U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-354/92-80

Docket No. 50-354

License No. NPF-57

Licensee: Public Service Electric and Gas Company
80 Park Plaza - 17C
Newark, New Jersey

Facility Name: Hope Creek Generating Station

Inspection Conducted: January 27 through March 4, 1992

Inspection Team: W. Baunack, Sr. Reactor Engineer, RI
L. Cheung, Team Leader, RI
E. Lazarowitz, Reactor Engineer, RI
C. Woodard, Assistant Team Leader, RI

NRC Consultants: W. Jouberg, Mechanical Engineer
H. Leung, Electrical Engineer
J. Weinberger, Electrical Engineer

Prepared By: W. H. Ruland for 5/1/92
Leonard Cheung, Team Leader, Electrical Section, Engineering Branch, DRS — Date

Approved By: W. H. Ruland 5/1/92
W. H. Ruland, Acting Chief, Electrical Section, Engineering Branch, DRS — Date

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

Results: As described in the Executive Summary.

TABLE OF CONTENTS

Table of Contents

EXECUTIVE SUMMARY

During the period between January 27 and February 14, 1992, a Nuclear Regulatory Commission (NRC) inspection team conducted an electrical distribution system functional inspection (EDSFI) at the Hope Creek Generating Station. 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.

The review covered portions of the onsite and offsite power sources and included 480 Vac Class 1E Unit Substations, 480 Vac Motor Control Centers, 208/120 Vac distribution, 120 Vac Uninterruptible Power Supply (UPS), and 125 V and 250 Vdc batteries, battery chargers, dc switchgear, distribution panels and dc Motor Control Centers. The inspection also addressed 120 Vac Class 1E inverters, and the UPS distribution system.

The review included an examination of equipment condition and a walkdown of equipment to verify the as-installed condition. The walkdown also examined equipment condition with respect to maintenance and calibration/testing. The equipment selected included the power transformers, diesel generators, 4160 Vac switchgears, 480 Vac transformer load centers and switchgears, HPCI 250 Vdc batteries, inverters, safety related motors, and selected safety related relays.

The documents reviewed included dynamic (motor starting and transfers) and steady state load flow studies, electrical loading analyses, short circuit and voltage drop studies, system protection and coordination including relay set point calculations, penetration protection and fuse-to-fuse and fuse-to-breaker coordination.

Based on the sample documents reviewed and equipment inspected, the team concluded that the electrical distribution system at Hope Creek is capable of performing its intended functions. In addition, the team concluded that the engineering and technical support staff, both at the Hope Creek site and at the engineering office adjacent to the plant site, provide adequate support for the safe operation of the EDS at the plant. The inspection identified three deviations and 14 unresolved items as discussed in the inspection finding summary paragraph below. One of the unresolved items, the control of chemical constituents of new fuel oil, was resolved following the inspection.

The team determined that, in general, adequate maintenance and testing were provided to the EDS equipment, although several issues were raised in these areas. These issues are discussed in Section 4.0 of this report.

The team observed that both the offsite engineering personnel and the onsite technical staff were knowledgeable and familiar with the EDS. Engineering staffing was found to be adequate. An excellent training program for onsite technical staff is being implemented. The training for offsite engineering personnel needs to be formalized.

High quality self assessment activities are being performed. Significant findings resulting from these activities indicate a continuing need for improvement in their performance. An adequate program for the preparation of plant modification packages has been provided. Continued improvements to this program were noted. Evaluations performed for installed temporary modifications were of a high quality. However, errors were noted in the temporary modification procedure and in the log book kept in the control room. The licensee committed to review and revise the temporary modification procedure. Root cause analysis/evaluations are addressed in many procedures. Applicable procedures need to be revised to provide clear direction for the performance of root cause evaluations.

The inspection findings are summarized as follows:

Three Deviations	Discussed in Paragraph	Item Number
1. Failure to incorporate EDG maintenance specified by EDG vendor for engine and generator bearing insulation	4.2	92-80-11
2. Fuel oil storage for 7-day EDG operations not meeting FSAR commitment	3.2.1	92-80-05
3. EDG day tank capacity not meeting FSAR commitment	3.2.1	92-80-06

Fourteen Unresolved Items		
1. Fast transfer scheme to be verified by test data	2.3.1	92-80-01
2. Potential flip-flop problem during LOCA load sequencing	2.3.2	92-80-02
3. Degraded grid voltage setpoints	2.6	92-80-03
4. Minimum acceptable terminal voltages of 125 V and 250 V batteries	2.12	92-80-04
5. Seismic concern for the EDG crankcase exhaust system	3.2.4	92-80-07
6. Inactive 4160 V undervoltage relay connected to Class 1E dc bus	4.1	92-80-08
7. Deformed EDG cable	4.1	92-80-09
8. Cause of transformer auto-load tap changer failure	4.1	92-80-10

9. Corrective actions for 12 concerns identified during 1986 EDG preoperation test	4.2.1	92-80-12
10. EDG surveillance test did not include a) sufficient KVAR and b) analysis of dynamic response to EDG loading	4.2.1	92-80-13
11. During monthly surveillance test, EDG cannot respond to accident or remote start signal	4.2.1	92-80-14
12. Control of chemical constituents of new fuel oil	4.2.2	None - Items resolved following inspection
13. Power transformer oil analysis	4.2.4	92-80-15
14. One terminal post of 250 V battery separated from battery case	4.2.9	92-80-16

1.0 INTRODUCTION

During inspections in the past years, the Nuclear Regulatory Commission (NRC) staff observed that, at several operating plants in the county, the functionality of 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 NRC developed an Electrical Distribution System Functional Inspection (EDSFI) program for operating plants. There are two objectives for the EDSFI. The first objective is to assess the capability of the electrical distribution system's power sources and equipment to adequately support the operation of safety related components. The second objective is to assess the performance of the licensee's engineering and technical support in this area.

To achieve the first objective, the inspection team reviewed calculations and design documents. Particular attention was paid to those attributes which ensure that quality power is delivered to those systems and components which 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 34.5 kV offsite power grid, station auxiliary transformers, 4.16 kV power system, emergency diesel generators, 480 V Class 1E buses and motor control centers, 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 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, lube oil, and cooling systems for the emergency diesel generator and the cooling and heating systems for the electrical distribution 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 covered organization and key staff, self assessment program and technical training, 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 10CFR Part 50. The team also reviewed the plant's Technical Specifications, the Updated 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 2.0 through 5.0 of this report.

2.0 ELECTRICAL SYSTEM

The output power of the Hope Creek Generation Nuclear Station is transmitted over three 500 kV transmission lines feeding into the Pennsylvania-New Jersey-Maryland (PJM) power grid. These three 500 kV transmission lines connect the Hope Creek 500 kV switchyard to Keeney, Salem, and New Freedom lines in three different directions over three separate right-of-ways. The offsite power for the plant was fed from the 500 kV system via the 13.8 kV yard ring bus.

The 13.8 kV ring bus is the source of offsite power during station start-up, shutdown, and post-accident cooling. This ring bus provides both the normal and alternate offsite power supplies to all the safety Class 1E 4160V buses. In the event of loss of offsite power (LOOP), four independent emergency diesel generators (EDG) provide the power supplies for the Class 1E loads and selected non-Class 1E loads.

The principal medium and low voltage Class 1E system components include the EDG, 4160 Vac switchgear, 480 Vac unit substations, batteries, battery chargers, dc switchgear, dc motor control centers, and uninterruptible power supply rectifier/inverters . This equipment is centrally located in the southwest quadrant of the Hope Creek Station auxiliary Building.

Low voltage power is distributed to remote station areas and buildings via cable and raceway systems, supplying local 480 Vac motor control centers, 480-208/120 Vac distribution transformers and ac and dc distribution panels serving local electrical loads.

The team reviewed, on a sampled basis, several features and components of the Class 1E EDS. Particular attention was given to a selected sample "vertical slice" load path of Channel "D" Class 1E power supply and its corresponding hierarchy of levels in the Class 1E system. The scope of the review included the adequacy of the following attributes of the station EDS:

1) 500 kV offsite power supply capability;

2) EDS design, fault analysis, load analysis and load flow, cable sizing, voltage drop studies, first and second levels of undervoltage set-point selection, transfer schemes and protection/coordination studies of the 4160 Vac system, the Class 1E 480 Vac system, the 120 Vac vital bus system, the 208/120 Vac distribution system, and 250 Vdc and 125 Vdc Class 1E systems;

3) EDS equipment ratings, including motor ratings, transformer ratings, transformers basic insulation levels (BIL), circuit breaker (CB) momentary and interrupting ratings, unit substation and motor control center ratings, distribution panel ratings, vital bus inverter ratings, 250 V and 125 Vdc battery and battery chargers, dc switchgear and dc motor control centers, and motor over-load protection;

4) EDG loading and rating, EDG load sequencing and load shedding, EDG protection schemes, the steady state and transient load profiles on Class 1E safety bus "10A404" of the EDS under normal and abnormal operating conditions;

5) EDS equipment protective relay setting, and system coordination;

6) Cable sizing and voltage drops during motor running and starting;

7) Electrical containment penetrations sizing and protection; and

8) System grounding and ungrounded system detection schemes.

The details of the team's review and findings are discussed in the following sections.

2.1 Offsite Power, Grid Stability

The electric power output of Hope Creek main generator is rated for 1300 MVA. The 25 kV output power is stepped up via the main generator transformer to the station 500 kV switchyard, where there are two transmission lines feeding into the Pennsylvania-New Jersey-Maryland (PJM) power grid. Line #5015 is connected to Keeney Substation; and Line #5023 is connected to New Freedom Substation. The third Line #5037 is connected to Salem Nuclear Station switchyard. Salem Station with 2 nuclear generating units is located next to Hope Creek Station; the Salem and Hope Creek nuclear generating units are collectively known as Artificial Island.

The offsite power supply for the plant is fed through the 500 kV system via the 13.8 kV yard ring bus. With normal open breakers, this 13.8 kV ring bus is normally subdivided into 4 sections. There are 4 station power transformers (T1, T2, T3, and T4), subdivided into two redundant divisions, transforming 500 kV power onto the 13.8 kV ring bus system. Each station power transformer (SPT) is correspondingly connected to one section of the 13.8 kV ring bus.

Section 2 provides power to class 1E channels "B" and "D" via station service [illegible] r "1BX501," and Section 7 provides power to class 1E channels "A" and "C" via [illegible] service transformer "1AX501." In the event of loss of offsite power, four independent emergency diesel generators provide the standby power for the class 1E loads and selected non-class 1E loads.

The licensee has performed a series of system analyses under various operating and system fault conditions. These conditions included: sudden loss of generation in the Eastern 500 kV PJM system; sudden loss of transmission lines and transformers at the 500 kV system; and major disturbance at the 500 kV system due to a fault at the transmission line and/or circuit breaker. Besides dynamic analyses, the licensee also provided the team with normal maximum and minimum power flows surrounding Artificial Island, and the installed capacity and spinning reserve power of PSE&G system.

The results indicated that the Hope Creek station offsite system would remain stable on loss of generation or loss of transmission facilities in the Eastern 500 kV PJM system. The effects on the above postulated events would not adversely affect the availability of the 500 kV offsite power supply to the station 13.8 kV ring bus system. The voltage and frequency at the 500 kV lines would recover to almost their pre-fault values within seconds after the clearance of the disturbance.

The team noted that the offsite power supply to the class 1E buses is essentially coming from the 500 kV system. Sudden loss of the Hope Creek main generator would not cause any transfer of power supply to the class 1E buses. The team concluded that the offsite power supply to Hope Creek generating station was stable and adequate with respect to GDC 17.

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

During normal plant operations as well as plant shut down conditions, all the station auxiliaries and class 1E loads are powered by the 13.8 kV ring bus via 8 station service transformers (SSTs). Two of these eight station service transformers are used to supply power to four class 1E safety channels A, B, C, and D. Three of 4 channels are required to provide safe shutdown capability following a postulated accident. The 13.8 kV ring bus Section 7 provided power to the class 1E channels "A" and "C" via station service transformer 1AX501; 13.8 kV ring bus Section 2 provides power to the class 1E channels "B" and "D" via station service transformer 1BX501. The 500 kV system provides power to the 13.8 kV ring bus Section 2 via SPT T1, and to Section 7 via SPT T4, respectively.

In addition to the class 1E station service transformers, there are 4 non-class 1E SSTs also connected to the Section 2 and Section 7. All SSTs are connected to the 13.8 kV bus sections without any breakers between the transformers for protection and isolation. Only disconnect switches are provided on the high voltage side of each SST. If an electrical fault occurs at the non-class 1E transformers, it will trip the 13.8 kV breakers, affecting the offsite power supply to the class 1E 4160V buses, and causing a bus transfer to the alternate power source. This is an observation.

2.3 Bus Transfer Schemes

There are two source breakers for each 7.2 kV and 4.16 kV bus. The source circuit breaker for the normal off-site power source is normally in the closed position and the alternate power source breaker is normally in the open position. There are three types of transfer schemes, the fast transfer, time delayed (dead bus) transfer, and manual transfer. They are discussed as follows:

2.3.1 Fast Transfer

The fast transfer is used when one source is lost, and the control logic determines that the bus conditions are correct for a fast transfer. This transfer involves a "break before make scheme" that is highly time dependent on the breaker opening and closing times. This is because the induction motor load on the bus can act as a generator for a very short duration (a few cycles) after the power source is removed. This induction motor current can be significant for several cycles after the breaker opens. Because it is not controlled, its voltage and phase can change significantly. The team noted that the equipment did not include any supervisory relays for this transfer, and none was shown on the design drawings.

The team also noted that, before the inspection, there was neither any analysis nor test result to prove that the fast live transfer scheme was properly designed and would function upon demand. The 18 month surveillance test only verified the control logic, the normal power source breaker opening, and the alternate power source breaker closing. The team could not obtain any operational record to verify that the fast transfer had operated in the past few years in the station.

During the inspection, the licensee performed a calculation based on the expected worst case conditions. The calculation indicated that the dead time on the bus (between opening of the preferred breaker and the closing of the alternate breaker) was less than 5.5 cycles, and the voltage difference was 1.33 per unit. This value is within the acceptable range.

In the February 26, 1992, letter to the NRC, the licensee committed to conduct a fast transfer test during the next refueling outage scheduled in September 1992. The test would include voltage, phase angle, and time during transfers along with a determination of the exact loading of the electrical distribution system prior to the transfer. The data obtained would be used to verify the calculation model, and the calculation would be updated accordingly. This item is unresolved pending NRC review of the licensee's test results (50-354/92-80-01).

2.3.2 Time Delayed (Dead Bus) Transfer

There are four Class 1E 4160 V buses at Hope Creek. Buses A and C are normally powered by station service transformers (SST) 1AX501 and buses B and D are normally powered by SST 1BX501. In addition, each of these four buses is connected to an emergency diesel generator (EDG) through a normally open circuit breaker. A non-safety-related automatic load tap changer, with 30 second response time, is provided for each of the two SSTs to maintain the bus voltage at about 4200 volts. These automatic tap changers have a history of operational failures at Hope Creek with unknown root causes.

The time delayed (dead bus) transfer scheme logic would trip the normal source breaker when the normal source voltage to the 4160 V buses is either: a) at or less than 92% (degraded voltage relay set point) of the normal 4160V class 1E bus voltage (90% for non-class 1E buses) for 20 seconds or longer; or b) at or less than 70% (under voltage relay set point) of the normal 4160V class 1E bus without time delay. The tripping of the normal source breaker in turn initiated closure of the alternate source breaker. After the normal source breaker was tripped, the 4160 V bus is de-energized and, as a result, the bus under voltage relay would drop out instantaneously and trip all the motor feeder breakers on the bus. The circuit breakers feeding the unit substation transformers were not tripped by this scheme.

The team raised the operational concern based on the following two scenarios:

1. The licensee calculations showed very low margin (less than 0.001 per unit) in the reset value of the SSV-T degraded grid voltage relay. Assuming offsite power is available, if a postulated accident occurs, the LOCA sequencer starts various safety-related motors at different intervals. If insufficient voltage margin is provided, starting of the core spray pumps (two pumps powered by each SST and start simultaneously) can cause the line voltage to dip below 92% of rated voltage, actuating the degraded voltage timer. The line voltage may not be able to rise above the reset voltage (98%) within 20 seconds. This will cause a load transfer from the normal source to the alternate source. The connected load will be deenergized for about 20 cycles. When the alternate source picks up the new loads, which is in addition to its existing load, its line voltage will dip below the degraded voltage condition. Twenty seconds later, it will transfer the whole load back to the normal source, since the normal source has now recovered from its degraded voltage condition. This creates a flip-flop situation. The connected motors will start and stop at 20 second intervals, assuming no operator intervention, until they break down.

To resolve this issue, on February 13, 1992, the licensee determined to revise their surveillance test procedures to limit the relay reset voltage to below 96% (about 115 V). This corrective action is to provide adequate margin to assure that the relay will reset within 20 seconds after the degraded voltage timer is activated.

2. If the automatic tap changers fail in such a position that the line voltages are near the degraded-grid reset voltage (about 98% of rated voltage), the above flip-flop condition could still happen regardless of the surveillance procedure revision mentioned above. As a short-term solution to this potential problem, licensee engineering issued a memorandum to plant operation to require the "Auto Close Block" pushbutton switch to be depressed after the infeed breakers of the Class 1E 4160 V buses have been placed in the closed position. This provision will limit the transfer switch to transfer only once during a degraded voltage condition, thus avoiding the flip-flop situation.

In the February 26, 1992, letter to the NRC, the licensee committed to conduct a more thorough and precise study (computer modeling) to evaluate these situations. The licensee expects the evaluation to be completed by May 29, 1992. This item is unresolved pending NRC review of licensee's evaluation (50-354/92-80-02).

2.3.3 Manual Transfers

The manual parallel transfer could be initiated by depressing the "close" push button for the normally open 4 kV breaker. If the EDG breaker were open, and all protective relaying associated with the normally open breaker were cleared, the normally "open" alternate supply breaker would close. Upon closure of the normally "open" breaker, a signal would be sent to trip the normally "closed" breaker. During the transfer period, the 4.16 kV bus would be powered by both off-site sources for several cycles before the normally closed breaker opens.

The manual transfer is used by the operator when the relaying on an incoming supply must have surveillance testing or maintenance performed on it. This transfer is typically performed twice a month. The operator transfers the bus source to the alternate supply to avoid making the affected bus inoperable. This transfer is done on a "make before break" basis to avoid any dead time on the bus. This scheme requires that both incoming sources be in phase, or that a synchronizing verification device such as a "sync-check" relay is used to prevent paralleling the buses out of phase and generating high circulating currents on the 4160 Vac bus.

The team noted that the equipment installed in the field does not have a sync check relay. Discussion with the licensee revealed that the licensee does not use any supervisory controls, automatic or manual, on this transfer. The licensee stated that he did not feel it necessary because: 1) the time the two sources are in parallel is only a few cycles, and 2) the sources to the two transformers would always be in phase because they are basically fed from the same source. The team agreed with this justification and had no further questions.

2.4 4160V Class 1E System

Station service transformer 1AX501 normally provides power to safety channels A (Bus 10A401) and C (Bus 10A403), and a non-class 1E bus 10A102; station service transformer 1BX501 normally provides power to safety channels B (Bus 10A402) and D (Bus 10A404), and a non-class 1E bus 10A101. The total load on each of these two transformers following a LOCA is about 32.497 MVA and within an hour the load would be reduced to about 29 MVA. The transformer was rated for a maximum of 29 MVA at 55°C temperature rise, and 32.5 MVA at 65°C temperature rise. The team did not identify any transformer loading problem.

The 4160 Vac Class 1E System was examined to determine if the various design ratings matched the as-installed ratings. The team determined that for the equipment under consideration, the designed agreed with the as-installed condition. The nameplate ratings of the two station service transformers feeding the 4160 Vac system were verified against the design drawings. The switchgear sections matched the vendor's description and the breakers installed in the switchgear matched the vendor and design drawing descriptions.

Each class 1E 4160V bus provides power to the 480V system via two sub-station service transformers; each dry-type transformer is rated for 1.33 MVA. The maximum loading after LOCA on each 480V substation service transformer varies from 528 kVA to 1108 kVA; such a range of loading demand falls within the capability of the substation service transformer. The team found these transformers to be adequately sized.

The team reviewed the sizing of the EDG neutral grounding transformer, and the neutral grounding resistor for the station service transformers. The team found them to be properly sized.

The team also reviewed the sizing of the 4 kV class 1E core spray pump motors, service water pump motors, residual heat removal pump motors, and safety auxiliary cooling system pump motors. The team determined that these motors were properly sized.

The team reviewed the type of cable being used in the 4 kV Class 1E system, and checked the sizing of the 4 kV cables for a few 4 kV class 1E motors. The team determined that these cables were properly sized.

2.5 Emergency Diesel Generators (EDGs)

The standby power supply for each of the four safety-related load groups consists of one EDG complete with all of its auxiliaries, which includes the cooling water, starting air, lubrication, intake and exhaust, heating and ventilation system, fuel oil system, instrumentation and control power. Each EDG is housed in a separate cell and is both physically and electrically isolated to maintain proper separation between redundant channels. The EDGs consists of four Colt Type PC-2 12 cylinder diesel engines each individually

coupled to a Louis Allis IX-30 frame generator. Each EDG has a continuous duty rating of 4430 kW at 4160 volts, 3 phase, 0.8 power factor when operated at a speed of 514 rpm. The EDG units are short-term rated for 4873 kW at 0.8 power factor for 2 hours in any 24 hour period. According to the FSAR, the sizing of the EDGs and the loads assigned to them is such that any combination of three out of the four is capable of shutting down the plant safely, maintaining the plant in a safe shutdown condition, and mitigating the consequences of accident conditions.

The team confirmed the validity of the licensee's ratings of the EDG units by conducting a review of the 1982 factory performance tests and the 1986 pre-operational performance acceptance tests which were conducted in accordance with licensee procedure PSSUG-PTB-BB-3. The team reviewed the current loading demands for the EDG units including the worst case loading during postulated design basis events The team found that the worst case demands were 4410 kW at approximately 0.86 power factor. Since this loading is within the verified ratings of the EDG units, the team concluded that the EDGs are sized adequately to perform their intended functions.

2.6 Degraded Voltage on Class 1E Buses

The isolation of the Class 1E onsite power system from the offsite power system is accomplished by tripping of the incoming off-site source breakers to the 4.16 kV Class 1E buses. The tripping is accomplished through the degraded voltage relays connected to the source side of the source breakers. The degraded voltage relays were set at 0.92 pu of the 4160V with 20 second time delay allowing for voltage transient on the bus due to motor starting or system disturbance.

The team reviewed Hope Creek calculation No. E-15.1 entitled, "Millstone Voltage Study - 1E Buses," Revision 3, dated December 12, 1985. The following deficiencies were noted:

1) Calculation E-15.1 indicated that the voltage drop at the 480 V motor cable during starting should not be more than 10%. This design criterion was based on Bechtel design procedure B2.11.2.1. However, page 9 of 80 of this procedure specified 12.5% to 18.3% cable voltage drop for motor starting. Other figures used in Calc. 15.1 were also based on the lower limit of the voltage ranges given in the above Bechtel design procedure. Justification for these cases must be properly documented.

2) The calculation did not include all relays and their minimum pick-up voltages in Class 1E motor control center control circuits.

3) The calculation E-15.1 incorrectly stated that "all Class 1E loads at the 120 Vac level are supplied from the 120 Vac Uninterruptible Power Supply System."

The licensee committed to revise the degraded voltage study (Calc. E-15.1) to address the above issues by May 29, 1992. This item is unresolved pending NRC review of the revised calculation (50-354/92-80-03).

2.7 480 Vac Class 1E System

The 480 Vac Class 1E system consists of eight Class 1E 480 Vac unit substations each rated 1350 kVA, several local Class 1E 480 Vac motor control centers, and local Class 1E 480-208/120 Vac transformers supplying 208/120 Vac Class 1E distribution panels. The 480 Vac system is a grounded system.

The short circuit analysis for the 480 Vac system was also reviewed. The results were compared to the technical specifications for distribution equipment. Based on the documents and calculations reviewed, the system was determined to be adequately designed.

Class 1E motor protection for 480 Volt equipment and below was reviewed. Based on calculations reviewed, the protection of motors was determined to be adequate.

The team noted that cable protection was not included in the protection analysis. The licensee provided additional evaluation substantiating the protection of 480 Volt power cables.

Coordination at the 480 V system (Calculation E-7.7) was determined to be adequate based on the documents and calculations reviewed.

Calculation E-17A was developed to demonstrate that sufficient voltage was available to pickup MCC control circuit contactors. Based on a selected sample of approximately fifteen MCC load control circuits reviewed, the team identified two relay types that had not been included in the above calculation. One circuit controlled the operation of the diesel generator fuel oil transfer pumps. The other controlled the operation of the intake structure supply fans. Although the licensee performed an evaluation to demonstrate that these circuits would have adequate voltage for worst case design basis conditions, and the team member deemed this evaluation to be adequate, the concern extends to any additional devices that may have been omitted. The licensee agreed to update the analysis and perform a broader review of all Class 1E MCC control circuits.

In calculation E-15, exhibit G, certain large 480 Volt motor loads and heater loads were incorrectly analyzed, being omitted from the load tabulations. The licensee performed an evaluation of this omission. The team reviewed this evaluation and determined the design to be adequate. The licensee agreed to revise the calculation.

Also, in calculation E-15.1, large 480 Volt MCC motor loads, that could be started at any time, were omitted from the LOCA transient analysis. These added loads could affect the worst case condition for voltage at local Class 1E motor control centers. The licensee performed an evaluation in response to the team's question for worst case steady state conditions at Class 1E MCCs 10B563 and 10B583 to demonstrate minimum required pickup voltages would be available. Based on the team review of this analysis, the system design was deemed to be adequate.

The team noted that the licensee had discontinued the implementation of an electrical motor and load database (last updated about 1985), developed by Bechtel Corporation. This document was seen to be an asset in the station's original documentation databases and it continues to be an active reference in some calculations, e.g., E-15. The licensee indicated that this information is maintained via the calculations; however, the team believes that this form is not equivalent to a unified database and could contribute to errors in the application of load information (e.g., exhibit G of calculation E-15(Q) had an identified load tabulation error which is described above). The team believes this could have been prevented by maintaining an active load analysis document. Calculation E-8.3 provides some load information; however, the team believes that an electrical load database would support more comprehensive station load flow transient and steady state analysis. Although identified as a validated software package, the team perceived the load flow software used in calculation E-15 to be a candidate for update, as more powerful and comprehensive analysis programs were available today. The licensee agreed to evaluate these suggestions.

2.8 AC System Short Circuit Review

The team reviewed short circuit calculations to determine if the circuit breakers were properly sized to withstand the available short circuit current.

On the 13.8 kV bus, 1500 MVA circuit breakers with 115 kA momentary rating and 56.197 kA interrupting rating were used; on the 4.16 V bus, 350 MVA circuit breakers with 80 kA momentary rating and 48.515 kA interrupting rating were used. The team reviewed short circuit calculation #1.1 (Q), and found all the cases were based on 4.16 kV bus nominal 1.0 pu voltage, which was assuming the on-load tap changer was functioning properly. The computer result indicated that the system fault current would fall within the interrupting and momentary ratings of the 4160V Class 1E breaker.

Since the calculation was done by using Bechtel computer "LOADX" TE501 program, the licensee could not repeat the calculation by changing the pre-fault voltage at the 4 kV Class 1E bus from 1.0 pu to 1.1 pu., which was the postulated worst scenario. By simplified linear extrapolation method, the momentary fault current would exceed the CB rating but the symmetrical fault current should fall within the interrupting rating of the CB. Since there were some conservative factors included in the assumptions, and all the input data and assumptions were done in accordance with IEEE standards, the team considered this calculation to be acceptable.

2.9 AC System Protection and Coordination

The team reviewed the time-current curves of the 4160 Vac and 480 Vac circuit breakers to determine if the 4160 Vac and 480 Vac systems are properly coordinated and protected. The 4160 Vac "D" bus was reviewed, and the setpoints as installed were found to match the setpoints as shown on the various design documents and calculations. A discussion of setpoint control and calibration is found in Section 4.3.

The team reviewed some of the protection relay setting of the motor feeders on the 4 kV Class 1E system, the protection coordination of the EDG, the off-site power supply incoming feeders, and the load feeders on the 4 kV class 1E system. The review results indicated that this equipment was properly protected.

The team reviewed the 4160V Class 1E system ground fault detection and ground fault protection coordination among different feeders on the safety bus. The design was done according to the methodology generally employed in the electrical industry.

The control logic diagram of the Class 1E EDG Circuit Breaker (E-3080-0 Rev. 11, Sht. 1 of 2) erroneously indicated that the EDG could be tripped by its ground fault overcurrent relay during an accident. The licensee confirmed that it was an error on the drawing and agreed to correct the drawing.

The team reviewed calculations E-7.7, E-7.9 and E-26 for the circuit protection for Class 1E 480 Vac loads. Based on these calculations, the protection of electrical loads and coordination of the distribution system was concluded to be adequate. The team noted that cable thermal limits were not included in the protection studies. In response to the team's question, the licensee provided additional analysis demonstrating that all 480 V power cables would be protected for 250°C. The team concluded that 480V system circuit protection and coordination, including cable capacity limits, was adequately addressed in the Hope Creek Station design basis.

2.10 Electrical Penetration Sizing and Protection

The team reviewed calculations E-7.13 and E-7.13A, and equipment Specification E-135 for drywell electrical penetrations to confirm penetration sizing, protection and conformance with Regulatory Guide 1.63. The team also reviewed some surveillance testing requirements delineated in the Technical Specifications. The team did not identify any problem with the 480V penetration sizing and protection.

The only medium voltage circuits routed through a penetration were the 3.92 kV circuit for the two reactor recirculation pump motors. Each motor was powered from a variable frequency motor-generator set. The primary protection and backup protection for the 1000 MCM penetration were provided by two class 1E circuit breakers in series. The team reviewed the circuit breaker protective curves, and available short circuit current from the M-G set, and the penetration short circuit capability. The team found that the penetration was properly protected.

2.11 120 Vac Class 1E System

Four Class 1E 120 Vac Uninterruptible Power Supplies (UPS) were provided at Hope Creek. Each included a rectifier/inverter with static transfer capability and a maintenance bypass switch, which provided the capability to bypass the rectifier/inverter and connect to a regulated 480-120 Vac supply. There were additional UPS systems serving Class 1E instrumentation. Two 480 Vac non-Class 1E motor generator sets were provided to support the Reactor Protection System, isolating the latter for system switching and/or motor starting transients and system surges.

The design basis for the 120 Vac system included cable sizing, voltage drop, short circuit and coordination studies. Based on a review of these documents, the team determined that not all Class 1E 120 Vac loads had been addressed in the analysis. A discrepancy was identified in calculation E-15, for failing to identify those safety class loads (principally solenoid operated valves) supplied from sources other than the Class 1E UPS.

The licensee performed additional analysis and evaluation during the inspection for circuit feeds to the 480-208/120 Vac transformers and to safety class "Y" distribution panels. Based on a review of this analysis, the team concluded the design to be adequate.

The team reviewed safety loads required to operate in the long-term, post-accident environment of the reactor building. For these loads, power circuits were analyzed based on 50°C conductor temperature, whereas 65.5°C was specified for the cable ambient conditions. The licensee performed an evaluation for the correct circuit conditions. Based on a review of this documentation, the team determined the design to be adequate. The licensee agreed to revise the affected calculations (E-17).

The team reviewed the UPS inverter ratings and specification and determined that the inverter would satisfy all of its performance requirements.

Short circuit calculations E-7.13, E-7.13A and E-25 were reviewed to confirm that the 120 Vac distribution panel ratings (225A/10,000A SYM) were conforming to the design basis analysis. Containment penetration protection analysis for 120 Vac circuits were included in the review, and Appendix R coordination studies were reviewed. The results of these reviews indicated that the 120 Vac system was adequately protected.

2.12 125 Vdc and 250 Vdc Class 1E System

The Station's Class 1E dc systems were composed of six 125 Vdc Class 1E batteries each rated at 1800 ampere-hours (AH), ten 200 A battery chargers (two chargers connected to each 125 Vdc switchgear channels A through D and two additional chargers serving Class 1E instrument channels C and D, respectively), two 250 Vdc batteries (to support the HPCI and RCIC emergency systems, 825 AH and 330 AH capacity, respectively) with corresponding 50 A battery chargers serving each system and a common spare battery charger of the same rating. Switchgear and dc motor control centers were provided for the 250 Vdc distribution system. The dc systems were ungrounded. Direct current ground detection was provided.

The team reviewed calculations for battery and battery charger sizing, a calculation addressing voltage drop and calculations for short circuit studies to verify design adequacy. In addition, coordination study and dc system performance calculations were also reviewed.

According to the documents reviewed (calculation E-1.4 entitled, Class 1E 125 Vdc and 250 Vdc short circuit and voltage drop studies, dated November 21, 1991; calculation E-4.2 entitled, Class 1E dc Equipment and Component Voltage Study, dated December 8, 1991; and Appendix A of Procurement Specification 10855-E-121(Q) for dc switchgear and control centers, dated April 13, 1984), the minimum voltage for 125 Vdc equipment at the switchgear is 105 V. When cable voltage drop is added, the minimum voltage at the battery terminals is 110.4 Volts. Similarly, the minimum voltage for 250 Vdc equipment at the motor control centers is 210 Volts. When cable voltage drops is added, the minimum voltage at the battery terminals is approximately 213 Volts.

Technical Specification 4.8.2.1.d.2 states, "The battery capacity is adequate to supply a dummy load of the following design profile while maintaining the battery terminal voltage greater than or equal to 105 volts for the 125-volt battery and 210 volts for the 250-volt battery." This indicates that the minimum acceptable battery terminal voltage is 105 volts for the 125 volt battery, and 210 volts for the 250 volt battery. Consequently, these incorrect minimum voltage requirements at the battery terminals were incorporated into the surveillance test procedures (HC.MD-ST.PJ-003 and 004; HC.MD-ST.PK-003 and 004) as acceptance criteria.

The team reviewed a sample of surveillance test records for the 125 V and 250 V batteries. The records indicated that the measured voltages at the end of the duty cycles were all above minimum required voltages (110.4 Vdc and 213 Vdc). In the February 26, 1992, letter to the NRC, the licensee indicated that they would conduct a more precise voltage drop calculation to determine if the existing voltage limit was acceptable.

Before the conclusion of this inspection, the licensee issued a discrepancy report addressing this issue. The discrepancy report provides a tracking mechanism for the licensee to review and revise, as required, all affected documentation including calculations, procedures, the Hope Creek Technical Specifications, the UFSAR and set point documents. This item is unresolved pending NRC review of licensee's corrective actions (50-354/92-80-04).

The dc System coordination studies were reviewed. Based on the documents reviewed, the team concluded the design to be adequate in this area. These studies included fuse-to-fuse and fuse-to-breaker coordination.

The team reviewed the battery charger sizing calculations. For the case of the 125 Vdc systems, two 200 A battery chargers were on line (in parallel), the "lead" charger's float was set slightly higher than the backup's. The team observed that the dc load could exceed 200 A in the condition I (accident) and condition II (testing) scenarios (reference calculation E-4.1). The licensee demonstrated that when the condition I analysis was examined on a channel by channel basis, the load requirements would be less than one battery charger's output rating; and that in the condition II analysis, although the load requirement could be 247 A, the condition II mode would not be expected to exceed two hours and the lead charger loading would not exceed approximately 10 percent, where it would go into current limiting. The backup charger (or battery) would pickup the balance of the load. The team reviewed these evaluations and concluded them to be acceptable.

The team reviewed the dc System ground detection scheme provided, and the licensee's response procedures when a system ground is detected. Based on the documents reviewed, the team determined the design to be adequate.

2.13 Conclusion

The team's review of the design attributes within the scope of this inspection concluded that, with the exception of the specific findings noted above, the EDS components were adequately sized and configured, the design was generally adequate. Some of the significant concerns identified by the team include: 1) potential flip-flop problem of the delayed-time transfer scheme caused by starting of core-spray pumps following a postulated LOCA conditions; 2) incorrect criteria for determining minimum acceptable battery terminal voltage at the end of the duty cycle; 3) no analysis or test to verify proper operation of fast transfer scheme; and 4) degraded grid voltage setting issues and revision of calculation E-15.1.

One good design aspect of the Hope Creek EDG is the two ring bus configuration. Normal Class 1E power source comes from the 13.8 kV ring bus, and is not connected to the output of the main generator. No transfer is required on loss of main generator.

3.0 MECHANICAL SYSTEMS

To determine the functional ability of mechanical systems to support the EDS during postulated design basis accidents, the team reviewed the UFSAR, the Technical Specifications, and samples of other documentation. The team also conducted a walkdown of the fuel oil storage and transfer, lubricating oil, starting air, and diesel heating and cooling equipment. On Thursday, January 16, 1992, the team witnessed a monthly test performed on "B" diesel generator.

The team reviewed equipment associated with the heating, ventilation and air conditioning (HVAC) of the EDG rooms, switchgear rooms, battery and associated equipment rooms, the 1E panel room, the lower control equipment room, and selected EDG and HVAC design modifications. The team also reviewed the power demand for major loads (selected pumps and fans) for input into the EDG load and other design basis calculations.

The Class 1E Channel "D" equipment was selected for enhanced inspection.

3.1 Power Demands for Major Loads

The team reviewed the power demands for the major pump motors powered by the EDGs following loss of offsite power (LOOP), a loss of coolant accident (LOCA), and a LOCA with a LOOP. All electric motors were found to be adequately sized with respect to the power requirements of their associated pumps as determined by the performance curves submitted by the licensee.

3.2 Diesel Generators and Auxiliary Systems

The team reviewed the licensee's calculations, procedures, drawings, and other documents to determine the design adequacy of the diesel fuel oil storage and transfer system, the jacket water cooling system, the intercooler and injector cooling system, the combustion air intake and exhaust system including the crankcase vacuum system, and the starting and control air system. A summary of the team's findings is discussed below.

3.2.1 Fuel Storage and Transfer System

Section 3/4.8 of the Technical Specifications require "a separate fuel storage system consisting of two storage tanks containing a minimum of 48,800 gallons of fuel." The licensee's calculations did not clearly demonstrate that sufficient fuel was available in the storage tanks to meet the requirements. The licensee performed a new draft calculation during the inspection. The draft calculation showed that the requirements of the Technical Specifications were met. The licensee agreed to finalize this calculation with proper management approval.

Section 9.5.4 of the UFSAR states that "each set of storage tanks can store a quantity of diesel fuel oil that is sufficient for 7 days of continuous operation of one EDG unit under rated full operating loads as described in EDG loading tables 8.3-2 through 8.3-6." Licensee calculations including calculation JE-0014 of January 27, 1992, failed to demonstrate the validity of the UFSAR statement. Calculation JE-0014 showed a shortage of 5579 gallons to meet the 7-day requirement of 151,979 gallons when three EDGs are operating (assuming one EDG is inoperable). Under this condition, fuel is transferred from the non-operating storage tanks to the operating storage tanks to make up the shortage. The licensee has an approved procedure for this fuel transfer. However, each dedicated EDG fuel reserve cannot independently sustain 7 days of worst case EDG operation. This constitutes a deviation from FSAR commitment (50-354/92-80-05).

Paragraph 9.5.4.2.1 of the UFSAR states that the EDG fuel oil storage system is sized in accordance with the requirements of Regulatory Guide (RG) 1.137. Paragraph 1.8.1.137 of the UFSAR further indicates compliance with RG 1.137, Revision 1, which in turn refers to ANSI N195-1976.

Section 6.1 of ANSI N195 specifies "each diesel to be equipped with day or integral tank or tanks whose capacity is sufficient to maintain at least 60 minutes of operation at the level where oil is automatically added to the day or integral tank or tanks. This capability shall be based on the fuel consumption at a load of 100% of the continuous rating of the diesel plus a minimum margin of 10%."

According to the licensee, the day tank can only provide 47 minutes of EDG running time when the fuel reaches the level at which the transfer pump(s) are required to start. The licensee is presently assessing the situation and is planning to raise the levels switch setpoint in the day tanks to ensure that the ANSI N195 requirements are met. The team concluded that failure to meet the FSAR commitment is a deviation (50-354/92-80-06). In the February 26, 1992, letter to the NRC, the licensee committed to recalculate the transfer pump start setpoint to provide 66 minutes of operation from transfer pump start. The licensee plans to issue a design change package to implement the setpoint change in September 1992.

3.2.2 Diesel Generator Cooling Water System

The EDG cooling water system consists of two separate cooling loops: the jacket water cooling loop, and the intercooler and injector cooling loop. Both subsystems have been reviewed and the documents provided confirmed the adequacy of the system design.

Heat exchanger performance is monitored during EDG surveillance by means of established instrumentation. The data obtained is included in the EDG trending program. The heat exchangers are cooled by demineralized water from the Safety Auxiliary Cooling System (SACS) and are thus virtually exempt from fouling.

3.2.3 Starting and Control Air System

According to FSAR Section 9.5.6.2, the EDG starting air system is designed to provide the capacity and capability to provide for a minimum of five EDG starts from a cold condition and at a minimum air receiver starting pressure. Each EDG is provided with two separate air starting systems which include separate air start receivers, piping and control valves. A common compressor with a refrigeration type air dryer is used to charge both receivers. Check valves are provided to prevent one receiver from blowing down to the other. Cross over piping and isolation valving between the two air receivers permits them to operate individually or in parallel as a single system. The piping from each air start receiver is stainless steel to minimize corrosion. Each air receiver is piped to its own respective air start distribution for the right or left engine cylinder bank. Licensee preoperational testing showed that each system had the ability to start up to 11 times (22 total starts) utilizing its own air receivers. Periodic quarterly EDG surveillance tests demonstrate EDG starting capability from a single system. Routine monthly EDG surveillance tests are conducted with the air start systems in their normal parallel configuration. The inspectors reviewed the licensee EDG surveillance tests for 1990 and 1991 and found that the EDG units consistently start in approximately 7 seconds. The inspectors concluded that the EDG air starting system is adequate to provide for reliable starting of the EDG units.

To maximize the availability of the air starting system, the licensee is planning to add a compressor bypass line to each EDG unit so that another EDG unit air supply can be used to charge the air start receiver storage tanks in the event of a compressor failure.

3.2.4 Combustion Air Intake and Exhaust System (including the Crankcase Vacuum System)

The Hope Creek seismic II/I evaluation program identified the potential seismic II/I interactions between the crankcase exhaust (vacuum) system and the diesel engine. However, documentation submitted by the licensee did not indicate that a proper seismic analysis of the exhaust piping in its actual configuration, including the flexible joint and the cross sectional area reduction at the ejector, has ever been performed. Failure of the crankcase exhaust system can cause explosive gases to accumulate in the diesel engine, or poisonous fumes to be released in the EDG room.

The licensee agreed to evaluate specific issues and to resolve this concern. In the February 26, 1992, letter to the NRC, the licensee committed to complete the evaluation by March 31, 1992. This is an unresolved item pending NRC review of licensee's evaluation (50-354/92-80-07).

3.3 Heating, Ventilation and Air Conditioning System

The team reviewed the design of various HVAC subsystems which are part of the Control Room and Control Area HVAC System and to the EDG Area Ventilation System. The subsystem reviewed included the Control Equipment Room Supply System (CERS), the Control Area Battery Exhaust System (CABE), the Diesel Area Safety-related Battery Room Exhaust System, the Diesel Area Non Safety-related Battery Room Exhaust System, the Switchgear Room Cooling System (SRC), the Diesel Area Class 1E Panel Room Supply System (DAPRS), and the Diesel Room Recirculation (DRR) System.

The calculations pertaining to the CERS system appeared adequately conservative. The calculations were revised in 1988 to support a design change package to lower the relative air humidity in the lower control equipment room 5302 (LCER) where Bailey 862 solid state logic modules (SSLMs) are located. The Bailey relative humidity requirements for the SSLMs in room 5302 are 10% to 80% continuous and 80% to 90% for up to 24 hours. The licensee is maintaining the relative humidity of the air in the LCER below a maximum of 60% to maximize the reliability of the SSLMs.

The team also noted that the Environmental Design Criteria for Hope Creek (Doc. 10855-D7.5), the UFSAR, and the Configuration Baseline Document (CBD) for the Auxiliary Building Control Area HVAC still specified the obsolete limits of 20 to 90% for the relative humidity (RH) of air in the LCER. The Design, Installation, and Test Specification (DITS) for the Auxiliary Building Control Area HVAC (Doc. 10855-D3.50) does not specify any air RH for the LCER. The latest revision of calculation GK-1 (Q) also fails to identify the new air RH design limit for the LCER. The licensee concurred with these discrepancies and agreed to revise the affected documents accordingly.

The Control Room and Electrical Equipment Room Heatup calculation GK-26 (Q) was performed by a computer and was thus difficult to assess. However, some references were missing and data on pages 6, 17b, and 18 appeared to be contradictory.

The HVAC design was reviewed and found adequate for the EDG room. However, when the diesels are running and the mufflers warm up, the corridor room 5315 may reach a temperature as high as 118°F when the DRR fan farthest away from the supply ducting is in operation. The carbon dioxide control panel and switches located in this room for fire protection of the EDG rooms is rated for 115°F. On March 3, 1992, the licensee contacted the carbon dioxide control manufacturer and confirmed that the equipment can be operated at 120°F. The licensee agreed to revise the affected documents accordingly.

3.4 Service Water System

The EDG heat exchangers are cooled by the Safety Auxiliary Cooling System (SACS) which also cools the EDG room coolers pertaining to the HVAC DRR system and the Class 1E equipment chillers. The SACS is a closed loop demineralized water system which is in turn cooled by river water pumped through the Station Service Water System (SSWS). The SACS consists of two redundant loops, A & B, with two 50% capacity pumps and two 50% capacity heat exchangers per loop. It is designed to meet its safety objectives despite the unavailability of any one pump due to maintenance or failure. It is also designed to protect against a complete loss of function due to single active or passive failure during normal conditions, LOOP, LOCA, and post-LOCA conditions coincident with LOOP. The pumps and associated motor-operated valves for each loop are powered from Class 1E buses.

The team reviewed the performance of the SACS system and its surveillance procedures. Documentation provided by the licensee demonstrated that minimum pump performance was verified by quarterly testing under procedures HC.OP-15.EG-0001 (Q) through 0004, as required by Section XI of the ASME Code. Routine 8-hour round inspections of the pumps include as a minimum oil and bearing checks, seal inspections, and electrical and process parameter verifications. The SACS shell-and-tube heat exchangers are made of titanium tubing and inconel overlaid tube sheets. They are cooled by river water supplied by the SSW system. They are also tested periodically in accordance with procedures SE-PR.EG-001 (Q), IAW MD-PM.EG-001, and SE-PR.ZZ-048 to ensure that fouling is maintained below the design factor.

Upon a LOOP, all four SACS pumps sequence onto their respective diesels automatically. The operator checks for operation and availability of service water to each SACS heat exchanger. Further operator action is only required in the event of pump unavailability.

The design SACS flow for each EDG is 1176 GPM at a maximum temperature of 95°F. The SACS system easily meets these requirements provided that the river water temperature entering the SSWS is less than 90.5°F. Above that temperature, the station must be in an LCO action statement.

During normal plant operation the pumps have a 6% negative capacity margin and thus a single loop is not capable of meeting the design requirement. As such, the operator starts a pump in the standby loop if requirements warrant. This operator action thus overcomes the pump capacity deficiency. For the LOCA and LOOP conditions, when the EDGs may be in operation, the pumps have positive capacity margins.

Normal shutdown flow feeds some non-safety-related equipment. As a result, the pumps have a 8% negative capacity margin for this particular condition. However, the non-safety-related loads may be selectively shut off by operator action as necessary, to make design flow available to essential equipment.

The SACS heat exchangers meet the design requirements for heat transfer capacity with a 2.8% margin.

3.5 Conclusion

The team's review of the design attributes within the scope of this inspection concluded that the mechanical systems supporting the EDS are capable of performing their design functions. Adequate information was available to review and address the operability of the systems. However, two deviations and an unresolved item were identified in these areas:

1. Fuel oil storage for 7-day EDG operations does not meet the UFSAR commitment.

2. EDG day tank capacity does not meet the UFSAR commitment.

3. Seismic II/I interactions between the EDG crankcase exhaust system and the diesel engine.

The team considered the licensee's mechanical engineering personnel technically capable and knowledgeable of the mechanical supporting systems.

4.0 ELECTRICAL DISTRIBUTION SYSTEM 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 is properly tested and maintained. This effort was accomplished through field walkdown and verification of the as-built configuration of electrical equipment as specified in the electrical single-line diagrams, modification 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 the installed equipment. Areas inspected included the diesel generators, 4160 Vac switchgear, batteries, inverters, and 480 load center. Transformers, both main power and station feed transformers, and protective relays were also examined.

The equipment installed generally reflected the design requirements. The walkdowns indicated that adequate measures are in place to effectively control the system configuration. However, one example of a lack of configuration control was noted when a walkdown revealed that a dc undervoltage relay was not shown on the one-line drawings. The relay was connected to a Class 1E dc bus, but it was not hooked up to any alarm or actuation system. This relay was not maintained because custody was unclear. There was no setpoint provided. The relay was never calibrated or maintained. Interviews revealed that the maintenance group and relay group were aware that the relays existed, but each thought the other was responsible.

In the February 26, 1992, letter to the NRC, the licensee stated that they would conduct an evaluation of this issue. The licensee committed to initiate a design change by June 1992 if they plan to remove the relay. The licensee committed to initiate maintenance by the end of 1992 if the relay is left in place. This item is unresolved pending NRC review of the licensee's corrective actions (50-254/92-80-08).

The team noted that the "B" EDG has at least one dented flexible cable connecting the generator stator to the current transformer star-point output lead cabinet. There are four cables per phase for the power output leads, and four cables per phase for the star-point connection. One cable for the "B" generator power lead bundle appeared to be deformed to about 75% of the original diameter. The cable was laid over an angle iron support within the generator. The cable is inside the machine and can only be viewed through a screen on the side of the machine when the EDG is operable. The licensee performed a calculation to determine the amount of deformation. However, with the assumptions used, the calculation concluded that the cable was only dented a maximum of three thousandths of an inch. The licensee then assumed that the effect seen through the screen was a baggy fiberglass braided shield on the outside of the cable. Since this assumption could not be proven, the licensee planned to open up the generator during the early March 1992 outage and determine to what extent if any, the cable was deformed. Based on this inspection, the licensee will determine what action to take next. This item is unresolved pending NRC review of the licensee corrective actions (50-354/92-80-09).

The team examined the material condition of equipment, and found that the EDGs had numerous loose bolts and fittings on them. These included a microswitch used to sense the actuation of the engine mechanical overspeed trip, a loose electrical flex grounding connector, and bolts on the camshaft inspection cover plates. Although these loose bolts and fittings do not impair operation of the safety-related components, the walkdowns found that there is a need for more attention to detail with respect to the physical condition of this equipment.

The team observed the physical condition of transformers 1AX501 and 1BX501, which feed the four 4160 V Class 1E buses, and found that the automatic load tap changer supervisory indicator for both transformers showed that the tap changers had been fully ranged. During the licensee's presentation, the licensee stated that the 500 kV voltage changes only a few percent over a year. The team asked why the transfer load tap changer (LTC) had gone through extremes of travel. The team was told that the LTCs had failed, causing them to swing through their entire range. The operations group had to take manual control of the LTCs to maintain bus voltage. The licensee indicated that the problem was an intermittent one. The tap change supervisory indicator was later reset during this inspection. The team found out later that in the past three years, there were four failures on the transformer LTCs. Three of the failures were on the non Class 1E transformers and one on the Class 1E transformer. The cause of these failures remains unknown. Failure of the transformer LTC can affect the time-delayed transfer (refer to Section 2.3.2) and the available voltage at the 480 V MCC. This issue is unresolved pending NRC review of licensee actions to identify the cause and correct the transformer LTC problem (50-254/92-80-10).

The team also assessed station and equipment housekeeping, relevant separation criteria, condition of equipment meters, lights, indication and monitoring, and cable-tray fill. Based on the walkdown inspections performed, the team concluded these areas to be adequately controlled and maintained.

The team identified a human factors and personnel safety concern regarding operation of the EDG units. Both ends of each EDG are approximately two feet lower than the operating platforms on each side. On the generator end there are access steps from the EDG room entry doorway to the operating platform. However, on the engine end there are no steps. Personnel normally step out onto a small EDG instrument tubing protective channel. They hold onto a portion of the EDG and either jump or stretch to make the step down. Falling could be hazardous. Personnel injury in the EDG room could prevent operators from performing emergency actions in a timely manner and there is a possibility for equipment damage during a fall. The licensee concurred in the team observations and proceeded with a modification for the design, fabrication and installation of steps and handrails at the engine end of each EDG.

On February 14, 1992, the team observed that the safety access steps had been installed for the four EDG units. The team considered this to be an observation and found the licensee to be responsive in correcting this human factors/safety issue.

4.2 Equipment Maintenance and Testing

The team reviewed various operations, maintenance and testing procedures for equipment such as the diesel generator, protective relays, circuit breakers, and batteries. Licensee personnel were interviewed to ascertain their understanding of the testing programs. The team also reviewed the program established to control protective relay setpoints during the calibration and testing process. During this review, the team reviewed the Diesel Generator System Engineer's and Electrical Maintenance Department's records for the incorporation and performance of a EDG Vendor Service Information Letter (SIL), C.4. The team member found that the SIL had not been incorporated into the testing requirements for the EDGs.

Hope Creek UFSAR, Rev. 1, Section 8.3.1.1.3.10, states that, "A comprehensive preventive maintenance (PM) program for the EDG incorporates the latest vendor recommendations...". However, during this inspection there was no evidence that the licensee had included the recommendation of Fairbanks Morse Service Information Letter, Volume C, Issue 4, dated April 15, 1985, and SIL Volume C Issue 4, Rev. 2, dated February 2, 1989, which requires specific testing of the emergency diesel generators to determine if they have generator shaft currents which can damage the engine and generator bearings. This condition has existed since the issuance of the first SIL in April 1985. The licensee's Action Tracking System indicated that the licensee received the SIL and closed it without further action. The licensee noted that they used a voltmeter and needle probes to touch the shaft coupling through the shield to take a similar type of measurement, but did not clean the shaft or assure continuous contact with the turning shaft coupling. The licensee demonstrated a knowledge of the need to perform the measurement, but did not incorporate all the various testing locations and test equipment as specified by the SIL. Failure to assure that shaft currents do not develop can result in the pitting and failure of the generator pedestal bearing, and pitting and failure of the engine main and connecting rod bearings. This is a deviation (50-354/92-80-11).

In the February 26, 1992, letter to the NRC, the licensee stated that they were revising the EDG maintenance procedure HC.MD.KJ-005 to incorporate the SIL C.4 recommendation. The licensee committed to fully implement the recommended maintenance by the end of the fourth refueling outage beginning in September 1992.

4.2.1 EDG Surveillance Testing

To assure that the EDGs can perform their intended operational safety function, the team reviewed the EDG factory performance test record (1982) and the initial installation pre-operational performance acceptance test (1986) as described in Procedure PSSUG-PTB-BB-3.

In addition, the team reviewed periodic monthly and 18-month surveillance testing of the EDGs in accordance with procedures OP-ST-KJ-002(Q) and OP-ST-KJ-007(Q), respectively. Further, the team witnessed the performance of a monthly surveillance test of the "B" EDG on January 23, 1992. The team confirmed licensee commitments in FSAR Sections 1.8.1.9 and 1.8.1.108 to Regulatory Guide (RG) 1.9 and RG 1.108, respectively, for the design, rating, qualification and testing of the EDG units.

The team noted that the 1982 factory performance tests included demonstrations of satisfactory EDG starting, load acceptances, load rejections, continuous rated load and 110 percent load capabilities at 0.8 power factor. The 1986 pre-operational performance tests demonstrated the steady state capability of each EDG to perform satisfactorily at their continuous load rating of 4430 kW at 0.8 power factor (5538 kVA) for 22 hours, and for 2 hours at their 110% rating of 4873 kW at 0.8 power factor (6091 kVA). These tests also demonstrated the dynamic performance capability of each EDG to start, accept all loads within the required time sequences and to reject maximum loads without exceeding the time, voltage, and frequency requirements. These tests verified compliance with RG 1.9 and RG 1.108.

However, the test records indicated that the 1986 pre-operational test identified 12 specific concern areas, e.g., fuel oil day tank size, fuel oil consumption rate, etc. During the inspection, the licensee could not provide evidence that the identified 12 concerns were evaluated and the problems corrected. The team did not identify any of the 12 items as a current operability issue. The licensee agreed to evaluate these concerns and committed to complete the evaluation by September 30, 1992, as indicated in their February 26, 1992 letter to the NRC. This item is unresolved pending NRC review of the licensee corrective actions (50-354/92-80-12).

In reviewing the surveillance test procedures and test records, the team noted that neither the periodic monthly nor the 18-month surveillance tests fully demonstrate the EDG steady state and dynamic load performance capabilities. The steady state tests are conducted at near unity rather than at the EDG rated (0.8) power factor. As a consequence, the electrical current producing/carrying components are tested at approximately 25% less than their rated currents. The 18-month dynamic tests properly include the fast start and dynamic loading by means of the load sequencer and by manual load additions and rejections. However, the EDG transient response data, e.g., the dips and rises of voltage and frequency and recovery time were recorded, but were not properly analyzed to determine their acceptability. The only analyses performed is that the EDG starts within the required time and that all sequenced loads are on within two minutes. FSAR load sequence times and EDG transient response data were not evaluated to determine compliance with RG 1.9, Section C4.

In the February 26, 1992, letter to the NRC, the licensee committed to: 1) include KVAR loading (equivalent to 0.8 power factor) in future surveillance tests starting April 1992; and 2) revise procedures HC.OP-ST.KJ-005, 6, 7 and 8 before the next scheduled 18 month testing, to provide necessary steps for conducting dynamic load response evaluation. This item is unresolved pending NRC review of the licensee's corrective actions (50-354/90-80-13).

On January 23, 1992, the team observed the "B" EDG in an inoperable condition during a test and with the plant in condition 1 operations. During the monthly surveillance test, which was conducted in accordance with Procedure OP-ST-KJ-002(Q), the EDG was locked out by means of a key switch lock in the EDG room. While locked out, the EDG cannot respond to any accident or remote start signal. This procedure provides for locking out the EDG during certain pre-operational verifications including opening the cylinder cock valves and rotating the engine to verify absence of water or oil in the cylinders. The test procedure includes no precautions or time limits for the EDG lock-out. The team noted that the time of lockout was approximately 30 minutes during this test.

In the February 26, 1992, letter to the NRC, the licensee agreed to establish various precautionary steps to alleviate the potential consequence of an inoperable EDG during testing. These steps include: 1) limiting the inoperable time to 15 minutes each test; 2) dispatching an operator to the EDG room to provide prompt response to the control room demand; 3) not scheduling an EDG test when a redundant train is inoperable; and 4) providing additional training to operators and technicians of the potential problem during EDG testing. This item is unresolved pending NRC review of licensee corrective action (50-334/92-80-14).

The periodic surveillance procedures for EDG units requires pre-operational checks of many devices and systems prior to starting the EDG. During the witnessing of the monthly surveillance test for the "B" EDG, the team noted that one of the two air start distributor oil reservoir levels was found to be low by test personnel prior to the start. Accordingly, oil was added. The inspectors noted a similarity between this and the root cause of failure to start for the "D" EDG on May 22, 1991 (Special Report 91-03-01) when the governor min/max fuel boost switch was improperly positioned, thereby preventing EDG start. In this case the licensee appropriately added a pre-op check to the surveillance procedure for this switch position. The inspector observed that assuring switch positions, oil levels, etc. on an EDG unit just prior to a planned surveillance run is very important. However, it is much more important to assure that all critical pre-op parameters are verified immediately following a surveillance test and periodically by an operator. This ensures that the EDGs are ready to accept an emergency start signal to perform their intended functions at any time. The licensee concurred and has taken action to review each of the procedures and act accordingly.

The inspectors confirmed that during 18-month surveillance testing the licensee verifies that all EDG trips are bypassed during LOOP/LOCA accident conditions except for overspeed, low engine oil pressure, and high generator differential current. The inspectors observed a discrepancy between the bypass logic diagrams and detailed circuitry drawings for the generator ground fault trip. The licensee agreed to correct the logic diagram to eliminate this discrepancy.

4.2.2 EDG Fuel Oil Surveillance

The requirements for acceptable EDG fuel oil are established by the EDG manufacturer. The manufacturer's fuel oil specifications closely approximate the ASTM D 975 requirements for No. 2 commercial grade fuel oil. Accordingly, the licensee has established requirements in the Technical Specifications with specific acceptance values for each of the fuel oil parameters which are in accordance with ASTM D 975.

The licensee's Technical Specification Paragraph 4.8.1.1.2.f provides requirements for the sampling, analysis of new fuel oil and stored fuel oil. This includes the acceptance criteria and timing of various parts of the analysis and the frequency for performing analyses. The team found that the licensee's procedure CDP-8 invokes all of the appropriate ASTM fuel oil specifications, sampling and test methods required for the proper evaluation of the EDG fuel oil quality.

By reviewing completed sampling and testing results for both the stored fuel oil and new fuel oil for the previous year, the team found that the EDG fuel oil was well within the acceptable specification limits. However, the team reviewed the licensee's technical specification and procedural requirements for the sampling and evaluation of the quality of new fuel oil. These procedures only require that the licensee test new fuel for water and sediment content, viscosity and specific gravity as provided for in RG 1.137 prior to adding it to the storage tanks. An additional two weeks is permitted prior to the receipt of laboratory verification of the other 11 ASTM D 975 specification fuel oil parameters. During this time, the quality of the EDG fuel oil in the storage tanks is unknown.

An example of this problem occurred when, on January 15, 1992, the licensee received a tanker of new fuel oil and performed the required technical specification verification preliminary analyses for the receipt of new fuel oil. Subsequently, the licensee off-loaded the new fuel oil into the storage tanks for all four EDGs. Samples of the new fuel were sent to an approved outside laboratory to confirm that the remainder of the ASTM D 975 fuel oil parameters were within the technical specification. On January 29, 1992, the licensee was notified by the laboratory facility that the fuel oil was out-of-spec for one of the parameters (Ramsbottom carbon residue was reported to be 0.70%; specification maximum is 0.35%). Since the potential out-of-specification fuel oil had been added to all four of the EDG fuel oil storage tanks, the question immediately arose as to whether or not the fuel oil in the storage tanks was within technical specification limit. Poor quality fuel oil could affect the operation of all four EDGs.

Based upon the relatively small amount of suspect fuel added to the much larger volume in the storage tanks, the licensee concluded (on January 30, 1992) that the stored fuel oil was still acceptable. The licensee also confirmed with the EDG manufacturer that the suspect fuel oil, although detrimental to the engine, would not prevent EDG operation for 7 days at rated load with the as-delivered oil (before mixing).

On January 31, 1992, the licensee received confirmatory analysis for both the new fuel and the fuel in each of the storage tanks that all of the fuel met the ASTM D975 specification requirements. The licensee discovered that the contract fuel-analyses-laboratory had made an error in the January 29, 1992, analyses of the new fuel. Root cause analyses for the error was attributed to the contract laboratory's failure to properly follow the established ASTM diagnostic procedures. Failure to properly conduct the analysis for the Ramsbottom carbon residue was attributed to the contract laboratory using a new laboratory facility with new personnel. The team confirmed that the licensee has taken appropriate corrective actions to ensure that contract laboratory analyses are reliable. A part of the confirmatory corrective actions included verification analyses of duplicate samples by another approved laboratory.

The team concluded that prior to this inspection, the licensee had not properly assessed the consequences of adding fuel with unknown chemistry and combustion properties into the EDG fuel tanks. Licensee procedure CDP-8 failed to provide adequate controls, instructions and appropriate precautions. Subsequent to the inspection, on March 3, 1992, the team verified that the licensee had established a program to assure the quality of the EDG fuel oil. The program includes a new EDG fuel oil specification which includes:

- All of the Technical Specification 4.8.1.1.2 fuel chemistry and physical properties requirements.

- Requires that the fuel oil be considered safety-related commercial grade and be procured and controlled in accordance with the established PSEG commercial grade dedication process with appropriate QA involvement.

- Specifies that prior to adding new fuel to the storage tanks, the fuel must be sampled and controlled, as needed, until the complete fuel analyses result is received and the correct chemistry is confirmed.

- Requires that the periodic sampling and analysis of the fuel oil stored in the EDG tanks be performed to the same QA and acceptance criteria as new fuel.

Based upon the licensee's establishment of the new programs to ensure proper quality of EDG fuel oil, the team considered this item to be resolved. No further action is required.

4.2.3 Large Circuit Breaker Testing

The team witnessed the surveillance testing of a 4160 Vac air circuit breaker. This breaker was a non-1E unit; however, because the non-1E and 1E units are from the same manufacturer, and the surveillance procedures are the same for 1E and non-1E, the surveillance was deemed to be representative of the testing done on 1E breakers. The surveillance was performed using approved procedures, and the team observed that the contact lubricant used on the breaker stab connectors was as specified in the procedure. The technicians performed the testing per the procedure and seemed knowledgeable in the aspects of the work they were performing. The team member observed that when the testing was completed, the breaker was placed back in the cubicle. The breaker cubicle was labeled as a spare. When asked, the technicians said that the breaker was formerly in-service, removed to the spare cubicle for testing, and would be returned to service later.

4.2.4 Transformer Oil Analysis

The team reviewed the station transformer oil analysis program for both the Main Power Transformers and the Station Service Transformers, 1AX501 and 1BX501, that feed the safety related buses. The transformer oil was not being sampled during the inspection, so no conclusion can be reached about the sampling methodology.

The team reviewed the oil analysis data provided by the licensee. This data represented the results of oil analyses done by the parent utility laboratory. The team noted that the results for each transformer contained the date of the sample, no oil temperature was filled in (even though there was a space for it), oxygen, nitrogen, carbon dioxide, hydrogen, carbon monoxide, methane, ethylene, ethane, acetylene, propane/propylene, total gas concentration, total combustible gas in parts per million, and total combustible gas percent in gas. The data started in 1987 and continued to present.

The team conducted independent evaluations of the transformer oil sample data by means of the industry accepted Rogers method in accordance with ANSI/IEEE C57.104. The team found that:

- The main power transformer (MPT) has experienced overheating in the range of 150°-200°C for sustained periods during this time.

- The 1AX501 transformer has experienced overheating in the range of 200°-300°C for one sample; other samples were normal during this time.

- The 1BX501 transformer has experienced overheating in the range of 200°-300°C for 6 of the 8 samples taken during this time.

Based on this review and the interviews with the licensee and the documentation presented by the licensee, the team concluded that the adequacy of the licensee's oil analysis program for his important-to- safety transformers was questionable, and the material condition of 1BX501 transformer may be degraded. Failure of this transformer would result in a transfer of its load to the 1AX501 transformer, and a possible challenge to the EDGs if the transfer fails (as described in Section 2.3 above). This item is unresolved pending NRC review of licensee corrective actions for this issue (50-354/92-80-15).

4.2.5 Molded Case Circuit Breaker Testing

The team reviewed the methodology and procedures used to test molded case circuit breakers (MCCBs). The team found that the licensee performs time-current response testing on only those breakers listed in the Technical Specifications (TS). These breakers include the breakers used to protect the electrical penetration assemblies that carry power through the reactor containment wall. The majority of breakers utilized in this service are 480 Vac, three phase MCCBs. No dc breakers are used for penetration protection. The team reviewed a random sample of the test results and found that the test results were complete and in general reflected the vendor's requirements and documented the proper testing to meet the TS requirements. However, the test program did not cover the majority of MCCBs in the plant. The non-TS breakers were not tested to verify that the time-current curves were not changed. Those that were tested were verified for one current-time point, in accordance with the vendor's recommended testing procedures.

The licensee stated that a plan to increase the scope of testing to include other breakers was under study. The team reviewed procedure HC.MD-ST.ZZ-011(Q), Revision 6, dated December 11, 1990, (most recent Revision) entitled, "Low Voltage Molded Case Circuit Breaker Overcurrent Trip Testing." Section 5.2.20 of this procedure states, "Multiply ammeter reading by .9 to obtain true dc average current for dc test currents." The team questioned this and was told that although that statement was in the procedure, it was not used. The licensee agreed to remove the statement during the next revision of the procedure.

4.2.6 Fuse Control

The team reviewed the fuse control procedure as specified in HC.MD-AP.ZZ-0009(Q) Revision 10 and unsigned Revision 11. The team found that the procedure appeared adequate and included most of the elements needed to assure a reasonable program. Revision 11 will add some more elements of control, and formalize the requirements describe below. The procedure uses several checks and balances to assure that the correct fuse is installed. Further, because of the Bill of Materials listing in the computer MMIS system, fuses are identified via the computer when the technician needs to draw the parts to complete the task.

4.2.7 Motor Lubrication Program

The team reviewed the station lubrication program as it is applied to electric motors. The program, described in the plant document entitled "Station Lubrication Manual," dated November 20, 1985, is administered by Operations. The procedure covers various equipment in the plant including electric motors. The procedure is well written and includes requirements to assure that amounts of lubricant to be replenished are determined, and includes measures such as the quantity of grease a grease gun delivers with each stroke.

The program also includes checks to assure that the right type of lubricant is used to replenish the motor bearings. The correct quantity of lubricant is essential to assuring that the bearing has an adequate supply of lubricant, and that no lubricant is forced out into the motor's windings, since the lubricant can soften and damage the winding insulation system. The team concluded that the licensee has a good lubrication program to assure that lubrication-related failures are minimized.

4.2.8 Inverters

The team reviewed inverter surveillance testing and operating procedures. The team found that testing and operation were generally acceptable. However, because the inverters have a source of power that can be isolated during maintenance and testing, the inverter could be disabled which would render the associated EDG inoperable during a loss of offsite power event.

Inverters are used to supply uninterruptible power to various 1E loads including EDG loads. The inverters use three different and diverse power sources to feed the incoming section of the inverter. The first section uses a 480 Vac power-feed supplied by the offsite powered bus. The inverter converts this ac power to dc, and compares the voltage of this power with the second source of power from the dc battery. Normal operation usually finds the ac-derived dc-source greater than the dc battery source, so normal operation is powered by the ac source. The third source of power is from the emergency bus itself. This source of power is made available to the loads via a solid state transfer switch which selects either the ac produced by the inverter, or the ac available from the emergency bus. The inverter has a switch that allows the operator to select different modes of operation during periods of maintenance or testing. One of the positions allows the solid state switch to be manually set to the bypass (emergency bus) position. If this occurs, and there is a loss of off site power, the EDG will not start, since the power to the EDG start circuitry will have been lost. In response to this concern, the licensee stated that if the switch is set to the bypassed position, it will cause a digital group alarm to annunciate in the Main Control Room (MCR). The operator would then go to the inverter and determine what specific condition caused the group alarm. The team noted that there was no trouble shooting guide at the inverters, so the operator must depend on memory and help from the MCR operator to correct the situation. The licensee stated that their operators were trained to recognize this problem. The team had no further questions.

4.2.9 Battery Surveillance Testing

The team reviewed the 125 V and 250 V battery systems. The team found that the batteries were installed as described in the design documents.

The team witnessed the surveillance test of the 250 V HPCI battery. The test was conducted using an approved procedure, and that the technicians followed the procedure. The team noted that the battery appeared to be in good physical condition, and the battery room was clean and dry. At the end of the test, the procedure required the measurement of the battery voltage. The technician noted that his voltmeter leads were not long enough to reach across the room to get both the positive and negative terminals. He then measured the voltage from the outgoing terminal to ground on one side of the room and the corresponding terminal to ground on the other side of the room and added the voltages together. The team pointed out that the battery is designed to be ungrounded, and the measurement he made introduced an error of the voltage drop of the ground detector circuit. The technician then remeasured the voltage from the outgoing terminal to the jumper terminal on both sides of the room and determined that the error was about 0.5 Volts. The licensee management was informed of this improper process. They agreed to provide specific instruction to the technician to avoid using this process.

While in the battery room, the team and the licensee's system engineer found that one of the battery's jumper terminal posts had separated from the case (but the post was still connected to the plate). This apparently was caused by the strain induced on the post by the jumper cable that connects one half of the cell on one side of the room to the other half of the cell on the other side of the room. The team noted that the cable entry into one side was a smooth transition from the cell post to the conduit. However, on the damaged cell, the transition involved several angles which allowed the cable to swing upward before coming back to meet the cell terminal. This upward sweep produced a moment arm which allowed a continuous side force to be placed on the terminal. The licensee committed to review the rest of his battery installations for similar configurations and to replace the damaged cell at the next opportunity. This is an unresolved item pending NRC review of licensee corrective actions (50-354/92-80-16).

4.3 Protective Device Set Point Control and Calibration

The team reviewed set point calculations and surveillance reports for low voltage containment electrical penetration circuits having overload and/or bypassed protection, large 4160 Vac motor protection, switchgear bus and feeder protection, and EDG generator protection. These are discussed as follows.

4.3.1 Protective Device Setpoint Settings

The team reviewed the various protective device setpoint calculations and compared them to the "as-found" setting in the field. The team also reviewed the setpoints associated with Channel D 4160 Vac switchgear. The team found that the as-found settings agreed with the design documents.

4.3.2 Protective Relay Setpoint Calibration and Testing

The team reviewed a surveillance test report of an undervoltage relay and determined that the testing was done in accordance with the established procedure and that it assures that the relay will maintain the manufacturer stated accuracy.

The team witnessed the surveillance testing of a Class 1E degraded grid undervoltage relay. This testing is performed monthly and includes the testing of an SSV-T solid state relay that detects the undervoltage condition, the Agastat timer relay, and an HFA auxiliary relay. This test also verifies that the 125 Vdc control power for the circuit is available, indicating no blown fuse for this circuit. The test crew followed the test procedure during the testing of the relay. The team observed that the relay test personnel had to stand on the bus potential transformer (PT) cabinet to perform certain steps of the relay test procedure associated with the connection of the HFA relay. This practice exposes both the technician and equipment to possible harm. Apparently, a ladder could not fit in the area. The licensee management was informed of this condition. They agreed to evaluate this issue.

The team was impressed with the knowledge level and professionalism of the relay test crew and was fully satisfied with the performance of the test.

4.3.3 Protective Device Setpoint Control

The team interviewed personnel in the relay department and determined that, even though they report to the parent company relay department, they had a strong sense of ownership with the plant. Further, they were knowledgeable in the plant modification procedures and recognized the impact their activities could have on plant safety. Their activities were fully integrated with plant Engineering, Maintenance and Operations.

The team interviewed several engineering personnel and found that they were aware of the origin of the protective device setpoints, and that they understood the relationship of the modification program to changes in protective device setpoints.

4.4 Conclusions

Based on the documents reviewed and the tests observed, the team concluded that, in general, adequate maintenance and testing were provided to the Hope Creek electrical distribution system equipment. However, the team identified two deficiencies in the maintenance and testing areas: 1) during monthly surveillance testing of the "B" EDG, the EDG was not declared inoperable; 2) one of the vendor recommended EDG preventive maintenance activities (diesel engine and generator bearing insulation) was not in the maintenance program. In addition, seven unresolved items were identified: 1) deformed EDG lead insulation; 2) inactive 4160 V undervoltage relay connected to Class 1E dc bus; 3) EDG surveillance tests did not include a) sufficient KVAR and b) analysis of dynamic response to EDG loading; 4) no evidence that the corrective actions have been done to address the 12 concerns identified during the 1986 preoperational test of the EDG; 5) inadequate transformer oil analysis program to detect degraded insulation conditions; 6) the cause of transformer auto-load tap changer failures was not identified and the problem corrected; and 7) a terminal post of the 250 V battery was separated from the battery case due to strain induced on the post by the jumper cable.

5.0 ENGINEERING AND TECHNICAL SUPPORT

The team assessed the capability and performance of the licensee's technical organization to provide the engineering and technical support needed to safely operate the facility in compliance with regulatory and other requirements. This was accomplished by reviewing both the onsite and offsite technical support groups, the established root cause analysis and corrective action programs, and the self assessment programs being implemented.

Also reviewed was the modification control program including the review of selected modification packages. The temporary modification program, engineering interfaces and technical support staff training were included in the review. A walkdown of operating procedures was conducted to assess their adequacy.

5.1 Organization and Key Staff

Facility technical support is provided mainly by onsite and offsite technical support groups. The offsite technical support group is located adjacent to the site boundary making it convenient for technical support personnel to visit the site. The offsite group known as the Engineering and Plant Betterment (E&PB) group is organized to provide support in long term projects; design change package (modification) development, implementation and closeout; major technical analyses; supplemental engineering support; and configuration management control. A method has been established which gives high priority to tasks that affect safety and reliable station operation.

An organization composed of a general manager, managers, supervisors, and engineers has been established to provide support in nuclear engineering standards, mechanical engineering, electrical engineering and engineering sciences. The offsite technical support group consists of 261 engineers (serving both Salem and Hope Creek) with an average of 13.4 years of engineering experience. Of these 261 engineers, 18 are assigned to Hope Creek electrical and instrumentation and controls. This group of 18 engineers has an average of 10.5 years of engineering experience. The team observed a daily meeting which was found to be effective in keeping the group apprised of activity status and assignments. Based on many interfaces with offsite technical support personnel, the team judged the group to be knowledgeable and effective in providing technical support to the facility.

The onsite technical support is provided by station system engineers. Engineering responsibilities for individual systems is assigned to specific system engineers who report to the technical manager through supervisors. System engineers are assigned to balance of plant systems, instrumentation and controls systems, electrical systems, and nuclear steam supply systems. System engineer responsibilities include trending system performance, recommending needed modifications, reviewing modifications (station project team member), providing operational and maintenance technical support and performing procedure reviews. Thirty-three system engineers have been assigned. These engineers have an average experience of approximately 10.6 years. Of the 33 engineers, 18 are assigned to the electrical and instrument and controls areas. These 18 have an average experience of 11.2 years. Based on many interfaces with system engineers, the team judged them to be knowledgeable and competent.

5.2 Root Cause Analysis and Corrective Action Programs

The licensee's root cause and associated corrective action program was found to be addressed in numerous procedures. Examples of nuclear common procedures (procedures which are applicable to both Salem and Hope Creek) which describe actions to be taken which are associated with root cause analysis are:

- NC.MA-AP.22-0010(Q), Preventive Maintenance.
- NC.MA-AP.22-0048(Q), Station Performance Monitoring Program.
- NC.MA-AP.22-0058(Q), Corrective Action Program.
- NC.MA-AP.22-0006, Incident Report/Reportable Event Program and Quality/Safety Concerns Report System.

In addition to the above nuclear common procedures, the following are examples of Hope Creek Station procedures which also address root cause analyses and corrective actions.

- HC.SA-AP.22-0048(Q), Station Performance Monitoring.
- SE-AP.22-048(Z), System Engineering Station Performance Monitoring.
- HC.TE-PR.22-002(Q), Performance Parameter Monitoring, Trending and Analysis.
- HC.TE-PR.22-005(Z), Monitoring of System and Component Failures.
- HC.SE-PR.RL-0001(Q), Bailey 862 Logic Module Trending Program.
- HC.TE-GP.ZZ-0030. Failure Analysis and Root Cause Investigation.

The licensee agreed that numerous procedures appear to address or refer to "Root Cause Evaluations." The licensee also agreed that these procedures appear to overlap and had the potential to cause confusing/conflicting direction.

The licensee has committed to review applicable procedures and revise them as necessary to provide clear direction on management expectations for the performance of root cause analysis. This review is expected to be completed by December 31, 1992.

The trending of data is an important aspect of problem identification and correction. The licensee is developing a new trending program. Under this program the system engineers identify the data to be trended. The performance group collects, trends, and plots the data. The system engineer is then responsible for analyzing the data.

This new process will relieve the system engineer of the time consuming task of collecting and plotting data and will provide him more time for analysis and determination of corrective actions.

The licensee has developed other procedures which are intended to identify deficiencies, both hardware and administrative, and to provide for the initiation of corrective action. These procedures include:

- NC.NA-AP.22-0009(Q), Work Control Process;
- NC.NA-AO.22-0120(Q), Nonconformance Process;

- HC.SE-PR.22-0001(Q), Rosemount 1153 Transmitter Trending and Data Analysis Program;
- DE-AP.22-0018(Q), Engineering Discrepancy Control; and
- MC.MA-AP.ZZ-0061(Q), Significant Event Response Team Management.

The team reviewed a number of engineering evaluations (sometime termed root cause analysis), incident report evaluations, and significant event response team reports and determined that events and equipment failures are being evaluated. The procedure review and changes should help to improve the existing program.

2.3 Self Assessment Programs

The licensee has instituted a number of self assessment programs which were reviewed by the team. One program the licensee has implemented establishes a process for the review of both internal and external operating experience information to assess the lessons learned. This program is being effectively utilized to prevent recurrence of events and to improve plant safety and reliability. This program is described in procedure NC.MA-AP.22-0054, Operation Experience Feedback Program. A number of electrical and instrumentation and control related information notices and industry significant operating experience reports were verified to have been reviewed in accordance with this procedure.

Several QA group audits were reviewed. These were Audit 91-100, Engineering Nuclear Department and Audit 89-91, Performance Monitoring Nuclear Department. The audits appear to be comprehensive and detailed. In each instance, significant findings were identified to management. The audits appear to be effective in identifying concerns.

Another self assessment process used by the licensee is the establishment of a Significant Event Response Team (SERT) to review selected events. SERT reports for a March 19, 1990, scram and a May 7, 1991, scram were reviewed. A detailed nuclear electrical engineering evaluation was attached to the March 19, 1990, SERT report. The SERT provides an initial evaluation for significant events. A comprehensive scram analysis performed by the licensee provided comments intended to improve SERT evaluations. The team noted that the recommendations of these SERT reports were not tracked in the established action tracking system to assure closeout. After being notified, the licensee promptly entered these reports into their tracking system.

Another self assessment initiative implemented by the licensee was a comprehensive scram analysis review. This review was conducted by a team from onsite safety review, offsite safety review, quality assurance and human performance review groups. Twelve station scram events since August 26, 1988, were reviewed. This was a comprehensive review and resulted in a number of recommendations to management. This review also identified that SERT recommendations had not been entered into the action tracking system.

The licensee's outage management procedure, NC.MA-AP.ZZ-0055(Q), requires that the onsite safety review group perform an independent risk management review of the refueling outage schedule. This review was performed for the third refueling outage and a report with recommendations was prepared. Also, although not specifically required, the onsite safety review group conducted a review of the planned mini-outage of March of this year. The review concentrated on the periods which required alternate decay heat removal capabilities. This review provided the outage manager with insights into alternate decay heat removal methods. Another initiative by the onsite safety review group was the identification, during the third refueling outage, of a potential reduction in the margin of plant safety dealing with electrical power supplies. It was noted the general manager acted immediately on these findings.

Overall, the licensee has established varied means to provide self assessments of performance. Reports and documentation reviewed by the team indicate high quality reviews are being performed. The overall quality of facility operation should improve due to the established quality self assessment activity.

5.4 Plant Modifications

The licensee has established a process for the control of plant modifications. This process is described in procedure NC.MA-AP.ZZ-0008(Q), Control of Design and Configuration Change, Test and Experiments. This procedure provides the process description for controlling design changes. Specific instructions for the preparation of a design change package (plant modification) are provided in five preassembled workbooks. These workbooks provide the forms and instructions needed for the preparation of a design change package. Altogether, five workbooks are available to provide specific instructions for all activities related to facility changes. Workbook one developed to control standard design changes was reviewed and was found to provide all forms and instructions needed to complete a design change. The workbook provides for an orderly assembly of a design change package.

Several design change packages were reviewed to assess the effectiveness of the licensee's program and procedures. The team was told that the same procedure was used to prepare both non-safety packages and safety-related packages. These are discussed as follows:

a) The team reviewed two non-safety-related modification packages. The team found that packages were generally complete, and could be applied to a field construction organization for work. The packages contained appropriate calculations and sign offs to identify the quantitative requirements. The packages also contained adequate description of the materials needed to complete the work.

   The packages also contained adequate descriptions of the existing condition that required modification, and a description of how the modification would correct the concern.

One of the two packages contained a letter written by the parent company's Transmission and Distribution (T&D) Department recommending the installation of a specific type of instrumentation. The licensee installed an entirely different type of instrument. The licensee provided a brief description of how the new instrument could accomplish the same task as the original recommendation, but the package did not contain any documentation that showed that the licensee discussed the change with the T&D department. The system engineer said that he contacted the T&D department by phone and discussed the change. This is an observation.

b) A design change package was reviewed for the replacement of ten cathodic protection anodes serving the diesel generator fuel lines buried in the yard. The integrity of the cathodic protection system for the fuel lines is addressed in the Hope Creek Technical Specification page 3/4 8-3, paragraph h. The licensee indicated the Station was in the process of replacing the anodes. The team reviewed the methods used to survey and determine the integrity of the cathodic protection system. Based on a review of test data, procedures and criteria presented by the licensee, the team concluded that the criteria for surveillance, testing and maintenance of the system was adequate. However, the team identified an omission in the ohmic value specified for the surrounding back fill "coke breeze" material, a parameter that had been delineated in the original specification but not in the procurement documents and which was described as germane to assuring the proper voltage drop. The licensee indicated that conformance to this specification value for the replaced anode package would require additional evaluation or performance of a test by the supplier. Subsequently, the licensee provided documentation and evidence to demonstrate that there were alternative methods for replenishing fuel oil to the storage tanks that did not depend upon these lines.

c) The team also reviewed packages DCP 4HC-0015 and DCR 4HC-0311. The first package addressed a change in the compressor size for an emergency air compressor. Although the modification package did address design analyses and calculations, page 3 of 3 of the final DCP closeout form, which constitutes the final verifications, had indicated as "Not Applicable" the category of required calculation updates. The licensee's response showed that the design parameters, including cable feeder sizing and equipment capacity, were not affected. The team concluded that the modification package was adequate.

A second design change package reviewed addressed the elimination of a Topaz inverter and the replacement of the load on the station vital buses. The adequacy of original fuses was questioned. Also, confirmation of an assumed cable design length was requested. Sizing of feeder cables and adequacy of voltage drop was questioned including the non-conservative use of 50°C, where 90°C is the criteria for power feeds. The licensee provided an evaluation of these concerns. Based on a review of those evaluations, the team concluded the design change package to be adequate.

d) Two recent design change packages 4EC-1054, Air Supply and Drain Line Modification Stby DG "B" and 4EC-3182, Modify 24 Vdc Power Supply were reviewed to verify that they were prepared in accordance with the instructions provided in workbook one. No discrepancies were noted.

The team, in reviewing specific design change packages, noted that some older packages, prepared before the current guidance for design change packages was issued, were in some instances difficult to follow. Also, in a number of instances certain questions relating to the change packages required additional clarification from the licensee.

Overall, based on the review of a number of completed design change packages, the team concluded the packages were adequate, with the more recent packages being a significant improvement over older packages. Additional revisions to the process are currently under review to further enhance the process.

5.5 Temporary Modification Program

The licensee has established a process for the control of temporary modifications. Procedure MC.NA-AP.ZZ-0013(Q), Control of Temporary Modifications, describes the program to be used within the nuclear department for controlling the installation and removal of temporary modifications. Procedure HC.SE-AP.ZZ-0013(Q), Temporary Modification Package Preparation, provides guidelines for the preparation of temporary modification packages. Temporary modification packages are prepared using the forms and following the requirements of the standard design change workbook one described in Paragraph 5.4.

A review of packages describing three installed modifications shows them to be prepared in accordance with procedural requirements and of a high quality.

During the review of the temporary modification procedure, several errors were noted. These were discussed with licensee management. The licensee committed to correct the errors as appropriate and to review the entire procedure for consistency and clarity. This review is to be completed by June 1, 1992.

The temporary modification log maintained in the control room area is an interface between the modifications installed in the plant and the operators knowledge of the installation of these modifications. The log is reviewed each shift. During the review of the temporary modification log, the team identified two errors contained in the log. The description of one modification, 91-22, did not indicate that an annunciator was jumpered out. Therefore, the

operators were not aware of this condition and a red stripe was not placed across the annunciator window as procedurally required. Also, temporary modifications 91-14 and 91-22 did not have their mode dependency indicated in the log as required. These errors were immediately corrected. These examples of failures to follow procedures would normally be classified as a severity level V violation. However, this violation is not being cited because the criteria specified in 10 CFR Part 2, Appendix C, Item VII(B), mitigation of enforcement sanction, were met and the licensee initiated prompt corrective actions.

Other aspects associated with temporary modifications were reviewed by the team and found to be performed as procedurally required. These were the performance of offsite safety review group reviews, the mark-up of working drawings to reflect the installation of the temporary modification, and the verification and tagging of installed modifications.

Overall, the licensee has an adequate program for the control of temporary modifications. Increased attention is required in the preparation and review of the temporary modification procedure, the maintenance of the temporary modification log and the control of operator aids. It was noted the licensee was prompt in taking corrective action and in committing to make necessary changes.

5.6 Engineering Support/Interface

Engineering support is provided to the facility by two groups, the offsite technical support group known Engineering and Plant Betterment (E&PB) and the onsite technical group. Essentially, all design changes are processed by the E&PB group within the nuclear department. This group generally assumes responsibility for long-term, larger scope, or more complex engineering projects. Other support as requested by station management is also provided by this group. One means of requesting support is through the use of engineering work requests (EWRs). During 1991, approximately 160 EWRs were initiated by Hope Creek. Several procedures, particularly those associated with design changes, require onsite and offsite technical support interfaces. Based on discussions with site technical personnel, maintenance personnel, and operators, it was determined that in addition to the formal interfaces required by procedure informal interfaces have been established which are considered to be beneficial to plant operations.

The presence of E&PB engineers onsite along with system engineers during the walkdowns associated with the preparation of design change packages was noted as being beneficial in the preparation of change packages.

However, the team noted a difference between the Nuclear Operations and the Engineering and Design groups specifications for battery room temperature. The system engineer's weekly surveillance procedure for batteries specified, a battery room temperature range of 60°F to 90°F; whereas design and engineering specified and used a battery room temperature range of 72°F to 82°F per the UFSAR. The licensee described that any design change packages initiated by Engineering & Plant Betterment (E&PB) are reviewed by the system

engineer but the reverse is not necessarily true. The system engineer can change a surveillance procedure without the review or approval of E&PB. The team member believes that enhanced coordination is needed and could be realized between these two groups with stronger organizational ties and improved procedures.

Station technical support is provided primarily by the onsite technical group using the system engineer concept. Under this concept, engineering responsibility for individual systems is assigned to specific system engineers. One of the responsibilities of system engineers in addition to being cognizant of the status of their systems is to interface directly with E&PB, maintenance, radiation protection, nuclear services, and operations.

During this inspection, the team frequently talked with both E&PB engineers and system engineers. The team found them knowledgeable and with good familiarity with their areas of responsibility.

Overall, both the formal procedurally required technical interfaces and the informal interfaces which have been established are effective in providing the technical support required for facility operation.

5.7 Technical Staff Training

Staff training requirements are defined in NC.VP-PO.ZZ-0012(Q), Training, Qualification, and Certification; and MC.NA-AP.ZZ-0014(Q), Training, Qualification and Certification. Essentially, the procedures require that general manager and department managers are responsible for assuring that training and qualification criteria are defined and maintained current for their personnel. Additionally, they shall assure that their personnel only perform work for which they are qualified in accordance with ANSI 3.1-1981.

The system engineer training required by the above procedure is implemented through additional sub-tier procedures. One of these procedures TQ-TP.ZZ-0909(Q), System Engineer Training, describes the requirements for six month system engineer training courses. Another procedure, TQ-TP.ZZ-0903(Z), Technical Staff and Technical Staff Manager Continuing Training, describes the continuing training for system engineers. In addition to the formal training, system engineers are required to complete a qualification card. The qualification card includes such items as preparation of a procedure for a special test, evaluate a proposed design change package, prepare a safety evaluation, and perform a root cause analysis. An oral qualification board is conducted at the end of the system engineer training. Based on a review of documentation and discussions with system engineers, the team considered the system engineer training program to be excellent.

The training provided to the staff in the engineering and plant betterment (E&PB) group is not as formalized as that provided the system engineers. The E&PB staff is considered, by procedure, to be offsite personnel and, consequently, not subject to the criteria of ANSI 3.1-1981. As a result, not all portions of the procedures describing training apply to this group.

Required training for E&PB engineers includes a four-hour course devoted to 10 CFR 50.59 safety evaluations, a three-hour course on configuration baseline documentation and a six-hour course on control of design/configuration changes. All personnel, before they are involved in design changes, configuration baseline documentation, and 50.59 reviews, are required to complete the above training.

Other courses are available to E&PB engineers. A review of training records shows that selected individuals have had additional training. Examples of this training course are in nuclear codes, standards, and regulations; applied protective relaying; root cause analysis; and BWR technology. E&PB managers indicate that training is provided on an as-needed, case-by-case basis. Each manager has budgeted a certain amount for training.

A QA audit performed during 1991 identified that E&PB did not have a personnel qualification and certification program, and issued an action request addressing this issue. E&PB took eleven months to respond to this item. In reviewing the response, the team noted that although some action relating to training had been taken, no qualification and certification program has been developed. The licensee has committed to developing a formalized training program for E&PB personnel.

One training initiative established for selected E&PB personnel are Lunch Time Seminars. These seminars are conducted approximately once each month and address topics such as performance of heat exchangers, introduction to reactor theory, and breaker coordination.

Overall, excellent formalized training is provided for system engineers. Some training is provided to E&PB engineers. However, it is not provided in accordance with any formal program. E&PB responses to QA findings relating to training appear to have been slow.

5.8 Electrical Distribution System Operation Procedures

During the inspection, the team frequently used electrical operating procedures during their review of specific activities. In general, electrical operating procedures were considered to be adequate in both content and completeness. Instances were noted where procedure weaknesses existed. These are discussed in the various detail sections of this report.

A partial walkdown was performed of several operating procedures to evaluate the ability of the procedure to be implemented. One of the procedures for which a walkdown was performed was HC.OP-AB.ZZ-0135(Q), Station Blackout/Loss of Offsite Power/Diesel Generator Malfunction. This procedure was developed to consolidate three individual procedures, the station blackout procedure, the loss of offsite power procedure, and the diesel

generator malfunction procedure. Based on the results of the walkdown and discussions with operators, it was determined that the procedure, which would be used in conjunction with the emergency operating procedures, will provide additional useful information to the operators. Operators indicated that to the extent possible, operating procedures are validated on the simulator.

Another procedure for which a walkdown was performed was OP-AB.ZZ-147(Q), dc System Grounds. Although the value of several steps in the procedure was questioned based on the walkdown and discussions with operating personnel, the procedure was found to be adequate. However, the alarm response procedure for the alarms indicating dc grounds did not reference the use of the dc system ground procedure. The licensee immediately issued a procedure change request to correct this condition.

Operators are encouraged to submit procedure change requests to improve the quality of the procedures. However, they indicated that the lengthy revision and approval process was discouraging. Because of this delay, they felt change requests were not submitted as frequently as they might be.

In general, the facility has adequate procedures. Some deficiencies were noted which indicates a continued need to emphasize procedure improvements to both procedure reviewers and procedure users.

Operation Procedures relevant to the low voltage ac systems and to the 125 V and 250 Vdc systems were also reviewed. In general, the team considered the procedures to be adequate in content and completeness.

5.9 Conclusions

An offsite engineering group has been established in close proximity to the site to provide technical support to Hope Creek EDS. The onsite technical support group includes a technically strong and knowledgeable system engineers group. Together, these groups provide adequate technical support to Hope Creek EDS for both routine and major activities. Engineering staffing was found to be adequate. Root cause analysis/evaluations are addressed in many procedures. Applicable procedures need to be revised to provide clear direction on management's expectations for the performance of root cause evaluations. High quality self assessment activities are being performed. Significant findings resulting from these activities indicate a continuing need for improvement in their performance. An adequate program for the preparation of plant modification packages has been provided. Continued improvements to this program were noted. Evaluations performed for installed temporary modifications were of a high quality. However, errors were noted in the temporary modification procedure

and in the log providing operators with information relating to the modifications. Effective formal and informal technical interfaces have been established. An excellent training program for onsite system engineers is being implemented. The training for offsite E&PB personnel needs to be formalized. Generally, adequate procedures were provided. However, certain procedural weaknesses were also noted, indicating continued attention to this area is required.

Overall, the team concluded that the Engineering and Technical Support at Hope Creek was good. In the team's judgement, the quality of personnel in this area is high, and the understanding of the design basis is good. The team believes that improvement could be realized in the organization interfaces in some areas (specifically between E&PB and system engineers) and that databases and management of electrical information could also be expanded and improved (See Section 3.7 of this report).

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. Unresolved items are identified in the Executive Summary of this report.

Observations are not regulatory requirements. They are presented to the licensee for their consideration. Observations are discussed in various sections of this report.

7.0 EXIT MEETING

The licensee management was informed of the scope and purpose of the inspection at the entrance meeting on January 27, 1992. The findings of this inspection were discussed with the licensee representatives during the course of the inspection and presented to licensee management during the exit meeting on February 14, 1992. A list of attendees is presented in Attachment 1.

ATTACHMENT 1

Exit Meeting Attendees

Public Service Electric & Gas Company (PSE&G)

R. Brown, Station Licensing Principal Engineer
M. Burnstein, Nuclear Electrical Engineer Manager
D. Cooley, Safety Review Engineer
G. Davis, Operation Engineer
S. Furnstein, Hope Creek Maintenance Manager
R. Griffith, Hope Creek Station QA Manager
B. Hall, Hope Creek Technical Manager
S. Karimian, Technical Consultant, Electrical
S. Ketcham, Hope Creek Mechanical Engineering Supervisor
E. Liden, Manager, Nuclear Safety Review
M. Massaro, Maintenance Engineer, Control
M. Quabir, Sr. Project Manager
B. Rao, System Engineer
M. Raps, Principal Engineer, Engineering Standard
J. Rucki, Hope Creek Technical Engineer
R. Swanson, General Manager, E&PB
K. Suomi, Sr. Nuclear Maintenance Supervisor
F. Thompson, Licensing and Regulatory Manager
D. Wray, Sr. Hope Creek Staff Engineer

Atlantic Electric Company

M. Sesok, Hope Creek Site Representative

U.S. Nuclear Regulatory Commission (USNRC)

C. Anderson, Chief, Electrical Section, DRS
W. Baunack, Sr. Reactor Engineer
[illegible] Cheung, Sr. Reactor Engineer
[illegible] Dembek, Project Manager, NRR
M. Hodges, Director, DRS
T. Johnson, Sr. Resident Inspector
K. Lathrop, Resident Inspector
E. Lazarowitz, Reactor Engineer
C. Woodard, Reactor Engineer

U.S. NRC Consultant

W. Jouberg, Mechanical Engineer, AECL
H. Leung, Electrical Engineer, AECL
J. Weinberger, Electrical Engineer, EPM

ATTACHMENT 2

ABBREVIATIONS

A or Amp	Amperes.
AC or ac	Alternating Current.
AH	Ampere-hour
ANSI	American National Standards Institute.
ASME	American Society of Mechanical Engineers.
BHP or Bhp	Brake Horsepower.
BIL	Basic Insulation Level.
CRF	Containment Recirculation Fan.
CB	Circuit Breaker.
CFR	Code of Federal Regulations.
CCR	Central Control Room.
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.
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.
kV	Kilovolts.
kVA	Kilovolt-Amperes.
KVAR	Kilovolt-Ampere-Reactive
kW	Kilowatts.
LC	Load Center.
LOCA	Loss of Coolant Accident.
LOOP	Loss of Offsite Power.
LV	Low Voltage.
MCC	Motor Control Center.
MOV	Motor Operated Valve.
MS or ms	Milliseconds.
MVA	Megavolt-Amperes.
NEC	National Electrical Code.

NEMA	National Electrical Manufacturers Association.
pf	Power Factor
PR	Protective Relay(s).
PSI or psi	Pounds per Square Inch.
QA	Quality Assurance
RCP	Reactor Coolant Pump.
RG	Regulatory Guide.
SCR	Silicone Controlled Rectifier.
SF	Service Factor.
SI	Safety Injection.
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.

ATTACHMENT 3

Hope Creek Electrical Distribution System