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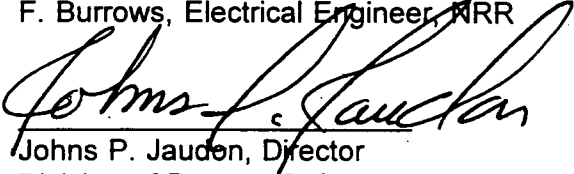
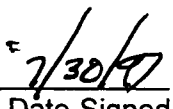
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EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2 & 3
NRC Inspection Report 50-269/97-11,
50-270/97-11, 50-287/97-11

The Augmented Inspection Team (AIT) reviewed the circumstances surrounding events associated with the failure of Keowee Unit 1 to achieve rated voltage following a loss of the Lee Steam Station dedicated electrical power path on June 20, the failure of Air Circuit Breaker (ACB) -7 and ACB-5 during testing on June 23, the licensee's response and investigation of the events, and the recovery. In addition, the AIT assessed generic aspects of Oconee and Keowee operations and inspections to evaluate applicability of the events to Keowee Unit 2 and the Oconee units. The report covers an eight-day period of reactive inspection using a team leader, one senior resident inspector, one regional reactor inspector and an electrical engineer from the NRC Office of Nuclear Reactor Regulation.

Engineering

- The AIT concluded that the licensee's investigation of the field flash breaker problem was effective. The AIT reached the same conclusions as the failure investigation process (FIP) which was that the root cause was potentially due to random fuse failure or random breaker failure. Accordingly, corrective actions were planned for both. The AIT concluded that the random breaker failure was the more probable of the two possible causes.
- A recent modification (set point change) may have increased the probability of the field flash breaker going to a "trip free" condition, which could defeat the generator start. The modification was performed outside the licensee's approved modification process and did not receive a post-modification test. In addition, the AIT identified an issue with the seismic qualification of a field flash overvoltage relay.
- The AIT concluded that the fuses installed in the field flash breaker control circuit were the correct fuses from a design viewpoint and that misapplication of a fuse was not a cause of the fuse blowing.
- Licensee post event analysis identified a defective close coil in the Keowee Unit 1 field flash breaker. The AIT learned that the close coils for this type (DB-25) circuit breaker may draw significantly higher currents than given in published data. AIT questions about this problem caused the licensee to perform an operability evaluation on voltage adequacy in the DC system. The AIT concluded that close coils may not be fully protected by the fuses and may be subjected to operating conditions beyond their rating as a result of breaker malfunctions. The licensee was evaluating this issue for potential corrective action.

- The AIT concluded that the licensee's failure investigation of the loss of auxiliary power effecting ACB-7 and ACB-5 on June 23, 1997, was effective. The AIT reached the same conclusions as the FIP on the root causes and also concluded that the FIP Team accomplished their evaluation in a detailed, critical, and methodical manner. Also, the licensee's personnel (from Oconee and the licensee's headquarters) were knowledgeable and addressed all pertinent issues.
- The AIT concluded that the licensee's activities related to the ACB-7 timer failure evaluation and its generic aspects were technically sound. The ACB-7 timer failure was most likely caused by the effects of an encapsulating epoxy expansion on the timer potentiometer.
- The AIT concluded that the licensee's choice of timer and timer setpoint used in ACB's 5, 6, 7, and 8 and the other Keowee DB-50 breaker closing coil circuitry may not be appropriate for its current use, even though the timer manufacturer verified the accuracy of the timer at the in-use setting.
- The AIT concluded that the licensee's activities related to the evaluation of the blown fuses in ACB-5 and ACB-7 and its generic aspects were technically sound, thorough, and adequate.
- The AIT concluded, based on review of the historical data of similar equipment failures and events, that fuse and circuitry design interactions may have contributed to breaker failures. The AIT also concluded that the number of timer failures (probably only one actual failure) did not appear to indicate a recurring problem. The AIT concluded that the anti-pump circuitry design using the "X" and "Y" relays may have also been a contributor to breaker failures, involving blown fuses, burnt coils, and switchgear lockouts. The AIT concluded that the corrective actions for the October 1992 loss of offsite power event did not directly cause the problems in 1997.
- The AIT concluded that both Keowee units were similar in design and that the problems of June 20 and June 23, 1997, could have manifested on either of the Keowee units. The auto-closure problem with the DB-25 breakers was not applicable to the Keowee motor control centers.

Maintenance

- The AIT concluded that the lack of detailed guidance in the preventive maintenance procedure for measuring the timer settings for the "Y" coil in DB-50 breakers was a weakness. Also, since all timers checked following the June 23, 1997, event were found with settings well below the required setpoint, past operability of the Keowee DB-50 breakers was questionable. Licensee low voltage testing revealed that all were operable, with the exception of ACB-6. The breaker was subsequently determined to have been operable.

- The AIT review of the licensee's maintenance procedure for the DB-25 circuit breakers identified that the procedure was generally in agreement with the Westinghouse Technical Manual, except one significant specific prevention maintenance step was omitted. This omission was the result of a deficiency in the process of translating information from technical manuals to Oconee procedures.

Operations

- The failure to follow a Lee Steam Station operating procedure caused the loss of the Oconee main feeder fuses on June 20, 1997. Further, the AIT noted several procedural deficiencies as well as training and knowledge deficiencies related to the Lee staff with regard to supporting technical specification required activities.
- The AIT concluded that the alarm response guide for Switchgear 1X was inadequate because it allowed the operator to reset the ACB-5 and ACB-7 lockout with the transfer scheme in automatic, which caused the unanticipated circuit response and blown fuses. Based on interviews and review of the sequence of events, the AIT determined that the Keowee operators appropriately followed established procedures. Also the team reviewed the revised guide and concluded that it was much improved with adequate detail, including appropriate caution and warnings.
- The AIT concluded that compensatory measures, including replacement of the fuse on the field flashing breaker following each emergency start, and the decision to evaluate the use of periodic emergency starts of the Keowee units to better assess the reliability, were satisfactory. The licensee conclusion to consider the Keowee units operable but degraded, pending successful completion of planned corrective actions, was deemed appropriate.
- The licensee did not verify operability of Keowee Unit 2 to the underground path within one hour of a failure of the other Keowee unit as required by the technical specifications. Keowee Unit 2 was verified operable in approximately two hours. No additional issues relating to meeting technical specification action statement requirements were identified. Further, the licensee confirmed that for the scenarios that the AIT questioned, design bases were maintained during the performance of the periodic test.

Plant Support

- The AIT reviewed the reportability decision basis for the events of June 20 and 23, understood the basis for the issues and agreed with all the decisions except the emergency start of the Keowee units on June 20, for which a voluntary notification was submitted. This issue will be reviewed with respect to the licensee's position that the June 20 Keowee start was a non-ESF start because the AIT questioned whether or not a report was required to be made.

REPORT DETAILS

Augmented Inspection Team (AIT) Charter

On June 27, 1997, an AIT was established by the NRC Region II Administrator to inspect and assess the circumstances surrounding two events that resulted in the failure of Keowee Unit 1 to achieve rated voltage following a loss of the Lee Steam Station dedicated electrical power path on June 20; and the failure of Air Circuit Breakers (ACBs) -7 and 5 during testing on June 23. The Augmented Inspection Team Charter Memorandum, with Attachment, is included as Attachment 1 of this report.

Summary of Plant Status and Events

Prior to the event, Oconee Unit 1 was shutdown, with low pressure injection (LPI) in service, for decay heat removal. Nitrogen pressure on the pressurizer was maintaining pressure at approximately 40 psig. Reactor coolant system (RCS) temperature was approximately 100 degrees F. Fuel was in the vessel, with vessel head tensioned. The unit was shutdown seven days before the event for high pressure injection (HPI) nozzle inspection and modifications related to the letdown storage tank (LDST). Both Oconee Units 2 and 3 were at 100 percent power. The main feeder buses for all three units were energized and Keowee Unit 1 was operable and in standby to the underground path and Keowee Unit 2 was operable and in standby to the overhead path.

On June 20, 1997, Oconee Unit 1 was performing a test of the 100 kV power supply from a Lee Station gas turbine via the 100 kV dedicated path. At 12:44 pm, the Keowee Unit auxiliaries, which were supplied from Oconee Unit 1, lost power when the 6C Lee gas turbine isolated itself from the line. After 20 seconds, both Keowee Units received an emergency start signal. Keowee Unit 1 was required to emergency start without any power to its auxiliary loads, which is generally referred to as a black start. Keowee Unit 1 started upon demand; however, the generator excitation failed with the result that the unit failed to energize the underground path. The voltage regulator field and supply breakers did close, and the field flash breaker closed. However, the regulator never saw enough voltage to become self-sustaining, so it did not transition into automatic. Initial troubleshooting revealed that the negative control power fuse for the field flash breaker had opened ("blown").

On June 23, 1997, Oconee Unit 1 was in the process of completing the test of the 100 Kv power supply from a Lee Station gas turbine. This test was reformed due to problems on June 20, 1997. The Lee gas turbine had been successfully connected to the 100 Kv dedicated path and loaded to the equivalent of an Oconee units maximum safeguards loads. After the test of the 100 kV dedicated line was completed, buses were being returned to their normal lineup by performing dead bus transfers of certain switchgear. Keowee Unit 1 Auxiliaries Switchgear 1X was being supplied from Oconee Unit 1 Switchgear 1TC via Breaker ACB-7. During the dead bus transfer, power was lost to Switchgear 1X, as expected, when ACB-7 tripped open after power to Switchgear 1TC was momentarily interrupted as part of the procedure. When power was restored to Switchgear 1TC, ACB-7 attempted reclosure on to Switchgear 1X but unexpectedly tripped open. This action initiated a Switchgear 1X lockout, as designed. By procedure, the operator checked the breaker and seeing no abnormal indications, reset the lockout. Both ACB-7 and ACB-5 attempted to close on Switchgear 1X. Both breakers immediately tripped open because of the interlock

which prevented simultaneous closure of both breakers. Details of the events are further discussed in the report details and in the Sequence of Events, Attachment 2.

Sequence of Events

The AIT charter required the team to develop a sequence of events associated with the specific failure events of concern. The AIT developed the sequence of events based on information gathered from Oconee control room logs, Keowee logs, sequence of events recorders, data printouts, interviews with personnel involved with the event, and from review of the licensee generated sequence of events. Some of the times associated with events are best approximates. The Sequence of Events is provided in Attachment 2 of this report. Also, a description of the Oconee electrical distribution system and an associated simplified electrical drawing are contained in Attachments 3 and 4, respectively.

I. Engineering

E1 Conduct of Engineering

E1.1 Failure Investigation of Generator Field Flash Breaker Problem

a. Inspection Scope (93800)

The AIT charter included instructions to evaluate the licensee's activities related to the event investigations (i.e., root cause analysis, precursor event reviews, etc.) and evaluate the effectiveness of the related Failure Investigation Process (FIP) team. The first problem requiring investigation was failure of Keowee Unit 1 to achieve rated voltage following an emergency start signal on June 20, 1997. This was caused by failure of the field flash circuit, which was due to blowing of a fuse in the field flash breaker control circuit.

b. Observations and Findings

The licensee formed a FIP (FIP Team #1) team which was dedicated to evaluating the problem of the blown fuse in the control circuit for the Keowee Unit 1 field flash breaker. The AIT reviewed three revisions to the FIP team's preliminary report. The final report had not been issued at the conclusion of the inspection.

The design for the field flash breaker operation included a specific logic sequence. Upon a Keowee emergency start signal, the field flash breaker (and other breakers in the voltage regulator) close to apply DC voltage to the field at time equal to zero, i.e. no intentional delay for speed buildup. An overvoltage relay (53 relay) senses at generator output voltage and trips the field flash breaker at the appropriate voltage level.

The field flash breaker is a DB-25, solenoid operated power circuit breaker manufactured by Westinghouse Electric Corporation. The control circuit power for this breaker is 125 VDC.

During the event, all control circuitry and equipment initially worked as designed. As generator voltage was building up, the 53 relay cycled between normal and trip. This caused the field flash breaker to cycle. The sequence of events recorder indicated the breaker tripped, closed and tripped; and the control power fuse blew 6 seconds after the final breaker trip. With the field flash breaker stuck open, and the generator voltage not yet at a level which could sustain self-excitation, the generator failed to achieve rated voltage.

The AIT observed that the FIP team addressed all the relevant areas. The FIP team performed the following actions.

- evaluated the control circuit fuse sizing,
- performed laboratory analysis on the blown fuse,
- reproduced the event conditions in a post-event test measuring control circuit current and voltage,
- performed all checks contained in the maintenance procedure on the breaker,
- performed bench testing on an overvoltage relay of the same style as the one that cycled during the event,
- reviewed the maintenance/failure history on the breaker, and
- performed diagnostic checks on the close coil.

The conclusion from this analysis was that the blown fuse was caused by one of the following two causes.

- Random failure of the fuse which had been weakened by accelerated aging due to being subjected to repeated current pulses of a magnitude equal to three times its continuous rating.
- Random failure of the breaker where the failure mechanism was going to the "trip free" mode. "Trip free" mode means that the breaker trips open in such a manner that latches in the operating mechanism fail to engage in their normal position. Subsequent attempts to close the breaker will fail and leave the close coil energized. This results in blowing the control fuse, overheating the close coil or both. The same condition can result during an attempted close operation. It was known from experience at Ocone that this breaker style was susceptible to this phenomenon, which was believed to be caused by mechanism recoil. The rapid cycling caused by the erratic overvoltage relay increased the probability of "trip free" mode. Once the close coil deenergizes, the latches are expected to return to normal position. Therefore, inspection of the breaker immediately following the event could not confirm this potential cause. There could also have been a relay/contact timing problem inherent in

the X-Y modification (Reference Section E2.2), implemented previously to correct another problem.

Based on review of the preliminary FIP report, examination of the breaker and overvoltage relay, discussions with plant personnel, and examination of drawings and documents on file, the AIT reached the same conclusion as the FIP report. Subsequent sections of this report will present further details about the evaluation of the fuse (Section E1.3), overvoltage relay (Section E1.2), close coil (Section E1.4) and maintenance procedure (Section M1.2). While the AIT found that the FIP team did very effective work, the AIT had the following comments on the FIP.

- The FIP team failed to evaluate the time rating of the close coil in developing longer term corrective actions.
- The FIP team did not review the breaker maintenance procedure against the manufacturer's recommendations. The AIT performed this review, and found one step recommended by the manufacturer that was not in the licensee's maintenance procedure.

The FIP report was not finalized at the end of the inspection because the maintenance step mentioned above had to be performed, a final laboratory report on the close coil had not been received and corrective action recommendations had not been finalized. The AIT concluded that the basic conclusions of the preliminary report would not change in the final report.

c. Conclusions

The AIT concluded that the licensee's investigation of the field flash breaker problem was effective. The AIT reached the same conclusions as the FIP which was that the root cause was potentially due to random fuse failure or random breaker failure. Accordingly, corrective actions are planned for both. Because the fuse blew 6 seconds after the final breaker trip and since the overvoltage relay had probably not stabilized at this point, the AIT concluded that the random breaker failure was the more probable of the two possible causes.

E1.2 Evaluation of the Overvoltage Relay

a. Inspection Scope (93800)

The AIT charter included instructions to evaluate the events for any relationships to recent modifications. The set point for an overvoltage relay in the voltage regulator had recently been changed, and the AIT evaluated this change in light of the failure of Keowee Unit 1 to achieve rated voltage following an emergency start signal on June 20, 1997.

b. Observations and Findings

The voltage regulator circuitry for the Keowee units includes an overvoltage relay, which senses generator output voltage, and the output contacts of this overvoltage relay control the field flash circuit breaker. The relay is a Westinghouse Electric Corporation style SV 292B402A10 rated 120 V, 60 cycle. The set point is adjustable from 70 - 160 V. It is an instantaneous plunger type relay of high accuracy. It has one normally open and one normally closed output contact. The contact travel between normal and tripped condition is about 0.75 inch.

The relay was not part of the standard equipment supplied by Westinghouse Electric Corporation with the hydro generator. The voltage regulator circuitry was modified at initial start-up to incorporate field flashing at time equal to zero for emergency starts. (Field flashing is controlled by a frequency relay for normal starts and occurs later in the start sequence.) Part of the modification installed the SV style overvoltage relay. The output contacts were placed in the control circuit of the field flash breaker normally open contact in the trip circuit and normally closed in the close circuit. The relay was set to operate at 100 V, 60 cycles. The concept was to trip and lockout the field flash breaker after the voltage regulator had switched to automatic mode and the generator was self excited. However, there was no documented basis for the 100 V setting.

In 1995, as part of the Emergency Power Project (Keowee), a calculation was performed to establish a set point for the SV style overvoltage relay and other set points associated with the voltage regulator. This calculation was KC-Unit 1 & 2-2023, Analysis of Keowee Voltage Regulator Settings, and it was approved in June 1995. Calculation Section 6.11, Voltage Buildup Relays, stated the generator was able to supply its own excitation at 20 percent voltage. Twenty percent generator voltage corresponded to 23 V at the relay, and, as stated above, the minimum setting was 70 V; therefore the calculation recommended a setting of 70 V. This calculation was the basis for developing Calibration Procedure IP/O/A/2005/003 which covered the whole voltage regulator. The relay in question was designated 53-31T. The set point was changed from 100 V to 70 V in March 1997 for Keowee Unit 1 and in October 1996 for Unit 2 using the new calibration procedure. These dates and voltage values were confirmed by the AIT by reference to plant records.

The AIT noted that the 53-31T relay set point was changed outside the licensee's plant modification process. The change was made via a calculation and calibration. The calculation, which formed the basis for the change, was performed according to the quality assurance program, and the calibration procedure, which implemented the change, received a safety evaluation and 10 CFR 50.59 screening. The AIT judged that the set point change was basically a safety-related plant modification; however, no post-modification test was specified or performed. Had a post modification test been conducted, the licensee could have identified that the 53-31T relay was not working as intended. The reason that the relay was not working as intended was that the KC-2023 calculation did not include all the relevant design inputs. The design inputs not considered were that the 53-31T relay would see low frequencies and the set point of the SV style relay varies directly with frequency. For example, the pickup

at 30 cycles is 50 percent of the pickup at 60 cycles. This information was not presented in Westinghouse Instruction I.L. 41-766.1J, which covered the SV style relay. However, it is presented in the book "Applied Protective Relaying" by Westinghouse in Section XIII. Generator Protection at Reduced Frequencies, Page 6-15.

As part of the Failure Investigation Process, the licensee bench tested the 53-31T relay. The test showed that an SV style relay calibrated to pickup at 100 V, 60 cycles, when subjected to 5 cycle input, would exhibit chatter of the normally closed contact at 9 V increasing. The test also showed that an SV style relay calibrated to pickup at 70 V, 60 cycles, when subjected to 5 cycle input, would begin to rapidly oscillate between the pickup and normal state at 9 V increasing. These particular voltage and frequency values are significant because they correspond to an actual point on the voltage/frequency buildup curves for an emergency generator start. This information explained certain data recorded by the sequence of events recorder. Sequence of events recorder data showed that, after the 53-31T relay set point had been changed, the field flash breaker would cycle rapidly during emergency starts where the relay was sensing low frequency and low voltage generator output. Similar records going back to and including 1994 indicated that the field flash breaker had not cycled during emergency starts before the set point change. The set point change altered the behavior of the 53-31T relay to the point where it would cause the field flash breaker to cycle. Cycling of the breaker, by itself, does not result in a failed generator start. As stated in Section E1.1 of this report rapid breaker cycling is believed to increase the probability of the breaker going to the "trip free" condition, which can defeat the generator start.

On July 8, during the inspection period, the licensee implemented a minor modification changing the set point of the 53-31T relay to 83.5 V in an attempt to eliminate the breaker cycling. This set point was derived from the results of bench testing on a SV style relay. However, the post-modification test showed that the breaker still cycled at the new set point, although the cycling was reduced in severity.

At the end of the inspection, the licensee intended to raise the set point back to 100 V as records showed that good operation was achieved at that set point. In the longer term, the licensee intends to reevaluate the application and concept of the SV style relay.

On July 17, 1997, the licensee reset the 53-31T relay to pick-up at 100 V, 60 cycles. Keowee Unit 1 had the relay setting changed. An emergency start test was done, which started both Keowee units. Then the change was made to Keowee Unit 2, and this was followed with a second emergency start test. Finally, the licensee performed one additional emergency start test. NRC Resident Inspectors witnessed the three emergency start tests. The licensee observed that the generators started and ran successfully with no significant test anomalies. The Resident Inspectors also specifically observed that the field flash breaker cycled only once as intended after the relay had been set at 100 V. In a subsequent conference call with several AIT members, the licensee further described that the field flash breaker, after the set point change, remained closed for 9.2 to 9.7 seconds during the emergency starts. The

licensee also stated that the new set point was expected to coordinate with the timing of breakers which applied load to the generator, thereby ensuring that the field flash was disconnected prior to loading the generator.

The AIT made the following additional observations concerning the KC-2023 calculation. First, the calculation states that the SV style relay was identified as an outlier in the SQUG program and should be replaced with a seismically qualified relay. The AIT discussed this issue with the cognizant engineer. That engineer stated that this changeout was tentatively scheduled for 1997 but could be delayed. This appeared to be contrary to the intent of the guidance in Generic Letter 91-18. Second, certain statements in the calculation indicated that the persons involved with the calculation were aware that the SV style relay could cycle between normal and pickup state as generator voltage built up at reduced frequencies. Apparently, the ramifications of that knowledge had not been explored.

c. Conclusions

A recent modification (set point change) may have increased the probability of the field flash breaker going to a "trip free" condition, which could defeat the generator start. The modification was performed outside the licensee's approved modification process and did not receive a post-modification test. In addition, the AIT identified an issue with the seismic qualification of the overvoltage relay.

E1.3 Evaluation of Fuse Application in Field Flash Breaker Control Circuit

a. Inspection Scope (93800)

The AIT evaluated the application of the fuses in the field flash breaker control circuit.

b. Observations and Findings

In a post-event test recreating the conditions of the event, the current seen by the control circuit fuses in the field flash breaker 125 VDC control circuit was recorded. This recording showed that the current peaked at 38 amps. It was later found that the close coil, which would account for most of the current, (the other devices in the circuit have high impedance) had an internal defect. This defect caused the close coil to draw more current than would a close coil without a defect. The resistance of this defective close coil was measured to be 2.8 ohms, which was consistent with the 38 amps mentioned above.

The fuses in the circuit at the time of the event were 15 amps NON style, Class H, fuses manufactured by Bussman Company. The exact age could not be determined, but they were manufactured prior to 1986 as deduced from the fact that Cooper Industries did not appear on the labels. This fuse size was the same as shown on the Duke Power Company elementary diagram and the wiring diagram furnished by Westinghouse Electric Corporation. The manufacturer's instruction book for the circuit breaker recommended a 10 amp fuse.

The time-current curve for the 15 amp NON fuse, published by Bussman Company, indicated that the average melt time for a 38 amp fuse was 10 seconds at 25°C. Therefore, the breaker cycling that occurred during the event should not result in fuse melt. This conclusion was substantiated by the fact that field flash breaker cycling had occurred on both Keowee units on several occasions without blowing the control fuse. In addition, the sequence of events recorder indicated that the fuse blew 6 seconds after the last breaker trip. That fact substantiated the potential of a continuously energized close coil.

The failed fuse and the other fuse in the field flash breaker control circuit were cut open at the Duke Power Company laboratory; however, the laboratory apparently came to no definite conclusion as to the level of current that caused the fuse to blow. These fuses were later sent to Cooper/Bussman Company for analysis. Cooper/Bussman concluded that the blown fuse had been subjected to some level of overcurrent.

Four other fuses were sent to Cooper/Bussman for analysis: Two fuses from the Keowee Unit 2 field flash breaker, which had probably been in-service since 1993, and two fuses removed from the Unit 1 field flash breaker after the post-event test. The report by Cooper/Bussman stated: "Due to discoloration of the copper, and the temperature required to change the color, it appears that a long term fatigue situation is occurring." It was not clear to the AIT whether Cooper/Bussman made this statement in the context of the fuses having been subjected to 38 amps for five seconds, which did not correspond to any actual condition. Due to this ambiguous statement in the Cooper/Bussman report, the licensee initiated the conservative corrective action of changing out the control circuit fuses any time the field flash breaker cycles rapidly, such as after every emergency start.

c. Conclusions

The AIT concluded that the fuses installed in the field flash breaker control circuit were the correct fuses from a design viewpoint and that misapplication of a fuse was not a cause of the fuse blowing.

E1.4 Evaluation of the Close Coils in DB-25 and DB-50 Circuit Breaker

a. Inspection Scope (93800)

In the process of determining the root cause of the failure of Keowee Unit 1 to achieve rated voltage following a valid start signal on June 20, 1997, the AIT identified issues related to the close coils in the DB-25 and DB-50 circuit breakers.

b. Observations and Findings

Background Information

The DB-25 circuit breaker is a solenoid operated breaker, which means the motive force to close the breaker and charge the tripping spring is supplied by a solenoid or

close coil. In 1979 or possibly early 1980, the close coils in the DB-25 circuit breakers for the field flash breaker and other functions were changed from the high burden coil originally supplied with the circuit breakers to standard burden coils. This change was driven by the concern that the high burden coils were supplying excessive operating force to the circuit breaker thus increasing the probability of the breaker going to the "trip free" condition upon close or open operations and causing excessive wear on the mechanism.

As part of the post event trouble shooting, the licensee measured the current in the control circuit during a generator start. The measured current was 38 amps. The engineer evaluating the fuse application noticed that this value of current was not consistent with the information in the instruction book for the breaker which stated that the current draw of the standard close coil is 23 amps at nominal voltage. The engineer wrote a PIP (Problem Investigation Process) report. This caused the licensee to measure the resistance in the close coil for the Keowee Unit 1 field flash breaker. The licensee measured 2.8 ohms, which would correspond to 44.6 amps at 125 VDC. At that point, the close coil was removed and quarantined for analysis. The coil was sent to a test laboratory affiliated with Westinghouse Electric Corporation. Preliminary results of the analysis indicated that the coil was in fact a standard burden coil, and that a number of turns were shorted which accounted for the unusually low resistance and high current.

Issues

The AIT obtained information on the resistance of the standard and high burden coils in the DB-25 circuit breaker. Referring to notes of telephone conversation with an engineer at an equipment supply/repair facility associated with Westinghouse Electric Corporation, the System Engineer stated that the standard burden coil has a resistance in the range of 3.2 to 4.0 ohms, with 3.6 being average. These values were at 25°C. The high burden coil has a resistance in the range of 2.1 to 2.7 ohms, with 2.4 being average. These values were further substantiated by field measurements on two standard burden coils which measured 3.6 ohms. Instruction Manual I.B. 33-850-1 & 2E, effective May 1965, indicated the closing current was 23 amps for the standard burden and 34 amps for the high burden coil. The differing telephone information and the manual information might not be inconsistent because the current draw may not reach full E/R value if the coil is deenergized prior to the current reaching steady state.

In light of the possible discrepancy between the information in the instruction manual and the verbal information, the AIT questioned what values the battery loading and DC System voltage drop calculations were using. The AIT found that the battery loading calculation would not be affected because that calculation was based on actual measurements of current during simulated design basis conditions. The voltage drop calculation was using the instruction manual values. The licensee performed an operability evaluation using the higher current values, and concluded that the system was still operable. This was primarily due to the fact that the original calculation incorporated a number of very conservative assumptions. The AIT did not identify any problems with the operability evaluation.

In addition, the AIT questioned the fuse size in the control circuit for the motor control center feeder breakers at Keowee. These circuits are protected by 10 amp fuses. Review of the fuse time-current characteristics provided by the licensee led the AIT to the conclusion that the 10 amp fuse could open upon an otherwise normal breaker operation. Using the 3.2 ohms mentioned above (i.e., from verbal information), the close coil could draw 39 amps. When tolerance on the average melt time is factored in, it was estimated that a 10 amp fuse seeing 39 amps could blow in about 0.3 seconds, which does not leave sufficient margin. Although the motor control center feeder breakers do not receive automatic open or close signals, the fuses for these breakers should not interfere with normal operation.

Another question raised by the AIT regarding the close coils for the DB-25 and DB-50 circuit breakers was whether the close coils were protected by the fuses. The concern involved cases where the close coil was not de-energized immediately after breaker closure. Specifically, the AIT inquired as to the time rating of the close coils. The licensee contacted Westinghouse Electric Corporation or Westinghouse affiliated persons to obtain this information. No definite time rating was provided as a result of these inquiries. The response was that the coils probably had about a one-minute rating. This response was questioned by the AIT because the AIT was aware of licensee problem reports where the close coil had sustained damage following a breaker malfunction. The concept that a close coil could be subjected to operating conditions beyond its rating even though the protective fuse opens was not considered by the licensee's FIP. The licensee responded to the AIT's concerns by stating that they planned to implement administrative controls to ensure that the condition of the close coil is evaluated following any mis-operation of the DB-25 or DB-50 circuit breakers.

c. Conclusions

Post event analysis identified a defective close coil in the Keowee Unit 1 field flash breaker. The AIT did not conclude this was the cause of the breaker failure. The AIT learned that the close coils for DB-25 circuit breakers may draw significantly higher currents than given in published data. AIT questions about this problem caused the licensee to perform an operability evaluation on voltage adequacy in the DC system. The AIT concluded that close coils may not be fully protected by the fuses and may be subjected to operating conditions beyond their rating as a result of breaker malfunctions. The licensee was evaluating this issue for potential corrective action.

E1.5 Failure Investigation of Loss Auxiliary Power at Keowee

a. Inspection Scope (93800)

The AIT charter required the team to evaluate the licensee's activities related to event investigations (i.e., root cause analysis, precursor event reviews, etc.) and evaluate the effectiveness of the related FIP team. A FIP team investigated the loss of auxiliary power from Switchgear 1X for Keowee Unit 1 on June 23, 1997. This was caused by the failure of the timer for the "Y" coil in the ACB 7 control circuitry leading

to a lockout of Switchgear 1X. Subsequently, fuses in the closing coil circuits for ACB 5 and ACB 7 blew when the Keowee operator reset the lockout condition.

b. Observations and Findings

The licensee had a Failure Investigation Process team (FIP Team #2) dedicated to the problems associated with the loss of auxiliary power from Switchgear 1X. The AIT reviewed two revisions to the FIP team's draft report. The final report had not been issued at the conclusion of the inspection.

The supply breakers for Switchgear 1X (ACB 5 and ACB 7) are designed with an impact spring that moves down and forward on closure of the breaker. If the breaker is tripped manually or by an overcurrent condition sensed by the built-in amptector, the impact spring will move straight back and, by contacting a micro-switch, will initiate a lockout of the switchgear. Also if the breaker-closing mechanism fails to latch during a closing cycle, lockout will be activated by the action of the impact spring and the micro-switch. As discussed in Section E1.6, the failure of a timer in the "Y" coil circuitry of ACB 7 led to the misoperation of ACB 7 and the related action of the impact spring caused the lockout of Switchgear 1X, on June 23, 1997.

Also, as shown in Attachment 5, Switchgear 1X has two sources of power, ACB 5 or ACB 7. The sources of power are Transformer CX through ACB-5 associated with the Keowee underground path and Transformer 1X through ACB-7 associated with the Keowee overhead path. The breaker control circuitry contains timers and undervoltage relays to provide automatic transfer capability to the redundant source should the selected source be lost. Interlocks are also included in the control circuitry to ensure that both breakers are not closed at the same time to prevent paralleling of the redundant sources. As discussed in detail in Section E2.1, the unanticipated operation of the transfer and interlock circuitry within these breakers caused the fuses to blow in the closing coil circuits of ACB 5 and ACB 7, when the Keowee operator reset the lockout of Switchgear 1X on June 23, 1997.

The supply breakers are DB-50, solenoid operated power circuit breakers manufactured by Westinghouse Electric Corporation. The control circuit power for these breakers is 125 Vdc.

The AIT observed that the FIP team addressed all the relevant areas. For the lockout of Switchgear 1X, the FIP team performed bench testing of ACB 7, evaluated the potential failure modes of the breaker, reviewed breaker and timer failure history, reviewed the timer design, investigated the timer calibration history and procedure; obtained manufacturer's analyses of the failed timer, and reviewed the alarm response guide (ARG). The FIP team concluded that the root cause of the lockout was the failure of the timer in the "Y" coil circuitry for ACB 7. The timer failed in such a manner that the resulting very small time delay did not provide for adequate closing and latching of the breaker which led to the lockout condition.

For the blown fuses in the closing coil circuitry of ACB 5 and ACB 7, the FIP team performed bench testing of ACB 5 and ACB 7 using approved preventive maintenance procedures, evaluated the potential failure modes of ACB 5 and ACB 7 control circuitry, reviewed the acceptability of fuse type and size; investigated fuses degradation issues and failure history, and obtained manufacturer's analysis of the blown fuses. The FIP team concluded that the root cause of the blown fuses in ACB 5 and ACB 7 control circuitry was the breakers trying to close simultaneously when the Keowee operator reset the lockout condition. Because of interlocks in the control circuitry, both breakers then received trip signals before they were completely closed and latched and went to the "trip-free" condition, as discussed in Section E2.1 of this report. This action resulted in the breakers closing coils remaining energized until the associated fuses blew on overcurrent.

Based on review of the draft FIP report, examination of the breaker operating mechanism and design, discussions with plant personnel, and examination of drawings and documents on file, the AIT reached the same conclusion as the FIP report. Subsequent sections of this report present further details about the evaluation of the timer failure (Section E1.6), calibration (Section M1.1), and range (Section E1.7), Switchgear 1X lockout reset (Section O1.2), and the ACB 5 and ACB 7 blown fuses (Section E2.1).

c. Conclusions

The AIT concluded that the licensee's failure investigation of the loss of auxiliary power from Switchgear 1X on June 23, 1997, was effective. The AIT reached the same conclusions as the FIP on the root causes of those two problems. The AIT also concluded that the FIP Team accomplished their evaluation in a detailed, critical, and methodical manner. Also the licensee's personnel (from Oconee and the licensee's headquarters) were knowledgeable and addressed all pertinent issues.

E1.6 ACB 7 Timer Failure Evaluation

a. Inspection Scope (93800)

The AIT Charter required the AIT to "Assess the licensee's activities related to the event investigations (e.g., root cause analysis, precursor event reviews, etc.)" and to "Assess the generic aspects of the Keowee Unit 1 equipment failures with respect to the applicability to Keowee Unit 2, as well as the Oconee Units."

b. Observations and Findings

On the morning of June 24, 1997, FIP Team #2 began investigating the root cause of the 1X lockout and ACB 5 and ACB 7 failures. A schematic of the ACB-5 and ACB-7 close control circuit is provided in Attachment 7. Bench testing revealed that the timer for the "Y" coil in the closing circuit for ACB 7 operated well below its nominal setpoint of 0.325 seconds. Further bench testing on June 25, 1997, disclosed that the timer did not provide a long enough time delay to keep the closing coil energized to ensure closing and latching of the breaker. With the failed timer reinstalled in ACB 7, this

defect revealed the breaker closing mechanism to move back away from the closed position and the mechanical linkage to actuate a microswitch which would initiate the switchgear lockout relay. The time delay provided by the timer was estimated to be about 0.020 seconds.

Subsequently, the licensee initiated conversations with the timer manufacturer, Cutler-Hammer. Those discussions revealed that there could be five potential failure modes related to the timer failing to provide a time delay. The failed timer was sent to the manufacturer for further testing. On June 28, 1997, Cutler-Hammer inspected the timer and discovered that a potentiometer was shorted to zero ohms. This was the only failed component found and it appeared that a potentiometer may have been defective when the timer was assembled. Also the failure could have occurred over some period of time due to forces on the potentiometer created by the encapsulating epoxy's curing process.

The licensee later concluded that the potentiometer in the failed timer was not defective during assembly because ACB 7 had operated properly during past maintenance tests and most recently on June 20, 1997, when ACB 7 operated in the same configuration and under the same conditions as during the June 23, 1997, event. The timer also was tested satisfactorily during past calibration tests. Thus the licensee concluded that the failure was most likely related to the epoxy's expansion and the resulting forces occurring over time. As corrective action the licensee replaced the failed timer in ACB 7 and installed a spare breaker for ACB 5 with a new timer. Additionally, the timers in ACB 6 and ACB 8 were verified to be operable.

The FIP Team also searched through past failure history for evidence of recurring problems. Specifically, on November 26, 1996, it was discovered that an intermittent short of the metal oxide varistor in the timer of ACB 7 blew a fuse during Keowee testing. The varistor failure was subsequently determined to be related to a material or manufacturing defect. Also there were approximately 200 timers of this type in service in the plant. There were no records of problems before 1992 and 11 problems have occurred since then. Five of those problems appeared to be related to component failures within timers between 6 and 25 years old. The licensee concluded that timer failures that have occurred at Keowee were all different. Additionally, based on that conclusion and on the small number of failures in relationship to the relative large timer population, the licensee also concluded that there appeared to be no strong indication that the timers are unreliable.

The licensee has documented the issues discussed in this section in the FIP Summary Report for Keowee Unit 1 June 23, 1997 Loss of Auxiliary Power.

c. Conclusions

The AIT concluded that the licensee's activities related to the ACB 7 timer failure evaluation and its generic aspects were technically sound. ACB-7 timer failure was most likely caused by the effects of the encapsulating epoxy expansion on the timer potentiometer.

E1.7 ACB 7 Timer on End of Range

a. Inspection Scope (93800)

The AIT Charter required the AIT to "Assess the licensee's activities related to the event investigations (e.g. root cause analysis, precursor event reviews, etc.)."

b. Observations and Findings

The timer for the "Y" coil in each closing circuit for ACB's 5, 6, 7, and 8 (and the other Westinghouse DB-50 breakers for the Keowee field and field supply) has a nominal setpoint of 0.325 seconds and is to be calibrated within ± 0.025 seconds. The range for this solid-state timer is 0.3 to 30 seconds with a repeatability within ± 3 percent of setting for repetitive cycles throughout the range of rated temperature and voltage per the manufacturer's (Cutler-Hammer) Technical Information Publication D87X. The FIP Team stated that the existing setpoint was very near to the end of the timer's range and that the required calibration accuracy was very small. The FIP team also stated that both of these make the timer difficult to set and recommended moving the setpoint further away from the end of the range. Further, they recommended specifying a setting range that is a larger percentage of the timer range, using a different timer, or returning the breaker closing circuit back to the original design with a mechanical "X" anti-pump relay.

The AIT also questioned the technical soundness of setting the timer so close to the bottom of its range. In response the licensee verified with Cutler-Hammer that the published repeatability was valid for the existing setpoint for this solid state devise.

The licensee documented this issue in the FIP Summary Report for Keowee Unit 1 June 23, 1997 Loss of Auxiliary Power.

c. Conclusions

The AIT concluded that the licensee's choice of timer and timer setpoint used in ACB's 5, 6, 7, and 8 and the other Keowee DB-50 breaker closing coil circuitry may not be appropriate for its current use even though the timer manufacturer verified the accuracy of the timer at the in-use setting.

E.2 **Engineering Support of Facilities and Equipment**

E2.1 ACB 5 and ACB 7 Blown Fuses

a. Inspection Scope (93800)

The AIT Charter required the AIT to "Assess the licensee's activities related to the event investigations (e.g., root cause analysis, precursor event reviews, etc.)," to "Evaluate the events for any similarity to previous equipment failures and events (like the October 1992 loss of offsite power event) or relationships to relatively recent testing and modifications," and to "Assess the generic aspects of the KHU 1

equipment failures with respect to their applicability to KHU 2, as well as the Oconee Units."

b. Observations and Findings

The licensee had determined that the cause of the June 23, 1997, loss of auxiliary power event was the failure of the timer for the "Y" coil in ACB 7 leading to lockout of Switchgear 1X. Subsequently fuses in the closing coil circuits of ACB 7 and ACB 5 blew when the Keowee operator reset the lockout condition. On the morning of June 24, 1997, FIP Team #2 began investigating the root cause of the blown fuses in ACB 5 and ACB 7 circuitry. Through analysis of the control circuit design for these breakers and review of event sequence information (Keowee event recorder, operator interviews, etc.), the FIP team concluded that when the Keowee operator reset the lockout condition on Switchgear 1X, both ACB 5 and ACB 7 received automatic close signals since the control switches for the breakers were in the automatic position and their voltage permissives were satisfied. Since the control circuits for ACB 5 and ACB 7 are interlocked to prevent them from both being closed at the same time, both breakers received a trip signal as the opposite breaker approached the closed position. The quick tripping of the breakers did not allow enough time for the timers in the "Y" coil circuits to time out (even with the bad timer in ACB 7) resulting in the "X" relays in ACB 5 and ACB 7 not de-energizing the breakers' closing coils. The breakers remained in this "trip-free" condition with a current for the DB-50 closing coil of about 20 amps which was enough to blow the 10 amp fuse in each closing circuit of ACB 5 and ACB 7 in about 6 seconds. The licensee characterized this as an unanticipated circuit operation.

The FIP Team also searched past failure history. Specifically, on July 16, 1992, a fuse blew in the control circuitry for ACB 8 due to an unanticipated circuit problem. On July 17, 1992, two fuses were discovered to be blown in the positive and negative legs of the control circuitry for ACB 8 (ACB 6 and ACB 8 have similar controls and interlocks to ACB 5 and ACB 7). Cause of that failure was attributed to improper fuse type and aging of the fuses. On November 26, 1996, a fuse blew in the circuitry for ACB 7 during load rejection testing due to failure of the breaker's "Y" coil timer. Also on December 19, 1996, a control power fuse blew in ACB 7 circuitry during the re-alignment of Keowee Unit 1 again due to the failed timer.

As discussed in Section O1.2 of this report, the licensee has revised the operator lockout response procedure. Discussions between the AIT and the licensee and specifically the FIP Team indicated that a hardware modification may be considered as a result of the above discussed failure mode and blown fuse history and the complexity of the X and Y anti-pump design. Potential effect of the "X" and "Y" relay anti-pump design is discussed in Section E2.2

The licensee has documented the issues discussed in this section in the FIP Summary Report for Keowee Unit 1 June 23, 1997 Loss of Auxiliary Power.

c. Conclusions

The AIT concluded that the licensee's activities related to the evaluation of the blown fuses in ACB 5 and ACB 7 and its generic aspects was technically sound, thorough, and adequate.

E2.2 Evaluate Similarity to Previous Equipment Failures and Events

a. Inspection Scope

The AIT Charter required the team to "Evaluate the events for any similarity to previous equipment failures and events or relationships to relatively recent testing and modifications.

b.1 Review of 1992 AIT

The AIT reviewed the October 1992 Loss of Offsite Power (LOOP) event to evaluate for any similarity to the current events.

The October LOOP event had resulted from a voltage surge on the switchyard DC control power battery charger affecting Oconee Unit 2 in October 19, 1992. The problems during the October 1992 event were exacerbated by a lack of appropriate guidance and the overall complexity of various electrical power system interactions (ref. NRC Inspection report 50-269,270,287/92-06, LER 50-269/92-04). The corrective actions as a result of the event included:

- Development of abnormal procedures providing guidance for the Keowee operators, including following an emergency start,
- a modification that deleted a trip of the Keowee units on undervoltage on the main startup transformer,
- completion of X-relay modification to change the anti-pump logic on the ACBs and the field flashing breakers,
- removal of speed switch logic,
- focus on increasing MG-6 logic reliability, and
- modification involving power supply for 1X and 2X.

The AIT reviewed applicable changes, discussed below, that resulted from the 1992 event.

Prior to the October 1992 event, both Keowee unit's auxiliary transformers (1X and 2X) energized the 1X and 2X 600 volt switchgear, and CX served as a standby source. Thus, ACB 5 and ACB 6 were maintained closed and ACB 7 and ACB 8 were maintained open. On loss of the normal power source, ACB 5 and ACB 6 would open

and back-up breakers ACB 7 and ACB 8 would immediately close to restore power to 1X and 2X switchgear. Further, if the normal source was restored for 10 seconds, a retransfer from the back-up to the normal source would occur.

During the October 1992 event, ACB 7 and ACB 8 failed to close following the loss of the normal source. The transfer from ACB 5 to ACB 7 was attributed to a mis-actuation of a breaker actuator device caused by repetitive breaker operation as 1X load center lost and regained power. The failure to transfer from ACB 6 to ACB 8 occurred due to either dirty contacts on a model MG-6 relay or a stuck, anti-pump "X" relay.

Licensee immediate corrective actions were to place the transfer logic between the normal and back-up sources to manual, thus removing the possibility of repetitive transfers. The licensee subsequently implemented a modification that changed the operating alignment of the load center incoming breakers such that the Keowee Unit aligned to the underground path would be normally fed from transformer CX (ACB 7 or ACB 8 would be maintained closed). For the Keowee unit aligned to the overhead path, the load center would be powered from the auxiliary transformer (ACB 5 or ACB 6 would be maintained closed). This modification was designed to prevent load center transfers as a result of expected transients during normal and emergency operations, and only have a load center transfer to its backup source if the normal source is lost for 30 seconds. Additionally, the modification was designed such that the load center transfers signal would originate from normal incoming breaker position versus a transfer only on a loss of normal voltage.

This modification did not directly cause the ACB-7 failure or the 1X lockout. However, the modification as well as the ARG had not anticipated the circuit interaction discussed in Sections E2.1 and O1.2 of this report.

With regard to the X-relays, Westinghouse had designed the original DB-50 and the DB-25 breakers for Keowee with a mechanical anti-pump feature provided by an "X" relay to ensure that the breaker would not cycle if the breaker were to trip with a continuous close signal present. The licensee stated that several breakers installed in Keowee began experiencing failures attributed to the "X" relay anti-pump circuit¹ in June of 1991 and continuing through February of 1992. In June of 1992, the licensee developed a design change (unique to Oconee) for the DB-50 and DB-25 breakers which replaced the mechanical anti-pump feature with an electrical (vice mechanical) scheme involving "X" and "Y" relays (see Attachment 8).

In September 1992, the licensee implemented this modification on Keowee Unit 1. This initial modification did not include the "Y" timer. During the October 19, 1992, loss of offsite power event at Oconee, the licensee found ACB 7 tripped and Keowee

¹The NRC issued Information Notice 93-85 on October 20, 1993, and Supplement 1 thereto on January 20, 1994, to alert licensees to the possible failures of the "X" relay in Westinghouse DB and DHP type breakers including those experienced in the Keowee hydro units.

Unit 1 600 V Switchgear 1X locked-out identical to the June 23, 1997, situation. The licensee suspected the new "X" and "Y" anti-pump design and subsequently determined that, without the timer, if the control voltage to the circuitry was low, the "Y" relay would energize and in turn de-energize the breaker's closing coil (through the de-energization of the "X" relay) before the breaker closing mechanism could latch close. This would allow the breaker's closing mechanism to move away from the closed position with the impact spring actuating a microswitch, and initiating switchgear lockout.

To correct this problem, the licensee, beginning in late 1992, implemented a modification which added a timer to the "Y" coil circuit to assure a sufficient time delay for the breaker to close and latch before the "Y" anti-pump relay de-energized the closing coil during periods of low control voltage (see Attachment 7). The licensee installed this modification only on DB-50 breakers, since DB-25 breakers have a smaller mechanical closing mechanism which moves faster. After reviewing the proposed design modification, Westinghouse expressed a concern about the selection of the time delay stating that a large time delay could keep the closing coil energized too long and possibly result in closing coil damage. The licensee performed tests to ensure that the new design with the timer would only maintain the closing coil energized as long as the original design with the mechanical anti-pump scheme. The 1X lockout on June 23, 1997, was identical to the 1X lockout in 1992. In 1992, the lockout occurred because a timer was not installed. The 1997 lockout occurred because of the failure of the timer.

Following the 1992 LOOP, the licensee performed several procedural and organizational modifications to enhance Keowee station performance during normal and emergency operations. This resulted in the development of abnormal and emergency procedures applicable to Keowee, upgrade of Keowee operator training programs, and the organization realignment of Keowee to Oconee. The overall impact of these changes was positive as Keowee operators were better able to respond to problems on June 20, 1997 as well as on June 23, 1997.

b.2 Search of Failure History

As part of the failure investigations performed for the June 20 and June 23, 1997, events, FIP Teams #1 and #2 performed searches through past plant failure history for evidence of reoccurring problems. Additionally, the AIT searched other sources related to Oconee (search was limited to Oconee since "X" and "Y" coil anti-pump design which is unique to Keowee) such as NRC inspection reports for evidence of similar previous equipment failures. Although some previous failure history has been included in other sections of this report, the following is a list of similar past failures at Oconee compiled by the AIT.

Timer Failures in DB-50 Breakers

- November 26, 1996 Timer in ACB 7 failed.
- December 19, 1996 Timer in ACB 7 failed.

DB-25 and DB-50 Breakers with Blown Fuses

- July 16, 1992 Blown fuse in ACB 8 due to an unanticipated circuit problem.
- July 17, 1992 2 blown fuses in ACB 8 due to improper fuse type and fuse aging.
- April 5, 1993 Blown fuse in Keowee Unit 2 field flashing breaker due to problem (mechanical binding or improper coil) with closing coil.
- April 12, 1993 Blown fuse in Keowee Unit 2 field flashing breaker due to problem (mechanical binding or improper coil) with closing coil.
- November 26, 1996 Blown fuse in ACB 7 due to "Y" coil timer failure.
- December 19, 1996 Blown fuse in ACB 7 due to "Y" coil timer failure.

DB-25 and DB-50 Breakers with Burnt Closing Coils

- April 12, 1993 Burnt closing coil in Keowee Unit 2 field flashing breaker due to problem (mechanical binding or improper coil) with closing coil.
- September 16, 1993 Overheated closing coil in Keowee Unit 1 supply breaker due to missing cotter pin.
- February 3, 1994 Burnt closing coil in Keowee Unit 2 field breaker due to worn latch mechanism.

DB-25 and DB-50 Breakers in Lockout

- October 19, 1992 ACB 7 tripped and Switchgear 1X locked-out.
- November 24, 1992 ACB 8 could not be closed (possible lockout).

The AIT review of the above historical data on blown fuses and burnt coils indicates that there may be a problem with fuse and coil interaction.

c. Conclusions

The AIT concluded, based on review of the historical data of similar equipment failures and events, that fuse and circuitry design interactions may have contributed to breaker failures. The AIT also concluded that the number of timer failures (probably only one actual failure) did not appear to indicate a recurring problem. The AIT concluded, with support from historical failure data, that the anti-pump circuitry design

using the "X and "Y" relays may have also been a contributor to breaker failures, involving blown fuses, burnt coils, and switchgear lockouts. The AIT concluded that the corrective actions for the 1992 event did not directly cause the problems in 1997.

E2.3 Generic Aspects and Applicability to Other Keowee Unit and Oconee

a. Inspection Scope

The AIT charter required the team to assess generic aspects of Keowee failures with respect to applicability to the other Keowee unit as well as Oconee Units.

b. Observations and Findings

The AIT reviewed the design and modifications related to the Keowee Units. The AIT noted that both the units are identical in design and that the problems that occurred on June 20 and 23, 1997 could have manifested on either Keowee unit. However, these failures were not common mode at the equipment level, but may be at the circuit level due to the potential impact from the X-Y modification, as discussed in Section E2.2. Also, a single failure would not have resulted in both Keowee units becoming inoperable.

The AIT also reviewed if any of the component problems at Keowee were also applicable at Oconee. The AIT noted that Oconee does not utilize Westinghouse DB 50 or -25 breakers. Keowee motor control centers (MCCs) do utilize DB-25 breakers in an application where they are not required to close automatically. Thus the problems experienced with the field flashing breaker would not manifest at the Keowee MCCs.

c. Conclusions

The AIT concluded that both Keowee units were similar in design and that the problems could have manifested on either of the Keowee units. The auto-closure problem with the DB-25 breakers was not applicable to the Keowee MCCs.

II. Maintenance

M1 Conduct of Maintenance

M1.1 ACB 7 Timer Calibration

a. Inspection Scope (93800)

The AIT reviewed maintenance activities associated with calibration of the timers for the "Y" coil in each closing control circuit for ACB's 5, 6, 7, and 8.

b. Observations and Findings

The timer for the "Y" coil in each closing circuit for ACB's 5, 6, 7, and 8 (and the other Westinghouse DB-50 breakers in the Keowee field and field supply) were checked and calibrated every three years to a nominal setpoint of 0.325 ± 0.025 seconds per Procedure IP/O/A/2001/003B. On June 26, 1997, FIP Team #2 determined that in the past the technicians performing the timer calibrations were hooking up their test equipment in such a manner that the measured time delay included normal breaker travel time along with the "Y" timer delay as opposed to just the "Y" timer delay. This was because the calibration procedures lacked detailed guidance. Discussions between the FIP Team and engineers involved with the maintenance of these timers revealed that confusion over the calibration procedure surfaced sometime in the 1994-1995 time period.

The FIP team performed a historical search of past timer calibration "as-found" and "as-left" data up to 1996. The "as-found" data indicated that the timers appeared to have a tendency to drift high which prevented the FIP team from determining exact dates of when the incorrect adjustment procedure started and stopped.

The licensee had determined that past operability was probably not in question since the breaker preventive maintenance procedures include a requirement to verify proper operation at a control voltage as low as 77 Vdc where proper timer delay were needed. Notwithstanding, past operability was revisited by the licensee. The licensee issued work orders to check the timer settings and breaker low voltage operation to ensure that the "Y" coil timers in all DB-50 breakers were adjusted properly and that the breakers were currently operable. Also the licensee updated the timer preventive maintenance procedure to include specific details to ensure that the timer setpoints were calibrated properly.

The AIT reviewed the "as-found" and "as-left" timer values from those work orders and determined that all the DB-50 timers had "as-found" values well below the required setpoint, which indicated that the timer time delays had likely been previously (circa 1995-1996) measured and/or adjusted with the incorrect procedure. The breaker low voltage operation was tested on all the DB-50 breakers. All operated at the low voltage test setpoint, except ACB-6. The ACB-6 timer was reset and tested and the licensee conducted an operability determination, which concluded that ACB-6 had been operable since the last calibration. The AIT reviewed this determination which evaluated low voltage test data and battery voltage conditions since the last calibration.

The licensee documented the issue in the FIP Summary Report for Keowee Unit 1 June 23, 1997 Loss of Auxiliary Power.

c. Conclusion

The AIT concluded that the lack of detailed guidance in the preventive maintenance procedure for measuring the timer settings for the "Y" coil in DB-50 breakers was a weakness. Also, since all timers checked following the June 23, 1997, event were

found with settings well below the required setpoint, past operability of the Keowee DB-50 breakers was questionable. Licensee low voltage testing revealed that all were operable, except ACB-6. The breaker was subsequently determined to have been operable.

M1.2 Evaluation of the Maintenance Procedure for the DB-25 Circuit Breaker

a. Inspection Scope (93800)

The AIT compared the licensee's maintenance procedure for the DB-25 circuit breaker to the recommendations in the manufacturer's instruction manual, industry operating experience generic communications and the AIT's knowledge of good industry experience. The licensee's maintenance procedure was contained in Procedure IP/O/A/2001/003B, Inspection and Maintenance of DB-50, DB-25 and DBF-16 Air Circuit Breakers, dated July 23, 1996. The manufacturer's recommendations were contained in Westinghouse Electric Corporation publication I.B. 33-850-1 & 2E, Instructions for De-ion Air Circuit Breakers Types DB-15, DB-25, DB-F & DBL-25, 600 Volts A-C, 250 Volts D-C, which became effective May 1965. At the AIT's request the licensee made various searches of their computer based records of industry operating experience generic communications, including NRC Information Notices, INPO SERs and manufacturer's bulletins.

b. Observations and Findings

Overall, the licensee's procedure was good. The procedure was not particularly detailed and relied to a great extent on skill of the craft to execute the maintenance. The procedure incorporated quality control hold points for any repairs that may have to be made during performance of the procedure, but did not incorporate hold points or second party verification for dimensional checks. The AIT's comments on the procedure are summarized as follows.

- Westinghouse recommended: "Check for over-adjustment [of contacts] by manually pulling the moving contact away from the stationary contact, with the breaker in the closed position. It should be possible to obtain at least 1/64-inch gap between the contacts". This step was not in the Oconee procedure. Since overadjustment could result in inadvertent "trip free", the licensee planned to perform this step as part of the Failure Investigation Process.
- Westinghouse recommended to check for loose bolts on the closing solenoid. The Oconee procedure checked for loose bolts only in a general statement which applied to all the bolts in the breaker.
- The licensee modified the breaker by replacing the special control relay originally installed with a contactor. The Oconee procedure did not include any specific checks on the contactor, although maintenance personnel told the AIT that they did make visual checks of the contactor.

- Westinghouse recommended: "Remove the front cover [of auxiliary switch] and make sure the contacts are touching well before the end of travel. And check for loose bolts and damaged contacts." The licensee's maintenance personnel told the AIT that, although not in the procedure, they performed an equivalent check on the auxiliary switch contacts without removing the cover. Since the cover was not removed they did not check bolt tightness and contact condition.
- The Oconee procedure included checks of the open and close times, but there was no criteria nor requirement to compare to past results.
- The Oconee procedure included a step to operate the breaker electrically open and close and check for any problems that may be observable. The AIT commented that standard industry practice would put the step at the very beginning of the procedure, but it was in the middle of the Oconee procedure.
- Good industry practice would verify proper operation of the anti-pump circuit. This step was not in the Oconee procedure. Licensee maintenance personnel told the AIT that they performed this check even though it was not in the procedure. The AIT observed that the test box for this check was included in the "required equipment" section.
- INPO Significant Event Report (SER) No. 88-15 described a problem at another nuclear power plant caused by the amptector trip device being installed too close to the trip bar. A recommended clearance was given in the SER. The Oconee procedure did not include any check for this clearance, therefore, it was not clear how Oconee evaluated this SER.

c. Conclusions

The AIT review of the licensee's maintenance procedure for the DB-25 circuit breaker identified that the procedure was determined to be generally in agreement with the Westinghouse Technical Manual, except one significant specific PM step was omitted. This omission was the result of a deficiency in the process of translating information from technical manuals to Oconee procedures.

III. Operations

O1 Conduct of Operations

O1.1 Conduct of Lee Steam Station Operations--June 20

a. Inspection Scope

The team reviewed the circumstances involving Lee Steam Station for the event on June 20, 1997. Several tours of the Lee station were also conducted. The dedicated 100 kV path from Lee to Oconee is a TS required function. Also, the event on June 20, 1997, was initiated as a result of a problem at Lee.

b. Observations and Findings

Lee Steam Station is located in Williamston, SC, approximately 45 miles from the Oconee site. The Lee station consists of three, 44.1 MVA gas combustion turbines. The Lee station typically feeds the 100 kV Lee Steam Station Switchyard. As shown in Attachment 6, this switchyard is tied to the Central 100 kV substation (22 miles away), which can be tied to the Oconee standby buses through transformer CT-5. Additionally, the Lee gas combustion turbines can also be dedicated (isolated from the Lee Switchyard and the Central Switchyard) to provide power to the Oconee standby buses through CT-5. This dedicated path alignment is through CS 89-3, MOD #90, and OCB 101 to CT-5. Oconee TS 3.7.4 allows one of the Keowee units to be inoperable for greater than 72 hours, provided the Oconee standby buses are energized by a Lee gas turbine through the dedicated path. Further, TS 3.7.7 allows both Keowee units to be inoperable for 24 hours, for unplanned reasons, provided that standby buses are energized from Lee within one hour.

On June 20, 1997, Oconee was in the process of performing Surveillance Procedure PT/1/A/0610/06, "100 KV Power Supply From Lee Steam Station." This surveillance was required by TS 4.6.7 to be performed at least every 18 months, usually, concurrent with an Oconee Unit 1 refueling outage. The surveillance demonstrates that a Lee Steam Station combustion turbine can be started and connected to the isolated 100 kV line and can carry the equivalent of the maximum safeguards load of one Oconee unit (4.8 MVA) within one hour. In addition to Procedure PT/1/A/0610/06, Procedure OP/O/A/1107/03A, "Oconee Nuclear Station and Lee Steam Station" and Lee Procedure "Emergency Power Or Back-up Power To Oconee" were also used to accomplish the surveillance. Procedure OP/O/A/1107/03A primarily involved verification of certain breaker alignments prior to starting the Lee gas turbines.

On June 20, 1997, at the request of Oconee, Lee operators had paralleled the 6C gas turbine to the grid per Enclosure 6.1 of Lee operating procedure "Emergency Power or Backup Power to Oconee". The Lee control operator (LOA) and Lee assistant control operator (LOB) were performing steps for the 6C Lee gas turbine in the Lee control room and were also monitoring the control boards for the three operating fossil units. The LOA and LOB were notified by Oconee operators that breaker alignments at Oconee were complete, and Lee Operators could initiate steps to dedicate Lee. The alignment that dedicated Lee were steps 6.1.5 through steps 6.1.9 of Enclosure 6.1 of Lee steam station operating procedure. Step 6.1.5, first required switcher 89-3 to be closed and then step 6.1.6 required switcher 89-2 to be open. The Lee operator performed steps 6.1.5 and steps 6.1.6 in reverse. First, opening switcher 89-2 caused the operating 6C Lee gas turbine generator to be separated from the grid, causing it to slightly "overspeed". When 89-3 was closed, the 6C Lee gas turbine was now slightly tied out-of-phase with respect to the grid. This caused a voltage surge which resulted in OCB-13 and breakers SL1 and SL2 tripping. Consequently, CT-5 was deenergized, resulting in the loss of voltage on the Oconee MFBs, and causing Keowee Units 1 and 2 to emergency start. The 6C Lee turbine generator continued to operate, following the separation from the system. Operation in the wrong order also caused sparking from Switcher 89-3 and a small grass fire underneath the switcher tower, which the Lee operators at the gas turbine promptly

extinguished. The gas turbine continued running until it was stopped by Lee operators 20 minutes after the event.

The AIT reviewed the three procedures that were utilized to accomplish the evolution involving dedicating Lee to Oconee. The AIT noted that the use of three different procedures, the weak linkage between the three procedures, and the lack of clarity and human factoring associated with numerous steps within the procedures, potentially contributed to the Lee operator error. Further, during interview with the Lee operators, the AIT noted the Lee operators were not particularly knowledgeable about the overall implications and reasons for the performance of evolution involving Lee as it relates to Oconee. Lack of formal training specific to the accomplishment of a TS related task was also noted by the AIT.

c. Conclusions

A failure to follow Lee Steam Station Operating Procedure "Emergency Power Or Back-UP Power To Oconee" caused the loss of CT-5 and the consequent loss of Oconee MFBs. Further, the AIT noted several procedural deficiencies as well as training and knowledge deficiencies related to Lee staff with regard to supporting TS required activities.

O1.2 Conduct of Keowee Operations--June 23

a. Inspection Scope (93800)

The AIT Charter required the AIT to "Assess the licensee's activities related to event recovery (e.g., actions to restore system and equipment operability, establishment of compensatory actions, etc.)."

b. Observations and Findings

The licensee determined that the cause of the June 23, 1997, loss of auxiliary power event was the failure of the timer for the "Y" coil in the control circuitry for ACB 7. This led to lockout of Switchgear 1X. The fuses in the closing coil circuits of ACB 5 and ACB 7 blew when the Keowee operator reset the lockout condition causing Switchgear 1X to be without power. On the morning of June 24, 1997, FIP Team #2 began investigating the root cause of the loss of auxiliary power to Keowee Unit 1. Through review of Keowee event recorder data and interviews with plant operators, the FIP team determined the following as the specific sequence of actions taken by the Keowee operator to reset the lockout condition of Switchgear 1X that occurred during the loss of auxiliary power:

The Keowee operator was notified by Oconee that the power to Switchgear 1X would be lost during the dead bus transfer on Switchgear 1TC. The operator was to verify that ACB 7 opened and then reclosed after Switchgear 1TC was reenergized. After ACB 7 attempted to close but tripped open, and the automatic transfer of Switchgear 1X to transformer 1X by closure of ACB 5 did not occur, due to a Switchgear 1X lockout. The Keowee operator referenced Alarm

Response Guide (ARG) SA1/E-04, "600V SWGR 1X Lockout Relay," in an effort to restore Switchgear 1X to operation. He went to Switchgear 1X and noticed that no protective relay (including the amptector) action had occurred. When checking the position of the impact springs (which actuate the micro-switches which in turn actuate the lockout relays) in ACB 5 and ACB 7, he found the spring in the non-lockout position for ACB 5 but in the lockout position for ACB 7 (indicating that ACB 7 either was tripped manually, experienced an overcurrent condition sensed by the amptector, or ACB 7 had malfunctioned while closing). The operator then contacted the on-call technical support specialist via telephone in order to receive assistance. He then reset the impact spring in ACB 7 and reset the lockout relay for Switchgear 1X. Upon reset of the lockout, ACB 5 and ACB 7 attempted to close and then tripped. When the operator noticed that the ACB 5 and ACB 7 position indication lights were extinguished, he notified the Oconee Unit 2 control room per the ARG. Subsequently, the Keowee operator with the assistance of the on-call technical support person determined that fuses had blown in the control circuits to ACB 5 and ACB 7.

The FIP Team concluded that the Keowee operator's use of ARG SA1/E-04 was appropriate and that his actions in response to the lockout condition were in compliance with the expectations of Keowee management. The FIP team also concluded that the operator's action was calm, deliberate, thorough, consistent with his training, and within the realm of the "skill-of-the craft."

The licensee characterized the cause of the blown fuses as an unanticipated circuit operation following the operator's action to reset the lockout condition. As immediate corrective action, the licensee revised ARG SA1/E-04 and ARG SA2/E-04, to require the transfer scheme for Switchgear 1X and Switchgear 2X to be placed in manual (in lieu of automatic), prior to the resetting of a lockout condition in order to preclude both breakers (ACB 5 and ACB 7 or ACB 6 and ACB 8) that supply power to the associated switchgear from receiving close signals at the same time. Additionally, the ARGs were further revised to provide clear and detailed guidance to the operator for evaluation of a lockout and the position of the impact springs. The AIT also noted, as discussed in Section E2.2, that the modifications to the 1X and 2X switchgear power supply alignment was conducted following the 1992 LOOP event. In addition, the ARG was also developed following the 1992 LOOP event. The licensee documented the issue in the FIP Summary Report for Keowee Unit 1 June 23, 1997 Loss of Auxiliary Power.

c. Conclusions

The AIT concluded that the ARG was inadequate because it allowed the operator to reset the lockout with the transfer scheme in automatic, which caused the unanticipated circuit response and blown fuses. Based on interviews and review of the sequence of events, the AIT determined that the Keowee operators appropriately followed established procedures. Also the team reviewed the revised ARGs and concluded that they were much improved with adequate detail, including appropriate caution and warnings.

O2 Operational Status of Facilities and Equipment

O2.1 Keowee Units Declared Operable But Degraded

a. Inspection Scope

The AIT charter required assessment of licensee activities relating to actions taken to restore equipment operability and establishment of compensatory measures. The AIT reviewed and discussed the operability determination that was performed by the licensee that concluded that the Keowee units were operable, but degraded, in view of the problems related to the field flash breaker.

b. Observations and Findings

The licensee, as discussed in Section E1.1, initially concluded that the cause for the fuse to blow on June 20, 1997 was age related degradation, accelerated by the current inrush that is experienced during emergency starts. As a compensatory measure, the licensee decided to replace the field flashing breaker control fuses after each Keowee emergency start. There have not been any cases of fuse blowing following emergency starts since the incident on June 20, 1997.

Later in the investigation, the licensee also considered the field flash breaker fail to latch closed with the close coil still energized as another potential cause of the June 20, 1997 problem.

Based on the above conclusions, coupled with approximately 50 successful starts of the Keowee units, the licensee concluded that both Keowee units were operable, but degraded. This degraded stipulation would be removed following the elimination of the field flash breaker cycling phenomenon.

For the problems experienced on Keowee Unit 1 on June 23, 1997, the licensee initiate corrective actions described in Section O1.2 of this report. No compensatory actions were warranted.

The AIT reviewed the operability evaluation and questioned the licensee if the reliability of the Keowee units would be further monitored by performing increased emergency start testing of the units due to the differences involved following an emergency and a normal Keowee start. Currently, Oconee TS require a normal monthly start of the units and the Keowee units are subjected to an emergency start approximately three times per year during required testing. The licensee was considering an accelerated testing program using emergency Keowee starts to confirm reliability of the units.

c. Conclusions

The AIT concluded that compensatory measures, including replacement of the fuse on the field flashing breaker following each emergency start, and the decision to evaluate the use of periodic emergency starts of the Keowee units to better assess the

reliability were satisfactory. The licensee's conclusion to consider the Keowee units operable but degraded, pending successful completion of planned corrective actions, was deemed appropriate.

O2.2 Technical Specification Applicability

a. Inspection Scope

The AIT reviewed and evaluated the Technical Specifications (TS) to determine if applicable Limiting Conditions for Operations (LCOs) and Action Statements were met during and following the events. In addition, the AIT requested the licensee to ascertain that design bases were maintained on Oconee Units 2 and 3 during the performance of PT/1/A/0610/06.

b. Observations and Findings

Oconee Unit 1 was below 200 degrees F and on LPI. Thus, Oconee electrical TS 3.7, which imposes operational electrical requirements, was not in effect for Oconee Unit 1. Oconee Units 2 and 3 were at full power. During the performance of PT/1/A/0610/06, Oconee Units 2 and 3 were not in any TS action statements.

Following the failure of Keowee Unit 1 to emergency start at 12:44 p.m., Oconee Units 2 and 3 entered a 72 hour action statement in accordance with TS 3.7.2 (a)(1). Further, this TS also required that Keowee Unit 2 be verified operable within one hour and every eight hours thereafter. At 1:44 p.m., since the requirement to verify operability of the other Keowee unit had not been completed, the licensee entered a 12 hour (to hot shutdown) action statement in accordance with T.S. 3.7.3. The licensee verified, operability of Keowee Unit 2 to the underground path at approximately 3:45 p.m. The one hour requirement was not met. The delay was partially caused by the evolution involving realignment of Keowee Unit 2 from the overhead to the underground path.

Additionally, following the failure of Keowee Unit 1 on June 20, 1997, the licensee discussed with the AIT whether the successful start of Keowee Unit 2 at 12:44 p.m. met the requirement of TS 3.7.2 (a)(1). The AIT determined that a start of a Keowee unit did not equate to an operability verification. Additionally, the AIT reviewed the TS basis, which discussed equipment conditions and specified that the action statement for TS 3.7.1 (a) (1) is met by verifying the operability of the Keowee unit through the underground path. Based on these factors, the AIT concluded that the one-hour requirement to verify operability of a Keowee unit was not met on June 20, 1997.

The AIT did not note any other problems relating to Oconee Units 2 and 3 meeting TS requirements during numerous evolutions that were conducted subsequent to the June 20, 1997 event, including on June 23, 1997 when problems related to ACB 5 and ACB 7 occurred. The entry and exit times into applicable TS action statements are detailed in Attachment 2, Sequence of Events.

With regard to maintenance of design bases for Oconee Units 2 and 3 during the performance of PT/1/A/0610/06, the licensee confirmed for a postulated LOOP/LOCA concurrent with a failure of the Keowee overhead path, the LOCA unit's MFB would be energized approximately 11 seconds following the event and the LOOP unit's MFB would be energized approximately 31 seconds following the event. The design bases assumed that the LOCA unit be energized within 33 seconds. Similarly, for a Keowee underground failure following a LOOP/LOCA during the performance of PT/1/A/0610/06, the LOCA unit's MFB would be energized within 20 seconds and the LOOP unit's MFB would have energized in 15 seconds. Several scenarios related to LOOP/LOCA are schematically provided in Attachment 9.

c. Conclusions

The licensee did not verify operability of Keowee Unit 2 to the underground path within one hour of a failure of the other Keowee unit as required by TS 3.7.2 (a) (1). Consequently, a 12 hour (to hot shutdown) action statement was entered per T.S. 3.7.3. Shutdown of Oconee Units 2 and 3 was not initiated as Keowee Unit 2 was verified operable in approximately two hours. No additional issues relating to meeting TS action statement requirements were identified. Further, the licensee confirmed that for the scenarios that the AIT questioned, design bases was maintained during the performance of PT/1/A/0610/06.

IV. Plant Support

P1 Conduct of Emergency Preparedness Activities

P1.1 Event Reportability

a. Inspection Scope

As per the AIT charter, the team assessed licensee performance with respect to event reportability.

b. Observations and Findings

Following the event on June 20, 1997, the licensee made a notification to the NRC HQ duty officer at approximately 4:05 p.m. The licensee reported the event as a voluntary notification. The licensee also subsequently periodically updated the NRC on the recovery activities. Additionally, licensee plans were to submit a voluntary LER to the NRC to document the details related to the event. The licensee considered several factors prior to deciding that the reporting to the NRC would be on a voluntarily basis. These included.

- The start of the Keowee units was not as a result of an ESF actuation as the MFB monitoring panel is a non-ESF/non-safety system; therefore, the reporting requirements of 10 CFR 50.72 (b) (2) (ii) were judged by the licensee to be not applicable.

- The licensee procedure requires a LOOP for more than 15 minutes before entering any emergency action level (Unusual Event). Thus, the reporting requirements of 10 CFR 50.72 (a) (i) were not applicable.
- No ECCS injection was required or occurred and therefore the reporting requirements of 10 CFR 50.72 (b) (1) (iv) were not applicable.
- The reporting requirements of 50.72 (b) (2) (iii) were not applicable as the condition where any event alone could have prevented the fulfillment of the safety function of structures or systems did not exist.

The AIT reviewed NUREG-1022, Rev. 1, Second Draft, and discussed the issue with the licensee. The AIT particularly discussed the issue in view of the fact that the Keowee units are required to start following an ESF actuation and that the identical failure, as the one on June 20, 1997, would have manifested, if the actuation had been following an ESF start. The licensee had considered this aspect and maintained a position that a reporting requirement was not indicated for the June 20, 1997 event. The AIT did not identify any additional problems, including, those related to the June 23, 1997 event where the condition was not reportable.

c. Conclusions

The AIT reviewed the reportability decision bases for the events of June 20 and 23, understood the bases for the issues and agreed with all the decisions except the emergency start of the Keowee units on June 20, for which a voluntary notification was submitted. This issue will be reviewed with respect to the licensee's position that the June 20 Keowee start was a non-ESF start because the AIT questioned whether or not a report was required to be made.

V. Management Meetings

Exit Meeting Summary

The AIT team leader presented the inspection results to members of licensee management at the conclusion of the inspection during a public meeting on July 10, 1997. The licensee acknowledged the findings presented.

Partial List of Persons Contacted

Licensee

- *L. Azzarello, ONS/Engineering Special Project Manager
- *M. Bailey, ONS/RGC/Licensing Engineer
- *R. Beaver, ONS/ESE/Electrical Eng.
- R. Bond, SA/Safety Review Manager
- J. Bryan, ONS/ESE/Electrical Engineer
- *E. Burchfield, ONS/RGC/Compliance Manager
- M. Calhoun, Lee/Manager Convert Engery

*K. Caraway, G.O./ESE/Technical System Manager II
 T. Curtis, ONS/OPS Superintendent
 *J. Davis, ONS/Engineering Manager
 J. Davis, Lee/Senior Technical Specialist
 D. Donaldson, G.O./ESE/S. Tech. Spec.
 *G. Edens, ONS/ESE/Electrical Engineer
 *B. Foster, ONS/Safety Assurance Manager
 *T. Grant, ESE/Electrical Engineer
 *J. Hampton, ONS/Vice President
 B. Jones, ONS/Training Manager
 *T. Ledford, ONS/ESE/Electrical Supervisor
 *C. Little, ESE/Engineering Manager
 *E. Lynch, Maintenance/Electrical/SPOC Manager
 W. Matthews, OPS Support
 B. McCollum, ONS/Vice President
 B. Millsaps, Work Control/SUPT
 *M. Nazar, ONS/Engineering Manager
 *B. Peele, ONS/Station Manger
 J. Perry, ONS/Nuclear Eng.
 *J. Rowell, ONS/ESE/Electrical Engineer
 C. Schaeffer, ONS/ESE/Electrical Engineer
 *R. Severance, Keowee Mechincal Engineer
 *S. Severance, ONS/ESE/Electrical Engineer Supervisor
 *J. Smith, ONS/RGC Technical Specialist
 *J. Stevens, ONS/ESE/Electrical Engineer

NRC

*D. Billings, Resident Inspector
 *E. Christnot, Resident Inspetor
 *S. Freeman, Resident Inspector
 *M. Scott, Senior Resident Inspector

*Attended exit meeting on July 10, 1997

Inspection Procedures Used

IP93800 "Augmented Inspection Team Implementing Procedures" dated July 7, 1989

List of Acronyms

ACB	-	Air Circuit Breaker
AIT	-	Augumented Inspection Team
ARG	-	Alarm Response Guide
DC	-	Direct Current
FIP	-	Failure Investigation Process
KHU	-	Keowee Hydro Unit
kV	-	Kilovolt
LCO	-	Limiting Condition for Operation
LDST	-	Letdown Storage Tank
LER	-	Licensee Event Report
LOA	-	Lee Control Operator
LOB	-	Lee Assistant Control Operator
LOCA	-	Loss of Coolant Accident
LOOP	-	Loss of Offsite Power
LPI	-	Low Pressure Injection
MCC	-	Motor Control Center
MFB	-	Main Feeder Bus
NRC	-	Nuclear Regulatory Commission
PIP	-	Problem Investigation Process
RCS	-	Reactor Coolant System
SQUG	-	Seismic Qualification User's Group
TS	-	Technical Specifications



UNITED STATES
NUCLEAR REGULATORY COMMISSION

REGION II
ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303

June 27, 1997

MEMORANDUM TO: Paul E. Fredrickson
Team Leader
Augmented Inspection Team

FROM: Luis A. Reyes *Luis A. Reyes*
Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER

An Augmented Inspection Team (AIT) has been established to inspect and assess the Keowee Hydro Unit (KHU) 1 equipment failures encountered during Oconee Unit 1 100 KV Power Supply Testing related activities from June 20 - 23, 1997. The specific failure events of concern are: (1) the failure of KHU 1 to come up to voltage and re-energize Oconee Unit 1 Main Feeder Busses (via the underground path) following a loss of the Lee Steam Station dedicated electrical power path on June 20; and (2) the failure of Air Circuit Breakers 7 and 5 during testing restoration on June 23. The team composition is as follows:

Team Leader: P. Fredrickson (RII)

P. Fillion (RII)
F. Burrows (NRR)
B. Desai (SRI - Robinson)
Resident Inspector - Assist Team

The objectives of the inspection are to: (1) determine the facts surrounding the specific events; (2) assess licensee response to the events; (3) assess licensee activity during their event review and recovery; and (4) assess the generic aspects of the KHU 1 equipment failures with respect to their applicability to KHU 2, as well as the Oconee Units.

For the period during which you are leading this inspection and documenting the results, you shall report directly to me. The guidance of Inspection Manual Chapters 0325 and 0610 apply to your inspection and the report. If you have any questions regarding the objectives or the attached charter, contact me.

Attachment: AIT Charter

cc w/att: H. Thompson, DEDR
E. Jordan, DEDO
S. Collins, NRR
S. Varga, NRR
H. Berkow, NRR
G. Tracy, OEDO
E. Goodwin, NRR
D. LaBarge, NRR

J. Rosenthal, AEOD
J. Calvo, NRR
C. Ogle, RII
R. Carroll, RII
J. Johnson, RII
J. Jaudon, RII
M. Scott, RII

11700

AUGMENTED INSPECTION TEAM (AIT) CHARTER
OCONEE NUCLEAR STATION
KEOWEE HYDRO UNIT (KHU) 1 EQUIPMENT FAILURES

Basis for the formation of the AIT - The failures appear to have characteristics which meet the criteria of Manual Chapter 0325, Section 05.02, including: (1) multiple failures in safety-related systems; (2) possible adverse generic implications; (3) considered to be complicated and probable cause is unknown or difficult to understand; and (4) repetitive failures or events involving safety-related equipment.

Associated with Oconee Unit 1 100 KV Power Supply Testing related activities, the specific failure events of concern are: (1) the failure of KHU 1 to come up to voltage and re-energize Oconee Unit 1 Main Feeder Busses (via the underground path) following a loss of the Lee Steam Station dedicated electrical power path on June 20; and (2) the failure of Air Circuit Breakers 7 and 5 during testing restoration on June 23. Accordingly, the objectives of the inspection are to: (1) determine the facts surrounding the specific events; (2) assess licensee response to the events; (3) assess licensee activity during their event review and recovery; and (4) assess the generic aspects of the KHU 1 equipment failures with respect to their applicability to KHU 2, as well as the Oconee Units. To accomplish these objectives, the following will be performed:

- Develop a sequence of events associated with the specific failure events of concern.
- Assess the licensee's activities related to the event investigations (e.g., root cause analysis, precursor event reviews, etc.) and evaluate the effectiveness of the related Failure Investigation Process team.
- Evaluate the events for any similarity to previous equipment failures and events (like the October 1992 loss of offsite power event) or relationships to relatively recent testing and modifications.
- Assess the licensee's activities related to event recovery (e.g., actions to restore system and equipment operability, establishment of compensatory actions, etc.).
- Assess the licensee's performance with respect to event reportability.
- Assess the generic aspects of the KHU 1 equipment failures with respect to their applicability to KHU 2, as well as the Oconee Units.
- Document the inspection findings and conclusions in an inspection report within 30 days of the inspection.

SEQUENCE OF EVENTS

TIME ITEM DESCRIPTION

June 20, 1997

- 9:30 a.m. A pre-job briefing was conducted at Oconee in preparation for the performance of TS required surveillance PT/1/A/0610/06 to demonstrate that a Lee gas turbine can be started and connected to the isolated 100KV dedicated line, and carry the equivalent of the maximum safeguards load of one Oconee unit (4.8 MVA) within one hour.
- 11:40 a.m. Oconee commenced alignment of Unit 1 main feeder buses (MFBs) to the Central Switchyard through SL1, SL2 and CT-5.
- Oconee Unit 1 control room received a UV statalarm for transformer CT 5. This had no significance related to the event. Oconee operators have noted this on other occasions and is caused by slight variations in the Central Switchyard voltage.
- A live bus transfer, to the standby buses, was made where the S1 and S2 breakers are closed and E1 and E2 breakers are opened. This transfer resulted in the Oconee MFBs being energized from the Central Switchyard, via CT-5.
- 12:15 p.m. Oconee notified Lee Steam Station that power was required for furnishing backup power to Oconee. Subsequently, Lee operators started the 6C Lee gas turbine and initiated actions to parallel it to the Lee Steam Station 100 KV service station, per enclosure 6.1 of Lee Operating Procedure "Emergency Power or Backup Power to Oconee". At this point, the dedicated path from Lee was not yet established.
- 12:30 p.m. CT-5 was aligned to the 100 KV line from the Lee 100 KV switchyard and Oconee was awaiting notification from Lee the 100 KV line was aligned from the Lee gas turbine to CT-5.
- 12:44 p.m. Lee Operators were intending to perform steps 6.1.5 (close 89-3, connecting Lee to the central line) and 6.1.6 (open 89-2, disconnecting Lee from the rest of the switchyard). Instead, the operator reversed the steps and performed 6.1.6 (open 89-2) and 6.1.5 (close 89-3). This caused Lee to be first separated from the grid and then being reconnected. This reconnection was with the Lee slightly out-of-phase/sync with the Lee 100 KV Switchyard. This caused OCB 13 and SL1 and SL2 to open.

- 12:44 p.m. The opening of SL1 and SL2 caused a loss of power to Unit 1 MFBs. In 20 seconds, both Keowee units received an emergency start signal from the MFB monitoring panel. Then, one second later, load shed occurred as expected, and in five more seconds the retransfer to startup logic allowed the E breakers to close in from the startup source. The unit was without power for approximately 26 seconds. This resulted in momentary interruption of decay heat removal, as the running A LPI pump lost power. RCS temperature on Unit 1 increased slightly from 102.5 degrees F to approximately 103 degrees F.
- 12:44+p.m. Oconee Unit 1 was powered from the 230 KV switchyard through transformer CT1 and the E breakers in approximately 26 seconds following loss of power to the MFBs, as designed. Oconee Units 2 and 3 were unaffected, as designed, and were continued to be powered from the N breakers.
- 12:44+p.m. Keowee Unit 2 started without any problems and did not tie to the overhead path as designed. However, Keowee Unit 1 received an emergency start signal, but did not successfully flash its field.
- 12:44+p.m. Units 2 and 3 enter a 72 hour TS action statement 3.7.2 (a)(1) for not having Keowee Unit 1. This TS action statement also required that the other Keowee unit be verified operable within one hour of the loss, and every eight hours thereafter.
- 12:45 p.m. The 1A LPI pump was restarted after power to the MFBs was automatically restored through the 230 KV switchyard through the E breakers. The RCS temperature had increased to approximately 103 degrees F.
- 1:00 p.m. A blown fuse in the control circuit of the failed Keowee Unit 1 field flashing breaker was identified during troubleshooting.
- 1:44 p.m. With one Keowee unit inoperable for up to 72 hours, TS 3.7.2 (a) (1) required that the other Keowee unit be verified operable within one hour of the loss of the other unit and every eight hours thereafter. Following the failure of Keowee Unit 1 at 12:44 p.m., Keowee Unit 2 was not verified operable within 1 hour. Consequently, per TS 3.7.3, a 12 hour(to hot shutdown) action statement was applicable for Oconee Units 2 and 3, that started at 1:44 p.m. Oconee Unit 1 was not in any TS action statement as RCS temperature was below 200 degrees F and electrical system TS 3.7 is only applicable above 200 degrees F.
- 1:45 p.m. Oconee Unit 1 restored plant loads to normal conditions.
- 3:00 p.m. A failure investigation team FIP Team (#1) was formed to review the circumstances and determine root cause, including those related to the Keowee Unit 1 failure.

- 3:45 p.m. Operability of Keowee Unit 2 was verified through the underground path. The 12 hour action statement per TS 3.7.3 was exited on Units 2 and 3. However, a 72 hour action statement was still applicable for Keowee Unit 1 being out-of-service.
- 4:05 p.m. NRC HQ Operations Center was notified (event 32517).
- 5:01 p.m. An investigation team was sent to Lee to interview involved Lee individuals. It was also determined that the 4C and 5C Lee gas turbines were available if needed.

June 21, 1997

Investigation was ongoing at Keowee and at Lee. Keowee Unit 1 was still out-of-service and a 72 hour action statement was in effect. Keowee Unit 2 was aligned to the Underground path and was tested via a normal (not emergency) start every eight hours as required by TS. The 6C Lee gas turbine was verified to be fully operable. Two normal starts were performed on Keowee Unit 1 and the field flashed successfully during these investigative starts.

June 22, 1997

Keowee Unit 1 was in a 72 hour action statement that would expire at 12:44 p.m. on June 23, 1997. Investigation efforts were underway at Keowee and a special test procedure was developed to verify circuit performance under conditions as close as possible to those that existed on June 20, 1997. The special test also included installation of test instruments to collect data on the field flashing breaker circuit. The special test also involved establishment of the dedicated path from Lee to Oconee.

- 9:10 p.m. The dedicated path from Lee steam was established for planned testing and troubleshooting at Keowee.
- 9:27 p.m. A 24 hour action statement was entered per TS 3.7.7, applicable to Oconee Units 2 and 3 for having both Keowee units inoperable. Keowee Unit 1 was already out-of-service and Keowee Unit 2 was being taken out-of-service to perform the test to as close to 6/20 as possible. Keowee Unit 1 was being tested in the black start configuration. (black start means no power to 1X, following the loss of MFB on 6/20, 1TC-4 was deenergized resulting in loss of power to 1X)
- 10:03 p.m. The special test was performed successfully with both units successfully starting. However, the field flashing breakers on both Keowee units cycled 3 to 4 times during the field flash period. Cycling was confirmed visually on Keowee Unit 1.

June 23, 1997

The FIP(1) team continued their investigation of the of the root cause. Both Keowee units were out-of-service and a 24 hour action statement was in effect for Oconee Units 2 and 3.

- 10:00 a.m. A Management oversight meeting was conducted to re-perform PT/1/A/610/06 to demonstrate capability to dedicate Lee to Oconee within one hour.
- 12:17 p.m. Following review of the data gathered during testing, both Keowee units were declared operable, but degraded, and the 24 hour TS action statement exited. Further, with Keowee Unit 1 now considered operable, the 72 hour action statement was also exited. Keowee Unit 1 was aligned to the underground path and Keowee Unit 2 was aligned to the overhead path.
- 2:45 p.m. A conference call was made to NRC/NRR to discuss status.
- 3:55 p.m. The 100 KV path from Lee was successfully retested and Oconee Unit 1 MFB were energized from the dedicated path within one hour.
- 5:51 p.m. Following completion of the Lee dedicated procedure, the transfer from the S breakers to the E breakers was a dead bus transfer as designed. This caused a momentary interruption, by procedure, to the Oconee Unit 1 MFBs. Since Keowee Unit 1 auxiliaries are fed from 1TC-4 via the CX transformer, 1X lost power as expected. ACB 7 opened as a result of UV on 1X as expected. ACB 5 was already open.
- 5:51 p.m. After re-energization of the Oconee MFBs, Oconee operator closed 1TC-4 and power to CX was restored. ACB 7 was expected to re-close upon sensing voltage on CX. However, ACB 7 attempted to close and tripped due to a failed Y timer. 1X switchgear lockout occurred and a statalarm was received in the Keowee control room. The operator responded to the statalarm and verified that no targets were present on the breakers and he reset impact spring for ACB 7.
- 5:51 p.m. Keowee Unit 1 battery became inoperable because it was not capable of being recharged as a result of 1X lock out. A 24 hour action statement was applicable for Units 2 and 3 per TS 3.7.2 (e). Further, Keowee Unit 1 was maintained out-of-service for investigation and troubleshooting, resulting in a 72 hour action statement.
- 5:51 p.m. Keowee operator noted that CX had been out longer than expected. He had also heard 1X lockout alarm. At this point the Keowee operator noted that ACB 5 trip spring position was in the correct position and ACB 7 spring position was not in the correct position.

- 6:00 p.m. Keowee operator contacted the technical specialist via telephone to discuss annunciator response guidance related to the 1X lockout.
- 6:07 p.m. Keowee operator reset ACB-7 breaker impact spring and returned to the control room to reset 1X lock-out relay 86S1X.
- 6:07 p.m. Upon resetting 1X lock-out, ACB 5 and ACB 7 closed and immediately tripped back open due to an interlock.
- 6:40 p.m. Keowee Unit 2 was aligned to the underground path.
- 6:47 p.m. Keowee Unit 2 was successfully tested to the underground path. Keowee 1X had been isolated, thus, the Keowee Unit 1 auxiliaries were swapped to Keowee Unit 2 (2X) to recover AC power to the battery chargers.

June 24, 1997

The 24 hour TS action statement was exited at 12:08 a.m., following recharging of the batteries. Keowee Unit 1 was inoperable and in a 72 hour action statement. ACB 5 was replaced with a spare and Keowee auxiliaries were returned to load center 1X. A FIP(#2) was initiated to determine root cause of the loss of auxiliaries to Keowee Unit 2. FIP(2) determined the root cause of ACB 5 and 7 tripping and blowing fuses was related to resetting the lockout relay without putting the switchgear transfer switch in manual. The Keowee alarm response guide has now been revised to require the Auto/Manual transfer switch in Manual prior to resetting the lockout relay.

June 25, 1997

Failure investigation continued and a conference call was held with NRC. FIP (2) determined root cause for ACB 7 not re-closing after loss of power to be a failed time delay "Y" relay which did not allow sufficient time for the breaker to close before de-energizing the close coil.

June 26, 1997

The 72 hour action statement for Keowee Unit 1 was exited at 2:04 p.m.. The failed Y relay was sent to Cutler hammer for failure analysis. The Y timers of ACBs 5, 6, and 8 were verified to be operable.

June 27-July 17, 1997

The licensee continued their investigation of the two problems. On July 8, 1997 the licensee modified the voltage associated with the field flashing breaker overvoltage relay. The setpoint was changed from 70 volts to 82.5 volts. During the test, the Keowee field flashing breakers were noted to cycle. The licensee continued to maintain the Keowee units in an operable but degraded status. On July 17, 1997, the licensee reset the relay to 100 volts, followed with several emergency start tests. The generators started and ran successfully with no significant test anomalies. Based on the results of these tests, the Keowee units were returned to a fully operable status.

DESCRIPTION OF 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.

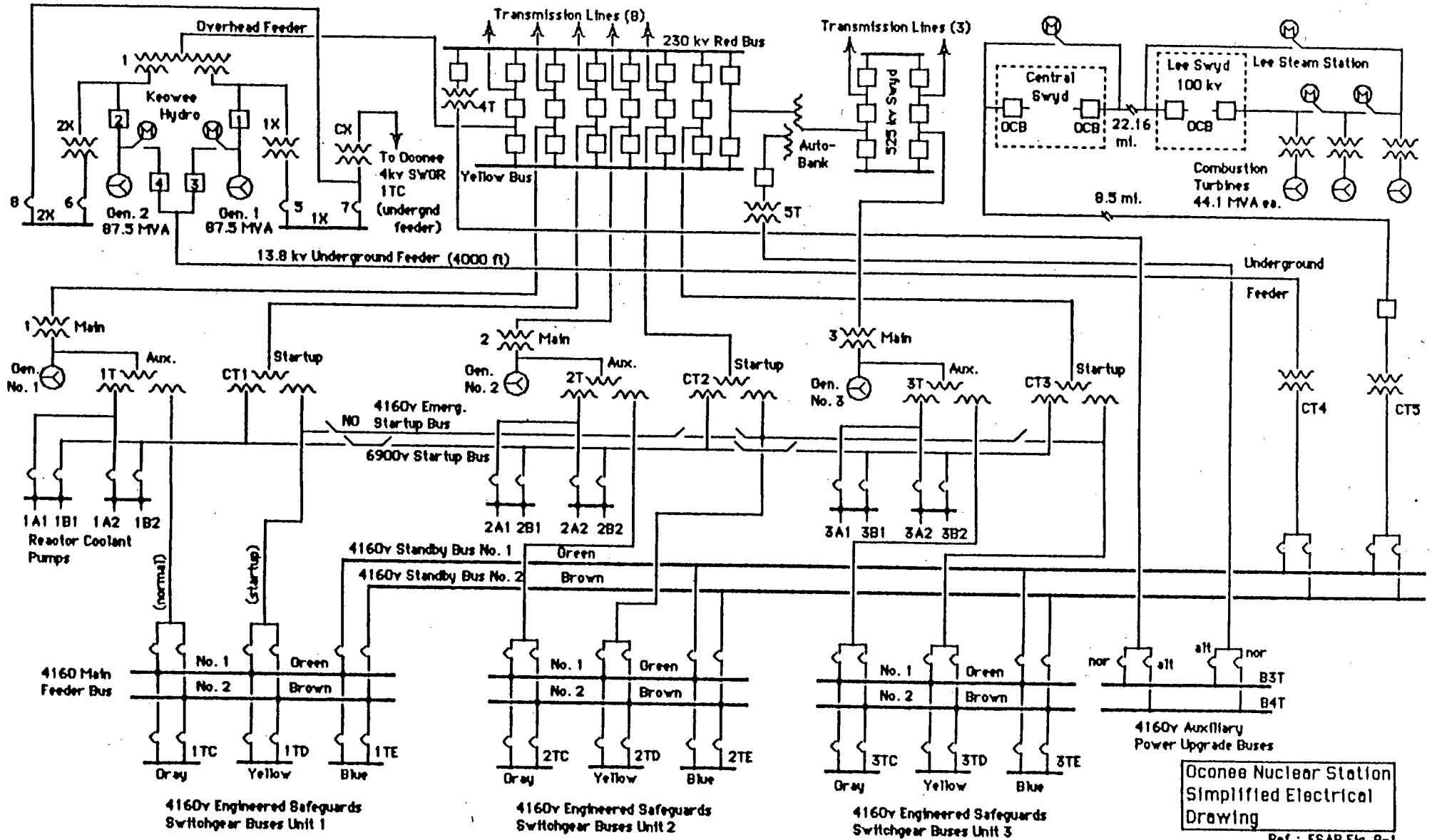
The 230 kV switchyard is divided into two busses designated as the Red Bus and the Yellow Bus. This switchyard is normally operated with both busses energized through a breaker-and-one-half scheme to the grid. The Yellow Bus in the 230 kV switchyard is identified as being safety related. Upon loss of 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 unit's 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.

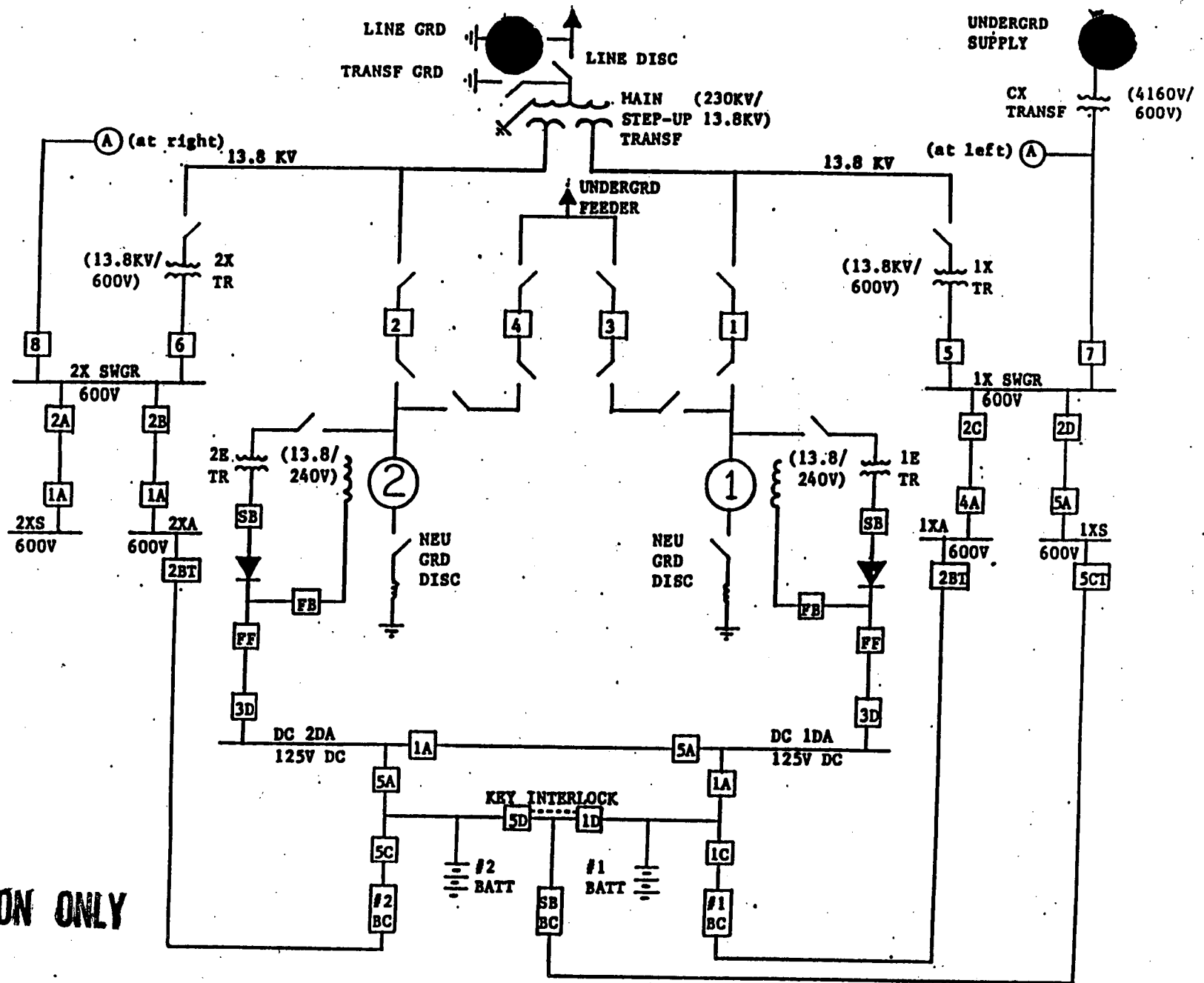
The unit auxiliary power system for each Oconee unit is designed as a dual-train cascading bus system. There are two 4.16 kV main feeder busses, Main Feeder Bus 1 (MFB1) and Main Feeder Bus 2 (MFB2), with each supplying power to three 4.16 kV load busses TC, TD, and TE. The power to MFB1 and MFB2 is 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.



Oconee Nuclear Station
Simplified Electrical
Drawing

Ref.: FSAR Fig. 8-1



INFORMATION ONLY

TITLE: Keowee Hydro Station, KHG

NOTES: AC & DC Systems

ID NO: OC-EL-KHG-21

DATE: 6-10-92

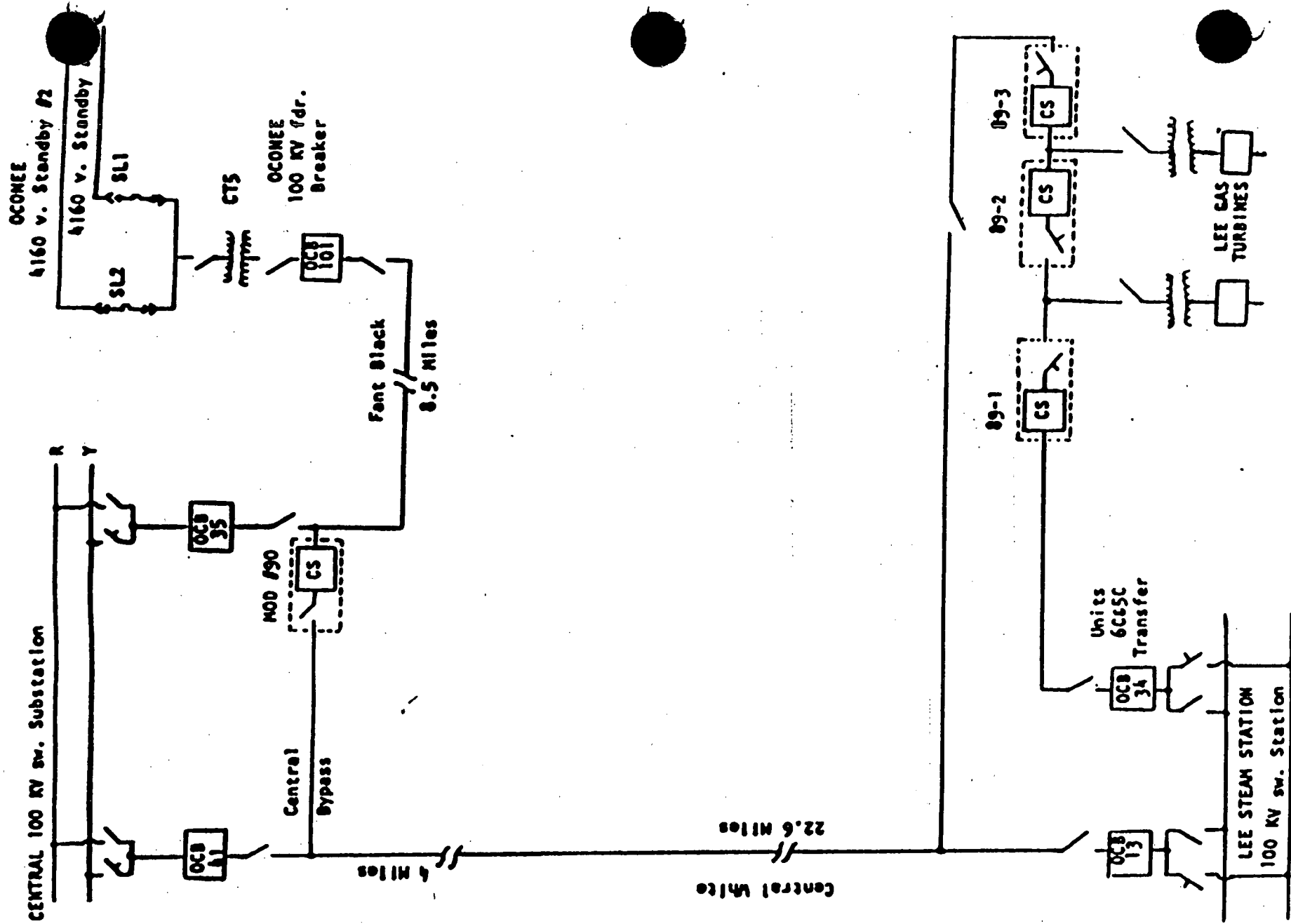
REF: K700, K702, K704

DRN BY: Sam Burton

APP. BY:

TRAINING USE ONLY

LEE STEAM STATION 100KV
TO OCONEE SCHEMATIC



ELECTRICAL POWER
DISTRIBUTION

100KV TRANSMISSION LINE from LEE STEAM
STATION to OCONEE STANDBY BUSES

OC-EL-EPD-7 3-1-88

OP/O/A/1107/03

OKM / ARB LMB

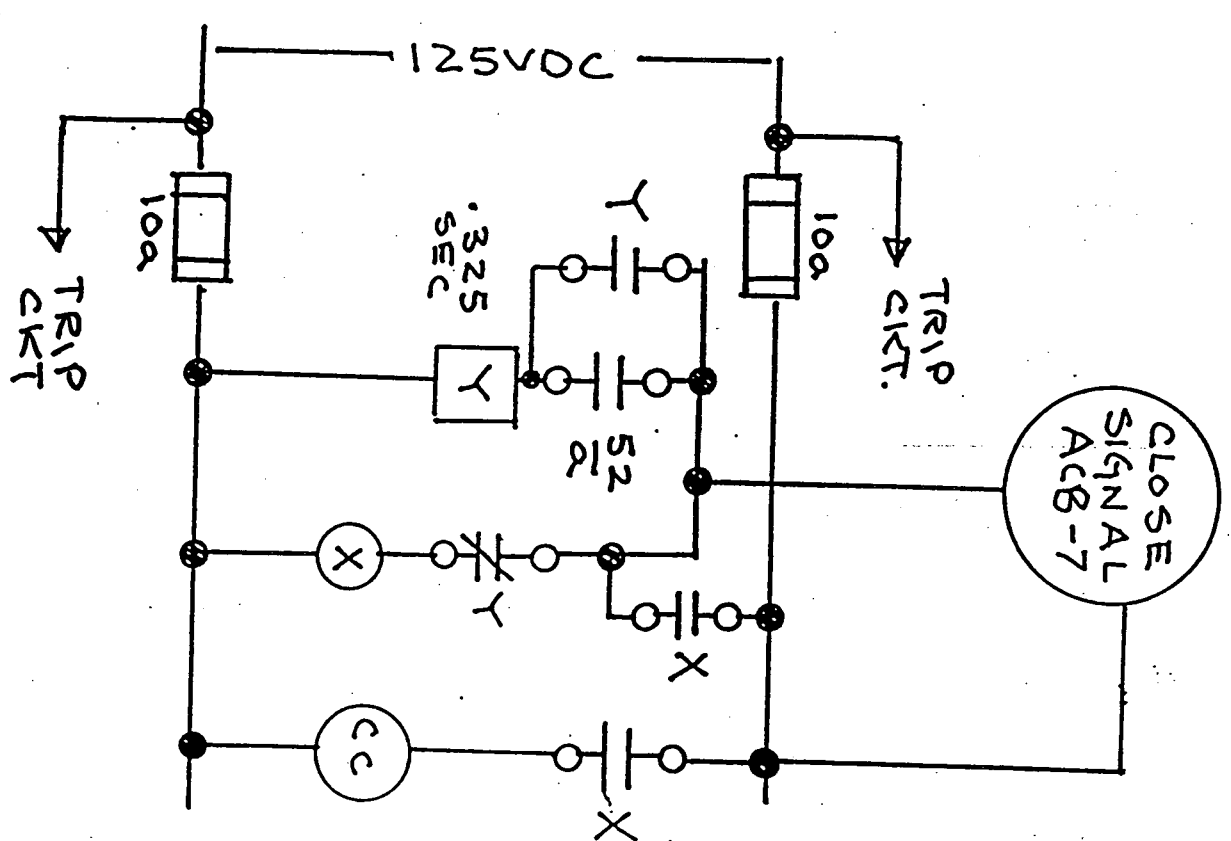
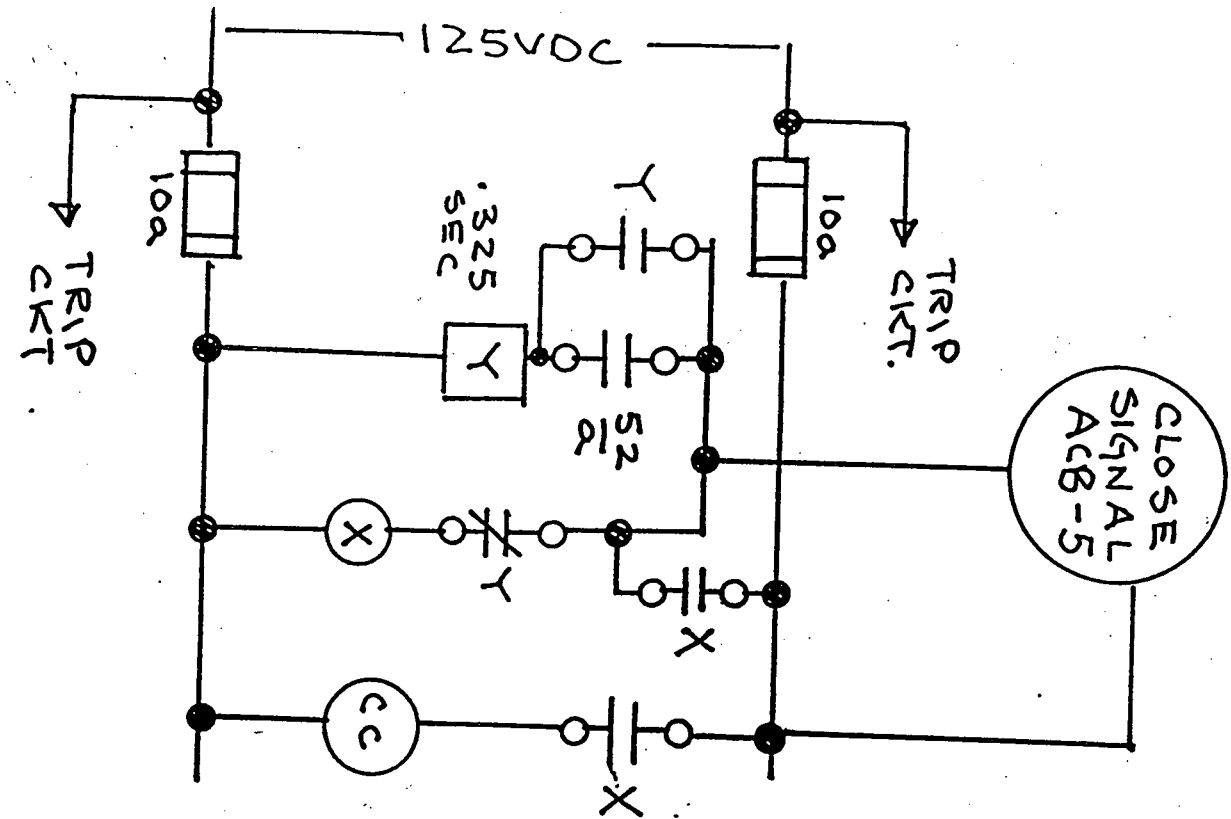
TRAINING USE ONLY

INFORMATION ONLY

ATTACHMENT 6

BREAKERS ACB-5 AND ACB-7
CLOSE CONTROL SKETCH

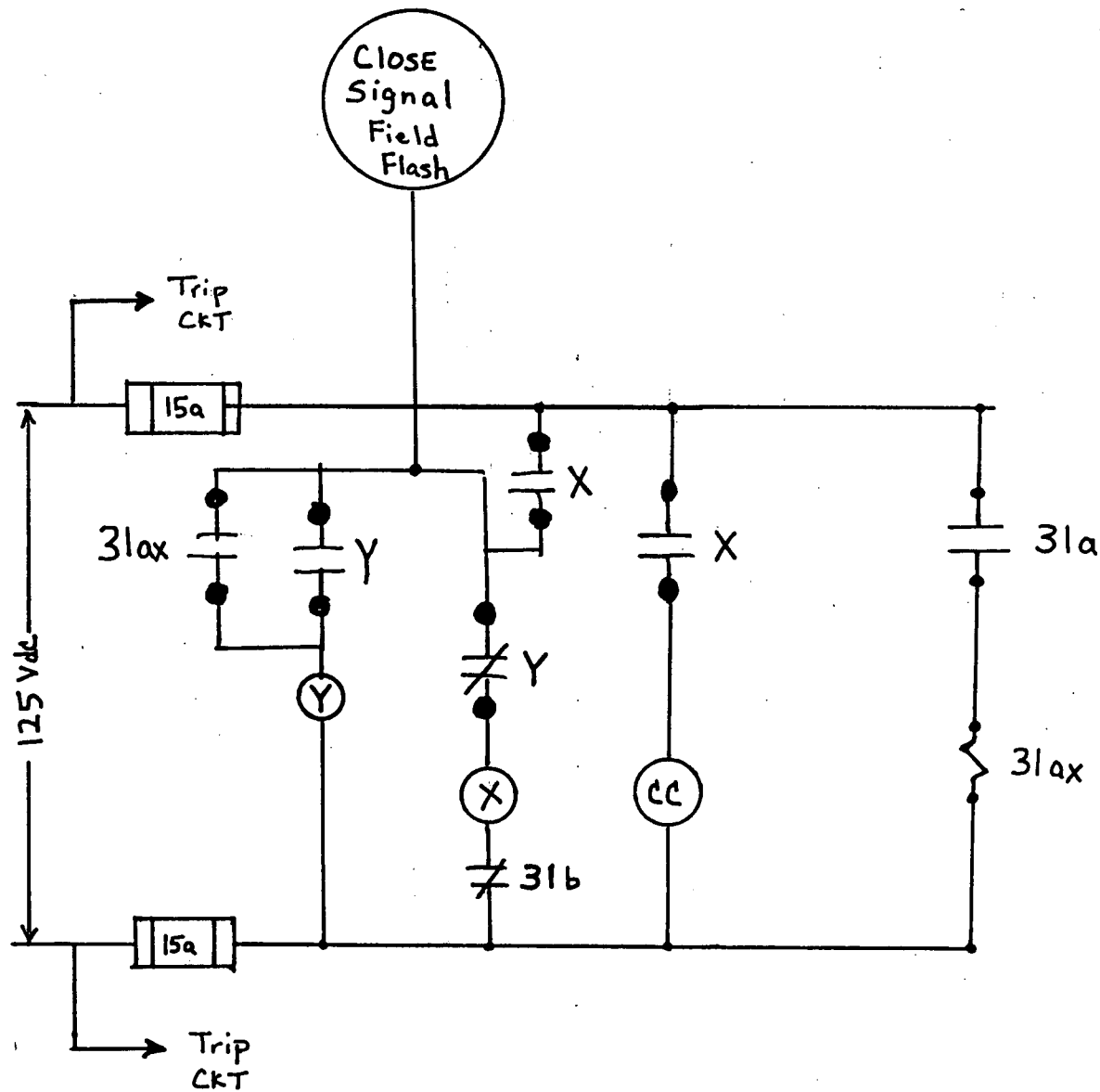
INFORMATION ONLY



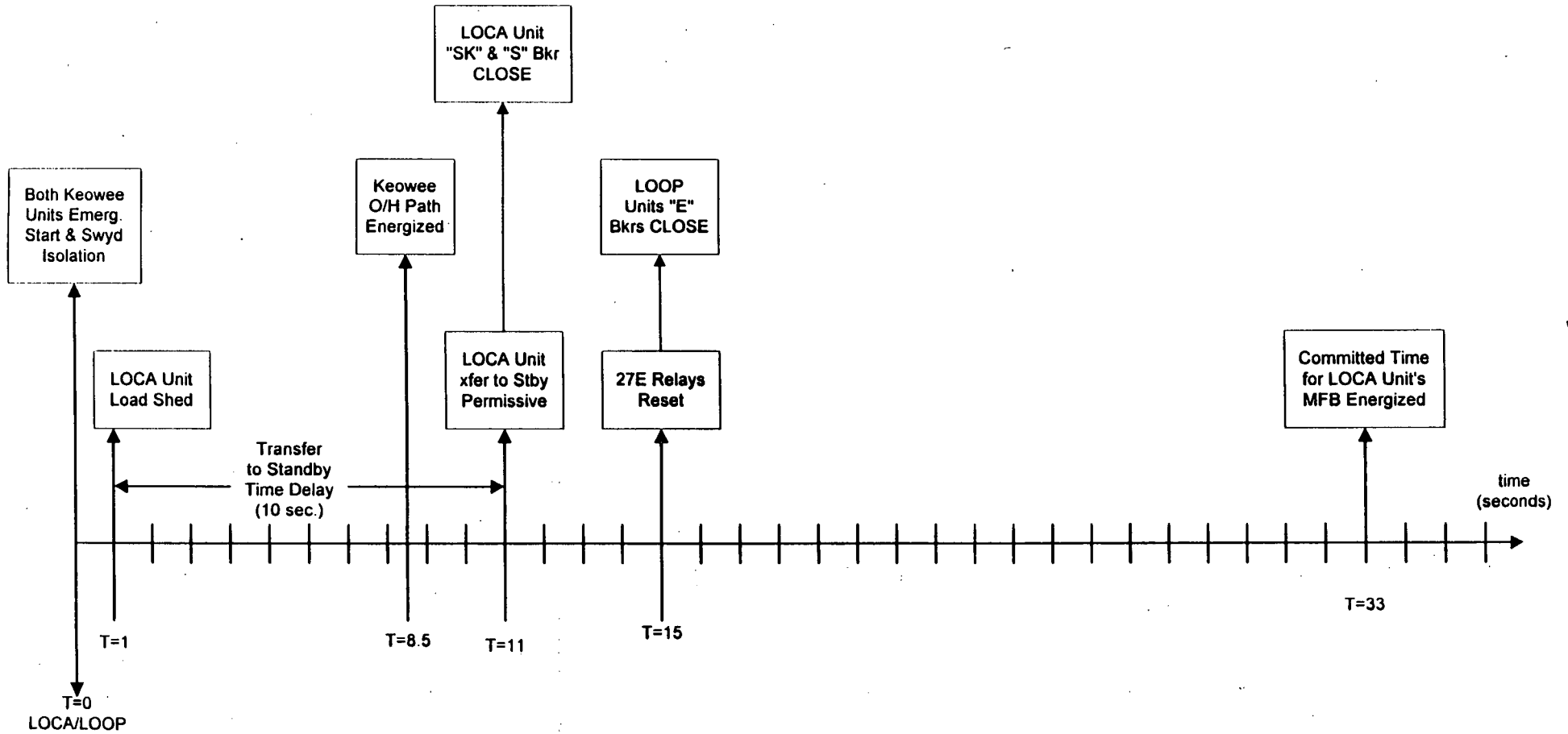
KEOWEE BREAKER ACB-5 AND -7
CLOSE CONTROL CIRCUIT

GENERATOR Field Flash BREAKER

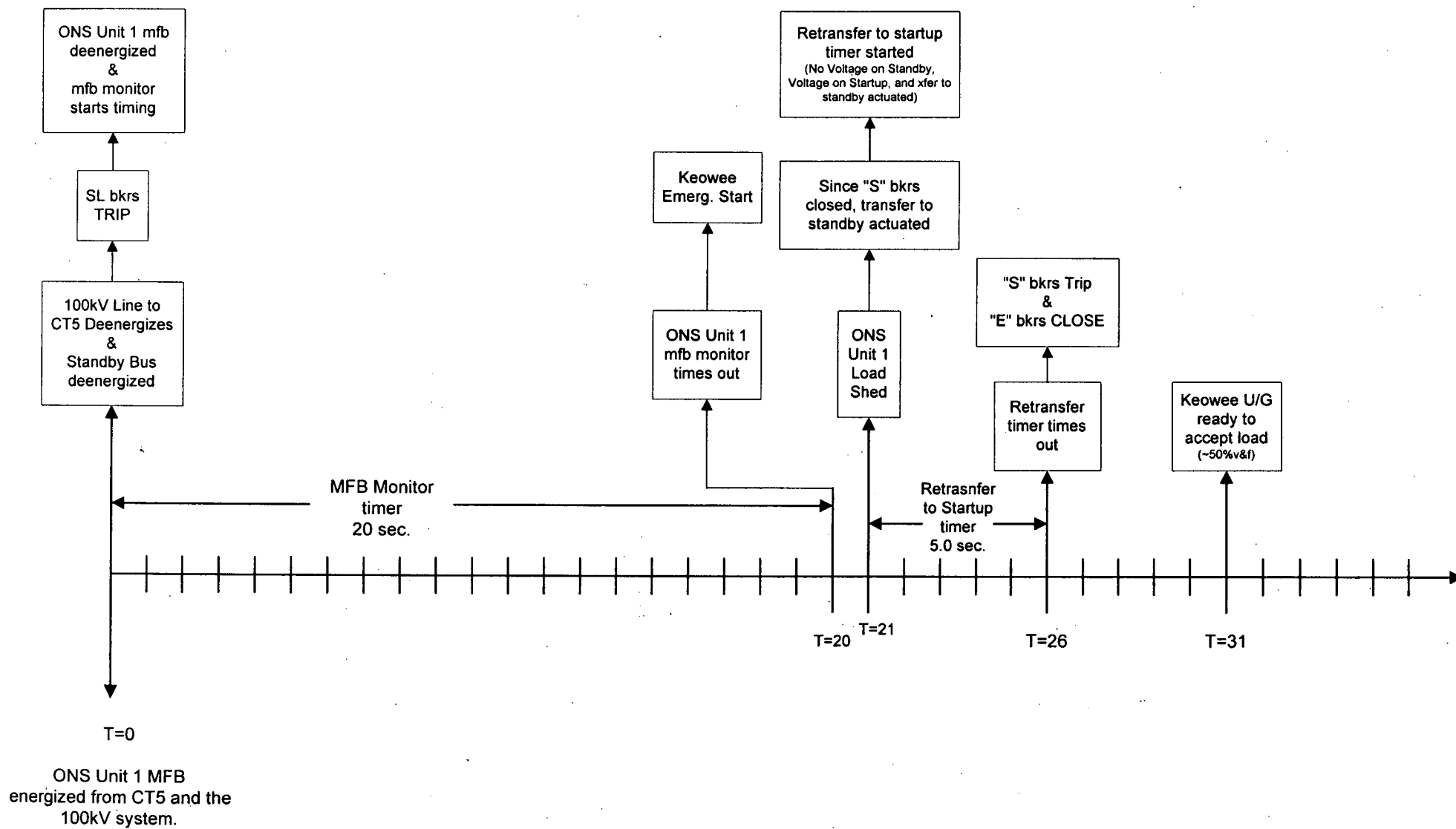
KEOWEE FIELD FLASH BREAKER
CLOSE CONTROL CIRCUIT



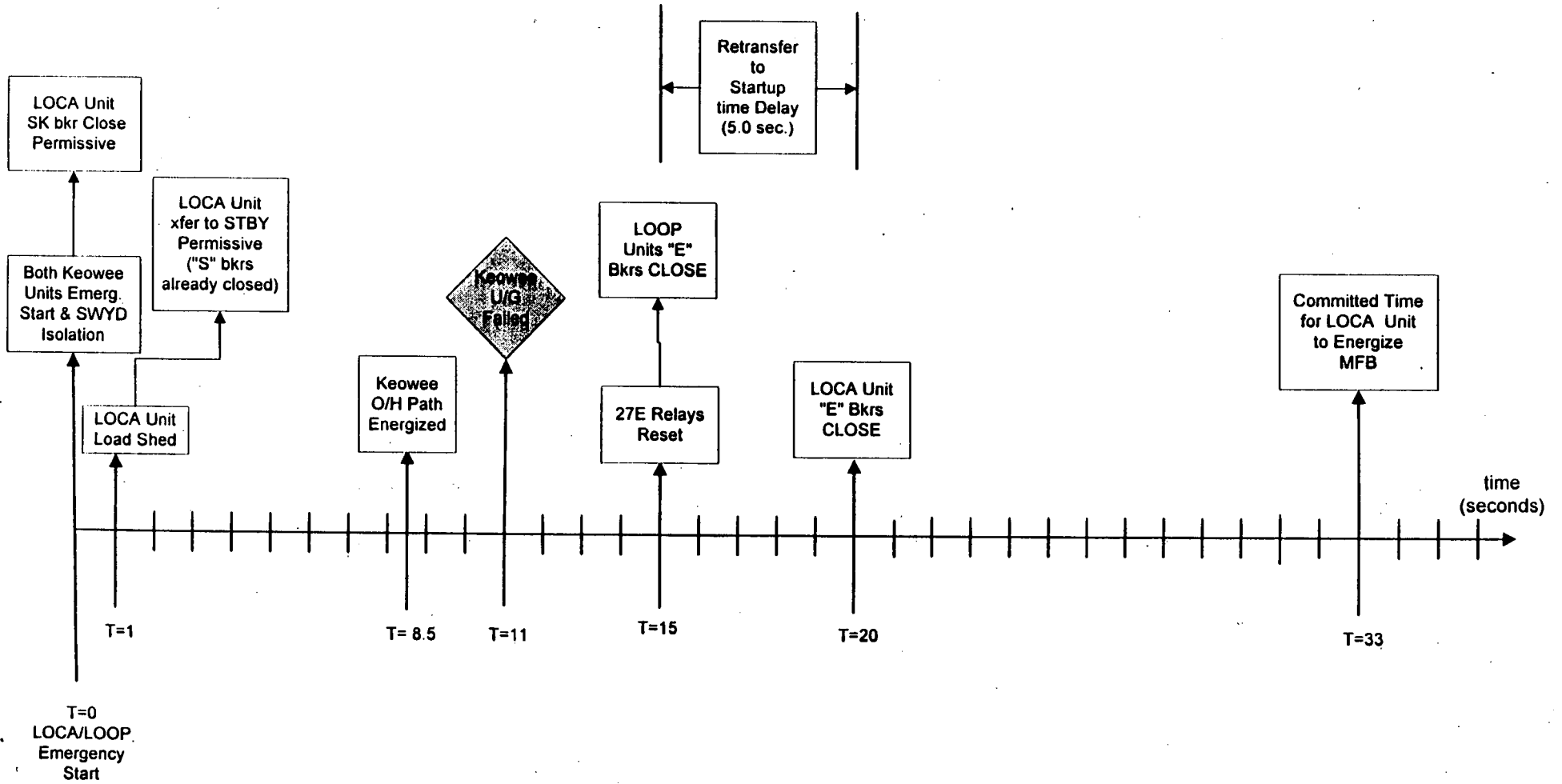
Keowee/EPSSL Sequence of Events for a LOCA/LOOP



Keowee/EPSSL Sequence of Events for the Event of 6/20/97 Except Keowee Underground Unit Does NOT Fail



Keowee/EPSL Sequence of Events for a LOCA/LOOP With the Lee Event of 6/20/97



Keowee/EPSL Sequence of Events for a LOCA/LOOP With O/H Path Failure & the Lee Event of 6/20/97 ("S" breakers Closed)

