special project to resolve the issues. The team identified that the swing diesel starts on an undervoltage signal but does not automatically align itself to a safety-related bus. Following the steps in the emergency operating procedures, if the swing diesel is left unloaded without cooling water for 15 to 20 minutes, the diesel could fail. Also, for a LOOP/LOCA in one plant and LOOP in the other plant with a single failure, or, in the event of a LOOP without a LOCA, the swing diesel could automatically shutdown at high temperatures by the lack of cooling water and if a single failure occurs, one plant will be in a station blackout condition. The team concluded that the procedures were inadequate to ensure the availability of the safety-related power supply, and could leave the station unprotected against a single failure. The licensee took acceptable interim actions to prevent the failure of the swing diesel.

The team identified several common mode failures of the switchgear HVAC system that challenge the availability of the safety-related equipment in the switchgear rooms. The licensee's calculations for loss of HVAC considered the operator's response to a loss of the air conditioning refrigeration loop, but did not address the total loss of ventilation air flow. The team questioned whether the requirements of Appendix R for safe shutdown could be satisfied.

Based on the sample review of Calvert Cliffs Units 1 and 2 EDS design attributes, the team noted that most of the original design requirements were still met and the design changes over the life of the station were generally acceptable. However, the team noted tight margins in some of the EDS, particularly the Diesel and voltage profile for the electrical system. The design control measures failed to properly verify or check the adequacy of the non-conservative assumptions used in the load flow calculations, degraded voltage analysis and diesel load study. Other concerns identified by the team include: adequacy of overloaded 4 kV power cable and cable ampacity of 50 horsepower cable for worst case were not established; lack of adequate procedures to cope with battery room cold temperature conditions assuming a heater failure; potential for increased fault current contribution from battery charger due to silicon-controlled rectifier design; non-conservative conductor temperature assumed for battery voltage drop calculation; and lack of adequate coordination for control room HVAC compressor, assuming degraded voltage condition.

During and after the inspection, the licensee took actions to address the team's questions and concerns. The licensee took appropriate interim action or agreed to perform additional analyses where necessary. The team found the licensee very responsive to the questions and issues, with their focus maintained on nuclear safety.

Based upon the sample of documents reviewed and of personnel interviewed, the team concluded that the nuclear and plant engineering organizations were staffed with competent personnel. The recent staff reorganizations appeared to be working well and to have been a positive step toward improving the effectiveness of the engineering staff. The calculations initiated as a result of the design basis reconstitution program were good and comprehensive. Communications between the various engineering groups and operations organizations were considered good.

The self assessment program was found to be extensive and with good insight in identifying areas requiring improvement. This program is further enhanced by an excellent root cause analysis program. However, the corrective action programs need further attention both in the identification of problem areas and in the implementation.

Several observations were also made during this inspection regarding actions which could improve the functionality of the EDS.

A summary of team's findings is contained in the attached table.

SUMMARY OF INSPECTION FINDINGS

		Section	Tracking Numbers 50-317/50-318
A.	**Violations**		
1.	Inadequate surveillance tests	4.3 4.2.2	92-80-001
2.	Inadequate Procedures	4.3 4.2.2	92-80-002
3.	Inadequate design control for verifying adequacy of the design	4.2.2 2.8 4.3	92-80-003
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C.	**Unresolved Items**		
1.	Adequacy of EDGs to support worst case accident loads	3.2.2 4.2.2	92-80-005
2.	Adequacy of degraded bus relay set points and load flow study	2.8	92-80-006
3.	Adequacy of cable ampacities	2.5	92-80-007
4.	EDG loading calculation	2.6 3.1	92-80-008
5.	HVAC for EDS equipment	3.3.1	92-80-009
6.	Overpressure protection for EDG fuel line	3.2.6	92-80-010
7.	Adequacy of swing diesel operation	5.3; 3.2.3	92-80-011
8.	Maintenance program for air start check valves	3.2.4	92-80-012
9.	Procedures to address battery room cold temperature	2.11.6	92-80-013

10.	Battery charger contribution during short circuit	2.11.1	92-80-014
11.	Battery voltage drop calculation	2.11.3	92-80-015
12.	Miscoordination	2.9	92-80-016
D.	**Observations**		
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2.	Cable ampacity derating values for some of the cables are less than 125%	2.5	
3.	Switch yard voltage continuously declined	2.1	
4.	Seismic II/I concerns	3.5	
5.	No alarm or direct measurement for measuring dp	3.2.5	
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1.0 INTRODUCTION

During recent inspections, the Nuclear Regulatory Commission (NRC) staff observed that, at several operating plants in the country, the functionality of safety-related systems had been compromised by design modifications affecting the electrical distribution system (EDS). The observed design deficiencies were attributed, in part, to improper engineering and technical support. Examples of these deficiencies included: unmonitored and uncontrolled load growth on safety-related buses; inadequate review of design modifications; inadequate design calculations; improper testing of electrical equipment; and use of unqualified commercial grade equipment in safety-related applications.

In view of the above, the objectives of this inspection were to assess: (1) the capability of the electrical distribution system power sources and equipment to adequately support the operation of Baltimore Gas and Electric Company's safety-related components and (2) the performance of the licensee's engineering and technical support in this area.

To achieve the first objective, the team reviewed calculations and design documents paying particular attention to those attributes which ensure that quality power is delivered to those systems and components that are relied upon to remain functional during and following a design basis event. The review covered portions of onsite and offsite power sources and included the 500 kV offsite power source, 13.8 kV system, service transformers, 4.16 kV Class 1E system, emergency diesel generators, 480 V Class 1E load centers and motor control centers (MCCs), station batteries, battery chargers, inverters, 125 Vdc Class 1E buses, and the 120 Vac Class 1E vital distribution system.

The team verified the adequacy of certain aspects of the emergency onsite and offsite power sources for the EDS equipment by reviewing regulation of power to essential loads, protection for calculated fault currents, circuit independence, and coordination of protective devices. The team also assessed the adequacy of those mechanical systems which interface with and support the EDS. These included the air start, lubrication oil, and cooling systems for the emergency diesel generator and the cooling and heating systems for the electrical distribution system equipment.

A physical examination of the EDS equipment verified its configuration and ratings and included original installations as well as equipment installed through modifications. In addition, the team reviewed maintenance, calibration and surveillance activities for selected EDS components.

The team's assessment of capabilities and performance of the licensee's engineering and technical support included review of organization and key staff, self assessment program, temporary and permanent plant modifications, operating procedures for EDS, root cause analysis and corrective action programs and engineering support in design and operations and their interface.

In addition to the above, the team verified general conformance with General Design Criteria (GDC) 17 and 18, and appropriate criteria of Appendix B to 10 CFR Part 50. The team also reviewed the plant Technical Specifications, the Final Safety Analysis Report and appropriate safety evaluation reports to ensure that technical requirements and licensee's commitments were being met.

The details of specific areas reviewed, the team's findings and the applicable conclusions are described in Sections 2 through 5 of this report.

2.0 ELECTRICAL SYSTEMS

The scope of this EDSFI included the electrical distribution system (EDS) of Calvert Cliffs Units 1 and 2 and the offsite power sources supplying power to the station 500 kV service transformers. The team reviewed, on a sample basis, several features and components of the EDS. Particular attention was given to a selected sample "vertical slice" load path, which was the class 1E train ZA and EDGs 11 and 12 and their subsequent levels. The scope of the review included the adequacy of the following attributes:

1) 500 kV offsite power supply capability;

2) EDS design, fault analysis, voltage drop study, first and second levels of under-voltage set-point selection, and protection coordination studies of the 4160 Vac, 480 Vac, vital 120 Vac, and 125V class 1E dc systems;

3) EDS equipment ratings, such as switchgear rating, motor rating transformer ratings, circuit breaker (CB) momentary and interrupting ratings, 125 Vdc battery charger and battery sizing, motor over-load protection;

4) EDG loading and rating, EDG load sequencing and protection schemes, the steady-state and transient load profiles on class 1E busses of the EDS under normal and abnormal operating conditions;

5) cables sizing and voltage drops during motor running and starting; and

6) electrical containment penetrations sizing and protection.

The team also reviewed procedures and guidelines governing the EDS design calculations, design control and plant modifications, and EDS single line diagrams and wiring schematics. A simplified single line diagram of Calvert Cliffs Units 1 and 2 is shown in attachment 2.

2.1 Offsite Power and Grid Stability

The electric power output of Calvert Cliffs Units 1 and 2 main generators is 1020 MVA and 1012 MVA respectively. The main power transformers associated with each of the generators step up the output of the generators to 500 kV at the switchyard. The switchyard is arranged in a breaker-and-one-half arrangement and has two bays consisting of three breakers each and one bay of two breakers with two main buses and connections to both of the generators' main power transformers, the two plant service transformers and two 500 kV lines to the Baltimore Gas and Electric Company power system. Each line has sufficient capacity to carry the entire output of both turbine generators. Both of these transmission lines connect at the Waugh Chapel substation.

Discussions with Baltimore Gas and Electric operations personnel indicated that the Waugh Chapel substation consists of three 900 MVA transformers connected in parallel. These transformers are rated 500/230 kV and have automatic tap changers which may be adjusted in 5/8% increments for a total range of $\pm$ 10%.

During normal plant operation, station auxiliary loads are connected to the offsite source of power via the switchyard. If generation from both units is unavailable, the preferred source of offsite power would be from the Waugh Chapel substation via either one of the two 500 kV transmission lines. During the plant walkdown the team noted that the switchyard arrangement provides a maximum level of independence with respect to physical separation and provision of two independent sources of 125 Vdc control power.

The team requested historical data documenting the maximum and minimum switchyard voltages over the last 5 years. Using Control Room records, the licensee was able to provide data on a daily basis for the period from January 1987 through February 1992. Review of this data indicated a gradual decline in switchyard voltage over this period of time. Typical values of voltage declined from a range over 500 kV (typically 500 kV to 515 kV in 1987) to values less than 495 kV (typically 487 kV to 495 kV in 1992). The team observed that this results in the switchyard tending to operate in the lower end of the desired voltage ranges which the licensee has committed to maintain (485 - 515 kV).

Current Technical Specifications (3/4.8.1, Amendment No. 58) allows for the substitution of the 69 kV Southern Maryland Electric Cooperative (SMECO) line if one of the two 500 kV offsite sources is out of service. The 69 kV SMECO line ties into 13 kV bus No. 23 and either bus 11 or 21 as required. The SMECO line would be used to power any two (2) 4.16 kV safety-related buses, one for each unit, through either 13 kV bus 11 or 21. The 69 kV line is designed to supply the essential loads for one unit under Loss of Coolant Accident (LOCA) conditions and the essential loads to attain and maintain a safe shutdown in the other unit. The voltage swing of the 69 kV line is maintained at $\pm$ 1% by the use of a voltage regulator. There are no automatic transfers of loads from one bus to another.

The licensee has provided an alarm at its Electric System Operation Department (ESOD) Energy Center (i.e., system load dispatch center) which is activated when the switchyard voltage declines to 485 kV. After calling the plant control room, the dispatcher takes corrective action by adjusting the transformer tap settings at the Waugh Chapel substation. In addition, a future 500 kV interconnection tie line with Potomac Electric Power Company will be constructed from Chalk Point to Calvert Cliffs. The proposed line would be a segment of the 500 kV interconnection grid around the metropolitan areas of Washington, D.C. and Baltimore, Maryland, and could greatly improve the grid system reliability and stability.

2.2 Bus Alignments During Start-Up, Normal, Abnormal and Shutdown Operations

Each of the generating units are connected to a common 500 kV switchyard. The onsite distribution system for both units is supplied by two service transformers (P13000-1 and P13000-2) from the 500 kV switchyard. The Class 1E distribution systems are supplied by four 13.8-4.16/4.16 kV service transformers (U-4000-11, U-4000-12, U-4000-21 and U-4000-22) which have a maximum design rating of 20 MVA (i.e., 10 MVA per winding). There are four 4160V Class 1E buses (i.e., two per unit). These 4160V buses are powered such that Unit 1 buses 11 (train A) and 14 (train B) may be fed from either service transformer U-4000-11 or U-4000-21 and Unit 2 buses 21 (train A) and 24 (train B) may be fed from either service transformer U-4000-22 or U-4000-12. The 480V Class 1E buses (i.e., load centers) are fed from the 4160V Class 1E buses through respective 4160-480V service transformers. Various 480V Class 1E motor control centers are powered from the 480V Class 1E load centers. In addition, the two 500-14 kV service transformers P13000-1 and P13000-2 provide power to eight 13 kV nonsafety-related buses. Each bus feeds one of the plant's eight reactor coolant pump motors (4 per unit).

During normal plant operation, the switchyard operates with all breakers in the closed position. Therefore, the offsite source of power is always available in the event of loss of plant generation. As a result, there is generally no need for realignment of the electrical distribution system during abnormal or shutdown operations. The existing design of the electrical distribution system does provide flexibility with respect to cross connecting switchgear loads to alternate power sources.

2.3 Bus Transfer Schemes

Since normal plant operation aligns station auxiliary loads with the switchyard (i.e., the offsite source of power is always available), Calvert Cliffs does not require a fast transfer scheme during unit trips to provide offsite power.

The three diesel generators have been designed to be connected to various 4.16 kV safety-related buses via a series of 4.16 kV isolating disconnect switches. These isolating disconnect switches are interlocked to prevent an operator error that would parallel redundant standby power sources. The isolating disconnect switches are manually operated and, therefore, have no automatic or electrically operated means of control.

2.4 Electrical Distribution System Loading

The team reviewed the licensee's calculation E-90-31, to determine the worst case loading of transformers, switchgears and motor control centers. This calculation includes a load flow calculation representing the worst case condition with two units at full load and an ESFAS actuation in Unit 1 under a steady state running condition. Unit 1, Train A associated transformers and buses were identified as the most heavily loaded safety-related equipment and were reviewed by the team to determine whether the loadings remained within equipment ratings. The team found the ratings of the above electrical equipment to be within the rating of their original design.

2.5 4160V /480V Class 1E Systems

The team reviewed the licensee's cable sizing specification. Section 4.3 of the Electrical Installation Specification E406 provides information for the sizing of cables used to power 460V motors. E406 uses Insulated Power Cable Engineers Association (IPCEA) Publication No. P-46-426 "Power Cable Ampacities" as the basis for sizing these cables. In the case of motors powered by motor control centers, the associated power cables are not spaced when installed in a cable tray. As a result, cables must be derated 50 percent of their in-air rating in accordance with IPCEA P-46-426 Table VII. Section 4.3 of E406 tabulates the process for sizing these cables for motor sizes up to 60 horsepower. As part of this process, motor full load currents are multiplied by 125% to determine the minimum required cable ampacity. This practice is consistent with the National Electrical Code which considers the possible increase in full load current due to reduced voltage and encroachment into the service factor of the motor. However, the team observed an inconsistency in the cable installation specification tabulation for 20, 25, 50 and 60 horsepower motors. In each case, the tabulation indicated that the cable derated value of ampacity was less than the 125% of full load current rating of the motors.

In addition, the team noted that, under degraded voltage conditions, the cable sizing associated with 50 horsepower motors could result in the conductor operating temperature exceeding 90°C which is the maximum design operating temperature for continuous operation. The licensee had previously identified a power feeder cable as being overloaded under plant worst-case conditions. This feeder cable provided safety-related 4.16 KV power to Unit 1 buses 11 (safety-related) and 12 (nonsafety-related) from service transformer U-4000-11. This feeder cable was determined by the licensee to operate at 108% load factor which corresponds to a conductor temperature of 102°C. The team's concern was that this cable could potentially operate at temperatures well above its design rating of 90°C. No operating restrictions or evaluations were done to show the acceptability of this condition. This item remains unresolved pending the licensee determining the adequacy of 50 horsepower motor feeder cables operating at conductor temperatures greater than 90°C for motor voltages less than the nameplate ratings; and completing the analysis of overloaded 4.16 kV power feeder cables to Unit 1 buses 11 and 12 and review by the NRC (50-317/92-80-07 and 50-318/92-80-07).

2.6 Emergency Diesel Generators

Calvert Cliffs Units 1 and 2 use three 4160V, 3-phase, 60 Hz diesel generators where only one diesel generator per unit is required to supply the minimum power requirements for its engineered safety features equipment. Each diesel generator is rated as follows:

Rating	Load (kW)
Continuous	2500 kW
2000 hr	2700 kW
200 hr	3000 kW
168 hr	3250 kW

The team reviewed calculation E-88-15 dated November 3, 1988, "Diesel Generator Accident Loading," to ensure that the loading was within the capability of the diesel generator ratings via verification of design input data, methodology and assumptions. The team identified several discrepancies:

1. Where no manufacturer's data was available, an efficiency of 0.90 was assumed for 460V motors powered from motor control centers. The team's concern was that this was a non-conservative assumption. Typically, the efficiencies for small 460V motors powered from motor control centers varies from approximately 0.80 to 0.90 depending upon the size of the motor. To evaluate the impact of this non-conservative assumption, the team used an average efficiency of 0.850 and estimated the difference in total MCC loading for Unit 1 Train A MCCs 114R and 101A[illegible]. In the case of a main steam line break for 0.5 to 8 hours into the accident, the decrease in efficiency results in an increased loading of approximately 6 kW. In the case of a small break LOCA for 1 to 2 hours into the accident, the impact of decreased efficiency results in an increased loading of approximately 13 kW.

2. The licensee did not consider cable losses. The team estimated an additional 15 kW load.

The total EDG loading including additional loads discussed in Section 3.1 for the worst case event (with a small break LOCA) estimated by the team would be 3058 kW instead of 2988 kW as shown on the licensee's calculation. This condition is not reflected in the FSAR.

For the worst case scenario where loss of offsite power is followed by a large break accident, calculation E88-15 determines a total load (including manual loads) of 3172 kW. Considering the team's estimated additional 70 kW load in the loading calculation mentioned earlier, the total projected loading would be 3242 kW. The licensee's diesel generators are mechanically limited by the manufacturer for steady state operation to a total loading of 3250 kW. The team concluded that the EDGs have only limited margin based on the team's sample loading review. This item remains unresolved pending the licensee finalizing the maximum loading on the EDG, updating the diesel generator loading calculation, revising any plant emergency operating procedures which may be necessitated and review of this information by the NRC (50-317/92-80-08 and 50-318/92-80-08).

The team noted that the licensee is planning to install two 5000 kW, Class 1E emergency diesel generators to address station blackout issues and to provide adequate margin for EDG loading. The licensee stated that the engineering design changes to install these EDGs are in progress, and the existing schedule for the operation of EDGs is December 1995. This project, when completed, would certainly improve the reliability of safety-related buses.

2.7 AC System Short Circuit Study

The team examined the magnitudes of fault current in the AC system, as shown in licensee's calculation E90-3, Rev. 0. This included inputs from the incoming 500 kV switchyard system, the main and standby generators, and with the contribution from motor loads on the 13.8 kV, the 4.16 kV and the 480 volt sub-systems. Three phase bolted faults were assumed and a computer program "FAULTMASTER" was used to generate results based on the calculation techniques of ANSI/IEEE C37.010-1979 and ANSI/IEEE C37.13-1981. The team reviewed the assumptions used as a pre-requisite for the generation of calculated short circuit values, and found them to be generally conservative. In particular, the licensee assumed a cable temperature of 25°C and that all high voltage power was supplied through one service transformer (P13000-2). Eleven cases were studied by the licensee and momentary, interrupting and half-cycle asymmetrical fault currents were derived. The worst-case study assumed by the licensee showed that all circuit breakers at the 13.8 kV, 4.16 kV and 480 volt busses could satisfactorily interrupt the highest fault current available at the presumed switchyard voltage of 1.0 per unit. The calculation also showed that sufficient margin exists for the highest switchyard voltage of 1.03 p.u.

2.8 Degraded and Loss of Voltage Study

The team reviewed the licensee's load flow study to ensure that quality power is fed from the preferred sources. The study consisted primarily of three sets of calculations associated with (1) development of design input (e.g., cable impedances, transformer impedances, minimum required bus voltages at the 480 V level, MCC loading, etc.), (2) the master load flow calculation containing the various test cases performed, and (3) calculations either using the results of the master load flow or providing technical justification for deficiencies identified in the master load flow. Also, the team reviewed the licensee's design for the degraded grid and loss of power relays.

Calculation E-90-24 determines cable resistances and reactances to be used in the load flow study. This calculation contains an assumption which credits a conductor operating temperature of 75°C. The team was concerned that, since plant power cables were originally sized for an operating conductor temperature of 90°C, a 75°C conductor temperature may be non-conservative. Using an industry accepted relationship, the team determined that to ensure that a cable would not operate at a temperature greater than 75°C, the ratio of full load current to the derated cable ampacity could not be greater than 83.66%. In addition, if it were assumed that minimum acceptable terminal voltage existed for motors (i.e., 90% of rated nameplate voltage) resulting in an increase to full load current by approximately 11%, the above ratio would decrease to 75.29%. A review of the licensee's cable sizing standard determined that this ratio was exceeded for motor sizes in the range of 20 horsepower-60 horsepower. This confirms that the licensee's assumption crediting operation of power cables at 75°C is non-conservative.

Calculations E-90-28 and E-90-41 determine the minimum required voltages at load center and MCC buses, respectively, assuming minimum acceptable starting voltages at motor terminals. The licensee has credited a minimum acceptable motor terminal voltage of 75% of motor nameplate for 460 V motors powered from load centers and 70% of motor nameplate for 460 V motors powered from MCCs. In addition, the master load flow calculation E-90-31 assumes the above motor starting capability as well as 75% starting capability for 4 kV motors. The above calculations concluded that reasonable assurance exists such that 460 V motors fed from load centers and MCCs will successfully start at 75% and 70% voltage, respectively; however, acceleration times would be somewhat longer than at rated voltage. This conclusion was based upon plant motors having typically been purchased to National Electrical Manufacturers Association (NEMA) design B and NEMA Standards Publication MG1, ensuring certain minimum values of starting, pull-up and breakdown torque. Based on these NEMA requirements, the licensee concluded that the motor torque available would always exceed load torque requirements.

Sample purchase specifications showed that none of the nonsafety-related motor specifications contained any specific requirement for 75% or 70% starting capability. In addition, two of the safety-related motor specifications (i.e., Containment Spray Pumps and Control Room Air Conditioning compressor) did not identify specific starting requirements at 75% or 70% voltage. Although the licensee provided a motor data sheet for the Containment Spray Pump motors which indicate starting capability at 3,000 V, its starting capability remains in question due to the lack of a specific 75% starting requirement in the original purchase specification. Since 75% starting capability for motors is a non-standard requirement, it would not be likely that a motor manufacturer would provide this capability without the purchaser having clearly identified this requirement. At the end of the inspection, the team had not been provided with a sufficient number of safety-related motor specifications that specified 75% or 70% starting capacity to give a high level of confidence that safety-related motors will start at the minimum voltage requirements. Prolonged starting and acceleration of either safety-related or nonsafety-related motors could result in excessive locked rotor currents and voltage drops not considered by the load flow study. This could also cause inadvertent tripping of the degraded bus relays. The licensee committed to aggressively pursue the team's concern regarding motor starting capabilities.

Subsequent to the inspection, the licensee submitted additional analyses addressing the starting capability of safety-related motors under degraded voltage conditions coincident with a design basis accident. This analysis in combination with the existing administrative controls supported the team's conclusion that there was no immediate safety concern regarding starting capabilities of motors. However, the licensee could not provide complete evidence of whether safety-related motors were purchased to start at 75% or 70% of motor nameplate voltage.

The team noted that, due to the limitation of the software, the licensee did not include all motor power feeders into the model. Only those loads the licensee considered to be worst-case (i.e., largest loads with the longest feeder cables) were modelled with their power cables. Therefore, some motors associated with a given power source were modelled at the bus instead of being modelled at the end of a power cable. The team's concern with this modelling technique was that it did not recognize or account for the additional currents encountered as a result of increased motor full load currents during degraded voltage conditions. These currents incur additional ''age drop through various main power feeders and transformers, which are not account y the licensee's present model. The team consid..ed this to be a non-conservative m ng technique resulting in less conservative voltage values. The licensee had previously indicated that it had decided to use another load flow software which has greater modellin d analyses capabilities than the present software. The new software is not expected to have this limitation with regards to modelling motor power feeders.

The team reviewed calculation E-92-16 which identifies deficiencies resulting from worst-case starting and running scenarios. The team determined that the following load flow deficiencies were not adequately resolved.

1) The motor associated with Charging Pump 13 experiences a starting voltage of 65.2% (460 V base) and a running voltage of 86.3% (460 V base). The licensee assumed that the starting and running values of torque required for this pump were equal without any verification. The licensee calculated a required motor starting torque of 326 ft-lbs for a large break LOCA and the motor capability as 348 ft-lb at a reduced voltage of 299.9 V. The licensee also determined that motor running current would remain within nameplate full load current under degraded voltage conditions. Based upon this evaluation, the licensee determined that the lower voltage values were acceptable.

   However, the pump curve showed that the required starting torque was significantly greater than the required running torque. The licensee's estimated starting torque value based for a small break LOCA was 294 ft-lbs. However, the team calculated a new starting torque of approximately 357 ft-lbs based on 62 hp power demand from pump curve and 95% efficiency for the gear reducer. Subsequent to the inspection the licensee provided additional analysis regarding the starting capabilities of the charging pump motor. However, the analysis was inconclusive since the analysis did not clearly demonstrate that the motor had adequate starting torque to drive this pump. The team believes this condition under degraded voltage condition to be marginal.

2) Upon an ESFAS initiation in Unit 1 and degraded grid voltage conditions, the licensee identified that all 460 V motors powered from 480 V Bus 11A and some 460 V motors powered from 480 V Bus 11B experience running voltages lower than the acceptable voltage of 90% of rated nameplate value. The licensee has addressed these running voltage deficiencies on a generic basis by assuming that a new minimum required running voltage can be determined by dividing motor nameplate voltage by motor service factor. The team noted that this less conservative approach was used by the licensee to demonstrate the increased full load current allowed by motor service factor of 1.15. However, this was neither verified nor validated. Also, this was not a standard industry practice.

3) Distribution Panel 1P14 provides control and instrumentation power to several safety-related systems such as the Hydrogen Analyzer, Reactor Vessel Level Monitoring System (RVLMS) and Switchgear Room Air Conditioning. Under worst-case starting conditions during an ESFAS initiation, voltages at the terminals of various panel loads were estimated by the licensee to range from 84.7 to 87.5 V. The calculation also provides terminal voltages assuming the 4 kV motors have accelerated to rated speed and the 460 V motors are still accelerating. Even in this ideal (i.e., less stringent) case the terminal voltages for these 120 V loads were less than 100 V. The licensee did not provide any acceptance criteria for these results or any justifications. Instead, the licensee indicated that these loads will experience momentary voltage dips and was of no concern since these same loads experience a complete loss of voltage when the diesel generators are started on an undervoltage signal. In addition, the licensee has not provided acceptance criteria or technical justification for the steady state running voltages determined in Calculation E-92-16 for loads associated with Panel 1P14. The terminal voltages at these loads after ESFAS loads were estimated to be in the range from 102.5 to 105.3 V.

4) An evaluation was performed by the licensee to demonstrate thermal withstand capability of contactors associated with MCC 114R which fail to pick up during starting of all ESFAS loads. The method used a comparison of I^2t values between MCC contactors and dry-type transformers. The licensee concluded that the I^2t value of MCC contactors is 17% of the permitted I^2t value for a dry-type transformer and therefore the contactors are capable of withstanding reduced voltage inrush current until voltage recovers sufficiently for them to close without any technical justification or validation.

Failure to implement adequate design control measures to verify or check the assumptions used in the load flow studies to assure adequate voltage regulation for the EDS is a violation of 10 CFR 50, Appendix B, Criterion III (50-317/92-80-003 and 50-318/92-80-003).

The team reviewed the degraded voltage and loss of voltage relays settings. The licensee has provided two levels of protection for Class 1E equipment for undervoltage conditions. The first level (loss of voltage) has setpoints of 2450V ± 105V (59% of 4160V) with a time delay of 2 seconds ± 0.2 seconds. The second level (degraded voltage) has setpoints of 3628V ± 25V (87.2% of 4160V) with a time delay of 6 seconds ± 0.4 seconds. The undervoltage protection is located on each 4160V Class 1E bus. Both degraded voltage and loss of voltage signals are initiated using a set of four relays and a two out of four logic scheme. The coincidence of two out of four undervoltage signals from either set of four relays in combination with the associated time delay initiates diesel generator start and loading.

The team reviewed critical functions, setpoints and bases for the degraded voltage protection. Calvert Cliffs is committed to maintain a minimum switchyard voltage of 485 kV. However, the licensee indicated that the existing nominal reset point of 3668V at 4.16 kV bus for the degraded voltage relays was not based on a corresponding switchyard voltage of 485 kV or more. The existing reset point of these relays actually corresponds to a lower switchyard voltage of 479 kV. This setpoint was based on the limitations associated with setting the existing relays, i.e., 3668V at the 4.16 kV bus corresponds to the highest relay setpoint of 104.8V. The team noted that the licensee has not determined the adequacy of plant voltages for the degraded bus relay range between nominal reset (i.e., 3668V) and minimum dropout (i.e., 3603V). It was also noted that licensee established the degraded bus set points based on reset values rather than the minimum drop out value.

Based on the existing administrative controls and the actions taken by the load dispatcher, the team did not consider the existing operating condition at Calvert Cliffs Units 1 and 2 was an imminent safety concern. Operating Instruction OI-28, Revision 7, requires switchyard voltage to be maintained at least at 485 kV. This is done by continuously monitoring the 500 kV switchyard to determine whether switchyard voltage is approaching the minimum required value of 485 kV. An alarm is initiated at its Electric System Operation Department (ESOD) Energy Center (i.e., system load dispatch center) when the switchyard reaches 485 kV which corresponds to an approximate 4 kV bus voltage of 3772V. To provide minimum rated voltages for the motors in the interim, the grid voltage is maintained in the range of 485 kV to 515 kV.

This unresolved item (degraded voltage and load flow questions) is pending the licensee: 1) performing a voltage regulation study for the voltage range between nominal reset and minimum dropout of the degraded voltage relays and determining the adequacy of the degraded bus relay setpoint; 2) revising the calculations to reflect higher conductor operating temperature, accounting for cable impedances; 3) establishing adequacy of starting and running voltages for charging pump 13 under a worst case condition; 4) providing technical justification for 460 V loads, powered from bus 11 A and B; 5) establishing adequate starting and running voltages for panel 1P14 loads; 6) establishing MCC 114R contactors thermal capability during degraded voltage condition; 7) analyzing motor starting and running capabilities based on motor purchase specification and testing; and 8) review of this information by the NRC (50-317/92-80-006 and 50-318/92-80-006).

2.9 AC Protective Device Co-ordination

In assessing the co-ordination of the protective devices, the team considered the margins between the tripping times on short circuit of staged relays, circuit breakers and fuses. In addition, for motor protection devices, the starting currents at full and reduced voltage were examined to assess the margin existing between the starting current curves and the curve for the overcurrent device. Lastly, the adequacy of the devices to protect the feeders from thermal damage from short circuit and ground fault currents was also reviewed.

The team reviewed calculation E90-65, Rev. 0, which examined the co-ordination of equipment protecting various motor loads on the 4 kV safety bus 11. In all cases, the team found that effective co-ordination had been achieved. The relay settings reviewed for emergency diesel generator No. 11 were satisfactory. For the 480 volt load centers supplying a number of safety-related loads, the team reviewed calculation E90-85 which examined equipment settings protecting various motor loads connected to the safety bus 11B. The co-ordination of protective equipment for the starting of motors on full and reduced voltage down to 70% of the nameplate value was satisfactory. For the running condition of the motors on reduced voltage, long time delay settings of the circuit breakers were such as to reduce the margin for tripping on overload due to the increased current at the running condition. The team found that the Control Room Air Compressor motor current, at the running voltage of about 85% of nameplate value, was high enough to cause concern that the current is in the circuit breaker trip region. This is an unresolved item pending clarification by the licensee, that the Control Room Compressor motor breaker will not trip prematurely with lowest running voltage (50-317/92-80-06 and 50-318/92-80-06).

The team reviewed calculation E92-13, Rev. 0, which showed the co-ordination of circuits for the MCC 114R. In all cases, the team found that effective co-ordination had been achieved.

The team observed that the overcurrent relay protection for the EDGs is not shown in the FSAR Section 8.4.1.2 for protective functions for the diesel generator. The licensee stated that this discrepancy will be updated in the next revision of the FSAR.

The team evaluated the use of surge protection devices for the medium and low voltage AC networks. The licensee stated that only devices fitted to the 13.2 kV reactor coolant pumps were in use. The licensee further advised that all circuit breakers used in the medium and low voltage systems were of the air break or molded construction, that no vacuum circuit breakers were used, and that continuous operation over a period of years had shown that surge protection devices were not required. For the reactor coolant pump motors, however, the motor manufacturer had advised using surge protection capacitors at the terminals of each motor. Because of problems due to heat and vibration with these capacitors, the licensee had replaced them with line inductors mounted in the switchgear. The team ascertained that the licensee had carried out extensive computer modelling, supported by field tests on a spare motor and supply cable, before the final choice of line inductor was made. Calculations were presented showing the different stages towards a suitable inductance value. The team concluded that the surge protection requirements for the medium and low voltage systems had been adequately addressed.

2.10 Containment Electrical Penetration Protection

The team reviewed the adequacy of the containment electrical penetrations, which were designed and fabricated in accordance with two specifications. The original penetrations in use at the plant were designed and fabricated in accordance with specification 6750-E-31. Later penetrations were fabricated to specification number 387. The latter specification revised the design requirements so that larger short circuit currents could be handled. In addition, the team reviewed various test reports relating to the testing of prototype units by the penetration fabricators Amphenol Sams Division and the Conax Corporation. A calculation, E87-8, Rev. 1, also was reviewed since it examined the short circuit current values at the various penetrations.

2.10.1 Short Circuit Loadings

The team noted that short circuit currents as calculated at the various penetrations were based on the conservative assumption that a bolted fault would occur on the containment side of the penetration, of a magnitude based on the maximum current obtained from calculation E90-33, Rev. 0, modified to include the effect of extra impedance of the feeder cables from the nearest bus to the penetration. Various penetrations were in use: type 1 supplying the reactor cooling pumps; types 2A, 2B, 2C, and 2E for low voltage power; and type 2D for control purposes. The type 1 penetration constructed only by Amphenol to specification 6750-E-31, had an adequate margin to handle the mechanical stresses imposed by a short circuit, and the design for the heating effect of the currents was well within the limits of the IEEE 317-1983, "IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations." The type 2A penetration containing twelve 350MCM conductors constructed by Amphenol and Conax was also found to be satisfactory to handle the maximum short circuit current for the clearing time of the protective equipment.

However, for the type 2B penetration containing eighteen 2/0AWG conductors, calculation E87-8 showed that the calculated current for several conductors was greater than the test value obtained during a test of a prototype Amphenol unit. The team discussed this issue with the licensee and final disposition was obtained when the licensee showed that the peak current in each case was essentially the same. The team concluded, therefore, that both designs of this penetration assembly were satisfactory from an electromagnetic and thermal point of view. For the type 2C, 2D, and 2E penetrations containing smaller size conductors

(#4 through #12AWG) and subject to reduced energy levels on short circuit, the calculations and test reports indicated that there would be no problem with short circuit currents, as calculated currents were below the tested levels.

The team noted that the licensee's calculation E87-8 did not address the effects of temperature increases due to the flow of steady currents in the various conductors, in particular, the temperature excursion of the conductor insulation and of the penetration/concrete interface. The IEEE standard 317 applies values of 90°C and 150°F to these situations, with an additional guideline of 30 watts dissipation for each 12 inches of the penetration. For the Conax penetrations, test report IPS-405, Rev. E, lists the watts/foot for the different penetration types. In all cases except one, the values were less than 30 watts/foot. For the type 2E (model No. 10001-01), containing a mixture of #4AWG and #8AWG conductors, a value of 54 watts/foot was calculated. However, during the test the interface temperature was monitored as being less than 150°F. Therefore, the team concluded that the heat loading of the penetrations was satisfactory. For the Amphenol penetrations, the team observed that there were no comparable test data for the steel/concrete interface temperature. However, the type 1 penetration containing three conductors supplying the reactor coolant pumps was calculated at less than 30 watts/foot and was considered to be satisfactory.

2.10.2 Co-ordination Protection

The team considered the suitability of circuit breakers and fuses in protecting the conductors of the electrical penetrations against the effects of sustained overloads or short circuits. Various examples for the penetrations type 1, and 2A through 2E contained in calculation E87-8 were reviewed. The team found that all conductors were adequately protected from damaging effects by the primary protective device, by the higher energy circuits, and by the backup protective device. It was concluded that the protective device co-ordination was satisfactory.

2.11 125 Vdc and 120 Vac Class 1E System

The 125 Vdc system consists of two 59 cell, 15[illegible] ampere-hour safety-related battery systems nos. 11 and 21 and two 59 cell, 19[illegible] ampere-hour safety-related battery systems nos. 12 and 22. The battery systems supply both safety and non-safety-related loads, including two single phase 7.5 kVA inverters per bus, which in turn supply 120 volt vital AC busses and panels. Additional loads supplied from each 125 Vdc bus consist of distribution panels and, in the case of batteries 12 and 22, a three phase computer inverter. Each battery system is connected to two battery chargers for supplying the loads and for battery equalization. A spare 60 cell, [illegible]0 ampere-hour battery system No. 01 is used as a reserve battery to replace any of the four batteries described above. Connection of the reserve battery to existing loads and of the normal battery to the load test resistor is performed manually by re-arranging cables.

2.11.1 Short Circuit Analysis

The team considered the consequences of short circuit currents in the various battery systems with the objective of determining the adequacy of protective equipment for fault interruption and coordination. In addition, adequacy of the supply cables to withstand thermal damage was also examined. The team reviewed calculations E85-10, Revision 1, and E88-8, Revision 2, which covered battery systems 11, 12, 21, 22, and the reserve battery system 01. The maximum fault current was calculated as 17.7 kilo-amps at the terminals of battery 22.

However, the team noted that the fuses used as protective equipment for the battery systems were tested by the Wyle Laboratories under an Appendix B QA program to only 15.2 kilo-amperes at 170 Vdc. The team discussed with the licensee this apparent shortcoming of the mid-span battery fuse for battery #22. The licensee stated that a direct short at the battery terminals was improbable because of the wide spacing between the battery positive and negative outgoing connections. In response to the team's concern, the licensee showed evidence that the fuse had been tested to 55 kiloamperes at 334 Vdc. The team examined the battery room layout and decided that there was no potential problem with this fuse.

The team also noted that the calculated short circuit currents from the two battery chargers had been determined at the current limit settings of 110% of full load capacity (i.e. 440 amperes each). Since these chargers use silicon controlled rectifiers (SCRs) for rectification and control, it is possible that the short circuit output current of each charger could be up to ten times its full load rating for a period of 8 milli-seconds. The team was unable to ascertain the full impact of this postulated condition by the end of the inspection period. Depending on the magnitude of this additional current, the potential problem areas are that the D.C. bus feeder supply fuses will be required to operate outside their tested rating, and that co-ordination between these fuses and the battery mid-span fuse may be compromised because of their different current/time characteristics for fuse operation. This issue is unresolved pending the licensee establishing adequate analysis or testing to establish the actual short circuit contribution of battery charger during a fault and its impact on the system and further review by the NRC (50-317/ 92-80-014 and 50-318/92-80-014).

2.11.2 Batteries and Battery Chargers

The team reviewed calculation E90-1, Rev. 01, in which the sizing of the most heavily loaded 125 Vdc battery system 11 and the reserve battery system 01, connected to the A train loads, was developed. This safety-related battery system supplies both 1E and non-1E loads, the former including the inverters supplying the vital 120 Vac system. The committed time for successful battery operation is listed in the FSAR as two hours for a LOCA event, and the battery sizing is based on a failure of the train "ZA" diesel generator, combined with a LOCA in reactor unit 1 or 2 plus a shutdown of the other unit. The calculation follows the method outlined in standard IEEE 485-1983, "IEEE Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Sub Stations," and results in a margin over the required capacity of 38% for battery 11 and of 45% for battery 01 replacing 11, at an electrolyte temperature of 69°F. The team considered that the batteries were adequately sized for this situation since a detailed assessment of battery loads had been made. In the case of a postulated station blackout (SBO) condition for a four hour duty cycle, the same method was used in determining a suitable size of battery. Calculation E85-5, Rev. 01, applies to this case which showed a 2% design margin to determine the capacity of batteries 11, 21, and 01.

The team noted that there was a submittal from BG&E to NRC dated March 30, 1990, advising of a design margin of 5% for the SBO situation. This represented a deviation from the licensee's commitment. However, subsequent to the inspection, the licensee showed evidence stating that 5% margin was derived from an older calculation (E89-5, Rev.0) which was the supporting calculation at the time the submittal was sent to the NRC. The licensee stated that the discrepancy between the two calculations is being reviewed and appropriate actions will be taken at that time.

The battery chargers were sized in accordance with IEEE standard 946-1985, "IEEE Recommended Practice for the Design of Safety-Related DC Auxiliary Power Systems for Nuclear Power Generating Station," and were found to be of adequate capacity to supply all DC loads, together with an equalizing charge for the battery. Redundant chargers with load sharing features are connected to each bus, but adequate capa y can be obtained with one charger of the redundant pair switched out of service. The team noted that the value of the load current for continuous service on the charger, comprising a current to the constant kVA inverters and a current to the constant resistance loads, had been calculated at a voltage of 115 Vdc, whereas the charger voltage supplying the load would be in the region of 137 volts, thus reducing the inverter input current and increasing the resistive load current in proportion. However, the team considered that there would be no significant impact on the size of chargers selected.

2.11.3 Protective Co-ordination

A review of the current/time curves for the various fuses in calculation E88-8, Rev. 2, showed that there was adequate co-ordination between all fuses, and that the ability of conductors to withstand the heating effect of a short circuit would be acceptable. The team observed that some non-1E loads supplied from 1E panels were protected by 100 ampere rated fuses and enquired about the ability of the DC system to detect higher resistance faults which would not cause fuse action but which would impose a significant current drain on the battery system during operations with no AC power available. The licensee stated that this condition is highly unlikely and appropriate operator actions will be taken to prevent any degradation of the batteries.

2.11.4 Voltage Profile

The calculation E89-42 for battery system 11 was reviewed to determine the voltage profile for the DC system. The most heavily loaded bus was considered, and the voltage drops were evaluated on the most heavily loaded circuits and most longer run loads, and at the minimum battery voltage of 105 Vdc as listed in the Technical Specifications for the plant. Voltages to the inverters were considered separately in calculations E85-5 and E90-1. The case considered was that for a LOCA on reactor Unit 2 with a shutdown of Unit 1 concurrent with a loss of offsite power.

Calculation E89-42 identified a number of loads, typically relays and solenoid valves, for which the calculated voltages at the loads were below the specified minimum values for satisfactory actuation of the equipment. At the same time, it was determined that all voltage drops had been calculated with the assumption of a cable conductor temperature of 25°C, a non-conservative approach which the team found unacceptable. During subsequent discussions with the licensee, it became apparent that load voltages outside specification applied only to non-safety-related loads, and a preliminary re-calculation of the voltages for safety-related loads at the more likely conductor temperature of 75°C showed that they were still above the lowest acceptable limit based on the samples reviewed. This item remains unresolved pending the licensee completing the calculation considering the worst case temperature to reflect the running condition of the plant and further review by the NRC (50-317/92-80-015 and 50-318/92-80-015).

2.11.5 DC Ground Detection

Two types of ground detectors are used on the 125 Vdc battery systems 11, 12, 21, and 22; namely, an automatic system using Seekirk detectors and a manual system comprising hand switches and indicating lights. The automatic system consisting of a number of saturable reactors used as detectors, and interfacing with an electronic warning unit, uses the principle of current unbalance during a ground fault. Any ground fault downstream of a detector will trigger the warning unit to energize local indication and provide an annunciation in the control room. A test feature fitted to the warning unit enables an operator to check the functioning of the unit. The unit can also identify a faulted line. The system can detect ground fault currents as low as 5 milli-amperes. The manual system uses two indicating lights continuously energized to indicate a non-faulted system, with a handswitch to test for a ground fault. A ground on the system will extinguish a light. A second handswitch selects a local pair of lights or a pair in the control room.

The automatic system will detect a ground fault on any of the branch feeders and is tested monthly in accordance with procedure PE-0220M. The manual system will also detect a ground fault on any part of the DC system. The automatic system is fitted to batteries 11 and 21 whereas the manual system is fitted to all battery systems. The team considered that the ground fault detection equipment is satisfactory.

2.11.6 Battery Room Ventilation

The team investigated the purging of hydrogen gas from the battery rooms and the consequences of equipment failure. Each of the five battery rooms is connected to a single safety-related inlet duct and a single safety-related outlet duct, containing automatic fire dampers with fusible links, able to isolate each battery room and the ducting between units 1 and 2. A single supply and a single exhaust fan/motor combination comprising safety-related components and with the fan motors energized from safety-related power supplies are used to extract hydrogen gas from each battery room. Either or both fans could be running to achieve this condition. A non-safety-related heater warms the intake air to maintain an adequate ambient temperature in the battery rooms, and intake dampers are re-arranged in winter to ensure that very cold outside air is not drawn into the ducting system. Nonetheless, a short calculation by the licensee showed that on failure of the heater, the battery electrolyte temperature could reach unacceptable levels in a time shorter than that existing between successive operator checks. Failure of a heater is not signalled to the control room staff. The team was concerned about this postulated event, but was re-assured that the licensee had recognized this potential problem and had created change request FCR 89-62 in 1990 which covers the inclusion of temperature monitoring switches in the battery rooms, with remote alarm annunciation in the control room.

However, until this change is implemented, battery room temperatures could fall below the value assumed in the battery sizing calculation (69°F) without the operating staff being aware of this condition in time. The battery rooms are visited routinely at the beginning of a twelve-hour shift but there is no schedule for re-visiting the rooms during the shift. The time between visits could extend up to twelve hours. There is also no procedure for handling the event described above. The licensee agreed to provide operators with the necessary procedures. This item remains unresolved pending the licensee establishing adequate measures to cope with this event (50-317/92-80-013 and 50-318/92-80-013).

2.11.7 120 Vac System

The 120 Vac system provided for each unit has four separate distribution boards which power the reactor protection system channels, the engineered safety features channels and auxiliary feedwater actuation systems channels. The team reviewed protective coordination for this system. The licensee's calculation E88-2, Revision 1, identified a lack of co-ordination between the circuit breaker on the MCC bus and the downstream fuses (from CB-11429 on MCC 114R to instrument bus 1Y09). This is being corrected by a modification (FCR 88-6). The team agreed that this change would achieve satisfactory co-ordination.

The team also reviewed calculations E90-1 and E85-5 that contained DC voltage requirements for two 7.5 KVA inverters fed from battery system bus 11. The review indicated that in all cases the team found the inverter voltages satisfactory.

Conclusions

Based on the sample review of Calvert Cliffs Units 1 and 2 EDS design attributes, the team concluded that, with the exception of the specific findings noted above, the EDS design was generally adequate and no safety concerns exist. However, the team noted tight margins on some of the EDS, particularly the diesel and voltage profile for the electrical system. Some of the significant concerns identified by the team that required expedited review and resolution include: establishing adequate diesel generator loading, establishing adequate load flow analysis and degraded relay settings. The design control measures failed to properly verify or check the adequacy of the non-conservative assumptions used in the load flow calculations to assure proper voltages for the electrical system. Other concerns identified by the team include: adequacy of overloaded 4 kV power cable; cable ampacity of 50 horsepower cable were not established; lack of adequate procedures to cope with battery cold temperature conditions assuming a heater failure; potential for increased fault current contribution from battery charger due to SCR; non-conservative conductor temperature assumed for battery voltage drop calculation; and lack of adequate coordination for control room HVAC compressor, assuming degraded voltage condition.

3.0 Mechanical Systems

The team reviewed, on a sample basis, the design, capacity and configuration of the mechanical systems provided to support the emergency electrical distribution system. The design was evaluated against the requirements of the applicable codes, standards and USNRC Regulatory Guides. The assumptions, input data, design bases, methodology and output results of selected calculations were spot checked for consistency between design documents and thoroughness of the engineering support. In addition, the power requirements for the major electrical loads on the diesel generator busses were evaluated and compared to the load lists in the design documentation.

3.1 Power Demands for Major Loads

The team reviewed the power requirements for the major mechanical equipment powered by the diesel generators. The team found that the power used for EDG loading in calculation E-88-15 did not always bound the maximum loads.

The load for the salt water pumps did not account for actual system flow rates which exceeded the flows given in the FSAR. The flow rates used by the operations department for the routine system performance evaluation were approximately 23,000 gpm for normal operation (slightly higher for the recirculation phase following a LOCA with flow to ECCS pump room coolers) and 17,500 gpm following an SI signal. The FSAR states that the salt water system flow rate is 15,500 gpm normally, 17,430 gpm prior to recirculation following a LOCA and 16,200 gpm after recirculation. The power demand for the recirculation phase is estimated to be 365 kW in the FSAR versus 337 kW shown in calculation E-88-15.

The power required to drive the component cooling water pumps was based on both parallel pumps running. The team noted that the licensee had not considered the power requirements with only one pump operating which would require increased flow. According to the manufacturer's pump curve, the power demand under this operating condition is 150 bhp for a motor efficiency of 92% which corresponds to a load of 122 kW versus 108 kW shown in the calculation E-88-15. In summary, as a result of the sampling review of the major loads reviewed, the team identified 42 kW additional load on the EDG. Refer to section 2.6 for additional loading discrepancies on the EDG (50-317/92-80-008 and 50-518/92-80-008).

3.2 Diesel Generators and Auxiliary Systems

There are three 2500 kW Fairbanks-Morse 38TD8-1/8 12 cylinder opposed piston turbocharged emergency diesel generators (EDG) serving the two units at Calvert Cliffs Nuclear Power Plant. EDG 11 is normally aligned to unit 1 and EDG 21 is normally aligned to unit 2. EDG 12 is a swing diesel that can be aligned to either unit. The swing diesel is aligned automatically to the accident unit following a LOCA/LOOP, or by operator action following an undervoltage signal. The FSAR states that two diesels are required for safe shutdown of the two units, with 2500 kW required for the shutdown unit and 3000 kW required for the accident unit. The diesel generators have a continuous rating of 2500 kW, a 2000 hour rating of 2700 kW, a 200 hour rating of 3000 kW and a 168 hour rating of 3250 kW.

3.2.1 Fuel Oil System

The plant has two above ground fuel oil tanks with two independent headers joined to both tanks. Tank 21 has been protected against the effects of a tornado, tank 11 is not credited following a tornado. A check valve is provided in each header to ensure that tank 21 cannot be drained as a result of the failure of tank 11. Each EDG has one fuel oil transfer pump located in the respective EDG room, with suction connections to both of the fuel oil headers. The auxiliary boilers also draw fuel oil from these tanks. The system is normally aligned such that EDG 11 and EDG 21 draw fuel from tank 11 and the swing diesel and the auxiliary boiler draw fuel from the tornado qualified tank 21. The suction line to the auxiliary boilers comes from standpipes inside the above ground storage tanks, to ensure a minimum reserve of vital fuel for the EDGs. The standpipe is 7.5 feet in tank 11 (32,600 gallons) and 11 feet in tank 21 (51,400 gallons). The extra 3.5 feet was added to the standpipe in tank 21 during construction to provide sufficient fuel for operation of two diesels at shutdown loads from tank 21 following a tornado. During an internal audit in January 1991, the licensee discovered that the design basis for the fuel oil system had not been properly reflected in the technical specifications, the fuel oil consumption rates used in the calculations were incorrect and the operating procedures and setpoints were not adequate to satisfy the requirements of the FSAR.

Subsequent licensee analysis revealed that a minimum of 33,900 gallons was required for one EDG to operate for 7 days at 2,500 kW and that 39,800 gallons was required for one EDG to operate for 7 days at 3,000 kW. A minimum level of 169 inches was required in tank 21 to hold the 67,800 gallons for the safe shutdown of the two units following a tornado. The plant is currently administratively controlling the level in tank 21 at 180 inches (in accordance with night order issued on October 3, 1991), although the low level alarm has not been changed from 139 inches. The internal audit also revealed that the logic for the auxiliary boiler fuel pump shuts off the pump only on low level (135 inches) in both fuel oil storage tanks.

The licensee is tracking these issues under a special project addressing all aspects of the fuel oil system design. The licensee stated that a technical specification amendment will be submitted when their internal review has been completed.

The licensee had taken the initial step of administratively controlling the tank to a higher level. The team questioned why the other changes recommended by the internal review had not been implemented:

- having more than just EDG 12 aligned to tank 21 (EDG 12 is the only diesel that will not align itself to a bus following a LOOP).
- revising the low level alarm to a higher setpoint.
- removing the auxiliary boilers from tank 21 .

The licensee replied that these modifications were not a high priority. The licensee stated that the operator can manually transfer the headers and realign the individual EDG fuel oil transfer pumps to the tank 21 header while the diesels are running off the day tank, the tank level is checked several times a day and the auxiliary boiler does not operate following a LOOP. During the last week of the inspection, night orders (GS-NPO Notes and Instructions for March 31, 1992) were issued requiring the valve from tank 21 to the auxiliary boiler to be tagged out of service.

The team identified no immediate concerns since the licensee has put administrative controls in place to maintain sufficient volume in the storage tank.

3.2.2 EDG Performance under Accident Conditions

The team reviewed the EDG capabilities to perform its safety-related function following a design basis event and found the following areas of concern:

- the reduced effectiveness of the turbocharger during the initial loading sequence has not been addressed.

- LOCA following LOOP results in greater than 3150 kW load with the fuel rack stop set to limit the steady state output to maximum of 3250 kW.

- the simplified predictions of the EDG dynamic performance did not account for the above limitations.

- voltage drop at step 4 in the SI simulation surveillance test is marginal under test conditions and would be worse under accident conditions.

The EDGs are very heavily loaded and the team was concerned about the limited margins available. This concern was manifested not only in the design calculations but in the results of the routine surveillance tests as well.

During the 18 month surveillance test, the LOCA load sequencer adds the loads on the diesel in rapid succession to simulate post-accident conditions. Many of the loads added are lower than those predicted for the design basis event due to pumps operating in recirculation mode, normal air density for containment cooling fans, etc. The final steady load at the end of the sequenced loading is about 60 to 70% of the predicted 2550 kW post accident load. Even under these reduced loads and without limiting boundary conditions for diesel engine operation, the voltage drop at step 4 of the sequencer is only marginally acceptable (refer to section 4.2.2 for further discussions of EDG surveillance tests).

The team felt that the licensee had not adequately demonstrated that the EDG would perform as required under design basis operating conditions. The effectiveness of the turbocharger is impaired by the absence of hot exhaust [illegible] during the initial loading sequence. During the surveillance test, it is possible that the [illegible] engine had sufficient capacity to accelerate the loads using combustion air from the scavenger blower without calling upon the turbocharger (the turbocharger is not aligned to the inlet manifold until a steady state power output of 2200 to 2500 kW). The team noted that the engine is required to produce peak power far higher than the steady state loads calculated for each step in the loading sequence.

The team also noted that, in calculation E-90-39, the diesel generator loads predicted following a LOOP are 2595 kW, and that a LOCA following a LOOP could result in a short term load of 3172 kW. The operator would reduce this load to 3079 kW by shedding nonessential turbine loads. The conclusion in the calculation was that since the peak load remained below 3250 kW, the results were acceptable. The team pointed out that the manufacturer had set the fuel rack stops at a steady state [illegible]ting load of 3250 kW, and that for the EDG to accelerate the SIAS loads to 3172 kW the [illegible]ne may be rack limited, i.e. the governor may demand more throttle to accelerate the load but the linkage may be at the stop setting.

The team requested the licensee to evaluate the capabilities of the EDGs to fulfill their safety function for all design basis events considering dynamic loading sequence, reduced turbocharger performance prior to engine warmup, limiting operating boundary conditions (combustion air temperature, range of fuel oil characteristics, etc.) and the limitations of the fuel rack stop. This assessment should include the variations in engine speed, generator voltage, recovery time and fuel rack position with all errors and drifts accounted. After the team left the site, the licensee provided, via telephone, their basis for the conclusion that the EDGs would still fulfill their safety function. The conclusion relied, in part, on licensee discussions with the appropriate vendor. The team had no concerns with continued plant operation while the licensee continued their analyses. In view of the above and discussions in Section 4.2.2 regarding the EDG capabilities to supply accident loads, this issue remains unresolved pending the licensee performing adequate analysis or testing to show its capabilities and further review by the NRC (50-317/92-80-005 and 50-318/92-80-005).

3.2.3 EDG 12 Operation Without Service Water

EDG 12 is a swing diesel that is normally aligned to power either bus 14 in unit 1 or bus 21 in unit 2. Two trains of service water are aligned to EDG 12 to allow cooling regardless of which bus is powered. A pair of pressure switches determine which service water header has the highest pressure and positions valves in the supply and discharge service water lines to EDG 12 accordingly. The valve operators are supplied by the instrument air system. The swing diesel does not align itself automatically to a bus on an undervoltage signal, and without power, the service water pumps in the two trains aligned to EDG 12 do not start. The swing diesel runs at idle without cooling water until the operator closes the breaker to one of the two safety-related buses.

The team expressed concern that the swing diesel may trip out on high temperature before the operator came to the step in the EOP that connected the diesel to a safety-related bus. The manufacturer had stated in a letter to Bechtel dated November 12, 1970, that, "after operating at full load with the jacket temperature of 185°F the diesel can continue to operate for one minute without service water before the jacket temperature reaches 200 to 205°F and the diesel is automatically shutdown. With an initial jacket temperature of 140 to 145°F the diesel generator can operate three minutes before tripping."

Based on this information, jacket water heat loads as a function of power (Colt letter Stull to Sharpe, dated July 24, 1990) and actual control setpoints, the licensee estimated the engine could operate at no load for about 10 minutes without service water before tripping on high jacket water temperature. A review of the emergency operating procedures indicated that with EDG 11 and 21 operating following a LOOP, the operator could take 15 to 20 minutes to reach the steps that align the swing diesel to a bus. The team expressed the concern that a LOOP, with the consequential tripping of the swing diesel on over-temperature, followed by a LOCA signal could leave the accident unit without protection against a single failure.

The team felt that the EOP was inadequate in this regard and that the EOP or station operating procedures should be revised to specify the time limit that the swing diesel can be operated without service water. The licensee acknowledged this concern and is reviewing the procedures to determine how this can be best accomplished. The team also noted that adequate instructions were not provided to the operator in the EOPs to address a LOCA/LOOP with a single failure of the EDG in the non-accident unit.

The operation of EDG 12 without cooling water and the realignment of the swing diesel following a loss of one other diesel remain unresolved items pending a more thorough review of the cooling requirements and the establishment of adequate procedures to ensure the availability of the vital power source. Subsequent to the inspection, the licensee issued a shift turnover information sheet requiring operator action to connect the swing diesel to the bus within 1.5 minutes of a LOOP event. Refer to section 5.3 for additional discussions (50-317/92-80-011 and 50-318/92-80-011).

3.2.4 **Air Start System**

Each EDG has two trains of starting air, consisting of a tank and an air-start solenoid valve. Each EDG has an air compressor which is connected, through check valves, to both air start tanks. The compressor discharge lines from each EDG are joined to form one common supply line. Every time a compressor starts the air supply check valves at all six tanks start hammering against their seats in response to the pressure transient generated as the positive displacement compressor strokes up and down. The wear on all the valves in both trains for all three EDGs is determined by the leakiest of the six air start tanks. The performance of these check valves is not monitored as part of any surveillance test program.

The team was concerned that this continuous hammering of the valves could introduce an undetected common mode failure of the air start systems for all three diesel generators. The licensee stated that these valves were included in recently instituted Check Valve Reliability Program MN-1-108, dated February 7, 1992. At the close of the inspection the team was not provided with documents showing the testing requirements, frequency or test results that had been generated to date for the one EDG that had been inspected. This issue remains open pending the licensee establishing adequate monitoring procedures, the successful inspection results confirming functionality of the valves and an evaluation of the system configuration causing the problem and further review by the NRC (50-317/92-80-012 and 50-318/92-80-012).

3.2.5 EDG Lubricating Oil Filter Pressure Drop

The lubricating oil filter has a pressure gauge with a 3-way valve that the operator uses to measure the inlet and outlet pressures and determine the differential pressure. This measurement is made as part of the operator's tour whenever the diesel is operating. There is no alarm on this parameter. The maximum allowable differential pressure is 18 psid with hot oil. At 20 psid, an internal bypass opens in the filter that effectively backwashes the accumulated crud from the filter surface and passes it to the engine bearings.

The team expressed the concern that the maximum allowable differential pressure was very close, possibly within measurement error, to the bypass pressure drop. Under startup conditions with the oil at a lower temperature (higher viscosity), the pressure differential may exceed the last value recorded under hot operating conditions. This high pressure drop during start up could purge the filter and return the pressure differential to normal values and hence be undetected by the operator completing the normal rounds. The licensee had a change package in process to install a differential pressure gauge for this measurement and is reviewing the setpoint requirements to ensure adequate protection is provided for the engine.

3.2.6 Overpressure Protection for EDG Fuel Oil Transfer Pumps

The team noted that the positive displacement fuel oil transfer pump for each diesel generator has a solenoid valve on the discharge line that is designed to open and close with the pump starting and stopping, and a pair of parallel check valves in the suction line. The pump has an internal relief valve that allows high pressure fluid in the discharge line to flow to the suction of the pump. This arrangement does not provide overpressure protection for this section of piping since the check valves block the relief flow from reaching a low pressure reservoir. Operation of the pump with the discharge valve closed could cause the pressure to rise beyond the system design pressure. The licensee stated that the pump is interlocked with the discharge valve to prevent any inadvertent operation of the valve.

This item is unresolved pending the licensee establishing adequate analysis to show the acceptability of overpressure protection for the DG fuel oil transfer system (50-317/92-80-010 and 50-318/92-80-010).

3.3 Heating, Ventilation and Air Conditioning Systems

3.3.1 Emergency Switchgear Room HVAC

The team noted that the emergency switchgear HVAC was susceptible to single failures that would impair the ventilation to both trains of safety-related switch gear. Although two parallel trains of redundant fans and air conditioning units are provided, there are common supply and return ducts for both trains. The common supply and return ducts for both switch gear rooms pass through the 45 foot switchgear room. Fire dampers in the common lines are provided to isolate air flow in the event of a fire.

A fire in the 45 foot switchgear room would destroy one train of switchgear and isolate the ventilation to the 27 foot switchgear room, impairing the second train of switchgear. Similarly, a missile generated by the motor generator set in the 45 foot switchgear room could destroy safety-related switchgear in the 45 foot room and the common ventilation ducting. Other common mode failures such as fire in the equipment room with the air handlers, and tornado generating missiles destroying the air handlers units and roof top condenser units, or collapsing the common ducting would also disable both trains of HVAC, impairing both trains of switchgear.

An evaluation had been performed by the licensee to demonstrate that the equipment in the switchgear room could tolerate temperatures of up to 150°F (calculation E-91-02 performed by Mainline Engineering). The licensee had a calculation (calculation M-90-33B performed by Bechtel) that predicted that with initial room temperatures of 101°F (high temperature alarm) and the ventilation in the recirculation mode (i.e. loss of the refrigerant cooling loop), the 27 foot switchgear room temperature would reach 150°F in 10 to 25 minutes assuming the reactor was at full power, and in 10 hours assuming the reactor was tripped with only shutdown loads running. The cover letter to the Bechtel calculation (Bechtel letter CC-A15,626, Falibota to Katz, August 10, 1990) stated that "one ventilation fan must always remain operable." The team advised the licensee that this calculation did not address all of the common mode failures being considered, since many issues related to total loss of ventilation air flow.

The team questioned whether the licensee's Appendix R analysis for safe shutdown considered the above potential common mode failures. A fire in the 45 ft. equipment room that also isolates the 27 ft. room ventilation could hamper the licensee's ability to safely shutdown the plant. The licensee agreed to review their Appendix R analysis to determine whether the issue was addressed.

The team identified that for the common mode loss of the two trains of roof mounted condenser coils, the operating instructions (OI-22H) do not ensure that the initial conditions used as a basis for the calculations are satisfied. The calculation was based on assuming an initial room temperature of 101°F and a final temperature of 150°F in 10 hours with shutdown loads. The team noted that this operating procedure does not provide any instructions to the operator to reduce the heat load, by running only shutdown loads, until the room temperature is in the range of 104 to 114°F for four days, or greater than 114°F for 20 minutes. Furthermore, OI-22H does not address what actions the operator should take when the room temperature reaches 150°F. The licensee stated that portable fans from the service water pump room could be used to blow air through the 27 foot switchgear room. The team pointed out that these fans are dedicated to the service water pump room and that, as per operating instruction OI-15, these fans must be operating within 7 hours of a loss of power and consequential loss of the non-safety-related ventilation to ensure adequate temperatures for the safety-related equipment in that room. The team also asked the licensee to consider whether a fire destroying air operated dampers in the 45 foot switchgear room would lead to a common failure of the fail open dampers in the 27 foot room as well.

The team was concerned that the analysis to support adequate ventilation to the 27 foot switchgear room did not address the heat load from a fire in the 45 foot switchgear room, the calculations did not address the total loss of ventilation air flow, the initial conditions assumed in the calculation were not consistent with the requirements of the operating instructions, and the operating instructions did not adequately outline a means of assuring the proper equipment and operator actions would be in place to provide long term cooling for the room. The licensee committed to review the analysis and procedures to ensure that an adequate operating environment is provided for at least one train of switchgear for all scenarios affecting the common HVAC system. This issue remains unresolved pending the licensee: (50-317/92-80-009 and 50-317/92-80-009)

- completing analysis that addresses all the accident scenarios including total loss of ventilation air flow.
- modifying the operating procedures to ensure the assumed initial conditions required to support the calculated thermal transients.
- amending the operating procedures to ensure that adequate equipment and instructions are provided to reliably establish long term cooling.
- resolving the Appendix R issues related to the HVAC system.

3.3.2 EDG Room Ventilation

The team noted that the louvers in the EDG room exhaust opening are not protected against external missiles and could fail in the closed position due to a of tornado generated missile. This could result in a common mode failure of the three EDGs. The licensee stated that the plant was not designed for tornado qualification with only a few exceptions, one being the protection of the #21 above ground fuel oil storage tank. The team felt that the intent of qualifying the fuel oil storage tank was to ensure EDG operation following a tornado, and that supplementary steps should be taken to ensure that failure of the EDG room ventilation will not result in the diesels being unavailable following a tornado. The licensee agreed to evaluate the common mode failure of the EDG ventilation following a tornado.

3.3.3 HVAC Design Basis

The design basis outside ambient temperature for the HVAC systems is 95°F. During a week in July 1991, the maximum outside temperature ranged between 95 and 102°F for seven consecutive days. The team felt that a review of the HVAC system design should be made to evaluate the impact of the higher temperatures on critical areas with little margin. One such area is the EDG rooms, which currently has no margin. The licensee indicated that the thickness of insulation on the EDG exhaust piping is being increased and this should provide some operating margin below the temperature limit for the EDG room (120°F).

3.4 Service Water / Salt Water Systems

The salt water system is an open system circulating bay water to a limited number of loads. Most heat exchangers in the plant are cooled by the service water or component cooling water systems, both of which are closed recirculating loops with saltwater-cooled heat exchangers. The team noted that the design temperature for the salt water system was recently increased from 85 to 90°F under a field change FCR-91-284. The design temperature of 95°F for the service water and component cooling water systems was not affected by this design change. The service water system has a transient peak temperature of 105°F following a LOCA.

3.4.1 Salt Water System Flow Rates

Section 9.5.2.3 of the FSAR states that the flow rate in the salt water system is 15,500 gpm during normal operation. Following a LOCA, the flow rates are 17,430 prior to recirculation and 16,200 gpm during the recirculation phase. During the routine performance evaluation of the salt water system, the operations department ensures that the system setup provides the following flows to individual loads:

	Service Water Heat Exchanger	Component Cooling Heat Exchanger	ECCS Pump Room Cooler
Normal Operation	14,976 gpm minimum	8,024 gpm maximum	0
SIAS	16,830 gpm minimum	0	600 gpm

These lineups would provide normal operating flow rates of about 23,000 gpm, 17,500 gpm prior to recirculation and about 23,500 gpm in the recirculation phase following a LOCA.

The FSAR states that the maximum recommended salt water pump flow is 22,400 gpm to ensure adequate pump NPSH during the lowest expected tide. The system operating procedure sets minimum limits on the discharge piping pressure to ensure adequate NPSH. The FSAR also states that the salt water system provides flow to the circulating water system pump room coolers. However, these lines have been disconnected. The licensee stated that discrepancies in the FSAR will be updated after the licensee's review.

3.4.2 Maximum Service Water Temperature

The design basis temperature for service water is 95°F; however, following a LOCA, the transient heat load from the containment coolers exceeds the capacity of the service water-to-salt water heat exchangers. The licensee's review indicated that the peak service water temperature could reach 105°F based on containment cooler heat loads for a short period of time. Although EDG operation with 105°F service water temperature was discussed with Fairbanks Morse by the licensee, the manufacturer was not aware that this temperature was the revised design basis for the diesel generators. When this miscommunication was discovered in March 1992 by the licensee, deficiency report PDR 92039 was issued by the licensee to address the operability of the diesel generators with service water temperatures in excess of 95°F.

The manufacturer has been contracted to analyze the effect of higher temperature on the diesels. As an interim measure, the following restriction has been inserted in the operating instructions for the salt water system, operating instruction OI-29: "If the instantaneous average waterbox inlet temperature, for waterboxes that have running Circulation Water Pumps, exceeds 75°F, then both service water heat exchangers are inoperable." Analysis has shown that the reduced salt water temperature will ensure that the peak service water temperature remains below the 95°F design temperature for the diesel generators. The analysis from Fairbanks Morse addressing the acceptability of higher service water temperatures is expected by early summer before bay temperatures reach 75°F, at which time the restriction in OI-29 can be deleted. The team noted that this issue was identified by the licensee in March 1992, during their review of EDG cooling requirements. The licensee stated that this issue is being tracked under issue report No. 013939 and appropriate actions will be taken to prevent any adverse operating conditions.

3.5 Seismic Qualifications

3.5.1 Buried Piping

The seismic analysis for the buried fuel oil and salt water system piping did not take into consideration the stresses induced due to relative ground motion during the event. The licensee has agreed to review the impact of ground motion on the salt water system piping and has requested Bechtel to evaluate the fuel oil system piping to complete the seismic assessment of these safety-related systems.

3.5.2 II/I System Interaction

The team identified several II/I issues during the system walkdowns, particularly in the EDG rooms. A II/I interaction would exist if a seismic class I system could be damaged by a non-class I (class II) system during an earthquake. The licensee stated that the interaction of nonseismically qualified systems with safety-related equipment had not been identified during the design of the plant. However, during construction, criteria for the assessment of system interaction was developed. An evaluation of the systems installed at the time was performed, and subsequent installations were made in accordance with these criteria (reference letter Allison (BGE) to Williams (Bechtel), October 27, 1972).

The station Q-list, section 2.7, lists the "categories of equipment that are exempt from II/I seismic support (SR-II/I) requirements for non-safety-related equipment." This list of exemptions is used to evaluate the need for a II/I assessment for plant modifications currently being implemented at the station. The licensee could not provide any support for the bases of these exemptions which included lights, fire extinguishers, public address equipment and any other items weighing less than 50 pounds.

The licensee agreed that these issues would be addressed at the time of the plant wide II/I system interaction assessment. The licensee has committed to respond to the USNRC generic letter 87-02, dealing with system interaction (USI A-46) on a timetable that is geared around the approval of the Seismic Qualification Utility Group (SQUG) generic implementation procedure (reference letter Tieran (BGE) to USNRC, October 7, 1988). The licensee committed to review the Q-list exemptions for II/I evaluation and provide the bases for the exemptions at the time of the plant wide II/I assessment to ensure consistency with the SQUG guidelines.

3.6 Conclusions

The team found a number of significant deficiencies in reviewing the mechanical systems supporting the Electrical Distribution System. The licensee had identified the fuel oil system deficiencies and created a special project to resolve the issues.

The EDGs are heavily loaded with very little operating margin. Both the loading calculations and the results of the surveillance tests led the team to conclude that additional analysis was required to demonstrate that the EDGs would serve their safety-related function for all design basis events under limiting operating conditions.

The swing diesel starts on an undervoltage signal but does not automatically align itself to a safety-related bus (see sections 3.2.3 and 5.3 for details). Following the steps in the EOPs, the swing diesel could be left unloaded without cooling water for 15 to 20 minutes. The team concluded that the current EOPs were inadequate to ensure the availability of the swing diesel, and could leave the station unprotected against a single failure.

The team identified several potential common mode failures of the switchgear HVAC system that could challenge the availability of the safety-related equipment in the switchgear rooms. The licensee's calculations for loss of HVAC considered the operator's response to a loss of the air conditioning refrigeration loop, but did not address the total loss of ventilation air flow. The team questioned whether the requirements of Appendix R for safe shutdown could be satisfied. The team also asked the licensee whether the total loss of ventilation air flow was considered during their Appendix R safe shutdown analysis.

The team also noted that the licensee did not provide adequate overpressure protection for EDG fuel oil transfer pump fuel discharge line assuming a single failure. Also, no program exists to evaluate the integrity of air start check valves that are subjected to a hammering effect.

4.0 EDS EQUIPMENT

The scope of this inspection element was to assess the effectiveness of the controls established to ensure that the design bases for the electrical system are maintained. This effort was accomplished through the verification of the as-built configuration of electrical equipment as specified in electrical single-line diagrams, modifications packages, and site procedures. In addition, the maintenance and test programs developed for electrical system components were also reviewed to determine their technical adequacy.

4.1 Equipment Walkdowns

The team inspected various areas of the plant to verify the as-built configuration of installed equipment. Areas inspected included the emergency diesel generators, 4160 V and 480 V switchgears, 125 Vdc systems, batteries, and the control rooms. Transformers, motor-generator sets, circuit breakers, pump motors, and protective equipment nameplate data were recorded. This data was collected to verify completeness and accuracy of the system calculations and applicable design drawings. Protective relay settings were also recorded and compared with the current calibration data.

The team found that the inspected equipment was installed in accordance with design drawings. The walkdown inspection suggested that adequate measures are in place to effectively control system configuration. Equipment inspected was well kept, with the surrounding areas generally clear of safety hazards.

During the walkdown, a sampling of the protective relays used for the 4160 V loads controlled by the 4160 Vac switchgear were noted by the team to have time dial (lever) settings different from those given in the relay setting sheets. Most of the relays involved were time-overcurrent relays. The team noted that the original settings were not under any site administrative control. The licensee had previously identified that the protective relay calculation and setting program was weak and was undergoing an overhaul. The new program, now being phased in, was used by the team to determine the acceptability of the as-found settings. The team's review of this issue identified no unacceptable conditions.

4.2 Equipment Maintenance and Testing

The team reviewed various maintenance and test procedures for such equipment as the diesel generator, 4.16 kV and 480 Vac switchgear, batteries, battery chargers, motors and protective relays. The licensee's personnel were interviewed to ascertain their understanding of testing programs. The team also reviewed the controls to establish instrument setpoints during the calibration and testing process.

4.2.1 Load Sequencer

The team reviewed the licensee's periodic surveillance test program for the Safety Features Actuation System (SFAS) which contains and controls the load sequencer unit. This unit provides the logic, controls and timing signals to sequence loads onto the emergency diesel generators (EDGs) during Loss of Offsite Power (LOOP) or Loss of Coolant Accident (LOCA) Events. The integrated test is conducted every 18 months as part of the Loss of Coolant Incident (LOCI) test, Surveillance Test Procedure STP-04.

The team requested that the licensee explain the operation of the load sequencer, since the documentation provided to the team did not adequately address the sequencer logic. During this presentation and review of the load sequencer design, the team noted that the drawing showing the logic design for the final actuation devices of the unit required both a "time signal" from the sequencer, and a "process required" signal from the SFAS logic to start the motor loads. The team also noted that the logic used the same concept for both the concurrent LOOP/LOCA, and the LOOP only incident.

The team raised a concern regarding the design that allowed for the control of EDG loading by two different methods. The process signal could already be present when a time signal was received or the time signal could already be present when the process signal was received. The latter condition may lead to an out-of-sequence start.

The team noted that the loads could be applied to the EDGs in a fashion other than that was intended by the design. Specifically, the team noted that the Containment Spray pump motors might not receive a start signal because the containment pressure had not reached the required setpoint when the load sequencer timer sent a signal to the actuation device to start the Containment Spray motor. The team reasoned that a small break LOCA might not develop sufficient pressure to actuate the containment pressure devices until the next step of loads (5 seconds later) were applied. The team asked the licensee if they had reviewed their design for this occurrence. The team was told that the licensee would investigate this concern. Section 14.17.7.2 of the licensee's FSAR indicated that Combustion Engineering (CE) analysis was used to evaluate small break LOCA events and found that they were adequately protected.

In response to the team's concern, the licensee presented calculation E87-1, which reviewed 34 possible loading combinations during a LOOP or a LOOP/LOCA event including combinations with equipment started out-of-sequence. This calculation contained a table (page 7C or 48) that identified results of EDGs trains A and B voltage response. This table identified that 12 of the 34 cases resulted in a voltage of less than 75% of nominal, as indicated by "LOW," which is the minimum required voltage. These included the application of the containment spray actuation signal (CSAS) loads coming after loss of coolant incident sequencer (LOCIS) step 3 loads and safety injection actuation signal (SIAS) loads coming after shutdown sequencer loads coincident with the above condition. The calculation stated that the above scenarios would cause excessive voltage drop in the EDG buses.

These EDG loading scenarios were presented to safety review committees, plant operating event assessment committee (POEAC) and plant operations and safety review committee (POSRC) to determine if any corrective action need be taken. The safety review committee concluded that no corrective action was necessary as summarized in a licensee internal memorandum dated April 18, 1987. The memorandum stated that the authors presented the analysis contained in calculation E87-1 with the resulting increased core melt frequency. The licensee concluded that the contribution to core melt frequency was insignificant, the event was not reportable, and no further action need be taken. The team asked the licensee on March 17, 1992, to provide the analysis that supported the conclusion that contribution to core melt frequency was insignificant. On March 18, 1992, the licensee provided the team with a draft of the Probabilistic Risk Assessment (PRA) analysis. They noted that the PRA was based on the probability of a LOOP/LOCA occurring simultaneously. The team observed that one of the design basis events for the plant was a concurrent LOOP/LOCA event. Further, the licensee confirmed that pipe breaks in the range of 4 inches to about 1 inch, or a stuck open PORV, or excessive reactor coolant pump seal leakage could produce a small break LOCA which would result in a delayed containment pressure actuation signal. The team noted that this scenario was also discussed in their PRA study.

After this review with the licensee, both the licensee and the team concluded that the process controlled signals could become available after the timing signal, and therefore, the loads could be applied at later times than originally designed. The licensee determined that since the loads could be applied during later steps and that if this mis-application of load were to occur, the voltage dip on the EDGs would be unacceptable. The team noted that because only one set of signals is used for both EDGs, this event would affect both EDGs, and could result in the loss of both EDGs in the middle of a LOOP/LOCA event. The licensee determined that the present plant conditions placed them outside of their design bases with respect to having two operable EDGs to mitigate the consequences of a LOOP or LOOP/LOCA. The licensee later declared all three EDGs inoperable and shut down both units. The licensee continued their review and evaluation of the problem, and determined that they had other "process controlled" or "process required" signals for items such as the control room chiller units. The licensee also determined that these signals could cause the same type of problem during a LOOP event and again declared the EDGs inoperable.

The team noted that the potential for severe voltage and frequency deviations if unsequenced loads start at the same time a large load is started due to a process-controlled parameter was known to the licensee since January 1986. This information was first reported by Watts Barr Nuclear Power Plant under 10CFR 50.55e. This report stated that this design deficiency if left uncorrected could affect the safety of the plant.

The NRC is concerned that safety and regulatory significance of this issue was not recognized by the licensee's safety review committees POEAC and POSRC when it was initially identified by them and no appropriate corrective actions were taken until this issue was identified by the NRC EDSFI team. The NRC is also concerned that the draft PRA presented to the EDSFI team failed to note the high probability failure items and gave non-conservative results.

The team noted that this unanalyzed condition was not reported to the NRC until March 19, 1992. Also, the licensee did not perform any evaluations to show that the plant modelling of emergency core cooling system still satisfies the original assumptions and analysis. The sequencer design problem could render the EDGs and ECCS components inoperable. The team also noted that the licensee did not perform any evaluations to show that the technical specifications limiting condition of operation for the onsite power sources and requirements for a reliable onsite power source with sufficient capacity and capability as required by General Design Criteria 17 were satisfied.

The licensee determined that a design modification was required to correct the problem. During the inspection, the licensee prepared the required documentation and design, and at the end of the inspection had installed the modification in Unit 2. The modification in Unit 1 was scheduled during the current refueling outage.

The team identified the following apparent violations regarding this issue:

1) Failure to take appropriate corrective action to preclude a potential common mode failure of EDGs and ECCS loads is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI.

2) Failure to take appropriate design control measures to prevent improper sequencing of loads that could render EDGs and ECCS loads inoperable is an apparent violation of 10 CFR 50, Appendix B, Criterion III.

3) Failure to notify the NRC as soon as practical and in all cases within one hour of the occurrence of the condition that results in the plant being in an unanalyzed condition that significantly compromised plant safety is an apparent violation of 10 CFR 50.72 (b)(ii)(A)

4) Failure to submit a Licensee Event Report within 30 days of the occurrence of the condition that resulted in the plant being in an unanalyzed condition that significantly compromised plant safety is an apparent violation of 10 CFR 50.73 (a)(2)(ii)(A).

5) Failure to consider the full spectrum of pipe breaks in determining the most limiting loss of coolant accident is a violation of 10 CFR 50.46.

(50-317/92-80-004 and 50-318/92-80-004.)

4.2.2 Emergency Diesel Generators Testing

The team reviewed the licensee's periodic surveillance test program of the EDGs. There are two types of tests conducted by the licensee. The monthly test parallels the unit to the offsite grid and, using the voltage regulator and governor controls, loads the machine. The 18 month test manually injects a LOOP/LOCA signal and records the system response. During the latter test, the EDGs are loaded in sequence by the SFAS/Load Sequencer logic, but because the pumps are typically in a recirculation mode, the total load rarely exceeds 1/2 to 2/3 of the EDGs rated output. Thus, the test does a limited check on the ability of the machine to start large loads while carrying running loads.

The team noted that during the monthly testing, the machine was loaded to 2400 (+/- 50) kW, but less than 1870 kVARs per procedure OI-27C. Interviews with the main control room operators indicate that the machine is typically loaded to only several hundred kVARs and a power factor of about .95. The machine is rated at 0.8 power factor and the load is approximately 0.85 power factor. This is significant because the EDG consists of two major subsystems, the Engine/Governor, and the Generator/Voltage Regulator. The kW tests only verifies the Engine/Governor capabilities. However, this testing (0.95 power factor) does not test the Generator/Voltage Regulator subsystem to a level that gives adequate confidence to supply motor starting currents required during a design basis accident.

The team noted that the EDG short term rating is 3250 kW for 168 hours, and the maximum load (as shown by calculation) that could be applied is 3234 kW. The EDGs have a mechanical stop incorporated in the governor control system to assure that the machine will not exceed the 3250 kW short term rating. However, if the machine is picking up a load such as the control room chiller when the EDG is near the maximum rating, this manual load addition could force the governor into the stop before the machine has picked up the starting portion of the load. This could stretch out the starting transient with unknown effect on the EDG or the loads.

In conjunction with this limitation, the team noted that the voltage dip, as recorded during the performance of the STP-04, 18 month surveillance test, showed that the machine voltage drops to the 75 percent to 77 percent range. Values of 75.96 percent (EDG 12 test dated 6/88) to 76.9 percent (EDG 12 test dated 3/91) have been recorded during load application in load sequence step four. Values as low as 75.24 percent (EDG 11 test dated 6/88) have been accepted. Since the surveillance test limit (which is based on the maximum allowed full load voltage drop calculation) is 75 percent, the load is only 1/2 to 2/3 of the rated load, and in at least one case the voltage drop was below the acceptable value, the team questioned the ability of the machine to supply the required voltage during a LOOP/LOCA event. The licensee stated that they have fine tuned the voltage regulator by changing the stability adjustment to make the machine voltage overshoot the 4,160 volt rating of the machine at the time the next load is being applied. This is documented in the licensee's March 28, 1990, letter that directs the resetting of the EDG voltage regulator stability adjustment and notes that the adjustment could result in instabilities being observed at or near the suggested stability setting. Since this is an imprecise process based on the amount of load applied at the earlier step and can result in the EDG becoming unstable during a LOOP or LOOP/LOCA and could be defeated by voltage regulator drift or load sequencer timer drift, the team asked for further justification for the adequacy of EDG control. After the inspection, the licensee reported that: 1) voltage dips on the EDG output are primarily caused by the current surge that generates breakaway motor torque and not significantly increased by whether a motor delivers 50% or 100% of rated load; 2) calculations shown as conservative through testing indicate voltage will not go below 75% of nominal voltage; 3) no equipment damage was noted during past surveillance test failures with voltage dips below 75% of nominal; and 4) a vendor engineer confirmed that regulator adjustments were proper and ought to improve voltage regulator performance. The team concluded that the above rationale was sufficient to resolve any immediate operability concerns. This item remains unresolved pending the licensee performing further review of the impact on machine stability at 100 percent load, and analysis and/or testing to demonstrate the machine's ability to supply the accident loads without exceeding the 75 percent voltage dip limit at the bus with all sources of instrument drifts and errors (50-317/92-80-005) and 50-318/92-80-005). Refer to section 3.2.2 for further discussions.

The team also noted that the 18 month STP-04 testing required the recording of the highest frequency reached during the test. The test limit was 66 hertz. The review of several STP-04 tests, and the corresponding Visicorder traces showed that the frequency recorded on the STP-04 and the highest frequency reached during loading of the machine did not match. For example, during the June 1991 EDG 11 STP-04 test, the highest frequency recorded on the Visicorder trace was above the upper limit of 66 hertz. The STP-04 Attachment 10 stated that the maximum frequency obtained during sequencing of steps was 61 Hz. A similar event also occurred during the November 1991 EDG 21 test.

In response to the team's concern, the licensee stated that they knew that the EDG exceeded the maximum frequency value listed in the surveillance test during initial loading. The licensee also stated that they did not consider the frequency of the machine during the "step zero" loading of the machine since it did not reach a steady state frequency value, but is considered starting transient during this loading. The team noted that the STP required the recording of the highest frequency reached during the test, and the licensee did not record this frequency even though they were aware of it and knew that they were applying loads to the machine during this time. Further, the licensee has not provided evidence that the loads applied at the highest frequency recorded, 66.2 hertz, would not be damaged by the higher frequency. Further, the licensee has not provided evidence that, in an accident condition, applying load to the EDG during the startup transient will not cause the machine to fail to perform as designed later in the load sequence.

The team concluded that the EDG is being loaded when the governor is still recovering from the starting transient. The output breaker is closing between 7.5 and 8.2 seconds. The charts for these runs show that the EDG voltage has reached it's permissive point prior to the governor recovering from the starting transient. Failure to properly evaluate the impact of frequency exceeding the maximum acceptable values during the STP is a violation of 10CFR 50, Appendix B, Criterion XI (50-317/92-80-001 and 50-318/92-80-001). (Refer to section 4.3 for another example of this violation.)

The team also noted that during testing of the EDGs, the inaccuracies of the various instruments used to collect the test data were not considered. Since some acceptable test voltage dips were in the range of 0.24 percent to 1.9 percent, with the best observed value of 4.3 percent, the inaccuracies induced by the various equipment, in particular the use of a ruler to read and interpret voltage from a Visicorder chart, could invalidate test results. These errors are not accounted for in either the engineering determination of the test value, or the reading and interpretation of the value during the surveillance test. It was also noted that a deficiency tag stating that the 12 EDG kilowatt meter was reading 100 kW different from the control room kilowatt meter. This meter was used to verify the EDG kW loading during surveillance testing of EDGs without considering the meter inaccuracies. The team also noted that surveillance test procedure STP-04 and design documents E88-15 and E90-39 for EDGs did not consider any instrument inaccuracies, tolerances or errors. The licensee stated that they were not factoring any instrument errors or drifts in determining the final acceptance values for test and/or design documents. Other examples where instrument inaccuracies were not considered will be found in section 4.3. Failure to establish adequate procedures to incorporate instrument inaccuracies, errors and drifts in surveillance test procedures and lack of adequate design measures taken to specify this in the design documents are violations of Technical Specification 6.8.1 and Criterion III (50-317/92-80-002 and 003 and 50-318/92-80-002 and 003).

The team noted that the licensee does not record information such as fuel rack position or field amps/volts during the performance of their surveillance testing. Based on good maintenance practice, the team commented that the licensee could significantly aid their EDG reliability efforts by recording and trending the data available to them during the various testing. The team also noted that the physical condition of the EDGs indicated a need for more attention to maintenance. The 12 EDG had a number of small oil leaks on gage fittings. These were marked with deficiency tags. Although the small leaks by themselves were not hazardous, the large number of them would indicate a need for attention.

4.2.3 Other Electrical Equipment

The team reviewed test procedures for other safety-related electrical equipment. The equipment included circuit breakers in the 4.16 kV class, 480 Vac drawout type breakers, transformers, motors, and protective relays. The procedures reviewed were determined to be technically adequate with applicable acceptance criteria except as noted in section 4.3.

The team noted that the licensee performs periodic preventive maintenance testing of electrical equipment. This included megger testing of 4.16 kV circuit breakers and associated pump motors, cable and transformers. The licensee performs a Doble test and a Transformer Turns Ratio (TTR) test on power transformers. The team did not review the test results. The licensee has an aggressive motor lubrication program. The team noted that the licensee is in the process of implementing a Molded Case Circuit Breaker (MCCB) testing program in place.

The licensee is reconstituting some of their older vendor manuals with the help of a subcontractor. These reconstituted manuals are helping the maintenance effort and should alleviate some of the licensee's former problems in this area. The team interviewed maintenance personnel and found that, in general, the licensee follows the vendor manuals when preparing the maintenance procedures, and follows their maintenance procedures when performing work on their equipment.

In summary, the team identified an inadequate test procedure for EDG testing. These inadequacies relate to the measurement and recording of the maximum frequency and lowest voltage reached during the test. Also, the team identified a concern regarding the EDG capability to support the applied LOCA loads during an event.

4.3 Meters and Protective Device Setpoint Control and Calibration

The team reviewed the licensee's program for controlling meter calibration and protective device setpoint and calibration. In addition, instrument calibration procedures and records were also reviewed to determine whether the contents of procedures and test results were acceptable. The control of setpoint data provides assurance that equipment will operate at pre-determined levels.

The team noted several deficiencies with the program and implementation. The first involved the Degraded Grid Relays. These relays are solid state undervoltage relays with a time delay. The surveillance test for these units set a range of values for the relay to drop out or actuate on undervoltage. The procedure also set a range of time delay for the relay to timeout before sending a signal to actuate the undervoltage logic and circuitry. The procedure, STP-M-522-2, records the reset voltage, that voltage at which the relay stops timing out and resets after turning on at the drop out value. This value was determined in Calculation E90-31, Attachment I as 3668 Volts. With the setpoint within tolerance, the relay will not cause a false trip and EDG actuation when motor starting causes the bus voltage to momentarily dip below the relay drop out voltage (3603 V). This value was given in the above calculation as 3668 volts. The potential transformer (PT) feeding the relay has a turns ratio (without accuracy consideration) of 4200 to 120, or 35:1. Thus, to maintain the 3668 volt relay reset point, the equivalent secondary voltage is 104.80 volts. The surveillance test procedure requires that the reset voltage be recorded for information only, and does not require the reset point to be set. Further, the M-522-2 STPs that were reviewed had reset voltages consistently higher than 104.8 V, with the highest value in the sample group being 105 V. This corresponded to a 4160 V bus value of 3675 V. This value, when reflected back to the 500 kV line, including meter inaccuracies, would result in the incoming line voltage being low but acceptable, and during a LOCA, the voltage dip due to motor starting and subsequent voltage recovery of less than 3675 V would trip and time out the bus undervoltage relay. If this were to occur, the operator would see a LOOP/LOCA event on safety-related buses while the non-safety buses and the switchyard would indicate no problem.

In response to the team's concern, the licensee prepared a formal response to address this issue after the inspection. The response was listed as "Response to NRC concern on degraded grid relay reset voltage." On page 2 of the response, the licensee states that Calculation E-87-13 was performed to analyze the replacement of the original relays which had a minimum deadband of 0.5% with a new relay which has a minimum deadband of 1.0%. The licensee states that "The calculation shows that a deadband of 1% is acceptable since the pickup (reset) voltage is less than the minimum steady state voltage for the worst case scenario of plant conditions and switch yard voltage." As noted above, calculation E-90-31 indicates that the worst case 4160 bus running voltage is 3668 volts. Again, as noted above, the potential transformer ratio is 35:1; therefore, the pickup (reset) voltage must be 3668/35, or 104.8 volts. The licensee, on page 2, states that the nominal reset is 104.9, which is above the 104.8 value, therefore, the licensee's answer does not address the minimum 3668 Volt value. Any reset voltage above this will allow the degraded grid relay timer to time out and cause the bus to transfer over to the EDG. The team was concerned that this would cause unnecessary challenges to the safety system especially when the offsite power is feeding the LOCA loads and is required to transfer over to the EDG due to incorrect degraded bus relay reset settings. Failure to incorporate adequate acceptance criteria in the surveillance test procedure for degraded bus relay reset points to ensure that the relays will operate within the design allowable values is another example for violation of 10 CFR 50, Appendix B, Criterion XI (50-317/92-80-001 and 50-318/92-80-001). (Refer Section 4.2.2 for another example.)

The team reviewed the meter setting sheets and noted that many of the meters used to read surveillance test results were calibrated to plus or minus 1.5 percent. Since many tests results are accepted with margins that are less than 1.5 percent, the team noted that these test results are in question when meter accuracy is included in the overall value read. The team noted that design documents E90-31 and E87-13 and surveillance test STP-M-522-2 for degraded bus protection did not consider any instrument inaccuracies, tolerances or errors for instruments such as current transformers, potential transformers, voltmeters and voltage relays. Failure to establish adequate procedures to incorporate instrument inaccuracies, errors and drifts in surveillance test procedures and lack of adequate design measures taken to specify this in the design documents are violations of Technical Specification 6.8.1 and Criterion III (50-317/92-80-002 and 003 and 50-318/92-80-002 and 003).

4.3.1 **Transformer Maintenance**

The licensee stated that they have an adequate test program for their large transformers. Interviews with their Electric Test group and Systems group indicate that they test the large, oil filled units by a combination of testing including Doble testing and oil analysis. Based on the interviews, the team concluded that the licensee is performing the basic industry standard tests on their oil-filled transformers including the Main Power Step-up Transformers, the 500 kV to 13.8 kV intermediate transformers, the 13.8 kV to 4.16 kV transformers, and the 4.16 kV to 480 Vac "Askeral" oil-filled transformers.

4.3.2 **Fuse Control**

The team reviewed the licensee's fuse control program, and performed a plant walkdown to verify the installation of fuses in accordance with as-built drawings. Guidance for the fuse control program is found in E-406, section 300. This document provides adequate field direction for fuse replacement. The team reviewed several fuse replacement evaluations done as part of the licensee's equivalency replacement program and found that Engineering had contacted the fuse vendor when appropriate, and had done coordination studies to assure that the equivalent part would provide the same electrical protection as the item replaced. The team found that the fuse replacement program was fully adequate and implemented within the plant.

4.3.3 **Motor Lubrication**

The team reviewed the licensee's motor lubrication program, and interviewed the personnel involved in implementing the program. The team found that the licensee has used their Engineering Department to review the items that need lubrication, and the type of lubricant recommended by the vendor. This information is passed to another group that reviews the lubricants, as necessary for equipment qualification requirements. The licensee has been able to break their qualified lubricants into two types, and based on the vendor's recommendation, picks the correct lubricant for the application. They assure that the old lubricant is cleaned out where necessary, and assures that the correct amount of approved lubricant is installed. The Maintenance Department is given the information for incorporation into the motor maintenance. Interviews with the Maintenance personnel indicate that this program is working quite well, with no evidence of over or under-greasing of motor bearings. The team therefore concludes that the lubrication program as presented is acceptable.

4.4 Conclusions

Based upon the sample of equipment and documentation reviewed, the team concluded that in several cases, the licensee failed to perform a through technical review of design requirements to establish the acceptability of test results or failed to adequately incorporate instrument accuracy or tolerance in test procedure acceptance criteria. In one case, the licensee failed to recognize that a design inadequacy could cause a common mode failure of both EDGs in a plant during a LOOP or LOOP/LOCI event. As a result, three violations regarding inadequate testing of the EDGs and undervoltage relays; and inadequate design control/corrective action/ reporting were identified. Generally the licensee had implemented controls to maintain electrical system configuration for all safety-related EDS components and were found acceptable.

5.0 ENGINEERING AND TECHNICAL SUPPORT

An evaluation was performed of the licensee's capabilities to provide acceptable engineering and technical support to the plant operations organization. For this purpose, the team reviewed organization and staffing, training, interfaces between the engineering organizations and the technical support groups responsible for the plant operations, and self assessment programs.

To address the licensee's performance in the engineering and technical support area, the review evaluated the implementation of programs and procedures and examined a sample of Issue Reports (IRs), Non-Conformance Reports (NCRs), Licensee Event Reports (LERs), major, minor and temporary modification programs, Quality Assurance (QA) audits, root cause investigation and corrective action programs.

5.1 Organization and Key Staff

The engineering and technical support for the Calvert Cliffs Units 1 and 2 are provided primarily by two onsite organizations, both having engineering capability for their specific functions.

The plant technical support organization is composed of nearly 300 engineers and engineering personnel divided into five groups, including the Plant (Systems and Components) and the Performance Engineering Sections. The plant technical support staff reports to the Plant Resident Manager through a Superintendent and several intermediate supervisory personnel. The various support groups, together with the Nuclear Maintenance organization and its supporting engineering staff, are primarily responsible for the day to day activities necessary for the smooth operation of the plant.

The nuclear engineering organization is composed of approximately 200 engineers and engineering personnel divided into five groups, including the Design, Strategic, and Technical Services Engineering and the Plant Design Support Sections. The nuclear engineering staff reports to the Manager of Nuclear Engineering and is primarily responsible for engineering and design of major modifications, the overall configuration control program, and the engineering and design standards.

The team's evaluation of the staff's performance concluded that it was generally good with engineering and technical personnel knowledgeable of the respective disciplines. New calculations initiated as a result of the current design basis reconstitution program were found to be generally good and presented in a comprehensive manner. However, the team also observed various inconsistencies in the accuracy of the calculations and in the conservatism of the assumptions. Throughout the inspection, responses to the team's questions were timely and complete.

5.2 Root Cause Analysis and Corrective Action Programs

To assess the effectiveness of the licensee's root cause analyses and corrective action programs, several licensee event reports (LER), problem reports (PR), non-conformance reports (NCR), and issue reports (IR) were reviewed together with the results of recent Quality Assurance (QA) audits.

An evaluation of the above programs indicated that they were recently revamped and that both programs benefitted from the changes that were implemented. In an effort to improve the identification of and to simplify the methods for reporting safety concerns and non-conformances, the various reporting systems were consolidated into one document, the issue report, that is governed by licensee procedure CCI-169. Although the procedure was originally scheduled for implementation in September 1991, as of the end of the inspection, some hardware issues continued to be handled via the maintenance request process. The procedure allows this alternate method as an interim measure.

A review of several IRs, as well as older PRs and NCRs, indicated that they were properly tracked and resolved. However, an Independent Safety Evaluation Unit (ISEU) trend report for the third quarter of 1991 expressed some concerns pertaining to the adequacy of closures for IRs and NCRs and states: "(1) problems which require detailed analyses and solutions are not always being effectively resolved, and (2) there is some reluctance to escalate important issues to upper management when there is disagreement among lower levels of management over problem validity and/or corrective action." In another section, the report expressed some concern that not all problem report candidates were documented on PRs.

The fourth quarter ISEU trend report continued to address the concern. However, subsequent discussions with the licensee indicated that some of the problems lingered from earlier dates and that the use and processing of IRs would resolve the issue. The licensee also indicated that, although improvements had already been observed between the third and fourth quarter of 1991, monitoring of IRs and their resolution would continue on a priority basis. A sample review of recent Licensee Event Reports indicated that they were appropriately handled with adequate corrective actions.

Regarding the root cause analysis, the team concluded that, despite some inconsistencies observed, the licensee had developed an excellent program. Two procedures are used to address this area. The first, Plant Engineering Section Guideline, PEG-6, provides guidance for performing and routing root cause analyses of non-conformances within the Plant Engineering Section. This guideline primarily addresses equipment and component failures. A sample review of root cause analyses performed according to this procedure found then to be detailed, but not to address human performance.

Root cause analyses of safety significant events were performed in accordance with procedure CCI-165, "Event Investigations." A review of analyses performed according to this procedure were found to be comprehensive and to perform a full investigation of human performance in conjunction with the event.

5.3 EDS Operating Procedures

A sample of operating procedures was reviewed to confirm that the operating instructions and administrative controls were adequate to ensure operability of the electrical distribution system under abnormal and emergency conditions.

While reviewing the electrical system, the team determined that each unit was equipped with one emergency diesel generator (EDG) capable of supplying the required emergency power to one of the two safety buses. A third EDG, No. 12, was designed to supply redundant emergency power to the other safety bus of either plant, i. e., to bus 14 of Unit 1 or to bus 21 of Unit 2. A review of the controls for this EDG revealed that, in the event of a loss of offsite power (LOOP) in conjunction with a loss of coolant accident (LOCA), the EDG would be automatically assigned to the unit affected by the LOCA. However, in the event of a LOOP without a LOCA, the EDG would start and run idle until it was assigned to either plant, by manual operator action. As indicated under Section 3.2.3, it was also determined that, in this latter case, EDG 12 would receive no cooling water flow until the load breaker was closed onto one of the buses and the respective service water valve opened.

The above observations caused the NRC inspectors to express the following concerns:

1. In the event of a LOOP with a LOCA, the plant not affected by the LOCA event could experience a temporary station blackout if it also experienced a single failure of the only available EDG.

2. In the event of a LOOP without a LOCA, EDG 12 could automatically shutdown on high temperature or be damaged by the lack of cooling water. In this case, a delayed LOCA affecting either unit could result in that unit being vulnerable to a single component failure.

In order to determine the extent to which the plant was vulnerable to the above concerns, the applicable emergency operating procedures (EOP) were reviewed and discussed with the licensee. The team concluded that the first issue was covered by the licensee's response to the Station Blackout rule, but that it was only in part addressed by the applicable EOP. The reason for the conclusion was that neither step O.1 nor alternative steps O.1.1 and O.1.2 of EOP-7, Revision 1, "Station Blackout," contained specific guidance for the postulated scenario. Discussions with the licensee pertaining to this issue indicated that the operators were trained for this situation and that other operating instructions (OI) would be available to them for the event recovery. However, no other OI was identified, as in the case of steps O.1.1 and O.1.2.

Regarding the second concern, a review of EOP-2, Revision 1, "Loss of Offsite Power," revealed that the alignment of EDG 12 to either Unit was not addressed until step G. Discussions with the licensee pertaining to the delay in the alignment of EDG 12 indicated that the delay would be in the order of 15-20 minutes, if no difficulties were encountered during the execution of EOP-0 and EOP-2.

After the inspection, the licensee issued a shift turnover information sheet requiring operator action to connect the swing diesel to the bus within 1-5 minutes of a LOOP event. The team had no immediate safety concerns with the licensee's interim operator guidance in place.

In view of the above and the discussions in Section 3.2.3 regarding the capability of the diesel generator to operate without cooling water, the acceptability of the current operating procedures is unresolved pending appropriate evaluation and corrective action by the licensee. (50-317/92-80-011) (50-318/92-80-011)

5.4 Operational Events and Industry Experience

The team reviewed the procedures used by the licensee to evaluate both in-house and industry operating experience and to process the information gained into reports, procedural and/or design changes.

The responsibilities and specific instructions, including those required for significant occurrence reports (SOR); INPO documents; vendor bulletins; and NRC generic letters, information notices and bulletins are primarily addressed by two licensee procedures. Procedure IOER-01, "Industry Operating Experience Review Unit Instructions," details the steps for processing, evaluating and screening the information received by the Operational Experiences Review (OER) group. Procedure CCI-139, "Organization and Operation of the Plant Operating Experience Assessment Committee," addresses the flow of information to and from the reviewing organizations and the closure of the package. In addition, Procedure CCI-154 details the processing of correspondence with the NRC.

Based upon its limited review, the team concluded that the licensee's procedures, if properly implemented, provided a satisfactory method for addressing nuclear plant experiences.

5.5 Self Assessment Program

The team reviewed the licensee's self assessment programs to ensure that safety issues are promptly identified and resolved in a timely manner. This review found the programs to be extensive and to include various engineering activities including safety systems functional inspections (SSFI), QA audits and surveillance, and various performance monitoring devices. Examples of these include a recently completed electrical distribution system functional inspection (EDSFI). Although the inspection failed to identify some significant concerns pertaining to the emergency diesel generators capabilities and to the load flow, it was considered to be adequate, covering electrical and mechanical design, surveillance and testing, operations and maintenance. The inspection identified approximately 37 significant issues and observations in all areas of review. At the time of the inspection, the licensee's findings had been either resolved or included in the plant tracking system awaiting resolution. Other SSFIs performed included the auxiliary feedwater system and the low pressure safety injection system.

An in-house performance monitoring program was provided by the operating experience review section which included approximately 13 engineers divided into three groups addressing plant and industry operating experience. The section also included an independent safety evaluation unit. Long and short-term performance goals were identified by management and translated into specific activities by the various engineering and plant organizations. Tracking of performance versus goals was appropriately kept by each group.

The licensee was also addressing programmatic issues that had been areas of concern in the past. One of these areas was the control of the design documentation and reconstitution of as-built design drawings and documents. Document control also had been the object of a QA audit which concluded that the program had not been clearly or consistently defined. At that time, QA also commented that the Procedure Upgrade and the Drawing Improvement Projects appeared to provide the necessary means to address numerous implementation and written program deficiencies and weaknesses found QA audits were found to be thorough, well organized, and with good insight.

5.6 Design Changes and Modifications

The team reviewed the area of plant design changes and modifications to ensure that they were controlled and performed in accordance with approved licensee procedures and in conformance with the regulatory requirements.

The Calvert Cliffs modification process recently underwent a major revision to ensure that tighter controls were imposed on the process. Currently, the design changes and plant modifications are categorized into major, minor design equivalency and like for like replacement modifications. Major modifications, also known as facility change request (FCRs), constitute design changes with major cost and engineering impact. Projects of limited scope and costs are identified as minor modifications or MCRs. Design equivalent modifications are considered to be another form of minor modification involving such things as a replacement of a component or sub-components with one of equivalent critical attributes. Like for like replacements are component changes of equal function. All changes constitute permanent plant modifications.

The change process is performed by the onsite engineering organizations in accordance with several procedures. Procedure CCI-702, "Change Control Process Overview", provides the means for determining the type of change and process to be pursued. It also provides the responsibility and the instructions necessary for a like for like replacement. Procedure CCI-703, "Initiation of Design Change, Modification and Equivalency Evaluation," describes the responsibilities and the steps required to perform FCRs, MCRs, and equivalency replacements. The process is complemented by additional procedures addressing engineering process (CCI-704), implementation (CCI-705), package close-out (CCI-706), and drawing change control (CCI-707). All changes, regardless of complexity or impact on human and financial resources undergo safety evaluation in accordance with 10 CFR 50.59. The procedures were found to be long and very detailed.

Several major modifications were reviewed for compliance with licensee and regulatory requirements. Adequacy of resolution of the identified problem was also evaluated. One example of major modification that was evaluated in detail was Facility Change Request (FCR) 91-231, applicable to Unit 1 only. The modification involved the relocation of the cross connecting piping between Service Water System trains 11 and 12 downstream of two isolation valves. The purpose of the new installation was to address some containment temperature concerns that existed when a service water heat exchanger was taken out-of-service for cleaning during the summer months. The modification package also included several supplements that were issued to address other concerns, such as water hammer.

The package was found to be well organized, thorough, and documented according with the applicable procedures. Both the original design and the subsequent supplements had been evaluated for safety impact under 10 CFR 50.49. Applicable drawings were also reviewed to verify appropriate documentation of the design change and were found to be acceptable.

The team also reviewed in detail selected minor and design equivalent modifications that were either in progress or completed to assess the quality of the engineering performed. One minor modification package, No. 91-005-001-0 for Unit 2, involved the change of trip settings in two circuit breakers associated with 480 V panel 2P55. As in the case of the major modification described above, the package was complete with an appropriate safety evaluation. The package also included a calculation addressing circuit protection. The team found this and the other modifications reviewed to be well organized, complete and in accordance with the applicable procedures.

5.7 Temporary Modifications

Procedure CCI-117 establishes the requirements for the installation of temporary modifications, bypasses, and jumpers throughout the plant and imposes the controls for their removal or conversion to a permanent modification. As in the case of the procedures for permanent modification, the procedure was very detailed, complete with charts and flow diagrams to aide in the selection of the applicable processes and procedures. The procedure did not specify the life of a temporary modification, but it required the identification of its expectancy at the time of the implementation. Temporary modifications require quarterly reviews and verifications; schedules extensions beyond the first extension require the approval of the plant's general manager.

The team reviewed several temporary modifications and found them to be satisfactorily performed and in accordance with the licensee's procedures. Technical and operational reviews were completed as were the safety evaluations and approvals. A log of the open temporary modifications is maintained in the control room.

5.8 Engineering Support/Interface

The team reviewed the effectiveness of the engineering interface between the various plant engineering organizations, the maintenance staff, and operations staff.

Engineering support at the Calvert Cliffs station is provided by various engineering and technical organizations at the site, each with specific functions and responsibilities. The engineering involvement in all plant activities was found to be extensive, as evidenced by the large contingency of engineering personnel present at the site and by the number of ongoing design changes and design basis reconstitution activities. The interface between the engineering personnel was found to be effective and with no specific inadequacies. The daily report meetings were found to be well attended by representatives from all plant functions indicating good communication and interface between organizations.

5.9 Conclusions

Based upon the sample of documents reviewed and of personnel interviewed, the team concluded that the nuclear and plant engineering organizations were staffed with competent personnel. The recent staff reorganizations appeared to be working well and to have been a positive step toward improving the effectiveness of the engineering staff. The calculations initiated as a result of the design basis reconstitution program were good and presented in a comprehensive manner. Communications between the various engineering groups and between these and the operation organizations also was considered good.

The self assessment program was found to be extensive and with good insight in identifying areas requiring improvement. This program is further enhanced by an excellent root cause analysis program. However, the corrective actions need further attention both in the identification and in the execution.

6.0 UNRESOLVED ITEMS AND OBSERVATIONS

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items or violations. Observations are conditions that do not constitute regulatory requirements and are presented to the licensee for their evaluation. Unresolved items and Observations are identified in a table titled "Summary of inspection findings."

7.0 EXIT MEETING

The inspector met with licensee corporate personnel and licensee representatives (denoted in Attachment 1) at the conclusion of the inspection on April 3, 1992. The inspector summarized the scope of the inspection and the inspection findings.

ATTACHMENT 1

PERSONS CONTACTED

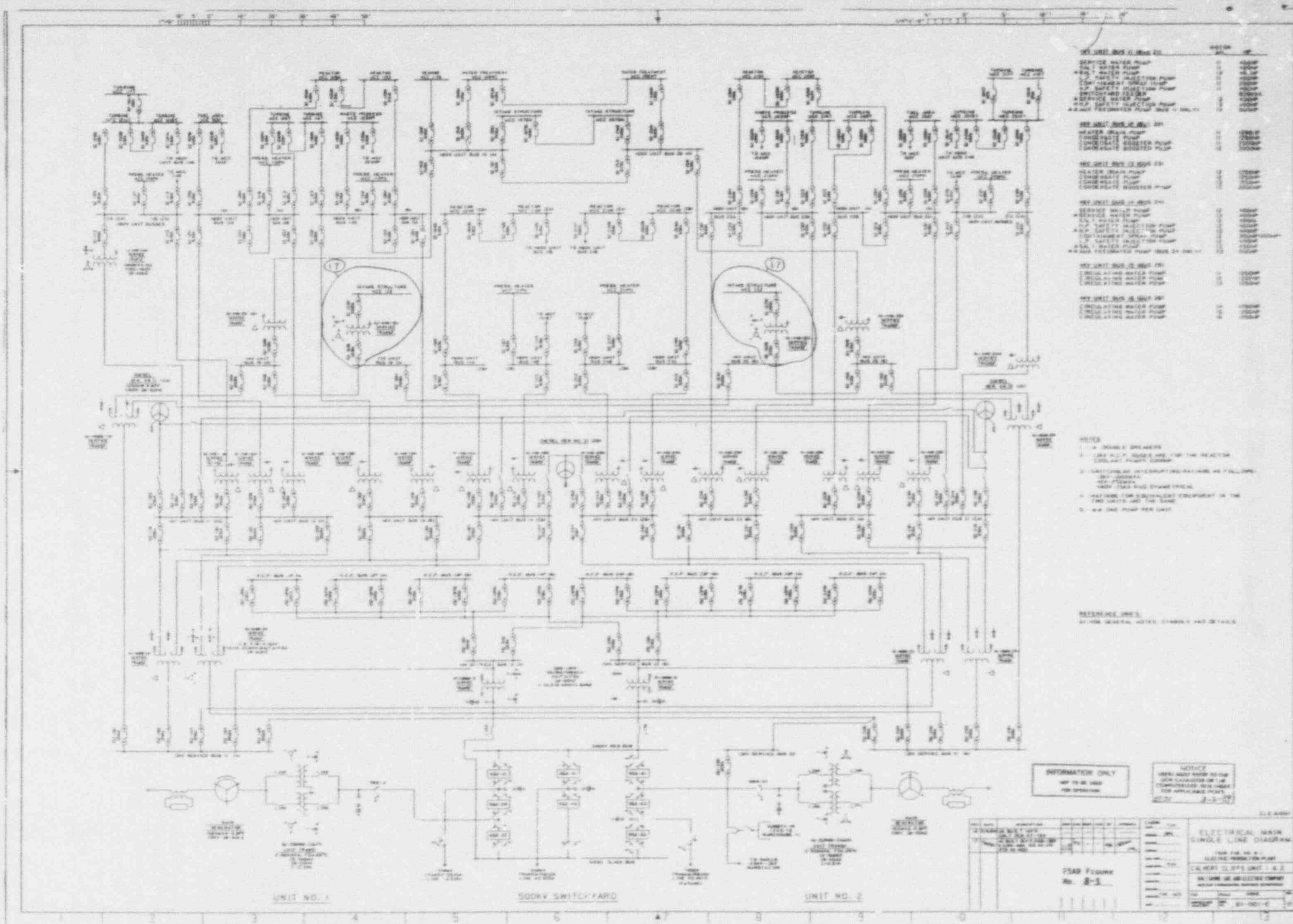
Baltimore Gas and Electric Company

* A. Anuje, NQAD
* R. [illegible]uttner, Nuclear Engineering Design
* C. [illegible]ruse, Manager, Nuclear Engineering Department
* T. Camilleri, Maintenance Superintendent
* P. Chabot, Director, Strategic Engineering
  S. Collins, Principal Engineer
* S. O'Connor, Plant Engineering Section
* G. Detter, Director, Nuclear Regulatory Matters
* J. Dickerson, Plant Engineering Section
* G. Dockstader, Plant Engineering Section
* J. Gaines, OPS support
  M. Ghan III, Principal Engineer
* D. Gladey, Nuclear Engineering Design
* P. Hebrank, Project Engineer
  W. Holston, Principal Engineer, Plant Design support
* M. Junge, NQAD
* P. Katz, Superintendent, Technical Support
* J. Kilpatrick, Nuclear Engineering Design
  G. Knieriem, Design Engineering
* T. Konerth, Mechanical Design Engineer
* J. Lea, Maintenance Department
  R. Lockhart, Mechanical Engineering Technician
  C. Mahon, Project Manager, Diesel Project
  C. Matassa, Senior Engineer, Electrical System
  E. McCann, Engineer, Design Basis Unit
* J. McVicker, Project Manager, EDSFI project
* B. Montgomery, Principal Engineer, Licensing
  J. Moraski, Supervisor, Operations Engineering Unit
* C. Nolan, Mechanical Design Engineer
* R. Olson, Director, State Regulatory Matters
* L. Salyards, Principal Engineer, Design Basis Unit
* K. Sebra, Nuclear Engineering Design
* L. Tucker, Group Supervisor, Plant Engineering
* D. Vincent, Plant Engineering Section
* R. Waskey, General Supervisor, Design
* L. Weckbaugh, General Supervisor, Electrical and Controls
* L. Wenger, Nuclear Regulatory Matters
* E. Wilson, Compliance Engineer

U.S. Nuclear Regulatory Commission (USNRC)

* C. Anderson, Chief, Electrical Section, RI
* W. Lanning, Deputy Director, Division of Reactor Safety, RI
* P. Wilson, Senior Resident Inspector
J. Beall, Team Leader, RI
F. Lyon, Resident Inspector

* denotes those not present at the exit meeting conducted on April 3,1992.



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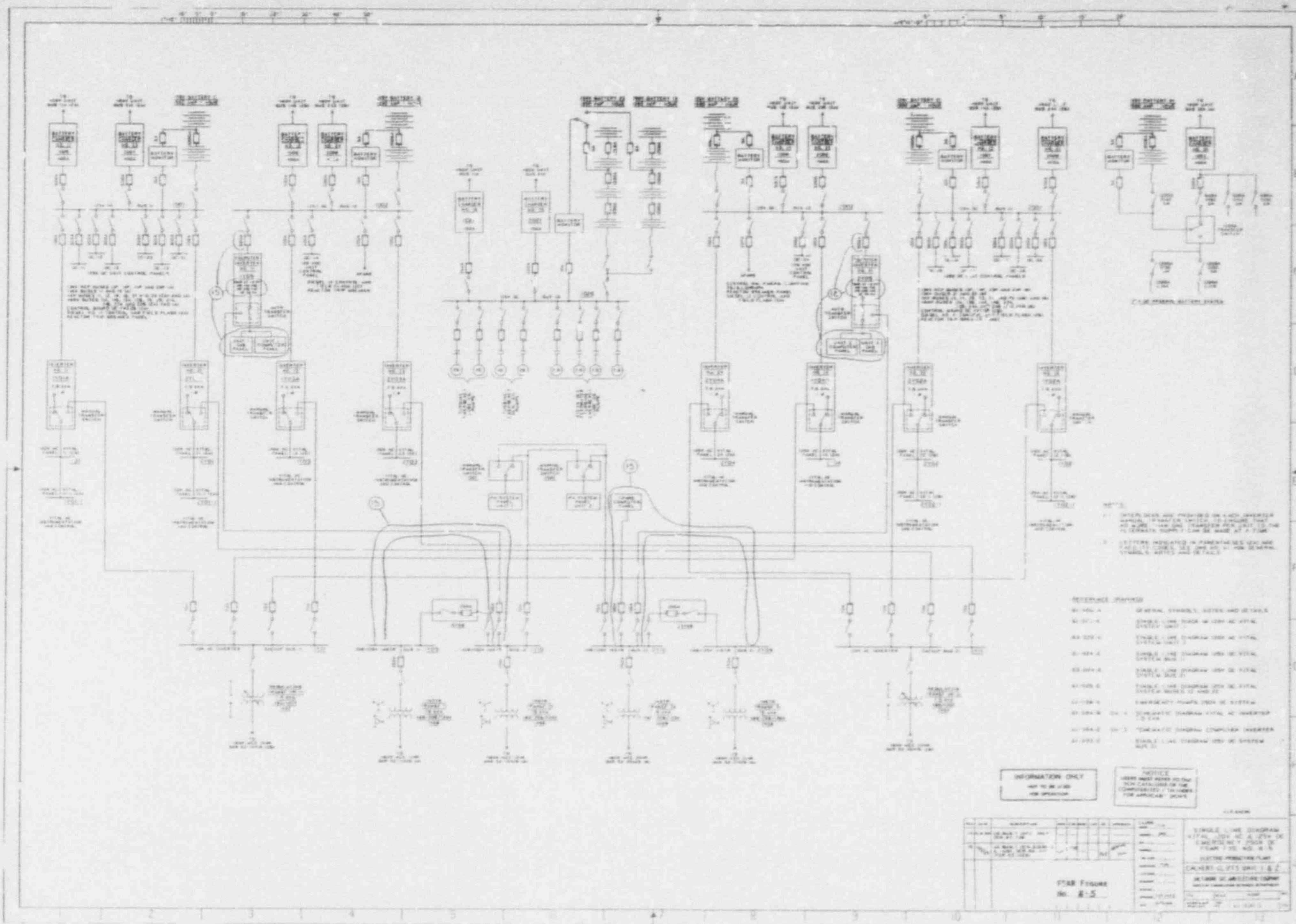

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ATTACHMENT 3

ABBREVIATIONS

A or Amp	Amperes.
AC or ac	Alternating Current.
ANSI	American National Standards Institute.
ASME	American Society of Mechanical Engineers.
BGE	Baltimore Gas and Electric.
BHP or Bhp	Brake Horsepower.
BIL	Basic Insulation Level.
CRF	Containment Recirculation Fan.
CB	Circuit Breaker.
CE	Combustion Engineering.
CFR	Code of Federal Regulations.
CCR	Central Control Room.
CSAS	Containment Spray Actuation Signal.
CVT	Constant Voltage Transformer.
DBA	Design Basis Accident.
DC or dc	Direct Current.
DEMA	Diesel Engine Manufacturers Association.
ECCS	Emergency Core Cooling System.
EDG	Emergency Diesel Generator.
EDS	Electrical Distribution System.
EOP	Emergency Operating Procedures.
ESOD	Electric System Operating Department.
FCR	Facility Change Request.
FLA	Full Load Amps.
FSAR	Final Safety Analysis Report.
FTOL	Full Term Operating License.
GDC	General Design Criteria.
GE	General Electric.
GM	General Motors.
GPM or gpm	Gallons per Minute.
HV	High Voltage.
HVAC	Heating Ventilation and Air Conditioning.
IEEE	Institute of Electrical and Electronics Engineers.
IPCEA	Insulated Power Cable Engineers Association.
ISEU	Independent Safety Evaluation Unit.
kV	Kilovolts.
kVA	Kilovolt-Amperes.
kW	Kilowatts.
LC	Load Center.
LER	Licensee Event Report.
LOCA	Loss of Coolant Accident.

LOCI	Loss of Coolant Incident.
LOOP	Loss of Offsite Power.
LV	Low Voltage.
MCC	Motor Control Center.
MOV	Motor Operated Valve.
MS or ms	Milliseconds.
MVA	Megavolt-Amperes.
NCR	Non-Conformance Report.
NEC	National Electrical Code.
NEMA	National Electrical Manufacturers Association.
POEAC	Plant Operating Event Assessment Committee.
POSRC	Plant Operations Safety Review Committee.
PR	Protective Relay(s).
PRA	Probabilistic Risk Assessment.
PSI or psi	Pounds per Square Inch.
PT	Potential Transformer.
RCP	Reactor Coolant Pump.
RG	USNRC Regulatory Guide.
RVLMS	Reactor Vessel Level Monitoring System.
SCR	Silicone Controlled Rectifier.
SF	Service Factor.
SFAS	Safety Features Actuation System.
SI	Safety Injection.
SIAS	Safety Injection Actuation Signal.
SQUQ	Seismic Qualification Utility Group.
SSFI	Safety System Functional Inspection.
STD or Std	Standard.
TS	Technical Specification(s).
UL	Underwriters Laboratories.
UPS	Uninterruptible Power Supply.
USNRC	United States Nuclear Regulatory Commission.
UST	Unit Service Transformer(s).
UV	Undervoltage.
V	Volt(s).
Vac	Volts alternating current.
Vdc	Volts direct current.
W	Westinghouse.