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NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-269/93-02, 50-270/93-02 and 50-287/93-02

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-269, 50-270, and 50-287

License Nos.: DPR-38, DPR-47, and DPR-55

Facility Name: Oconee 1, 2 and 3

Inspection Conducted: January 25-29, February 8-12, and February 22 - March 5, 1993

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SUMMARY

Scope:

This special, announced inspection was conducted in the areas of design of electrical systems and related engineering activities. NRC Temporary Instruction 2515/107, "Electrical Distribution System Functional Inspection (EDSFI)," issued October 9, 1990, provided guidance for the inspection.

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Results:

In the areas inspected, one violation and three deviations were identified. The violation involved the failure of the Quality Standards Manual to properly reflect that several circuit breakers were QA Condition 1 (safety related) components. This allowed maintenance activities to be performed on these components per a work order that indicated that the components were not nuclear safety related (paragraph 2.9). The deviations identified were, physical identification of safety related cables not properly color coded, mutually redundant safety related cables routed in the same cable tray, and where several Keowee equipment coolers were not properly designed to withstand increased pressure when isolated (paragraph 2.9 and 3.2.2).

A summary of the team findings is provided in Appendix A and will be identified as Inspector Followup Item (IFI 50-269,270,287/93-02-03).

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EXECUTIVE SUMMARY

A Nuclear Regulatory Commission (NRC) team conducted an Electrical Distribution System Functional Inspection (EDSFI) at the Oconee Nuclear Power Station. This inspection was performed by Region II staff, AEOD and consultants from January 25 to March 5, 1993. The objective of this inspection was to assess the capability of the Oconee Electrical Distribution System (EDS), including Keowee, to perform its intended functions during all plant operating and accident conditions. Keowee was reviewed to identify the root cause of deficiencies previously identified by the licensee and the NRC.

The team reviewed the Oconee EDS design with respect to regulatory requirements, licensing commitments and pertinent industry standards. The review included the examination of: EDS equipment size and rating, EDS as-built configuration, EDS material condition, maintenance, testing and calibration program for EDS components, root cause analysis of EDS deviation reports, and the adequacy of the EDS design documentation. A significant dedicated effort was spent in the review of the Keowee Hydrostation.

Overall Conclusions of the EDSFI were as follows:

Since plant startup, the Keowee Hydrostation had not been considered as an integral part of Oconee. The performance standards usually applied to the emergency power supply of a nuclear station were not applied to the operation of Keowee. The licensee had taken some actions, and more actions were planned to correct this situation.

The design basis and features of Keowee and its role in supplying emergency power to Oconee were not well documented or completely understood by the licensee.

During the October 1992 event, operability of the Keowee governor was almost lost due to loss of auxiliary electrical power. As of the start date of this inspection, the licensee had not conclusively determined what would be the result of inoperability of a Keowee governor and had not formulated an overall management plan to upgrade the status of Keowee. The licensee has agreed to develop such a plan.

There was no single document or organized program to document and control instrumentation and controls setpoints at Keowee. In one example, the EDSFI found a speed control switch setpoint was 50 RPM versus 65 documented on some licensee drawings.

There had been some procedure rewrites and upgrades, but some were still in process. Several I&E maintenance and calibration procedures lacked necessary detail.

The Keowee hardware is aging and becoming obsolete. This can contribute to reliability problems and increased failure rates.

Some aspects of Keowee have never been fully tested. A test had never been performed on the Keowee units supplying emergency power through the overhead path to demonstrate that it is capable of performing its design function. The

licensee planned to test this capability of the electrical system in the Spring of 1993. Periodic component testing and integrated testing may have led to earlier identification of design problems.

The definition of what is "safety related" throughout the Oconee station was not clearly defined. This can lead to inconsistencies involving design control, design changes, maintenance and quality control of equipment. Examples are Reactor Building Emergency sump valves, cables to CT-4 fans, and 1TA/1TB Reactor Coolant Pump breakers on 6.9kV bus and the 4.16 kV breakers. The licensee uses the term QA Condition-1 as being the same as safety related.

The design of the Oconee emergency power system resulted in an interconnected electrical supply to all emergency safeguards equipment. All redundant safety load groups are physically separated but were not electrically independent.

The team expressed concerns that degradation of the voltage and/or frequency of electrical supply from a Keowee unit could adversely affect ES equipment. The output of the Keowee units did not have automatic protection in the event of a Keowee malfunction that causes voltage or frequency to diverge from nominal. The licensee concluded there was no single failure identified that could cause such a Keowee transient.

Oconee design basis assumed only a single failure in the electrical supply systems, yet the section 3.1.39 of the UFSAR indicates that the "intent" of NRC draft Safety Design Criterion 39 was met. Design Criterion 39 states that the design should be capable of performing its safety function while sustaining an active and a passive failure, i.e., two failures. The design was submitted to the NRC during licensing. The team concluded that in certain areas, it is questionable as to whether Oconee fully meets the intent of Criteria 39.

The Technical Specifications (TS) for Oconee are very early custom TS. Section 3.7: Auxiliary Electrical Systems was nonspecific in many areas and open to interpretation as to what equipment is required to be operable in various plant conditions. For example, TS 3.7.9 appears to allow indefinite operation in excess of the electrical TS by the licensee notifying Region II within 24 hours and performing a safety evaluation. The licensee has agreed to submit for NRC approval new proposed TS for electrical equipment.

<u>The (DSFI) team concluded that the root cause of previously identified Keowee deficiencies were as follows:</u>

There have been at least 12 Licensee Events Reports (LERs) submitted from Oconee to the NRC since 1989 regarding Keowee design deficiencies. Most design deficiencies identified by the licensee were original problems identified during programmatic reviews by the licensee. These reviews were performed as part of the Operating Experience Program and the Design Basis Documentation Program which began in 1988.

The original design basis and features of Keowee were not well documented and therefore not readily available for reference and not fully understood by the licensee.

Keowee was originally constructed as a hydro unit without full quality assurance programs which are applied to nuclear power plants. Therefore there were few programmatic controls in place to control and capture the design basis for future use.

The Oconee and Keowee electrical systems are complex and unique. This makes design deficiencies difficult to identify. Deficiencies began to surface only when licensee resources were directed toward a programmatic review of the EDS design.

The Keowee Hydro Unit had been organizationally independent of Oconee since plant startup. The appropriate emphasis was not placed on Keowee as the emergency power supply to Oconee. The Oconee staff was not familiar with the day to day operations and maintenance of the Keowee Hydro Units.

REPORT DETAILS

1.0 INTRODUCTION

The objective of this inspection was to assess the capability of the Oconee EDS, including Keowee, to perform its intended function. Keowee was reviewed to identify the root causes of deficiencies previously identified by the NRC and the licensee.

The team reviewed the Oconee EDS design (which included the Keowee Hydro Unit) with respect to regulatory requirements, licensing commitments and pertinent industry standards. The review included the examination of: EDS equipment size and rating, EDS as-built configuration, EDS material condition, maintenance, testing and calibration program for EDS components, root cause analysis of EDS deviation reports, and the adequacy of the EDS design documentation.

Within this report FINDINGS are identified and are defined as follows: FINDINGS are facts or conclusions related to how well the electrical distribution system met its intended function. FINDINGS may indicate a requirement or an accepted industry practice that was not fully implemented. FINDINGS may indicate discrepancies or omissions in documents where these problems could credibly result in the intended function being compromised. The licensee's working knowledge of the EDS design as well as control of EDS design documents may be the subject of a FINDING. FINDINGS typically make statements about the need for corrective actions, or they may indicate an area where the licensee excels.

2.0 ELECTRICAL DISTRIBUTION SYSTEM

Oconee Unit 1 and Unit 2 generators provide power to the station's 230 kV switchyard system via step-up transformers T1 and T2 respectively (refer to Figure 1). This switchyard is connected to the 230 kV grid by eight transmission lines. These transmission lines also provide offsite power to the switchyard to feed Oconee unit auxiliaries when normal power is unavailable.The Oconee Unit 3 generator provides power to the 525 kV switchyard system via step-up transformer T3. This switchyard is connected to the 525 kV grid by three outgoing transmission lines. The 525 kV and 230 kV switchyards are connected through an auto-transformer which permits power distribution between two voltage levels.

The 230 kV and the 525 kV switchyards are divided into two busses designated as the Red Bus and the Yellow Bus. The switchyards are normally operated with both busses energized through a breaker-and-one-half scheme to the grid. The Yellow Bus in the 230 kV switchyard is identified as being safety related. Upon loss of power from the Oconee Nuclear Station (ONS) units and the 230 kV switchyard, power is supplied from both Keowee Hydro Generators through two separate and independent routes. The routes are identified as the Keowee Overhead Line and the Keowee Underground Feeder.

The Oconee units normally provide power to their own auxiliary loads through auxiliary transformers 1T, 2T, and 3T respectively. When a unit's generator is unavailable, electrical power is automatically supplied from the switchyard through its respective startup transformer CT-1, CT-2, or CT-3. Though Oconee Unit 3 feeds power to the 525 kV switchyard, the source of power for CT-3 is through the 230 kV switchyard.

The power to the RCPs for each unit is supplied by each units 6.9 kV switchgear TA and TB. Electrical power to TA and TB is supplied by either the operating unit through its own auxiliary transformer or from the 6.9 kV portion of its respective startup transformer.

The unit auxiliary power system for each Oconee unit is designed as a dual-train cascading bus system. There are two 4.16 kV main feeder busses, Main Feeder Bus 1 (MFB1) and Main Feeder Bus 2 (MFB2), with each supplying power to three 4.16 kV load busses TC, TD, and TE. The power to MFB1 and MFB2 is supplied by either the unit's auxiliary transformer through the "N" breakers or the startup transformer through the "E" breakers. In addition, MFB1 and MFB2 for each Oconee unit can be energized from the two Standby Busses SB1 and SB2, through the "S" breakers. SB1 and SB2 are common to all three Oconee units and can be energized automatically from the Keowee underground path through transformer CT-4, or manually through CT-5. CT-5 can be supplied from the Lee steam station through a dedicated line or from the Central substation.

All safety and non-safety AC loads (except RCPs) are fed from either the TC, TD, or TE busses. During a loss of power event, load shed circuits are provided to remove all non-essential loads from the MFBs of any unit prior to automatically tying to the Standby Busses due to the limited power capacity of CT-4 or CT-5.

2.1 Conclusions

The team concluded that the offsite power system at Oconee was flexible, reliable, and that the EDS was generally in agreement with TS/FSAR/SER. Equipment rating and size were adequate, and the system had sufficient capacity. Protection and coordination for the EDS was reviewed, and the team did not identify any safety concerns in this area. Calculations were generally available to support the EDS design, however, some deficiencies were noted.

In the area of safety classification of equipment, the team concluded that the licensee's methods for determining the appropriate designation were not clearly defined. Accurate and detailed instructions were not available to assist in the safety classification determination. Inconsistencies existed between the licensee's interpretation of what is safety related and the regulatory requirements and the Quality Assurance Topical Report on what is safety related.

A conservative approach by the licensee in the determination of safety related boundaries minimized the safety significance of this concern.

2.2 Offsite Power System

There are three reactor units at Oconee Nuclear Station. Unit 1 and Unit 2 generators were connected to the 230 kV switchyard via their generator-transformers, and Unit 3 was connected to the 525 kV switchyard. ONS is a part of the Virginia-Carolina subregion of the Southeastern Electric Reliability Council. In the 230 kV switchyard, there are eight transmission lines which connect to Dacus, Central, and Jocassee substations; in the 525 kV switchyard, there were 3 transmission lines connected to the Jocassee, Newport, and Norcross substations. There was an auto-transformer connecting the 525 kV switchyard and the 230 kV switchyard.

An additional 100 kV line is available from Central substation or from Lee Steam Station. This supply is provided through the CT5 transformer and the 4160 VAC standby busses. When one or both of the Keowee units is out of service, TS allows the Lee Power Station to serve as an emergency power source to safety and shutdown loads.

The licensee considered the 230 kV power supply through the startup transformer as the first offsite supply, and the 230 kV system backfeeding the generator transformer and the unit auxiliary transformer as the second offsite power source. On a loss of offsite power (LOOP), Keowee hydro units could either power the unit safety busses through the 230 kV yellow bus and its respective startup transformer or the underground path through CT4. The licensee classified the 230 kV yellow bus and the startup transformers as safety components. The team concentrated its review on the 230 kV offsite power system.

2.3 Degraded Voltage Protection

The following systems were relied upon to assure that adequate voltage was available to the safety loads.

2.3.1 External Grid Trouble Protection

The External Grid Trouble Protection System (EGTPS) was designed to detect severe system undervoltage and underfrequency conditions. After detection of these conditions the relaying would initiate closing or opening of the proper Power Circuit Breakers (PCBs) to provide a path for emergency power from Keowee to the Oconee auxiliaries. This EGTPS consisted of two redundant undervoltage and underfrequency relaying sub-channels. These relays monitor the voltage and frequency on the red and yellow busses. Each coupling capacitor potential device had two secondaries, with one being used for channel 1 and the other for channel 2. Either channel with at least two out of three red and yellow bus undervoltage or underfrequency measurements would trigger the EGTPS main

tripping relay (94). Upon the initiation of that (94) relay, the logic would isolate the yellow safety bus from the offsite power supply, providing a path for Keowee to supply the startup transformers, and provide a start signal to each Keowee unit.

The EGTPS testing was reviewed by the team. The undervoltage relays were tested and calibrated per procedures IP/0/A/4980/27B/RE, Westinghouse CV-22 Relay and IP/0/A4980/27C, General Electric IAV54 Relay. The frequency relays were tested and calibrated per procedures IP/0/A/4980/81C, Westinghouse SDF-1 Relay Test and IP/0/A/4980/81D, General Electric CFF12A Relay Test. The tests and calibrations adequately accomplished their intent, and the team identified no deficiencies.

The logic test procedure PT/0/A/0610/02, External Grid Trouble Protection System Logic and Switchyard Isolation Logic Test was reviewed to determine what parts of the system were tested and what parts were not. Undervoltage and frequency auxiliary relays are energized through a test pushbutton. One phase for each bus, red and yellow, per channel was energized to assure that the resulting relays for the two-out-of-three trip logic were energized. Lights in the logic gave indication of contact operation for the logic relays and coil continuity for the trip relays. The test was performed for each phase in each channel of undervoltage and frequency. The isolation complete relays were verified by energizing them through test pushbuttons. The PCB-9 reclosing relays were verified to energize at the required time after the isolation complete relay was energized. The team did not identify any problems with these particular tests. However, the team noted that the 94 relays (Switchyard Isolate) had never been tested. It was also noted that Switchyard Isolate Complete had not been tested. The licensee had tentatively scheduled a Switchyard Isolate test to be conducted during the next RFO on Unit 2. (See Appendix A, Finding 1)

2.3.2 Degraded Grid Protection System

The team reviewed the design of the degraded grid protection system and noted the degraded voltage setpoints were not listed in the TS. There was no degraded voltage protection in the original design of the electrical distribution system. In 1990, this degraded voltage protection system was added as modification NSM-ON-52850. Three undervoltage relays were added to monitor the switchyard voltage on the line side of each of the three startup transformers. Each undervoltage relay was connected to one of the three existing single phase "spare potential transformers." Two out of three voting logic would be used to trigger the undervoltage protection scheme. The team noted the following concerns in the system design:

- The degraded voltage minimum switchyard voltage level (219 kV) was based on calculation OSC-2059. This calculation may not have taken the worst bounding conditions when determining the voltage on the 4160V and on lower voltage safety busses. (See section 2.6.2 for details and See Appendix A, Finding 2)

- In determining the degraded voltage setpoint on the 230 kV bus, calculation OSC-3951 algebraically combined the random positive and negative uncertainties of the undervoltage relay, and only the negative uncertainty of the Coupling Capacitor Voltage Transformer (CCVT). The team noted that positive uncertainty of the CCVT should also be considered in the calculation. When both positive and negative uncertainties of the relays and the CCVT were algebraically combined, then the required reset voltage of the undervoltage relay could be higher than the minimum operating voltage 227 kV of the 230 kV system. In response to the team's question, the licensee had included the positive and negative uncertainties of the CCVT in the calculation; however, the revised calculation had to use statistical square root sum of squares methods to combine random uncertainties of the CCVT and the undervoltage relay. The team found this approach acceptable.

- The team noted that all three single voltage measurements were monitoring the same "Z" phase of the 230 kV bus. The selection of the setpoint did not consider potential unbalanced system voltage. The licensee did not have any operating procedure or surveillance test to monitor the phase voltage unbalance, nor any design criteria to define the acceptable limit of system phase unbalance. The phase unbalance voltage uncertainty should also be included in the calculation of the degraded voltage protection setpoint determination. The team considered that it was desirable to have a surveillance test procedure and acceptance criteria for the potential phase unbalance limit.

- The team noted that all the undervoltage relays, the 2 out of 3 voting logic, and both channel 1 and channel 2 initiating logic signals were powered by the same control circuit. Failure of this control circuit could either impair the entire degraded voltage protection circuit or could spuriously initiate the degraded voltage protection. Neither mode of failure was desirable. The design was susceptible to single mode failure, and this circuit was not directly monitored.

- In the present design, if one voltage measurement, due to phase voltage unbalance or due to component failure, were lower than the setpoint, the undervoltage protection scheme would not be triggered. However, this condition would not be known to the operator. Only a small red LED would be lit on the front panel of the undervoltage relay inside the unmanned instrument room.

The licensee utilized three ABB type ITE 27N relays to provide undervoltage protection for incoming feeder circuits. The team reviewed calibration procedure IP/0/A/4980/27G, ITE 27N Relay, which the licensee performs on an annual basis. The calibration had been performed once since the modification had been installed, and two of the three relays (27/CT1 and 27/CT3) were found to be outside the upper allowable

tolerance limit. The licensee trends the calibration results. The licensee will revise the tolerance limits in the procedure as a results of revision to calculation OSC-3951 Oconee Degraded Grid.

The team also reviewed the testing procedure, PT/2/A/0610/01J, Emergency Power Switching Logic Functional Test, for Oconee Unit 2. The procedure adequately tests the Degraded Grid Protection System logic, setpoints, and verifies that both voltage channels of EGTPS logic were initiated when the logic was satisfied, and any channel of any unit that has an ES actuation. No problems were identified.

The team performed walkdown inspections of the cabinets associated with these systems. The three undervoltage relays (1TE-27N) utilized by the Degraded Grid Protection System were housed in the same cabinet, 2ATB in the Unit 2 cable spreading room. The team observed that there were additional raceway covers stored in the bottom of the cabinet. The EGTPS cabinets were located in the relay house. Both cabinets containing their respective channel components were found in good condition. The overall assessment of the walkdowns found that good material conditions existed in the cabinets.

2.4 Onsite Power System - Safety Load Groups

The onsite power system for each reactor unit consisted of the main generator, the unit auxiliary transformer (1T, 2T, 3T), the startup transformer (CT1, CT2, CT3), the Keowee Hydrostation, and the auxiliary power system. Under normal operating conditions, the main generator supplied power through isolated phase bus to the unit step-up transformer and the unit auxiliary transformer with station auxiliary power being supplied from the main generator through the unit auxiliary transformer 1T. During startup, shutdown, and after shutdown station auxiliary power was supplied from the 230 kV system through the startup transformers.

The 4.16 kV output of the unit auxiliary transformer or the start-up transformer fed into two main feeder busses (MFB1 and MFB2). Each reactor unit had three redundant ES 4160 V switchgear bus sections (1TC, 1TD, and 1TE). These three safety busses obtained power from either MFB1 or MFB2. All redundant safety loads were divided among these three redundant load groups, however, these three redundant busses were interconnected and fed from the same source. The load groups were physically separated, but not electrically independent. To clear a bus or a supply breaker fault, requires the prompt operation of breakers in all three safeguard bus sections.

2.5 Bus Transfer

Following a unit trip, a fast rapid transfer scheme was used to transfer the power supply to the MFBs from the unit auxiliary transformer to the startup transformer.

The team noted that there was no analysis nor test to verify that the rapid transfer timing was correct, i.e. total transfer would be completed within about 10 cycles, and the dead time (timing between opening of the N breaker and closing of the E breaker) was about 6 cycles. (See Appendix A, Finding 2) The team noted there was no design limits nor verifications of the residual voltage on the bus, and the phase angles between the outgoing and incoming voltages prior to the transfer. There was no calculational support to demonstrate that the transient torque and transient current induced onto the safety motors were within the design limits of the motors.

There is a built in time delay of one second for the fast transfer. The licensee could not justify the delay time of one second, nor was there an analysis or test to support the selection of the delay. As a result, the licensee could not verify that the residual voltage on the safety busses would fall within the acceptable voltage range. Below this acceptable range, the motor speed would be too low to re-accelerate and the motor air gap flux might completely collapse. Following the one second delay transfer, the whole system would experience excessive inrush current. Overcurrent protection might trip the startup supply. If the residual voltage on the bus remained above the acceptable range, and if the phase angle between the residual bus voltage and the incoming supply were large, then the resultant voltage following the transfer could be too high. Thus, transient current and torque might exceed the design limit of the safety motors.

The team noted when the 525 kV - 230 kV auto-transformer was out of service, there was no operating procedure to prevent the fast rapid transfer on the startup transformer CT3 of Unit 3. Since the auto-transformer was out of service, there was no assurance that the phase angle between the 525 kV and the 230 kV systems would be maintained within the design limit. When the auto-transformer was out of service, the creditable tie between these two 525 kV and 230 kV power systems was at Jocassee. However, this tie may not be sufficient to verify that the phase angle between the incoming and outgoing source was acceptable.

In response to the team's concerns, the licensee agreed to carry out the detailed analyses to demonstrate the bus transfer scheme was acceptable.

2.6 230 kV System

2.6.1 Equipment Rating And Sizing

The team noted all the Power Circuit Breakers (PCBs) in the 230 kV had been recently replaced by Cogenel-Alsthom SF6 breakers. The team reviewed the rating of the PCB of 67.5 kA and compared this rating with the maximum 230 kV system requirements of 57 kA. The selection of this PCB was adequate.

The 230 kV switchyard employed a "one and a half" breaker scheme, and was sub-divided into red and yellow busses. The yellow bus and all the PCBs connecting to this bus were classified as safety components. The team found the equipment rating and capabilities of the safety components were the same as the other non-safety components of the 230 kV switchyard.

The nominal rating of the startup transformer and the unit auxiliary transformer was 60 MVA each, and rated higher for higher temperature rise. The team reviewed the loading requirements under various conditions, and found these transformers were adequately sized. The maximum normal loading was about 49 MVA per reactor unit. The team did not identify any sizing problem.

The nominal rating of the two standby power supply transformers (CT-4 and CT-5) was 20 MVA each, and their maximum ratings at higher temperature rise were even higher. The team reviewed the loading requirements under various conditions, and found these transformers were adequately sized under maximum steady-state condition of 20 MVA. The team did not identify any sizing problem. However, during starting of a unit LOCA loads, or starting of two unit shutdown loads, the transient voltage dip could exceed 20%. The licensee agreed to prepare a transient voltage study on the 4 kV safety load groups when they are supplied from the Lee gas turbine or from Central substation. (See Appendix A, Finding 2)

2.6.2 Short Circuit And Voltage Study Calculation

There were three short circuit and voltage studies, i.e. OSC-2059 for Unit 1, OSC-2060 for Unit 2, and OSC-2061 for Unit 3. The team reviewed OSC-2059, revision 1. The other two studies were under revision and were not available for the team to review. The team believed the results of these three studies should be similar, but might not be identical. The team noted the following deficiencies in the study:

- The momentary current on the 4.16 kV supply breakers under the worst scenario would be 83 kA which exceeded the circuit breaker rating of 80 kA. However, the team noted that some of the breakers had been successfully tested by the manufacturer up to 83 kA.

- There was only one input file for both the short circuit and voltage dip calculation. This file contained data between the minimum and maximum values expected, consequently the result was neither bounding for the short circuit study nor for the voltage dip study.

- The computer program might not adequately formulate the transformer tap position, nor the pre-fault voltage on the bus.

- When determining the total loads on transformers the study used, 75°C cable temperature, and constant motor efficiency and power factor at full load. Thus the study would indicate a less than full load condition.

- Only one 230 kV system impedance was used in both studies.

The team concluded that the result might not be bounding for either study, but they were acceptable due to the fact that the end results would only be off 2-5%. The team did not identify any operational problems. In response to the team's questions, the licensee agreed to revise the study accordingly in the next revision.

2.6.3 Protection and Coordination

There were four different relaying systems in the 230 kV switchyard: namely, Bus Protective Relaying System, External Grid Trouble Protection Relaying System, Breaker Failure Protective Relaying System, and Line Protective Relaying System. The team did not review the last system, since it was not a safety system.

The team noted that each 230 kV breaker was provided with two completely redundant schemes of protective relaying and trip coils. One scheme consisted of electro-mechanical relays, and the other scheme consisted of solid state relays. The switchyard was designed in a breaker and half scheme, and the protection scheme was designed in accordance with general industry practice. The team did not identify any safety concerns.

There were two busses in the 230 kV switchyard, the red one was classified as non-safety and the yellow bus was classified as QA Condition 1. The team did not find any difference in the control logic nor in hardware components in these two busses and their associated PCBs.

2.6.4 Lightning

The team noted there were lightning arresters at the end of each 230 kV transmission line and at the terminals of the transformers. The team reviewed the surge protection studies to ascertain that the surge arresters would properly safeguard the medium voltage and the high voltage systems. The team found the results of these studies and the application of the lightning arresters were adequate.

2.7 4.16 kV System

2.7.1 Protection and Coordination

The team reviewed the protective schemes and the protective settings for the 4.16 kV safety bus protection and motor protection, and found they were adequate. The team reviewed the High Pressure Injection Pump (HPIP) motor overcurrent protection (because it had the longest starting

time) while the pump was powered by either the normal 230 kV source or from the standby transformers. The team found the starting time was longer than the rotor safe heating time originally supplied by the motor manufacturer. However, the manufacturer, Westinghouse, subsequently provided a longer rotor safe heating time-curve for this HPIP. The team considered the starting time of this motor when being supplied from Central 100 kV system and determined it to be marginal, but acceptable. However, should the voltage dip lower than presently known when being supplied from Central substation or from Lee CTG, then the motor stall and overcurrent protection may then need to be reviewed accordingly.

The team reviewed the protection and coordination between the feeder breakers to the safety busses and the supply breakers from the unit auxiliary transformer, startup transformer, standby transformer CT-4, and standby transformer CT-5 respectively, and found they were adequate.

2.7.2 Motor and Cable Sizing

The team reviewed the safety motor speed torque curves and compared them with the pump speed torque curve and found the maximum motor torque was generally 200% or more higher than the required pump torque. The team did not identify any motor starting problem even when the 4.16 kV system voltage momentarily dipped to 80% of its nominal voltage.

The team noted that throughout the 4.16 kV system armor cables were used, and some of the power cable shields were grounded in more than one location. The licensee generally derated the cable ampacity by 30%. The team reviewed a few samples of cable ampacity, voltage drop at starting and at steady-state running and found the sizing of cables to be adequate.

The team was concerned about cable size #2 that was used for most of the safety motors. If a ground fault occurred near the feeding end of the #2 cable, the system short circuit current could exceed 45 kA. The temperature rise in the #2 size cable would well exceed 250C limit. The team requested the licensee to verify that such a fault at the #2 size cable would not cause a generated fire or source of propagation to its adjacent cables, which might belong to another safety load group. At the end of the inspection, the licensee provided a copy of the fault test report, which was done for the McGuire Nuclear Station. The team reviewed this report and determined that the cables size was adequate.

2.7.3 Control Circuits and Control Cables

In reviewing the control logic circuits, the team noted a number of relays, indicators, and relays contacts were grouped into one circuit, and most of the logic circuit also included the closing coil and Channel 1 trip coil. The total control cable length in the circuit could be very long, and a pair of 20 or 30 Amp (A) fuses or breakers were usually used to protect the control circuit. For those circuits routed to the 230 kV switchyard, the control cable length could be as long as 3020 feet one way. If a cable fault occurred near the end of the cable, the

cable resistance would be so high that the short circuit current would not be high enough to blow the fuse or trip the circuit breaker. Such an undetected fault would not be known until the nearby relay was required to function. By that time, the relay might not function, due to lack of voltage across the coil.

No study had been conducted to review control cable length and the size of the fuses being used to protect such circuits. (See Appendix A, Finding 2)

2.8 Automatic Switching Between Alternate Power Sources

2.8.1 Emergency Power Switching Logic

The Emergency Power Switching Logic (EPSL) system provides for automatic switching between the startup and standby power sources. EPSL directly controls the E, S, SK, and SL breakers (refer to Figure 1). EPSL also initiates load shedding of non-essential loads according to design requirements. It is a safety-related system comprising 14 induction disk voltage relays, 88 electromechanical auxiliary relays and 6 static timers on each reactor unit. The relays are mounted in dedicated cabinets, and are arranged in two channels. Three key relays in the system are the load shed, standby breaker closure and retransfer to startup relays.

The Main Feeder Bus Monitoring Panels (MFBMP), provide inputs to EPSL to initiate switching and load shedding in response to loss-of-power (but not ES actuation scenarios). MFBMP also provides an output to automatically start the Keowee Units. Each of the two main feeder busses had an associated monitoring panel; therefore, the MFBMPs are essentially redundant.

The scope of the inspection was to review the design, testing and operational performance history of the EPSL and MFBMP systems. Based on inspection activities, the team arrived at the following conclusions:

The EPSL and MFBMP will provide proper response (ie. outputs) for all possible combinations of initial conditions and initiating events.

The EPSL and MFBMP are designed to meet the single failure criterion.

A review of the corrective maintenance history and problem reports covering the two years prior to the inspection led to the conclusion that the relays in the EPSL and MFBMP were not experiencing any failures during testing or operations.

The licensee provided proper documentation indicating that the EPSL panels and devices were qualified for safety-related applications.

The TS Surveillance Test procedures and other tests procedures which cover the EPSL and MFBMP were adequate to help ensure that these systems are maintained completely operable.

Through walkdowns performed on Unit 1, the team verified the proper configuration of switches and indicating lamps in the EPSL and MFBMP systems.

The TSs, UFSAR and DED are consistent with the "as-built" configuration.

Normal engineering considerations, such as voltage rating and contact make/break ratings, had been applied to these systems by the licensee.

A review of industry operating experience data, such as NRC Information Notices and Bulletins, did reveal a problem with one type relay used in the EPSL. The Agastat 7000 series relays are not recommended for use in safety-related systems due to the lack of quality control applied in the manufacture of these relays. The manufacturer recommends the E7000 series for safety-related applications. The team confirmed that the licensee was in the process of replacing all Agastat 7000 series relays used in safety-related applications with more suitable relays. In the EPSL system, the two Agastat 7000 relays being utilized were actually performing a non-critical function.

The team's overall conclusion with respect to the EPSL was that the design was adequate.

2.8.2 Main Feeder Bus Monitoring Panel

The team reviewed the Main Feeder Bus Monitoring Panel (MFBMP) design and testing. No design concerns were identified in this review. However, the team noted that the MFBMP was designated as non-safety related. The licensee stated in their design basis documentation for the 4 kV electrical system that the MFBMP is designated non-safety related because (1) during a LOOP only DBE there is no established time period necessary for automatic power restoration, therefore manual operator actions would be appropriate, and (2) during a LOOP scenario the MFBMP logic inputs to the LOOP units but during a LOCA the EPSL logic would automatically restore power to MFB1 and MFB2.

The team was concerned with this designation because under certain hypothesized conditions (i.e. failure of a start-up transformer with a reactor trip) the MFBMP logic is required to automatically restore power to the main feeder busses. The designation of logic as non-safety related which restores power by starting and switching emergency sources automatically to safety related loads is unique to the Oconee emergency power system. This item is identified for further NRC review. This will be identified as IFI 93-02-24.

In discussions with the licensee regarding the designation of the MFBMP as non-safety related, the licensee stated that the MFBMP is essentially safety quality grade. The cables are separated, the relays and potential transformers are the same type as used in safety related applications, and the logic consists of redundant channels.

2.9 Safety Classification of Electrical Equipment

2.9.1 Oconee

The team reviewed the manner in which electrical components were designated as safety related for Oconee and whether those designation methods had been properly applied. The licensee utilized the Quality Standards Manual (QSM) to define the safety related components as required through the licensee's Quality Assurance Topical Report and associated implementation procedures. The manual consisted of a combination of text and a table to identify safety related components to which quality assurance standards would apply. If the QSM did not classify the equipment as safety related then the requirements of 10 CFR 50, Appendix B did not apply.

The QSM only designated large pieces of equipment. The one line electrical prints lacked a safety related boundary. The team requested the lead electrical engineer to draw the boundary. Through interviews the team ascertained verbal classification of the safety/non-safety boundary. Verbal classification by the cognizant engineer was not uncommon and when in doubt a conservative decision was the guiding principle. After a number of attempts, discussions, and licensing department involvement the boundary was ascertained.

The licensee guideline for establishing the safety/non-safety boundary was whether the electrical circuit supplied a mechanical safety related load. This philosophy was consistent with the QSM's safety related equipment table. However, this philosophy was inconsistent with the topical report as to what was safety related (i.e., quality assurance requirements applied). The licensee's philosophy excluded circuit breakers which supplied non-safety related loads but had safety related functions. This is significant because almost all the electrical busses providing safety related loads have non-safety related loads powered from the same bus. A number of circuit breakers at all voltage levels fall into this category including:

- There were 4.16 kV breakers classified as non-safety related load feeder breakers installed in seismically mounted switchgear that separate seismic and non-seismic circuits. In an earthquake the non-seismic load could ground fault requiring the feeder breaker to open protecting the safety related portion of the switchgear.

- Numerous circuit breakers on 6.9 kV (1A and 1B) and 4.16 kV (1C, 1D, 1E) busses must load shed in conjunction with an engineered safeguards signal to keep from overloading the onsite emergency power unit.

The team reviewed the past maintenance work requests for circuit breakers in these categories at the 4.16 and 6.9 kV levels. It was determined that the breakers were not designated as safety related due to error in the licensee's philosophy as implemented through the QSM.

10 CFR 50, Appendix B, Criterion II, states in part "The applicant shall identify the structures, systems and components to be covered by the quality assurance program." The introduction to Appendix B and the licensee's topical report through reference to ANSI 45.2.11 define those structures, systems and components to which quality assurance requirements apply as those necessary to mitigate the consequences of an accident. In the licensee's topical report the applicability of quality assurance requirements for structures, systems and components was identical to safety related classification. Therefore, failure to properly classify these breakers as safety related and not applying the commensurate quality assurance requirements is identified as (VIO 269, 270, 287/93-02-01)

Also, a discrepancy between the Quality Standards Manual and OSS-0254.00-00-3000, "Design Basis Specification for the 230 kV Switchyard and Emergency Power Overhead Power Path Structures," associated with the safety classification of the 230 kV power circuit breakers was identified. In one document it identified the breakers as QA Condition-1 and in the as non QA Condition-1. The licensee uses the term QA Condition-1 when referring to nuclear safety related.

Cable Commitments

The licensee also identified additional requirements for the safety classification of electrical cables. Specifically, UFSAR section 8.3.1.3, "Physical Identification of Safety-Related Equipment," stated a color coding scheme would apply to safety related cables and UFSAR section 8.3.1.4.6.2, "Cable Separation," stated mutually redundant safety related cables would be run in separate trays.

In a sampling of cables the team observed failures of the licensee to properly implement these UFSAR commitments. These failures were:

- Color coding the normal and emergency power cables for transformer CT-4 as non-safety related and running part of one of the cables in a non-safety cable tray.

- Running power cables 2LP-19 and 2LP-20 in the same tray even though they provide mutually redundant emergency core cooling recirculation sump isolation valves for Unit 2. The same condition did not exist for the other two units.

Failure to properly color code the two safety related cables is identified as an example of (DEV 50-270/93-02-02). Failure to run the two sump isolation valve power cables in separate trays is identified as another example of (DEV 50-270 /93-02-02).

The safety significance of running the two cables in the same tray was mitigated by a unique design feature at Oconee of installing cables in armored jackets.

Also, the cables feeding some switchyard components from the 4160 volt safety related switchgear 1TE and 2TE were identified as non-safety related and are loadshed under accident conditions. The switchyard feeder breakers supply power to the switchyard battery chargers. Technical Specifications require that the battery chargers be operable for the switchyard batteries to be considered operable. The licensee did not consider operable chargers a requirement following a loss of offsite power event. The basis for this position is that manual action in the switchyard could be taken to operate switchyard breakers if the switchyard batteries were unavailable due to depletion following the initial switchyard isolation signal. The licensee stated that the battery chargers themselves were considered safety related, however, the cables to the battery chargers were not safety related. The team questioned the licensee's position on load shedding the switchyard battery chargers and designating the feeder cables as non-safety related. This item is identified for further NRC review. This will be identified as IFI 93-02-04.

Other Documents Reflecting Safety Classification

To ease in the preparation of work requests for maintenance the licensee had begun a computerized data base which included a field for safety classification. The team reviewed select entries and noted the safety classification was not present in most instances. However, 120 VAC panelboard 1KVIA was designated non-safety related which contradicted the Quality Standards Manual safety related designation. Through interviews the team ascertained that minimal engineering review control existed in completing the data entry form used as input to the computerized data base.

2.9.2 Keowee

The licensee stated the Oconee safety, seismic/non-safety, non-seismic boundary philosophy applied at Keowee. However, the licensee indicated that due to the conservative nature of work request classification at Keowee, interface circuit breakers were probably designated safety related. The team confirmed this through a sampling of past work requests with no improper designations identified. A review of the Quality Standards Manual did identify an improper classification of the Keowee air circuit breaker air system as exclusively non-safety related. However, the system from the air circuit breaker, accumulator and associated check valve were safety related.

Summary

1. The licensee's QSM was not always accurate or detailed enough in specifying the safety related boundary. This caused or contributed to: additional burden on engineering personnel to properly classify components for maintenance and modification, inconsistencies in design documents as to the safety classification of equipment, and the generation of a component level "Q" list for work planners without the commensurate controls and consistency indicated in the QSM.

   The safety significance of these inadequacies have been minimized due to the conservative decision making process utilized by the licensee in safety related designations when a clear distinction was not possible.

2. The licensee's interpretation of safety related as it applies to electrical components which are part of the electrical load circuit for a non-safety related device performing a safety related function was inconsistent with the requirements of the Quality Assurance Topical Report and associated regulatory requirements. Therefore, certain aspects of the quality assurance program such as quality control inspections, level of quality control involvement in receipt inspection activities and level of documentation were not applied to select 6.9 kV and 4.16 kV circuit breakers.

   The safety consequences of this inadequacy were minimized since:

   - The same maintenance workers perform the tasks irrespective of the safety classification and past team observations did not note a difference in worker attitude due to safety classification.

   - The same maintenance procedure was used irrespective of the safety classification for all the circuit breakers.

- The same periodic testing program had been applied to the 4.16 kV breakers irrespective of safety classification.

- The same purchase order technical operational requirements were applied to replacement parts.

- Though the licensee considered these same type breakers at the 600 VAC level and voltage levels below as non-safety related from a licensing perspective, all work on these breakers was designated safety related.

However, the potential to install a substandard component, accomplish a maintenance activity improperly or not perform a necessary Part 21 evaluation was heightened by these inadequacies.

2.10 Fuse Control and Setpoint Control Programs

The licensee had a good fuse control program. Detailed selection criteria was established. Configuration control was being verified through walkdowns of all safety-related cabinets. These walkdowns were completed for Oconee Unit 1, and a minimal number of discrepancies were found. The team carefully evaluated the discrepancies, and agreed that they did not indicate a fuse control problem. Inspections for Units 2 and 3 will be performed in the near future. Some inspections had also been done at the Keowee plant. Class H fuses were failing at an increasing rate, therefore, the licensee was replacing all Class H fuses with more modern improved fuses.

Fuse control was examined at Keowee by inspection of compartments in the 125 VDC Distribution Center 1DA. The fuse sizes were documented on KM-306-1B. The Keowee fuse sizes had been inspected to the drawings in 1992 and only minor discrepancies requiring no physical changes were found. Replacement fuses were governed by Maintenance Directive 4.4.12.

Recently, all relay setpoints for the Oconee plant, Keowee plant, and switchyard had been reviewed. The basis for each setpoint was well documented. The team randomly selected some relays and compared the engineering documents to the calibration procedure and the actual relay setpoint. No discrepancies were identified in this effort.

The licensee had an acceptable program for the control of instrument setpoints, such as pressure switch, level switch etc. For the Oconee plant the instrument setpoint data was in the "Alarm and Setpoint List". Setpoints associated with package type equipment, such as the diesel generator, were held in documents for that equipment. With regard to the Keowee plant, many setpoints were delineated in the design basis document. To better control instrument setpoints at the Keowee plant, the licensee was planning to incorporate all the setpoints at Keowee in

the "Alarm and SetPoint List". The team reviewed the appropriate PIRs for the past 18 months to determine whether or not there had been any problems associated with the setpoints, ie. incorrect setpoints. This review did not identify any problems with the setpoint control program.

3.0 KEOWEE HYDRO UNITS

3.1 Conclusions

The team concluded that deficiencies exist involving the supporting analyses and testing of the Keowee hydro units and the associated emergency power paths. Although the licensee has recognized many of the problems and some corrective actions have been initiated, the team noted the lack of an overall management plan to coordinate the efforts. In some areas, the corrective actions have not been as thorough or timely as expected. The team concluded that the effectiveness of the overall Keowee upgrade program could be improved by prioritizing efforts commensurate with safety significance and more aggressive resolution of identified problems.

In several areas, the calculations/analyses were not sufficiently comprehensive and specific values were not referenced to bound the design criteria. In these same areas, the tests did not bound the design, and modifications had been implemented without sufficiently establishing the design bases. The team concluded that additional calculations/analysis and design reviews are necessary to assure that the Keowee units will provide emergency power to the Oconee units under all design basis conditions. Potential effects on Oconee safety loads due to problems (overvoltage, over or under frequency) on a Keowee unit should be more fully examined.

The team identified that several components involved in the operation of the Keowee units during emergency start conditions were not adequately tested. Some deficiencies were also noted regarding setpoint control, component designation (safety related), and other important Keowee documentation.

The team concluded that the licensee should ensure that the response of the Keowee governor systems to postulated conditions or potential failures be fully understood. While the team noted that the Keowee staff was highly professional, the ongoing efforts to increase the knowledge of the Oconee and Keowee operators to the operations of Keowee should continue. Reliance on the "on call" Keowee technician to deal with abnormal conditions or equipment malfunctions should continue to decrease.

Review of recent LERs and other operational experience information indicated that longterm efforts to improve/upgrade some of the aging components at Keowee are necessary and should be continued.

3.2 Review of Design

3.2.1 Civil and Electrical Structural Evaluation

The design basis of Keowee was described in the licensee developed documents, Keowee Emergency Power Design Basis Document (DBD), OSS-0254.00-00-2005, Revision 1, dated December 3, 1992 and in Design Basis/Test Acceptance Criteria for Keowee Emergency Power System DBD, Dwg. No. KTC-0-0113-0001-001, Revision) dated January 28, 1991. These documents were used by the team to evaluate Keowee's design. The DBDs for the Keowee mechanical systems and the 125VDC systems are scheduled but not yet issued.

The design and licensing documents associated with seismic qualification of the safety related electrical systems and equipment were reviewed by the team. Documentation supporting equipment qualification was available for that equipment identified as seismic per the UFSAR (Table 3-6B). However, the UFSAR omitted four transformers (1X, 2X, 1E and 2E) for which specific qualification documentation was not available. 1X and 2X provide 600 VAC auxiliary power to operate their respective turbine generator loads. 1E and 2E provide excitation for their respective turbine generators. Prior to the end of the inspection the licensee provided qualification documentation for comparable transformers. The licensee also plans to include these transformers in their SQUG program. The team concluded that the structural qualification of the Keowee electrical components was appropriate.

3.2.2 Mechanical Systems

The team reviewed the design and licensing documents for the Keowee mechanical support systems. This included the turbine generator cooling, turbine guide bearing oil, high pressure oil and governor air systems. The mechanical systems were designed and erected to conventional industry standards for hydro-electric facilities.

The team inspected the majority of the supporting systems which were required for the Keowee hydro units to perform their function. As stated in the Keowee mechanical DBD, these systems were designed and constructed to meet the industry grade equipment standards in existence at that time when the plant was constructed. The balance of the piping systems were constructed to B31.1-1967. Several of the safety related support systems contained significant quantities of brass and/or copper piping. Examples were noted of non-safety piping where components were located over important safety related equipment. One example which was apparently not addressed by previous Keowee audits was the presence of fire protection and vacuum system piping installed above the Keowee governor cabinets.

All systems appeared to have been constructed to the requisite industry standards except for the turbine generator cooling system. The coolers (turbine guide bearing oil, generator thrust bearing and generator air)

associated with this system were not protected from overpressurization due to thermal expansion of the water in an isolation mode (both upstream and downstream valves closed). No relief valves were installed to protect the piping.

The UFSAR Report 3.2.2.2 established the design criteria for this piping as USAS B 31.1.0. USAS B 31.1.0 section 101.4.2, "Fluid Expansion Effects," requires overpressure protection. The licensee was informed of this discrepancy and initiated PIP 0-093-0197 to address the problem. The appropriate course of action was under determination at the conclusion of the inspection. Failure to provide overpressure is identified as an example of a deviation (DEV 50-269,270,287/93-02-03).

The Keowee mechanical systems were not designed to seismic qualifications. Prior to the inspection the licensee had initiated a design study, ONDS-0258, addressing the seismic issue. The licensees Self Initiated Technical Audit (SITA) audits had identified some problems related to seismic issues on battery room Heating, Ventilation and Air Conditioning (HVAC) and cable supports. These specific cases were reviewed under the licensee's condition adverse to quality system with no problems identified. The comprehensive corrective action to this matter will be through the SQUG program as part of the resolution to USI A-46. At the conclusion of the inspection the licensee was completing a determination of what components were to be included in the SQUG program.

During the reviews, the team noted that the design and licensing documents associated with the mechanical systems omitted the noted aspects of the design. Examples included:

- No specific descriptions of how the Keowee mechanical systems function in the UFSAR.
- Omission of the portion of the cooling water line and manual valve that is common to both turbine generators in UFSAR section 8.3.1.2.
- Seismic Design Criteria, OSDC-1093.01-00-0001, did not specifically address the mechanical systems or how the design criteria apply to the mechanical systems.

Prior to this inspection the licensee identified numerous deficiencies in the documentation and had initiated corrective actions including preparation of a mechanical design basis document and flow diagrams for the different systems.

The team utilized the recently developed Keowee Flow Drawings (KFD) during walkdowns of the systems. Several discrepancies between the KFDs and the actual plant conditions were noted. These included differences in piping arrangements and valve numbering. In some cases, valves contained two conflicting labels because a previous tag had not been removed following installation of a revised label. During the

inspection, efforts were in progress to address the errors. The team also noted many examples of Keowee electrical drawings which contained safety related equipment which were not marked as "safety related" or as "QA Condition 1". Since the drawings of the electrical systems are not very user friendly, many of the drawings contained important information which had been penciled in. System drawings for the air system did not exist and some errors were identified on the recently developed KFDs. Detailed walkdowns of the loading configuration of one AC and one DC load center indicated that the drawings accurately reflected the existing equipment arrangement. Additional review of the documentation identified minor deficiencies. The specific drawing inaccuracies were documented on PIP 0-093-0197 so they could be corrected at the next drawing revision. (See Appendix A, Finding 3) Deficiencies involving testing of the mechanical systems are discussed in paragraph 3.4.2.4 of this report.

3.2.3 Separation and Sharing of Systems

The team noted several areas in which the two Keowee units were not totally independent. Various licensing documents discuss the common penstock. The team reviewed the controls associated with the headgate and concluded that appropriate measures were in place to prevent inadvertent blocking of the penstock by the headgate. A small portion of the cooling water system (supply line from the penstock) which contains one manual isolation valve was common to both units. Rigorous separation between the control and electrical cables of the units was not employed. In many cases, cables for the two units occupy the same trays. However, armored cables are used with voltage and current carrying ratings in excess of that required. Although many of the primary components for the units are separated physically, for 10 CFR 50 Appendix R criteria, Keowee is considered as one fire area. The fire protection systems are common to both units. The potential consequences of a failure of fire protection piping will be addressed by an internal flooding study scheduled for completion by March 31, 1993.

The batteries for the Keowee units were separated by a partial length block wall which contained several unsealed penetrations. Efforts were made to provide some separation between the emergency power paths. ACBs 3 and 4 (underground feeder path breakers from each Keowee unit) were separated from the other switchgear but were located in the same structure with only several feet of open space separating their cabinets. The air supply system for all four ACBs was connected together and check valves on small reservoirs at the breakers were relied upon to function if a break occurred in any section of the piping. Several other supporting air systems which were not required for the Keowee units to accomplish their intended safety function (if other systems perform as required) were shared by both units. The team concluded that under normal conditions and alignments, the failure of one of these air systems would not adversely affect both units. With one exception, the team did not identify any specific scenarios in which the potential

vulnerabilities noted above would present a likely failure of the Keowee units. The exception was that plugging of the common generator cooling water supply line had occurred once in the past.

3.2.4 Electrical Calculations and Analyses

Many of the electrical calculations associated with the Keowee Hydro System were reviewed to determine if the existing analyses, studies, and tests were sufficiently comprehensive. The following major issues were examined:

- Adequacy of the analyses and tests necessary to demonstrate the capability of Keowee to start, accept, and accelerate its worst case design load, within required times, without degradation of the connected safety loads.

- Assessment of the licensee's evaluations involving the potential vulnerabilities associated with a single Keowee unit powering all redundant safety groups of an Oconee unit following a DBE. Specifically, the team reviewed potential vulnerabilities associated with operation of both units to the grid and their hydro units' control systems.

- Adequacy of Keowee generator's electrical protection to prevent degradation of the Oconee auxiliaries during anticipated operational occurrences. This item was reviewed because the licensee has issued several LERs related to this subject as the result of unanticipated operational occurrences.

The licensee had generated a significant number of associated calculations as part of a design basis effort over the last three years. Because a single Keowee unit powers all redundant safety groups of an Oconee unit following a DBE, the EDSFI focused heavily on review of the licensee's assessment of the Keowee vulnerabilities associated with this arrangement.

3.2.4.1 Single Failure Criteria

The team questioned the licensee's conformance to the single failure criteria as stated in the UFSAR. Section 8.3.1.2 of the UFSAR states, "The basic design criteria of the entire emergency power system of a nuclear unit, including the generating sources, distribution equipment, and controls is that a single failure of any component, passive or active, will not preclude the system from supplying emergency power when required". The team found that the licensee had not fully analyzed the controls consistent with this requirement. The team concluded that the licensee had not adequately analyzed potential single failures within the hydro unit governor control systems. The team identified several other potential single failure vulnerabilities which had not been sufficiently analyzed. This item is identified for further NRC review. This will be identified as IFI 93-02-04.

The team noted that the licensee had completed the appropriate failure analyses of the generating and distribution systems and these had resulted in hardware modifications, setpoint changes and administrative controls. Design Study OSC-5096, Keowee Single Failure Analysis was approved by the licensee on January 21, 1993. The study documents the results of a single failure while both Keowee units are supplying power to the grid. The study applied the single failure criteria as stated in the UFSAR. A LOCA/LOOP was assumed and single active or passive failures, or spurious actuations, were examined down to the component level. The appropriate Keowee controls were included. The study identified that following a trip from full load operation, an overspeed switch in each Keowee unit could make both unavailable. The licensee's evaluation of this resulted in Keowee's power output being administratively limited to 63 Megawatts (MW). Previous load rejection test results were used to determine from what load Keowee could sustain an overspeed without making either unit unavailable. The team concluded that the administrative limits were set at a conservative value. The team verified that the Keowee operators were aware of these administrative limits.

The team noted that the study closely examined the performance of the Loss of Excitation Relay. This relay locks out its respective Keowee unit upon detection of loss of excitation voltage. The potential concern was if both units were running to the grid, both of the relays may actuate as a result of grid instability or an electrical fault. The study substantiated that both relays would not actuate as a result of grid instability or an electrical fault. The team noted that a recommended relay setpoint revision was provided in OSC-4300, dated 3/91 because the existing setpoint could be effected by grid stability response. The team's observations in the field were that the relay settings had not been implemented. The revised setpoint had been evaluated as not effecting operability, and was being tracked in Station Problem Report (SPR)-3426, and was awaiting management work authorization. During the quarterly senior management review, problems are identified to be worked, and to date this had not been selected.

During the review of the Keowee volts/hertz limiter, a design feature, in the voltage regulator was examined. No documented specific failure analysis for this feature existed, but the licensee was able to demonstrate that a single active or passive failure would fail safe. The team concluded that it was possible that a failure of the signal mixer or other features may not have the same result, causing an undetected increase in generator field current and an undetected overvoltage on the Oconee auxiliaries. The licensee responded that it was their licensing position not to analyze the controls and referred to an internal memorandum to file, dated 1/15/93, which stating "that in general it has been the Oconee position not to consider "smart failures" within control systems and the system is assumed to control or design to fail to its designed state". This item is identified for further NRC review. This will be identified as IFI 93-02-04.

The team evaluated the licensee's single failure analysis of the Keowee governor control systems. The licensee provided a copy of an internal Memorandum to File, dated 1/15/93, that documented the results of the single failure review of the governor. The team concluded that this review was not complete, since conclusions were not well supported. An example, the failure of the linkages within the governor and the wicket gate shear pins was evaluated. The review concluded that these were passive failures. Failures of inherently rugged items need not be postulated because normal operation of the unit would reveal actual problems with these units should they occur. The team did not agree with licensee's conclusions since the shear pins are designed to fail (active) during abnormal conditions. During discussions, the team identified that the licensee had limited this review to the collective experience of the involved personnel (including a technical representative of the governor manufacturer). Searches of LERs, Nuclear Plant Reliability Data System (NPRDS), etc., had not been performed. The team noted that the licensee had submitted LER 83-01 in which a single failure in the Keowee hydro Woodward governor system was identified which could have rendered the associated Keowee unit inoperable.

The licensee indicated that the principle reason that failures of the governor system had not been examined more closely was that undervoltage conditions would cause a governor abnormality to be promptly identified. The undervoltage device (27S) was set at 65% and its operation would result in connection of another power supply automatically. The team agreed the undervoltage relay will eventually detect the problem, however, it was not evident that this would be in sufficient time. The governor failure mechanism is described in section 3.6.1. and indicates that its failure could take place over some period of time and not instantaneously. The detection time of the undervoltage condition is critical to establish the connection of the alternate supply to protect Oconee safety loads. The team concluded that additional review was needed in the area of potential failures of the governor control systems. (See Appendix A, Finding 4)

A review of operating experience indicated that the overall Keowee design had been vulnerable to a single failure. Several LERs had been submitted in the past two years addressing single failure vulnerabilities. These were identified and corrected by the licensee. Most were corrected through equipment modifications. The licensee did not consider all credible failure modes for the Keowee governor control system and voltage regulator. (See Appendix A, Finding 5)

The team also reviewed the degree of independence between the onsite emergency power sources and between their distribution systems. The team found the licensee did not consider a single failure concurrent with the initiating event LOCA/LOOP (loss of the 230 kV Switchyard) in the development of Tables 8-3, Single Failure Analysis for Keowee Hydro Station, and Table 8-4, Single Failure Analysis for the Emergency Electrical Power Systems, of the UFSAR. The licensee considers a

portion of the 230 kV switchyard to be part of the onsite, and not the offsite, power system even though it is described and analyzed as the offsite power system in the UFSAR Sectio ".2. The team considered that the 230 kV switchyard is part of the off : system until the control logic isolates the switchyard and a single failure should be considered with the initiating LOCO/LOOP.

The licensee's current position regarding their definition of the single failure criteria and how it is applied in reference to the 230 kV switchyard is identified for further NRC review. This will be identified as IFI 93-02-04.

3.2.4.2 Protective Feature Issues

The team had several concerns which involved the electrical protective features associated with the Keowee hydro units. It was concluded that in some areas the features may not be appropriate to the degree of safety commensurate with the fact that redundant safety groups for each Oconee unit are fed from one emergency power supply.

The control logic bypasses all of the Keowee normal automatic electrical and mechanical protective trips on an emergency start. The bypassed trips include generator and turbine bearing overtemperatures, volts/hertz, overspeed, governor oil pressure, generator field ground, and maximum excitation. The licensee was asked to provide analysis/or bases for bypassing these protective trips from the perspective of one Keowee unit powering all three redundant safety groups. The licensee indicated that the bypasses were consistent with NRC Regulatory Guide 1.9. However, the basis for bypassing Keowee trip functions during emergency start of the unit was not fully analyzed or documented. In the Oconee arrangement, all the redundant load groups are powered by a single emergency power supply, and this necessitates the detection and isolation of an adverse condition in sufficient time to connect the alternate emergency supply. The licensee initiated PIP 0-093-0081 to request a study on this subject. (See Appendix A, Finding 5)

The team noted that the Keowee design did not provide for protection and detection of abnormalities such as over or under frequency operation that may be experienced by a single failure of a component in the speed control circuits. The auxiliaries are not protected for overvoltage conditions as might be experienced by an abnormality in the voltage regulator or during a sustained overspeed condition.

3.2.4.3 Keowee Auxiliaries

The licensee had completed a single failure analysis of Keowee auxiliary transformers 1X, 2X, and CX in KC-0082. This analysis resulted in operability requirements which were recently incorporated into TS requirements.

The licensee had performed single failure analyses on the coordination of safety and non-safety 600 volt switchgear protective devices to identify potential losses of redundant functions. The analyses had resulted in hardware modifications and administrative controls.

3.2.4.4 Other Calculations

The team reviewed other engineering calculations and analyses during the inspection. Some findings were noted:

KC-0073, Auxiliary Power System Voltage Level, Rev 1, (3/9/92), a voltage analysis of the Keowee 600V auxiliaries was considered incomplete. Sections 20.2.3.3, 20.2.3.4, and 20.2.3.5 of the DBD refer to KC-0073 as a basis of the voltage adequacy for Keowee auxiliaries when supplied from any of the three potential sources (either the Keowee generators via 1X and 2X transformers, from Oconee Switchgear 1TC via CX , or the 230 kV Switchyard via the 1X and 2X transformers). KC-0073 analyzes the voltages recorded before and after a Keowee start when fed by 1X, 2X, and CX, and also establishes a single baseline reference point. This methodology utilized representative data and did not consider variations in the supplied voltage levels. The results obtained was the normally expected bus voltage. The calculation should have obtained the maximum and minimum expected voltages and evaluated these in view of equipment voltage limitations. The maximum expected voltage is also an input to the short circuit analyses, and higher voltage will result in increases currents. In response to the teams comments, the licensee reviewed the calculation and concluded that no operability concern existed. The licensee indicated that an additional analysis (KC-Unit-1-2-0095) would be performed. (See Appendix, Finding 2)

The Keowee 600 volt cable sizing calculations were found to be generally acceptable. The team noted that technical standards and output documents existed but intermediate calculations were not present. Three examples were reviewed and the cables were found to be sized per the licensee requirements. The licensee provided a comparison of the Oconee cable sizing criteria to the 1990 National Electric Code and Insulated Power Cable Engineers Association (IPCEA) P-46-426 which demonstrated that the cables were oversized when they are routed in conduit, cable trays with maintained spacing, or cable trays with single layer fill. The documentation did not address derating if power cables were routed in overfilled trays along with control and instrument cables as was the case at Keowee. The team could not establish what cables were in what raceways from the documentation. The existing cable tray fill and contents of the trays and sizing was a concern. The licensee indicated that they were going to inventory the cables at Keowee in a manner similar to the process at Oconee.

Calculation, OSC-4328, Revision 2, Operability Evaluation for Keowee Load Centers 1X and 2X in Response to PIR-4-091-0039 (9/23/92), was reviewed. The analysis addresses operability of the Keowee auxiliary equipment power supplies (1X, 2X, and CX transformers). It was noted that in certain scenarios, the safety related electrical auxiliaries for both Keowee units could be supplied from only one Keowee unit. Keowee powers all redundant Oconee auxiliaries during a DBE. It is essential that abnormal voltages and frequencies not degrade redundant equipment. The equipment has voltage and frequency limitations; some critical performance characteristics of the electrical equipment can be adversely affected. The licensee initiated PIR 0-093-0081 on February 11, 1993, to address this issue. (See Appendix A, Finding 2)

This calculation, OSC-4328 is also used as a basis of Keowee 600 volt breaker coordination. The calculation identifies that coordination problems exist between load centers Motor Control Center (MCC) supply breakers and the MCC main feeder breakers and recommends corrective actions. The corrective actions have been implemented. The licensee identified one example that had not been corrected. The problem was miscoordination between the load centers and safety related MCC 1XS and 2XS. The licensee judged this to be of no concern as the MCCs powered a safety load (the standby battery charger), which is not needed at the start of the event. In review of drawing K-702, Rev 14, the team also noted that the Spillway and Intake Power Panels did not coordinate. The two major criteria utilized in the development of the analysis were discussed with the responsible engineer. The first consideration was that all branch circuits feeding safety-related loads shall be coordinated such that no overload or credible fault on a safety-related circuit can disable more than one safety-related power distribution string. The other criteria was that branch circuits feeding non-safety-related loads from safety-related busses shall be coordinated such that no overload or credible fault on non-safety-related equipment can disable any safety-related power distribution string. The team indicated to the licensee that the criteria should be clearly stated in the DBD, as it establishes the reference boundary for the design of this particular feature.

Calculation, KC-0076, Rev 2, dated 8/1/88, Voltage and Duty Cycle Calculation was reviewed, and it was noted that there was no discussion of the results considering the equipment voltage limitations. Other calculations were in progress to examine the adequacy of the emergency start channel (OSC-5077) and the adequacy of the voltage to the generator field, generator supply, and field flash breakers (OSC-5093). The comprehensiveness of the scope of the supplemental calculations to examine voltage adequacy at the component level should be considered by the licensee. It was also noted that KC-0075 was an input to this calculation that was issued subsequent to the issue of KC-0076. As a result,

KC-0076 may require update. The licensee should identify the full scope, and complete individual voltage component calculations for Keowee. (See Appendix A, Finding 2)

OSC-4653, Revision 1, Battery Charger and Safety Related Inverter Sizing Calculation (1/21/93) demonstrates the adequacy of the existing Keowee charger size based on KC-0076, a one hour discharge rate, and supply of continuous load. An improved charger, which the licensee stated was on order, will meet an 8 hour discharge rate and supply continuous load. This charger will more closely comply with accepted industry practices in this area.

Other calculations were reviewed. Their methods, assumptions, results, and conclusions were found to be consistent with the licensing bases. These calculations were: KC-Unit 1-2-0090, 1/22/93, Keowee 600 Volt Distribution Fault Study, KC-Unit 1-2-0084, 7/23/92, Keowee 13.8 kV Breaker Fault Study, and KC-0075, Rev 1, 4/9/91, Keowee 125 VDC Battery Load Test Report.

3.3 Operation of the Keowee Units

3.3.1 Emergency Start Operations

Following a DBE on an Oconee Unit, the hydro units will be emergency started from zero speed, and will accept a single block load with the Keowee voltage and frequency as low as 50% of their rating. The Keowee units may (and often are) operated to generate peaking power to the transmission grid. The practice is to load to the units in excess of 60 MW to limit long term degradation of the hydro impeller due to cavitation. Under these conditions, and following an emergency start, the unit is disconnected from the grid and then reconnected to the Oconee busses if required. This sequence includes tripping of the output breaker, a load rejection, and results in an overspeed condition on the Keowee unit. Connection to the Oconee busses will then occur before full recovery from the overspeed condition. These start and load sequences create voltage and frequency excursions on the Keowee output. Since the Keowee unit powers the required safety related loads for the Oconee unit, the ability of the Keowee generator to maintain voltage and frequency within limits that would not adversely effect the loads is critical.

The team concluded that the licensee lacked sufficient analyses and tests to fully demonstrate that Keowee would perform its function under these conditions. Transient voltage analyses were completed for the underground path and are planned for the overhead path. At the beginning of the inspection there were no analyses, existing or planned, which adequately address frequency performance. As a result, the effects of the frequency transients on the equipment had not been evaluated. The team was not able to establish that Keowee had been emergency started and loaded through the overhead path or that the existing tests fully bound the design. (See Appendix A, Finding 3)

Completion of the overhead voltage analysis and tests to demonstrate the ability of Keowee to start, accelerate and accept load were open items from the DBD effort and documented in a Memorandum to File dated May 14, 1991.

During the EDSFI the licensee supplemented the completed analysis with informal analyses to demonstrate that Keowee would function without degradation of its auxiliaries when started from zero speed. Additionally the licensee provided test data which demonstrated the units' capability to start, accept approximately 35% of the maximum expected LOCA/LOOP block load, and the maximum expected LOOP load, and accelerate with this loading within 18 seconds. Other data was provided which demonstrated that the Keowee units could accommodate approximately 72% of the expected LOCA/LOOP block load, and 44% of the LOOP load, but no time parameters were included in the testing.

These tests were reviewed by the team to establish a level of confidence that the power system will deliver the required Emergency Core Cooling System (ECCS) flows within the required time (48 seconds) via the underground path. No analyses or tests were available to assess the performance of the emergency power system when Keowee feeds Oconee via the overhead path. The team concluded that while emergency starts from zero speed should be bound by the existing analyses, connection from grid operation and from recovery of an overspeed condition require additional evaluation. The effects of the analyses and tests on margins was not determinable. The licensee indicated that these analyses and additional testing would be completed this year.

Chapter 8 of the UFSAR required that Keowee accept full emergency power load as it accelerates from zero to full speed within 23 seconds from receipt of an emergency start signal. The team found this requirement had been translated into the TS as 25 seconds. This was identified in 1989. However, the correct timing requirement was indicated in the test procedure.

3.3.2 Worst Case Loading

The UFSAR states that the capability of the 87.5 MVA Keowee units to continuously carry a maximum load of 21 MVA had been analyzed. The team determined that additional analysis had been performed in this area. The licensee had established the worst case load profiles, considering the transient and steady state, that are in excess of those stated in the UFSAR. The team's review indicated that the LOCA/LOOP and three unit LOOP scenarios represent the worst case loads and these load profiles are significantly higher than the UFSAR loadings. In those load sequences that connect the loads at reduced Keowee voltage and frequency, the initial load peak would be less than the maximum. However, under other accident conditions, the loads can be connected at higher voltage and frequency levels and thus the load peak may be much

greater. The team concluded that since the magnitude of the loads effects the ability of Keowee to meet its functional goals, the specific bounding load profiles should be indicated in the DBD.

3.3.3 Load Sequencing

When Keowee receives an emergency start, the required Oconee electrical loads are supplied power by one of the following load sequences:

- If Keowee was not generating to the grid, and there was a LOCA/LOOP, the load would be connected by the EPSL to the Keowee underground path approximately 11 seconds after the emergency start was initiated. At this time, the voltage and frequency could be as low as 50% of rated. After the load was connected, the unit should continue to accelerate to rated voltage and speed (frequency) within the 23 seconds prescribed in the UFSAR. If the other Keowee unit did not establish voltage in sufficient time, the loads of the non-LOCA Oconee units would also be connected to the underground path as early as 31 seconds after the emergency start. The functional Keowee unit would be at rated speed and voltage at that time. The connection of this load results in a frequency decrease that could last several seconds and affect the performance of the required safety loads at all three of the Oconee units.

- If Keowee was not generating to the grid and there was a LOOP, the Oconee loads are connected in approximately 31 seconds by the MFEMP system.

- If both Keowee units are generating to the grid and an emergency start signal was received, the units are tripped and begin to overspeed. The Units also experience an overvoltage as a result of the load rejection, however, the voltage regulator acts to rapidly restore the voltage. Test data indicates that the overspeed peaks at 195 rpm on Keowee Unit 1 and 188 rpm on Keowee Unit 2. (The actual value varies with lake elevation and Keowee loading.) The loads (for the non LOCA Oconee units) would be supplied by Keowee via the overhead path within 4 to 7 seconds after receipt of the emergency start signal and while the unit was recovering from an overspeed condition. Test results indicate that the Keowee unit would be between 132% and 138% of rated speed and voltage. This overfrequency corresponds to about 79-82 Hz.

Section 15.8.2 of the UFSAR, "Loss of Power Accidents" states that the required Oconee safety related loads can perform through an overfrequency transient lasting 40-50 seconds. Apparently, this information was relied upon to substantiate that the equipment would not be degraded during the above transient conditions. However, the licensee was not able to retrieve the analysis, or provide the technical basis for the statement that the electrical equipment can withstand the transient. (See Appendix A, Finding 2)

3.3.4 Keowee Operational Controls

3.3.4.1 Overall Keowee Operations

The team noted that informal means of control were sometimes relied upon regarding activities within the hydro station. The condensing mode of operation of the Keowee units, which had not been fully analyzed and thus was not authorized, appeared to be fully operable and controlled only by the fact that no specific procedure existed to support such operation. Deficiencies such as problem instruments were not formally tracked for resolution and in some cases were not labeled. The level and pressure in each Keowee unit's governor oil pressure tank was critical to the operation of the hydro units. This level was maintained and monitored (by the operators) through the use of two pieces of duct tape on the tank sight glass. By measurement and reference to the post installation testing data and vendor manuals, the team verified that the tape marks were in fact at the proper levels. The level switch which actuates an annunciator on abnormal tank levels had not been calibrated or tested. The controllers for the heaters in the turbine guide bearing oil systems for the units were set at different values.

Due to several equipment problems and a few recently identified design issues, numerous administrative controls were in effect on the Keowee equipment. The following is a list of the significant items:

- Due to a problem involving short circuit ratings, the alternate feeder breakers to several load centers were tagged to require entry into an Limiting Condition of Operations (LCO) if utilized.

- The disconnects for ACB 2 were tagged/locked open due to a zone relay protection issue and also due the use of a non qualified repair part in the breaker. These issues restrict the flexibility of the normal longterm Keowee alignment.

- When generating to the transmission grid (only unit 1), the Keowee unit was administratively limited to a maximum output of 60 MW due to a potential overspeed trip concern. Automatic Gain Control (AGC) was also not utilized on the unit to help ensure that this limit was not exceeded.

- The Keowee AC auxiliaries are maintained in a required alignment and in the "manual" mode due to problems with the automatic transfer system.

The team did not identify any safety related functions which were directly or adversely affected by the use of these informal administrative controls. Additionally, it should be noted that since the Keowee operating staff consists of five operators and three technicians, more formal methods may not be required regarding most issues. The team observed that procedural compliance, independent verification, and tagging activities during maintenance activities were appropriate. It was also noted that the procedures addressing removal

and restoration of Keowee Station equipment were highly detailed. Additionally, it was noted that the general quality of procedures which had been revised or written within the past two years by Keowee personnel was good. Procedures which had not been recently revised or which were not directly controlled by Keowee personnel, were not as detailed and in several instances, needed upgrading.

During the inspection, it was noted that the knowledge and skills of the Keowee technicians was heavily relied upon. The Keowee operators are limited in their knowledge and capabilities to address abnormal conditions or equipment malfunctions that occur. The common practice under such circumstances was to contact the power system dispatcher and the Oconee Control Room and await the arrival of the technician onsite to address the problem.

3.3.4.2 Material Conditions

Extensive tours of the Keowee facility were conducted. Overall housekeeping and control of combustibles was appropriate. The turbine wheelpit areas contained excessive corrosion products on the walls and on equipment mounted on the walls. Some small debris was noted under the switchgear in the battery room. The team inspected the interior of several critical control cabinets, the governor enclosures, several ACB compartments, and both generator enclosures. In all of the areas, no discrepancies were noted. The interior of the upper portion of the governor cabinets was noted to be particularly well maintained.

3.3.4.3 Keowee Setpoint Controls

A single controlling document for the setpoints of Keowee equipment does not exist. (Electrical relays are an exception and are listed in OSC-4300).

While recently revised procedures under the control of the Keowee staff contain the necessary setpoints, most other procedures do not contain the setpoints. The partial listings of setpoints do not contain tolerance acceptance bands. Personnel performing activities refer to drawings and sometimes rely on personal knowledge to determine setpoints. Often, the as found or as left setpoints were not recorded in the procedure. One example was the setting of Permanent Magnet Generator (PMG) speed switch number 4. These speed switches play a role in the generator's response during an emergency start. The switches had been set to actuate at 50 rpm by reference to a vendor provided listing. Questioning by the team led to the identification that the setpoint was listed as 65 rpm on two of the licensee's drawings. The licensee acknowledged that this problem existed and plans were being made to correct the problem. However, the team could not locate a PIP that identified this issue. (See Appendix A, Finding 3)

3.4 Testing of Keowee

3.4.1 Review of Voltage and Frequency Analyses and Tests

The DSD states that the voltage adequacy for the Oconee safety bus loads when fed from the underground power path was documented in calculation OSC-2444 and OSC-3696. The licensee advised that OSC-2444 presents the worst case analyses. Keowee analysis (OSC-2444) was performed using Continuous System Modeling Program (CSMP) to analyze the transient voltage performance at Oconee when fed by Keowee via the underground path. Similar analyses, addressing the transient voltage performance at Oconee when fed by Keowee via the overhead, were scheduled for completion in the spring of 1993. The licensee had concluded that the underground path was the worst case voltage response as there was more impedance in the underground circuit. The team concluded that this was appropriate if Keowee was started at zero speed. However, connection from grid operation could result in an overvoltage condition that was not bounded by the underground analysis.

Insufficient analyses exist to determine the frequency response of Keowee under differen conditions. In response to team questions, the licensee addressed the effects of abnormal frequency when powering Oconee via the underground path. The DSD did not consider the frequency response of Keowee and its potential effects on Oconee.

The existing transient voltage analysis assumed that the 13.8 kV generator was an infinite bus with terminal voltage constant at 13.2 kV, and the frequency constant at 60Hz. These assumptions did not appear to be valid as they did not reflect that the voltage and frequency could be as low as 50% of rated when the loads were initially connected. In response to the team's observations, the licensee pursued a dynamic voltage and frequency analysis using the underground path. The dynamic analysis was performed with a new software program that still required validation in accordance with the licensee's QA program. Both the existing dynamic analysis and analysis performed during the EDSFI had limitations. The CSMP could not model the voltage regulator or speed control dynamics and the software used in response to the EDSFI concerns would not accept other than rated voltage and frequency as the starting point. The final results of the analyses did not enable the licensee to obtain actual voltage and frequency versus time profiles.

The results of this dynamic analysis were provided to the team along with evaluations of equipment performance when experiencing both voltage and frequency below acceptable limits. The licensee substantiated that fuses would be able to sustain the current inrush associated with the undervoltage transients. Additionally the licensee evaluated the effects of the transients on safety related loads (HPIP, EFW, LPI, LPSW and RBS pumps motors) and concluded the voltage to be adequate. The evaluation of the induction motor performance resulted in more margin than the previous analyses because the volts/hertz control feature of the voltage regulator limits the ratio to 1.06. The licensee informed the team that the Keowee voltage regulator would follow the speed

(frequency) and maintain the ratio at 1.06. As the starting torque of a motor was directly proportional to the volts/hertz ratio squared, the net effect was that the motor provides 1.12 torque to load ratio and starts faster. The team concluded that this analysis was appropriate as long as the voltage did not drop below a point that results in the motor torque being less than the load torque. The licensee stated that the voltage would dip below 13.2 kV for a maximum of 36 cycles. The team noted that the analyses demonstrated that the recovery could take as long as 200 cycles. The licensee then provided further clarification that the recovery occurs within 36 cycles provided the generator comes up to speed with no load. As this was not the actual case, the team concluded that further review of this issue may be warranted by the licensee. This would ensure that the voltage not dip low enough to cause the motor torque to be less than its load and result in spurious tripping of the Oconee loads.

During review of the dynamic analysis, it was noted that the frequency of the Keowee supplied power was below rated for 40 to 50 seconds. The team concluded that the effects of this decreased frequency on the performance of the ECCS loads may need to be evaluated. The licensee provided the team with a copy of the B&W topical 10103A, Revision 3, dated July, 1977 "ECCS Analysis of B&W'S 177-FA Lowered-LOOP NSS," that indicated that the time delay for providing power to ECCS pumps was 25 seconds assuming the single failure of a diesel. The licensee provided updated information that substantiated 90% HPI flow was required to the Reactor Coolant System (RCS) within 48 seconds. The B&W analysis took no credit for flow before 48 seconds. B&W was also aware that one of the Keowee units supplied all of Oconee's emergency loads. The licensee correlated the B&W requirements with the results of the electrical analysis to establish that there would be adequate flow. The updated B&W report may need to be reviewed to confirm this information. The licensee also addressed the effects of operation below 57 Hz for approximately 10 to 16 seconds (57 Hz is the minimum frequency that an induction motor can run when at rated voltage). The licensee indicated that the increased current for this short duration would not cause the motor to trip or overheat. (See Appendix A, Finding 5)

The licensee stated that the conclusions of OSC-2444 should remain acceptable, except for the voltage adequacy evaluation on some lower voltage busses, which were addressed in part by the above equipment evaluations and OSC-4581. The team did not concur with this conclusion. The team noted that the dynamic analysis results did not agree with the UFSAR 23 second time requirement and more accurate consideration of the control logic would aggravate this concern. A more accurate representation of the actual voltage and frequency response may be required to assess agreement with the UFSAR. The licensee provided information indicating that the Keowee unit will continue to accelerate while accepting load due to the action of the speed control system. They were also able to provide test results with times to support these statements. In the pre 1997 Emergency Start Test, PT/1/A/0610/01J, shutdown loads were block-loaded onto the Keowee Unit in the same manner that would occur in an event. The test data

showed that the Keowee Unit accepted a block load of approximately 2 MVA and reached rated speed and voltage within 18 seconds. The data also demonstrated the actual frequency response was not what would be provided by the dynamic simulation. Further analysis may be warranted in this area. The team concluded that the licensee should define acceptable voltage and frequency limitations for the Keowee electrical auxiliaries and the emergency power system. Additional, acceptable recovery times from voltage and frequency excursions should be identified. (See Appendix A, Finding 5)

3.4.2 Keowee Performance Tests

3.4.2.1 Start and Load Acceptance Tests

The net results of these start and load acceptance tests should establish the capability of the unit to start and accept load within prescribed periods of time. These tests should also demonstrate that the frequency and voltage can be maintained within acceptable limits. The team concluded that the test results reviewed to date do not fully bound the design. The licensee has agreed to perform supplemental testing.

The DBD, KTC-0-0113-0001-003, requires verification of each Keowee units ability to supply a block load equivalent to the Oconee emergency load requirements. The licensee implemented this requirement by paralleling each unit to the grid and assuming load at the maximum practical rate.

Performance test procedure PT/0/A/0620/16, Keowee Hydro Emergency Start, verifies on an annual basis that the Keowee units will start and accelerate to rated speed and voltage within a designed time upon receipt of an emergency start signal. The unit is loaded after reaching rated voltage and speed. In section 8.3.1.1.1 of the UFSAR it indicates that Keowee starts, accepts load, and accelerates within 23 seconds. This feature is no longer tested. (See Appendix A, Finding 1)

During each Oconee unit refueling outage (approximately two units per year), performance procedure PT/0/A/0610/01J, Emergency Power Switching Logic Functional Test, tests the logic which aligns the Oconee loads to the Keowee underground feeder. This test ensures proper breaker operation.

A completed test in accordance with procedure PT/0/A/0610/01J which was performed prior to 1987 was provided. This test demonstrates Keowee's ability to start and accelerate a 2 MVA load block via the underground path. Subsequent to the exit the licensee provided the specific results of such a test performed on 10/1/86. That test connected the 2 MVA load at 11 seconds which was fairly close to the expected loading during a DBE. The test resulted in the starting and acceleration of 2 MVA load to rated speed and voltage within 18 seconds. The requirements of performance procedure PT/0/A/0610/01J had been relaxed from those in the pre-1987 procedure. The test is currently performed with a 2 MVA block load connected to Keowee after it reaches rated speed and voltage.

The most rigorous test appears to be the October 19, 1992 event. The licensee provided information concerning the loading of Keowee during this event. This event demonstrated the ability of Keowee to accept a 4 MVA block load, subsequently accepted a block load of 1.8 MVA with the 4 MVA running, and an additional 1 MVA block load with 5 MVA running. Comparison of the loading of this event with the design demonstrated that the unit can start and accelerate with 71% of the maximum LOCA/LOOP initial block load and 42% of the maximum LOOP initial block load. However, no times were available.

The licensee also provided a summary of testing performed at the Jocassee Pump Storage Station. The units at that pump storage station located near Oconee were very similar to the Keowee units. On a regular basis, one of the Jocassee units was utilized to start another Jocassee unit as a motor. The licensee concluded that a 140 MVA generator was starting a 140 MVA motor. Further questioning identified that the unit being started as a motor was being accomplished with the gate closed. The actual load corresponds to that of the inertias of both the motor and water wheel rotors and was expected to be approximately 2% of the machine rating. This was a reference value of power required to motorize a hydro unit. In response to further questioning by the team, the licensee also advised that it took 2-3 minutes to start and accelerate that load. This test did not appear to be as rigorous as other tests or events.

The team concluded that the existing tests collectively do not bound the design requirements. The licensee stated that additional testing would be performed in 1993 to demonstrate that Keowee can be loaded through the overhead as required by the design. (See Appendix A, Finding 1)

3.4.2.2 Rated Load Tests

The team reviewed these tests to ensure that they adequately demonstrate the capability and availability of the units to carry the continuous loads required by the DBE.

The units are routinely paralleled with the grid at loads much greater than those required by the DBE. These operations are performed on a frequent (often daily) basis. During the EDSFI, the team observed that the unit aligned to the overhead path was generally run at 60 MW on a daily basis.

The longest continuous time period of Keowee operation was thought to be three days. The team noted that the Keowee DBD stated that the Keowee unit may be required to run continuously for longer than three days.

3.4.2.3 Load Rejection Tests

These tests were reviewed to assess the ability of the Keowee units to reject a .ll load without electrical or mechanical damage to the unit or the connected loads. These tests were completed in 1971 and included

scenarios in which one or both units were initially generating to the grid. The maximum overspeed recorded was 195 rpm. Electrical parameters were not recorded.

3.4.2.4 Keowee Support and Control System Testing Issues

Several concerns were noted regarding testing of other safety related components necessary for the operation of the Keowee units. By virtue of the fact that the Keowee units are frequently operated to supply power to the transmission grid, significant portions of the Keowee units are functionally tested at frequent intervals. The team focused on those systems not required to perform their function during operation for power generation, but necessary for emergency operations. Inspection was centered on those specific components which could either prevent an emergency start or could result in the loss of unit under emergency start conditions. The team noted that the TS did not contain testing requirements for Keowee mechanical support systems.

Weaknesses were identified involving the testing of several lubricating oil systems essential to the operation of the hydro units. Although some testing of the DC powered turbine guide bearing oil pumps were being conducted, it was not complete to ensure those pumps would function properly to support Keowee operation when required. The pumps would be required to operate in case of a loss of the Keowee auxiliaries (AC power) or loss of the AC powered oil pump. Several safety related level switches in the oil systems which could affect the operability of the Keowee units under emergency start conditions had not been calibrated nor functionally tested. Discussions with involved personnel indicated that at least one of these testing inadequacies had been previously recognized and a testing procedure was under development. During a review of all PIPs and PIRs involving the Keowee facility, the team noted that this problem was not addressed in the system. The team was informed that the procedure for testing of the switches was under development.

During reviews of circuitry and devices involved in the emergency lockout feature (actuation of the 86E relay results in tripping and lockout of the unit under emergency start conditions), the team identified another discrepancy. A pressure switch in the carbon dioxide fire protection system (63FX) which should actuate the 86E relay if a fire occurs in the generator, had not been calibrated nor functionally tested. The circuitry from the switch to the 86E relay had not been tested. It was noted that during testing in accordance with Procedure MP/0/A/2000/59 several annunciators would be activated by this same pressure switch but those alarms were not checked during the test. Spurious activation or inoperability of this circuitry could adversely effect the performance of the Keowee generating units under emergency start conditions. This issue was discussed with licensee management on February 1[illegible], 1993. At the close of the inspection, the licensee was investigat[illegible] methods for testing the switch. (See Appendix A, Finding 6)

It was noted that performance monitoring testing was not routinely performed on the safety related mechanical components (coolers and pumps) at Keowee. Design study ONS-0275, completed on December 31, 1990, listed all pumps and valves at Keowee which should be tested. Actions were still in progress to develop the necessary program. (See Appendix A, Finding 6)

During the inspection, the team identified several valves which were required to change position for Keowee to provide emergency power, which were not included on the Keowee active valve list (KC-0085). These valves were: 1 and 2 OG-7 (the governor oil tank float valves) and the four check valves on the ACB air accumulators. Since that list was used to determine testing requirements, it should be complete.

During review of the testing associated with ACBs 1, 2, 3, and 4, procedural weaknesses were noted. MP/0/A/2001/2: Inspection and Maintenance of Keowee ACBs and associated Disconnects and Bus, did not provide sufficiently detailed instructions for testing of several important components. The check valve on the air accumulator in each breaker are relied upon to seat if a problem occurs anywhere in the ACB air system which was common to all four ACBs. Step 11.1.12 of the procedure states "Inspect the check valve" and "repair or replace if it is sticking." The team's review of the associated vendor manual (KM-303-26) did not identify any guidance for testing of these valves. Through discussions with I&E personnel who perform the ACB work, the team concluded that the actual testing performed was adequate to identify a malfunctioning check valve. Despite the lack of specific guidance provided in the procedure, the workers were knowledgeable of how to inspect the check valves after the test. The procedure also did not contain adequate guidance regarding testing of two air pressure switches which actuate an alarm on decreasing air pressure. The team confirmed that the switches were tested in accordance with the guidance provided in the vendor manual.

3.5 Keowee Modification Review

The design input calculations for several modifications were reviewed. The team concluded that the licensee did not establish adequate design input prior to proceeding with the modification and existing DBD did not identify specific design data.

OSC-4757, Rev 1, Electrical Design Input and EQ Verification for Urgent Modification On-52917, Replacement of "X" relays on Keowee Westinghouse "DB" Breakers (1/12/93) was reviewed. This calculation was found to be incomplete. The review indicated that the modification was incorrect in that if implemented as proposed, it would have defeated both the manual and remote operation of the breaker. The error was identified and corrected during implementation. The team concluded that the error was the result of not fully considering the performance of the equipment as required by the calculation. The licensee only considered performance with the anti-pump feature of the breaker and did not consider the performance during manual and remote closure operation of the breaker.

OSC-4077 is the design input calculation supporting NSM-52855/00. This modification resolved a potential overload condition as a result of not tripping reactor coolant pumps which would be operating prior to automatically connecting Keowee to Oconee via the overhead path following a LOCA/LOOP. The team concluded that the problem was the result of the existing DBD lacking appropriate reference bounds for voltage and was not adequately supported by analysis (i.e. overhead path analyses were planned). OSC-4077 required that ACB-1, ACB-2, and PCB-9 trip on switchyard isolation and added a four second time delay before reclosure of ACBs 1,2 and PCB-9. The 10 CFR 50.59 evaluation for this modification was completed in OSC-4080, dated 8/10/90. The modification appropriately considered the timing interfaces with the RCPs. Load rejection tests and an understanding of the volts/hertz feature of the voltage regulator show that changing this timing significantly increases the magnitude of the initial voltage and frequency at the time of breaker closure. Analyses or tests to demonstrate that the previous control scheme would work without degradation of the auxiliaries or causing spurious trips had not been developed. Allowable magnitudes and durations of voltages and frequency were not identified in the DBD. The team concluded that this information should have been developed prior to implementing the modification.

3.6 Review of Corrective Actions at Keowee

3.6.1 Loss of Switchyard Event (October 1992)

As a result of detailed reviews of the Keowee systems involved in the October 1992 event, the team concluded that in some areas, the licensee's corrective actions had not been commensurate with the significance of the event.

Although the development of an abnormal procedure for an emergency start condition addressed some concerns regarding the actions of Keowee operators, the team noted a weakness in the procedure. A significant issue identified as a result of the October event was that the Keowee operators relied excessively on the "on-call" Keowee technician. Review of the procedure and discussions with Keowee operators indicated that the operator would not restore the Keowee AC auxiliaries (even if lost due to a simple problem) without obtaining permission from the Keowee technician. The procedure was subsequently revised to correct the problem.

The operation of the Keowee hydro units' governor system without AC power or adequate control oil pressure/level was reviewed by the team in detail. This issue played a significant role in the October event and should have been fully analyzed by the licensee. Questioning by the team led to a better understanding of the failure mode of the Keowee turbine wicket gates under the postulated conditions. It was concluded that the gates would eventually fail (on a loss of oil level and continued operation of the unit) to a "neutral" or intermediate position. This position would be where the forces of the water flow (as directed by the flow vanes) are balanced out. The licensee's

discussions with the vendor indicated that this position would be just below the "speed-no-load" gate position. Keowee testing data indicates that this position would not support the required Oconee electrical loads. More importantly, since the ability of the governor to control the wicket gate position would be defeated (very soon after the oil level in the Governor Oil Pressure Tank (GOPT) went too low) the gates would initially remain in a fixed position despite any loading changes placed on the unit. The frequency and voltage levels of the electrical power being supplied to all of the Oconee emergency loads would not be controlled. The degraded Keowee unit may not automatically trip and permit the other available unit to provide power. Information indicates that if all air pressure were suddenly lost on the governor system, the gates would very rapidly (within seconds) fail to the "balanced" position. The team concluded that additional review by the licensee is ...nd based on the final understanding of the failure mechanism.

During the October event, the oil level in both of the governor tanks was observed by the Keowee technician to be about 4 inches on the sight glass. This level approximately corresponds to the level at which the float valve inside the tank would shut and the governor then becomes inoperable. The team concluded that the failure of the licensee to fully review this potential failure mechanism and understand the results of such a failure was a significant weakness.

During the inspection, the team noted the absence of an overall management plan addressing the incorporation of the Keowee hydro staff into the Oconee operations organization. Although numerous activities were in progress which addressed the change of organization and some objectives had apparently been informally established, no overall controlling plan or proposed timeline had been established. The team noted that extensive corrective actions were in progress in some areas. Significant effort was being dedicated to the establishment of Job Task Analysis (JTAs) on Keowee activities. Discussions with management indicated that the Oconee outage manager had recently been tasked with developing such an overall plan. The team concluded that the lack of an overall management plan limited the effectiveness of the resolution of identified discrepancies.

3.5.2 Review of Keowee PIPs and PIRs:

The team reviewed all PIPs and PIRs (since 1989) which involved the Keowee hydro station. Several problems were identified involving PIPs which did not become escalated to PIRs.

- Of the 32 total PIPs classified as Less Significant Event which were reviewed, only four had been closed. Many of the PIPs appeared to remain open unnecessarily long since corrective actions had been completed.

- Many of the open PIPs were open well beyond their "due" dates. Numerous reports did not have due dates assigned. The team noted that in some cases, the corrective actions required were very broad in nature and did not consider those open PIPs to be weaknesses.

- PIPs were not found for several items which had been previously identified by the licensee and appeared to meet requirements for generation of a PIP (or a PIR). Examples include:

  - inadequate testing of the oil system level switches and pumps,

  - lack of a controlling Keowee setpoint document,

  - and revision of the abnormal procedure for Keowee emergency start to correct excessive reliance on the on-call Keowee technician.

The review of the Keowee PIRs led to the following major conclusions:

- The majority of the DBD and SITA identified issues were the result of the licensee reviewing the electrical systems in a critical manner and often involved the recognition of single failure vulnerabilities.

- In 1992, there were a total of nine PIRs involving component failures. Even without the rash of the "X-relay" issues, that was a significant increase over the 1-2 component failure PIRs reported in each year prior to 1992. Some of the equipment failures at Keowee are related to aging of the system/component.

- The PIRs indicate that repetitive problems had occurred involving the ACBs, the AC auxiliaries, and the voltage regulators.

- The 1992 PIRs had not only increased in number but also seem to involve more significant problems than those addressed in previous years. It was noted that a smaller fraction of the 1992 PIRs were initiated as a result of formal review programs than in previous years.

3.6.3 Operational Experience Review

The team reviewed applicable NRC Information Notices and Bulletins to assess if they had been reviewed by the licensee for applicability to Keowee. The SITA had identified (May, 1992) that Bulletin 79-02 "Pipe Support Base Plates Designs using Concrete Expansion Anchor Bolts," had not been reviewed. The licensee resolved the situation through the condition adverse to quality system with no anchor bolt problems

identified. The licensee attributed the exclusion of Keowee from Bulletin review to a lack of clear definition of safety classifications for Keowee mechanical support systems.

In December, 1992, the licensee initiated a comprehensive review of operating experience documents (Bulletins, Information Notices, Generic Letters, etc.) for applicability to Keowee. The review is targeted for completion by June 30, 1993. This was addressed as an example of Finding 3.

3.7 Reliability and Availability of Keowee and Lee

The team reviewed the availability data for the emergency AC power system for the years 1989 to 1992. The licensee tracks total LCO time for the Keowee units. In 1992, the Keowee units were unavailable for a total of 382.37 hours which corresponds to an unavailability of 4.4%. The station goal for 1992 was 150 hours or 1.7%. In 1991 the Keowee units were unavailable for a total of 179.89 hours or 2.1%. In 1990 the Keowee units were unavailable for a total of 135.23 hours or 1.5%. In 1989 the Keowee units were unavailable 265.43 hours or 3%.

The licensee does not currently officially trend/track start failures on the Keowee units. The licensee is establishing a Keowee hydro emergency power source reliability program and a draft procedure has been developed. The draft program incorporates availability and reliability trending and establishes trigger values for start failures on a Keowee unit. The program will require that increased testing be performed if certain trigger values are exceeded.

The team reviewed licensee memorandums to file concerning Keowee hydro station operating data for the years 1980 through 1988. The data was obtained by review of the Keowee operator logs by licensee personnel. The data indicated that in the eight year period reviewed, a Keowee unit failed to start 22 times and 14 of the failures were considered valid failures. A valid failure indicating that the unit would not have started when an emergency start signal was generated. The data indicated that the Keowee units experienced 5 failures while operating to the system grid and 2 of these failures were considered valid failures. A valid operating failure indicated that the unit would have failed to continue operating if an emergency start signal was present. The data indicated that the Keowee hydro station experienced 16 valid failures of the Keowee unit during the 9 year period reviewed or approximately 1.78 failures per year.

Review of LERs by the team determined that Keowee Unit number 2 overhead emergency power path was inoperable for an undeterminate period of time prior to September 29, 1992 due to an undetected failure of an undervoltage relay. The failed relay was found during a post-modification test for a modification unrelated to the undervoltage

relay. The relay in question had never been functionally tested and may have been failed for an extended period of time prior to discovery during the post-modification test performed on September 29, 1992.

The team noted that an integrated test has never been performed on the Keowee overhead emergency power path and that on October 19, 1992 when the overhead power path was called upon to function during a loss of offsite power event the actuation resulted in a failure of the overhead path and a loss of Keowee auxiliaries on the Keowee unit supplying the underground path.

The data used in the PRA analysis for computing overall Keowee reliability is primarily composed of events and tests which involve Keowee starts and subsequent loading to the grid. This data, while useful in determining the hydro units ability to start and generate electricity, does not necessarily reflect the units ability to provide power to the Oconee emergency busses.

The team reviewed availability data for the three Lee gas turbines located at the Lee Steam Station which is approximately 30 miles from the Oconee site. The gas turbines are not safety related. However, a Lee gas turbine can be aligned to the Oconee standby busses through a dedicated transmission line to meet certain TS action statement requirements. The team reviewed availability data for the years 1990, 1991, and 1992. The team determined that at least one Lee gas turbine was available to energize the Oconee standby busses during this three year period except for a 16 hour and 59 minute period on March 20, 1990. All three Lee gas turbines were unavailable due to a transmission line problem.

3.8 Root Causes of Deficiencies Identified in the Electrical Distribution System

The team reviewed Licensee Event Reports (LERs) from 1988 through 1992. The LERs were reviewed in three functional areas, Oconee Switchyard, Oconee 1, 2, & 3, and Keowee.

The team reviewed facility generated LERs concerning the Oconee Switchyard since 1988 and have identified that twelve LERs have been submitted to the NRC. Of these twelve LERs, three of these were generated due to the Design Basis Document (DBD) process, one was generated due to the Loss of Offsite Power in October of 1992, and the remaining eight LERs were due to other various reasons. Of these twelve LERs, seven were due to design deficiencies, two were due to testing/maintenance problems, and three were due to operational inadequacies (i.e. procedural problems).

The team reviewed facility generated LERs concerning the Oconee Nuclear Station since 1988 and have identified that seven LERs have been submitted to the NRC. Of these seven LERs two of them were due to the DBD process, one was due to an engineering review, and the remaining four LERs were due to other reasons.

The team reviewed facility generated LERs concerning the Keowee Hydro Station since 1989 and have identified that twelve LERs have been submitted to the NRC. Of these twelve LERs two of them were due to the DBD process, two were due to the SITA process, two were due to the Operating Experience Program process, and the remaining six were due to other various reasons. Of these twelve LERs, eight were due to design deficiencies, one was due to testing problems, one was due to operational inadequacies and two were due to component failures.

Conclusion:

In 1992, there were five LERs associated with the Keowee Hydro Units concerning design deficiencies. The majority of these issues were identified as a result of the critical review of the Keowee Hydro Units by the licensee. Most of the deficiencies identified were original design deficiencies.

In general, based on the team's review, it was determined that the LERs generated by the licensee were due to the following:

- Most deficiencies identified were original design deficiencies identified during a programmatic review conducted by the licensee. Examples of these are: Potential closure of E-breakers on degraded grid voltage, incorrect relay setpoints causing lockout of the yellow bus, and single failure of protective relay inops. both the underground and overhead paths.

- The overall original design was not fully understood by engineering or operations. Examples of this are: Breaker Ferroresonance affecting CT2, EPSL Logic inoperable due to fuse removal during breaker maintenance, Lee line inoperability when adding Motor Driven Emergency Feedwater (MDEFW) pumps, and overloading of the Keowee Hydro units due to an RCP not tripping.

- The EDS is complicated and unique. Physical separation is present but not electrical independence. An example of this is that all safety busses for all three units are tied together when fed by the standby busses through CT-4.

- Testing of all safety related components has not been accomplished on a periodic basis. The following are examples of components not being tested: MG-6 relays, Keowee CO_2, Keowee governor oil level switch, yellow bus isolate function.

- Keowee Hydro organization was functionally independent of Oconee Nuclear Station. (Overall design of the electrical system was not fully understood.)

4.0 LEE EMERGENCY POWER SYSTEM AND 100 KV CENTRAL POWER SYSTEM

The 100 Kv power distribution system at Oconee consists of the Central switchyard and the Lee CTG. This system serves a dual purpose. The Lee CTG system serves as an emergency power supply as required by TS when the normal on-site power supply at Keowee is not available or when in a LCO. The Central switchyard serves as a back-up source of power to the off-site power supply in a worst case scenario when normal off-site power is lost and the emergency power source fails.

4.1 Review of Design

The team reviewed the design of the Lee Emergency Power System and the 100 Kv Central Switchyard System.

4.1.1 Lee Power System

The Lee Emergency Power System was reviewed to ensure adequate voltage would be available to supply the Oconee auxiliary power system and also to verify that the system had proper protection and coordination.

Calculation OSC-3290, "Voltage Study for Oconee Auxiliary Power Systems When Fed From Lee Combustion Turbine Via CT-5 Auxiliary Transformer" was reviewed to ensure adequate voltage would be available at the standby bus when supplied by a Lee CTG. During the review of this calculation it was noted that the Lee CTG was modeled as an infinite source. The licensee agreed that this source was not infinite. The program used to perform the voltage study was not capable of properly modeling the generator so it was treated as an infinite source. To ensure that this lack of conservatism did not adversely affect voltage levels within the auxiliary power system, administrative controls were in effect which increased the output voltage from the Lee CTG from 13.8 kV to 14.1 kV. Other administrative controls which were in effect when the Lee CTG was supplying the standby busses were the delayed loading of load centers X5 and X6 on non-LOCA units and placing the standby HPI pump in the OFF position. Procedures were reviewed to ensure that all administrative controls resulting from this voltage study were incorporated.

The team conducted discussions with the licensee concerning the Lee voltage study. Specifically, the modeling of the generator in the voltage study as an infinite bus. The licensee stated that the next revision of OSC-3290 would use the new CYME computer program. This software has the capability to model the CTG more accurately and the infinite source assumption would be deleted. The licensee expressed confidence that there was no immediate need to revise that calculation because of the added conservatism of increasing the output of the generator to 14.1 kV. Additionally, the Lee CTG would be at rated output voltage and frequency when placed in service. The licensee had tested the response of the Lee CTG by adding a load of two 3500 HP motors. The transient voltage dip lasted only 0.8 seconds. After

thorough review of the Lee emergency power system the team concluded that the Lee CTG would supply adequate voltage to the standby busses to meet load voltage requirements.

4.1.2 Central Switchyard

The team reviewed the 100 kV electrical distribution system under the conditions of transformer CT-5 being supplied from the Central switchyard. The licensee has recently installed degraded grid protection on that line. The modification package and supporting calculations were reviewed.

Calculation OSC-4513, "Design Input Calculation Relative To NSM-52878," provided a voltage study of the auxiliary power system when the system was being supplied from the Central switchyard. The calculation was used to determine the setpoints for the degraded grid protection system for the 100 kV system. No concern were noted.

4.2 Operation of the Lee Power and Central 100 kV System

Procedure OP/0/A/1107/03, "100 kV Power Supply" includes enclosure 3.10 which allows the MFB of a unit whose startup transformer was out of service to be energized from the Central switchyard. This alignment is not indicated in the existing TS or UFSAR.

In reviewing the Operating Procedure, enclosure 3.10, the team noted that step 1.3 requires at least 2 energized transmission circuits connected to the Central switchyard. The procedure does not require that both of these circuits not be Oconee transmission circuits. If all generating output from Oconee station was lost, the Central switchyard would also be compromised and unavailable as a last resource when providing emergency power. Therefore, the procedure should be evaluated to specify one circuit coming from a substation other than Oconee.

5.0 STANDBY SHUTDOWN FACILITY

The team reviewed the electrical distribution, mechanical systems, operation and testing for the SSF. The design basis specification for the 4160/600/120V SSF Essential AC Power System, Spec. OSS-0254.00-00-2-14, Rev. 0 was reviewed. The SSF was designed to provide the necessary equipment with an independent power source to achieve and maintain hot shutdown on any or all Oconee units for up to 72 hours in the event of a station blackout, loss of normal shutdown capability due to a fire as postulated by 10 CFR 50 Appendix R, sabotage, or turbine building flood. The SSF consists of a diesel generator, diesel service water system, SSF HVAC service water system, SSF diesel air system, SSF HVAC system, SSF auxiliary service water system, and SSF RC makeup system. In accordance with the above design basis document, the SSF is not required to meet single failure criteria since it is a backup to other existing safety systems installed in the Oconee units.

5.1 Review of Design

The team reviewed the EDS for the SSF. Calculations for the SSF were incomplete. A fault study for the SSF electrical system has never been performed. This was identified as an open item in the licensee's DBD for the completion of calculation OSC-5093. The licensee considers that the system design was adequate for potential faults on the SSF electrical system. The licensee provided three reasons for this conclusion. The electrical equipment was the same as equipment purchased for the plant thus they have the same fault duty ratings. The fault currents would be less within the SSF electrical system than faults within the Oconee units electrical system because of voltage drops through the cable. The SSF diesel generator was a smaller source of fault current than plant fault sources.

The licensee also identified possible miscoordination in the SSF electrical system. As identified in calculation OSC-1366, "Relay Settings for SSF Facility and Related Equipment," a possible miscoordination exists between the MCC XSF incoming breaker and the XSF feeder breakers. This cannot be determined until the completion of a fault study for the SSF facility.

Additionally, a voltage study has never been performed to document the adequacy of voltage in the SSF electrical system when it is being supplied from the SSF diesel generator. The licensee intends on performing these basic calculations to promote an increased confidence in the SSF electrical system. (See Appendix A, Finding 2)

The team's review of the RC makeup system determined that the pumps are required to deliver 26 gpm through the reactor coolant pump seal injection lines during an SSF event. The purpose of the 26 gpm is to provide cooling water to the reactor coolant pump seals to maintain the seals intact during an SSF event and to maintain RCS inventory. TS 3.1.6.9 states that loss of reactor coolant through reactor coolant pump seals and system valves to connecting systems (which vent to the gas vent header and from which coolant can be returned to the reactor coolant system) shall not be subject to the consideration of TS 3.1.6.1 through 3.1.6.7. An exception that such losses when added to leakage shall not exceed 30 gpm. This TS allows operation with leakage in excess of 26 gpm which exceeds the SSF makeup pump capacity.

The team questioned the adequacy of TS 3.1.6.9 with respect to the SSF. The licensee stated that the criteria for makeup capacity to the reactor coolant system is based upon Oconee operating experience and vendor information rather than allowable TS leakage rates. The intent is to provide makeup capability to the RCS based upon experience rather than extreme postulated conditions. The licensee also identified that the SSF SER dated 4/28/83 states that the capacity of the SSF RC makeup subsystem is sized to account for normal RCS leakage and shrinkage. The licensee stated that leakage rates approaching the limits stated in TS 3.1.6.9 are beyond the design basis of the SSF.

The team did not agree with the licensee position's that TS 3.1.6.9 was adequate as written. The team concluded that total leakage exceeding the capacity of the SSF makeup pump could result in questioning the operability of the makeup pump. The value specified in the TS exceeds the required capability of the SSF makeup system. This item is identified for further NRC review. This will be identified as IFI 93-02-04.

5.2 Testing

The inspection team reviewed the procedure, IP/0/A/0355/001B, "SSF 125 VDC Battery Service Test and Annual Surveillance", and observed the actual test and results for this battery surveillance. The results of the service test were consistent with the calculations performed by the team. No discrepancies were noted.

OSC-1132, 125 Volt DC Standby Shutdown Facility Auxiliary Power System Battery and Battery Charger Sizing Calculation was reviewed to verify the discharge amperages used to test the SSF 125 Volt DC battery systems for the yearly discharge test. This calculation is conservative and fully tests the capacity of the battery. No discrepancies were noted.

6.0 LOW VOLTAGE 600 VAC AND BELOW

6.1 600/208 VAC Power Systems Review

The team reviewed the 600/208 VAC low voltage power system to assess load current and short circuit current capabilities, voltage regulation, protection and coordination, and single failure criteria.

The team concluded that the 600/208 VAC low voltage power and 125 VDC systems were capable of supplying power of adequate voltage to safety-related loads and that sufficient redundancy exists to enable the systems to function despite a single failure of a safety related component. The team noted that some worst case scenarios were not considered in calculations, but preliminary calculations provided during the inspection demonstrated operability. It is expected that these calculations will be formalized to confirm the preliminary results. In addition, the team noted that testing used to demonstrate operability of equipment at voltages lower than manufacturer's guaranteed minimums was less than rigorous, and, in some cases, results were non-conservatively applied. The team did note, however, that testing generally demonstrated wide margins of available voltage so that this does not present a safety concern.

6.1.1 Voltage and Short Circuit Calculations

The team determined that voltage calculations did not consider worst case scenarios. Calculation OSC-2059, Oconee Unit 1 Voltage and Load Study, (without loss of off-site power) did not consider a single failure consisting of the spurious application of a large unscheduled load. Since the 4160 volt ES busses are interconnected, voltage effects

caused by such a failure would affect redundant safety strings. The licensee provided preliminary calculations which demonstrated that transient and steady state voltages resulting from this scenario would be 6% and 2.5% lower than previously analyzed, respectively, but these were bounded by worst case voltages determined in calculation OSC-2444 for a LOCA/LOOP fed by Keowee through the underground path.

Neither calculation OSC-2059 nor OSC-2444 considered worst case system alignments such as a feed from an alternate source. Preliminary calculations provided in response to the team's question demonstrated that voltages at safety busses could be approximately 1.5% lower than previously analyzed.

Voltage at the terminals of MCC control circuits had not been determined. Preliminary calculations provided in response to the team's inquiry showed voltages slightly lower than manufacturer's published minimums for starters, 82.16% of rated vs. 85% required. Base voltage used for this calculation was not derived from worst case scenarios, so slightly worst results are expected when these calculations are formalized. Alternate criteria cited in OSC-2059 were 65% for size 2 starters and 70.2% for size 5 starters. These criteria were based on tests of only one device of each size but they were nonetheless termed "minimum voltage criteria." The team agreed that adequate margin existed between the tested values and calculated voltage, but that a more rigorous approach was needed to establish conservative "minimum" operating voltages.

Calculation OSC-2059 demonstrated that all low voltage circuit breakers were applied within their interrupting ratings except one non-safety breaker which was applied approximately 2% in excess of its rating. This condition did not affect safety related equipment and was not considered significant. The licensee had not developed justification for fuses applied at voltages slightly higher than published ratings as recommended by the SITA team. Although the team considered this to be a valid concern, the fuses in question were used only in non-safety circuits and would experience overvoltage only during plant shutdown, and thus did not present a nuclear safety concern.

6.1.2 Protection, Coordination and Containment Electrical Penetration Protection

Coordination documented in calculation OSC-3120 was adequate although there was a lack of coordination between MCC load breakers and the MCC feeder breakers in the instantaneous region due to series molded case circuit breakers. Load cable impedance generally reduced fault levels such that coordination existed for faults at the loads. Armored cable was used and only one string was affected by faults near the output of breakers so this was adequate.

There was a slight loss of coordination between the 600 VAC MCC feeders and certain older model downstream 208 VAC MCC feeders. This miscoordination was in a narrow range and was not a significant problem.

Protective devices for low voltage motors were not expected to actuate during severe voltage dips experienced during loading from Keowee underground since control circuit fuses were sized for sustained inrushes and delayed contactor pickup was tolerable. Overload protection was oversized to avoid tripping of motors and Motor Operated Valve (MOV) motors could withstand stall conditions for the duration of expected voltage excursions.

The team noted that the licensee is not committed to and does not comply with IEEE-317 requirements for penetration back-up protection. In addition, formal calculations were not available to demonstrate the adequacy of primary protection. The licensee stated that a formal calculation was in progress.

6.1.3 Equipment Ratings

Calculations OSC-4441 and OSC-2059 demonstrated that ratings of load center transformers were adequate for expected loadings. There was no calculation relating to cable sizing, but a review of several cables by the team indicated conservative sizing for continuous, overload, and short circuit loading.

6.2 125 VDC Instrumentation and Control Power System

The 125 VDC Instrumentation and Control Power System was reviewed to assess battery capacity, system voltage, load and short circuit current capabilities, protection and coordination, and single failure criteria.

6.2.1 Battery Sizing and Battery Chargers

Battery capacity calculation OSC-2429 did not consider a single failure consisting of a fault on the system or the worst case configuration allowed by TS which would result in three batteries with 58 cells each available. Preliminary calculations performed by the licensee demonstrated that first minute voltage resulting from these scenarios would be lower by 0.7V and 0.9V, respectively, than the previously analyzed worst case. This difference was not sufficient to alter conclusions relative to system voltage as discussed below.

Calculation OSC-2059 demonstrated that battery chargers did not receive rated voltage under severely degraded grid conditions. The licensee provided an analysis to support operability of the chargers but no test data or vendor concurrence was available. The team noted that reduced battery charger output would not cause an immediate operability concern and that sustained operation at a voltage just above the first level protection setpoint was extremely unlikely. The licensee also stated that all of the chargers would be replaced within two years with equipment specified and tested to meet the postulated voltage extreme. On this basis, the team found the condition to be acceptable.

Per calculation OSC-4653, battery chargers were sized to meet the existing design basis of a one hour duty cycle. New chargers will be sized to meet the IEEE-946 criteria for an eight hour duty cycle.

6.2.2 System Voltage and Short Circuit Calculations

Draft calculation OSC-4276 indicated that system voltage was not sufficient to provide manufacturer's recommended minimum voltage to some equipment. Voltage shortfalls were small (less than 10% below guaranteed minimums) but component tests to prove adequacy were questionable in some cases.

Calculation OSC-2182 demonstrated that circuit breakers were adequately rated to interrupt the maximum available fault current.

6.2.3 Protection and Coordination

Data in calculation OSC-3120 indicated a lack of coordination in the instantaneous region between a non-safety load breaker and the upstream isolating diode protection and panelboard feeder breakers. This lack of coordination was for cable faults near or at the load breaker. Cable and fault resistance allow selective tripping for faults at the load. Armored cable was used and only one string was affected by unlikely close in faults, so this was adequate.

Calculation OSC-3120 further demonstrated that non-safety inverter isolating diode protection did not coordinate with upstream distribution center protection such that a bolted fault at the diode output could disable redundant 125 VDC strings. In response to the team's concern, the licensee performed preliminary calculations based on revised cable lengths which demonstrated adequate coordination.

6.3 Switchyard 125 VDC Power System

The Switchyard 125 VDC Power System was reviewed to assess battery capacity, system voltage, load and short circuit current capabilities, protection and coordination, and single failure criteria.

6.3.1 Battery Sizing

Calculation OSC-4458 determined switchyard battery capacity using a combination of measured loads and tabulated loads and was found to be adequate.

6.3.2 System Voltage and Short Circuit Calculations

Draft calculation OSC-4458 indicated that system voltage was not sufficient to provide manufacturer's recommended minimum voltage to some equipment. For example, the calculation determined that voltage at the terminals of the Cutler Hammer Type M relay used in the PCB trip on Transformer Lockout circuits was 71.5 VDC. This was less than 60% of rated voltage. Manufacturer's guaranteed pickup was 85% of rated, or

102 VDC. The calculation listed alternative minimum pickup voltages of 50% and 60% of rated for cold coils and warm coils respectively. These values were based on a test of 6 relays but the test report indicated that these were average values. These average values were incorrectly interpreted as the minimum values. The actual range of tested voltages was not known so the margin between the maximum tested values and calculated values could not be determined. (See Appendix A, Finding 2)

The team felt that rigorous testing of a statistically significant sample under controlled conditions, with conservative margins applied to the results should have been performed when manufacturer guaranteed minimums were not met. Test data presented to the team did not meet these standards.

Calculation OSC-3120 demonstrated that circuit breakers were adequately rated to interrupt the maximum available fault current.

6.3.3 Protection and Coordination

Data in calculation OSC-3120 indicated a lack of coordination in the instantaneous region of series molded case circuit breakers such that a fault at the output of the PCB control circuit isolation diodes could cause a loss of redundant panelboards. In response to the team's concern, the licensee performed preliminary calculations based on revised cable lengths which demonstrated that adequate coordination would exist for at least one panelboard, thus eliminating the possibility of losing redundant panelboards.

6.4 120 VAC Vital Power

Calculation OSC-4653 demonstrated adequate inverter capacity. Calculation OSC-3120 demonstrated adequate circuit breaker and fuse coordination.

EXIT MEETING

The team met with licensee representative noted in Appendix C at the conclusion of the inspection on March 5, 1993, at the plant site. There were no dissenting comments received. Proprietary information is not contained in this report.

Appendix A

Finding 1: Lack of Integrated Test of Emergency Power Source for Oconee and lack of test to demonstrate design capability.

Description:

The following electrical features of the emergency power source (Keowee) have not been tested nor has the power path been fully tested to demonstrate design capability:

The switchyard isolation (relay 94) of the EGIPS had never been tested. The switchyard isolate complete feature had not been tested. (para. 2.3.1)

The overhead path from Keowee to the switchyard has never been tested. (para. 3.3.1)

Keowee Hydro Emergency Start (PT/0/A/0620/16) test procedure does not test the units in the method that UFSAR Section 8.3.1.1.1 indicates that the unit is loaded. (para. 3.4.2.1)

The composite of the present Keowee tests do not bound the design requirements. (para. 3.4.2.1)

Safety Significance:

Tests would demonstrate that the emergency power system will perform its design bases function satisfactorily. A lack of these types of test could lead to the emergency power source being unavailable.

Finding 2: Analyses, study, or calculations not complete or not performed.

Description:

The following are examples of calculations that were not complete, or supportive:

The calculation OSC-2059 may not have taken the worst bounding condition when determining the voltage on the 4160V and lower voltage safety busses. (para. 2.3.2)

The team noted that there was no analysis nor test to verify that the rapid transfer (transfer of power to MFBs) timing was correct. (para. 2.5)

The licensee did not have a transient voltage study for the 4 kV safety load groups when they are supplied from the Lee gas turbine or from Central substation. (para 2.6.1)

No study had been conducted to review control cable length and the size of the fuses being used to protect such circuits. (para. 2.7.3)

KC-0073, Auxiliary Power System Voltage Level, Rev 1, (3/9/92), a voltage analysis of the Keowee 600V auxiliaries was considered incomplete. The maximum and minimum expected voltages should have been determined for the evaluation. (para. 3.2.4.4)

Analysis to support the fact that Keowee auxiliaries will not be degraded due to overvoltages or overfrequency conditions when being supplied from one Keowee Unit. (para. 3.2.4.4)

Identify the full scope and complete individual voltage component calculations for Keowee. (para. 3.2.4.4)

The licensee could not provide an analysis to support the assumption that Oconee safety loads could properly perform during an overfrequency transient lasting 40-50 seconds. (para. 3.3.3)

Several calculations were not complete for the SSF. (para. 5.1)

To support calculation OSC-4458 for the Switchyard 125 VDC power a more rigorous test of the minimum required pickup voltage may be needed. (para. 6.3.2)

Safety Significance:

Incomplete or inadequate design calculations can lead to unclear design bases, improper equipment specification and equipment qualification evaluations, performance, and modifications.

Finding 3: Examples of inadequate control of drawings and setpoint document.

Description:

Inaccuracies were noted in the recently developed Keowee mechanical support systems flow diagrams. Drawings of the Keowee air systems were not available. This was acknowledged as PIP-0-093-0197. (para. 3.2.2)

A controlled document for the setpoints at Keowee (except for electrical relay settings) was not available. (para. 3.3.4.3)

Safety Significance:

Lack of correct and controlled documents can effect how systems and components are maintained and operated.

Finding 4: Areas where additional licensee actions are warranted to complete corrective actions.

Description:

The response of the Keowee governor system to postulated failures (ie., loss of oil level) was not fully analyzed or understood. (para. 3.2.4.1)

Implementation of the setpoint revision to the Loss of Field relay at Keowee had not been implemented. (para. 3.2.4.1)

Safety Significance:

Corrective actions should be thorough and complete to assure that the complete problem is understood and corrected.

Finding 5: Keowee engineering analyses were not sufficiently comprehensive and specific values had not been established that would bound design criteria.

Description:

The licensee did not consider all credible failure modes for the Keowee govenor control system and voltage regulator. (para. 3.2.4.1)

The basis for bypassing Keowee trip functions during emergency start of the unit was not fully analyzed or documented. (para. 3.2.4.2)

The effect of frequency of the electric power supplied by Keowee to ECCS pump motors had not been fully evaluated. (para. 3.4.1)

Acceptable voltage and frequency limitations for Keowee electrical auxiliaries and the emergency power system should be defined. Additionally, acceptable recovery times from voltage and frequency excursions should also be identified. (para. 3.4.1)

Safety Significance:

Engineering analysis should be complete and address the application to which the equipment or system must perform.

Finding 6: Design Features and Mechanical Components at Keowee Were Identified That Were Not Being Tested.

Description:

The team identified several components involved in the operation of the Keowee units during an emergency start which were not being tested. (para. 3.4.2.4)

Testing was not being performed on safety related mechanical components (ie., coolers and pumps). (3.4.2.4)

Safety Significance

All design features and components that could effect the performance of the design bases function should be included in the testing of that function.

ACRONYMS AND ABBREVIATIONS

A	Amperes
ABB	Asea Brown Boveri
ACB	Air-operated Circuit Breaker
AEOD	Analysis and Evaluation of Operational Data, Office for (NRC)
AGC	Automatic Generation Control
AIT	Augmented Inspection Team
ANSI	American National Standards Institute
CCVT	Coupling Capacitor Voltage Transformer
CSMP	Continuous System Modeling Program
CTG	Combustion Turbine Generator
DBD	Design-basis Document
DBE	Design-basis Event
DED	Design Engineering Department
ECCS	Emergency Core Cooling System
EDS	Electrical Distribution System
EFW	Emergency Feed Water
EGTPS	External Grid Trouble Protection System
ES	Engineered Safeguards
GOPT	Governor Oil Pressure Tank
HPIP	High-pressure Injection Pump
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IPCEA	Insulated Power Cable Engineers Association
JTA	Job Task Analysis
KFD	Keowee Flow Drawing
kV	Kilovolts
LCO	Limiting Condition for Operation
LER	License Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MCC	Motor Control Center
MDEFW	Motor Driven Emergency Feedwater
MFBMP	Main Feeder Bus Monitoring Panel
MFB1	Main Feeder Bus 1
MFB2	Main Feeder Bus 2
MOV	Motor Operated Valve
MVA	Megavolt-Ampere
MW	Megawatt
NPRDS	Nuclear Plant Reliability Data System
NRC	Nuclear Regulatory Commission
ONS	Oconee Nuclear Station
PIP	Problem Identification Process
PIR	Problem Identification Report
PMG	Permanent Magnet Generator
PRA	Probablistic Risk Assessment
QC	Quality Control
QSM	Quality Standards Manual
RBS	Reactor Building Sprays
RCP	Reactor Coolant Pump

RCS	Reactor Coolant System
RFO	Refueling Outage
TS	Technical Specifications
SITA	Self Initiated Technical Audit
SQUG	Seismic Qualification Utility Group
UFSAR	Updated Final Safety Analysis Report
USAS	United States of America Standards
VAC	Volts Alternating Current

APPENDIX C

PERSONS CONTACTED

Licensee Employees

*S. Adams	Manager, Community Relations, Oconee
*?. Ballard	Corporate Communications, Charlotte
*W. Barron	Station Manager
R. Beaver	Electrical Engineer
R. Brock	Electrical Engineer
*D. Brown	Electrical Engineering
*R. Colaianni	Nuclear Licensing
D. Couch	Keowee Plant Manager
*D. Coyle	Systems Engineering Manager
*J. Davis	Safety Assurance Manager
D. Deatherage	Operations Support Manager
*R. Dobson	Supervisor, Electrical Engineering
*J. Hampton	Site Vice-President, Oconee site
*D. Hubbard	Component Engineering Manager
*N. Jamil	Electrical Engineering
*C. Little	I & E Superintendent
*B. McAlister	Supervisory Engineer, Component Engineering
*P. North	Compliance Engineer
*M. Patrick	Compliance Manager
*B. Peele	Engineering Manager
*G. Rothenberger	Superintendent, Work Control
*J. Rowley	Systems Engineering
*M. Sills	Civil Engineering
P. Stovall	Director of Operator Training
*P. Street	Systems Engineering
D. Sweigart	Operations Superintendent
*H. Tucker	Vice President Nuclear Operations

Other licensee employees contacted during this inspection included engineers, operators, technicians, and administrative personnel.

NRC Personnel:

*F. Burrows	NRR, Electrical Engineer
*K. Clark	Public Affairs
*B. Desai	Resident Inspector
*N. Fields	NRR, Events Assessment
*A. Gibson	Director, Division of Reactor Safety
*P. Harmon	Senior Resident Inspector
*A. Herdt	Branch Chief, Division of Reactor Projects
*C. Julian	Branch Chief, Division of Reactor Safety
*D. Matthews	NRR, Project Directorate
*J. Rosenthal	Branch Chief, Reactor Operations Analysis Branch, AEOD
*E. Weiss	NRR, Section Chief, Electrical Engineering
*L. Wiens	NRR, Project Manager

* Attended Exit Meeting

FIGURE 1
OCONEE ELECTRICAL DISTRIBUTION