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AUTH.NAME AUTHOR AFFILIATION
HAMPTON,J.W. Duke Power Co.
RECIP.NAME RECIPIENT AFFILIATION
Document Control Branch (Document Control Desk)

See Rpt.

SUBJECT: Forwards response to NRC 951222 RAI on plant electrical sys issues.Change 12 to Procedure PT/2/A/0610/01J, "Emergency Power Switching Logic Functional Test" also encl.

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Duke Power Company
Oconee Nuclear Generation Department
P.O. Box 1439
Seneca, SC 29679

J. W. HAMPTON
Vice President
(803)885-3499 Office
(803)885-3564 Fax

DUKE POWER

January 31, 1996

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Response to Request for Additional Information on
Oconee Electrical System Issues

In a letter dated December 22, 1995, the NRC Staff requested additional information from Duke Power by January 31, 1996. The Staff's request is in connection with its review of the Oconee electrical system, and is in addition to a prior request, dated November 2, 1995. Duke Power has made every effort to understand what information is being requested, and to provide a detailed response to the multiple parts of each of the questions. The Staff indicated that questions A1, A7, B1-B8, and C6 were of higher priority. Attachment 1 reiterates the Staff's requests, and contains our response to each request for additional information. A summary of the commitments that are contained in this response is provided in Attachment 2.

In some instances, the information that is provided in Attachment 1 has been newly developed based upon our understanding of the Staff's concerns. We request the opportunity to supplement and/or clarify the new information as appropriate. If additional information is needed by the NRC Staff, we suggest a meeting at your offices.

If you have any questions regarding this matter, please contact J. E. Burchfield at (864) 885-3292.

Very Truly Yours,

BWPeele for

J. W. Hampton, Site Vice President
Oconee Nuclear Station

MEB

A001

xc: L. E. Wiens, Project Manager
ONRR

P. E. Harmon, Senior Resident Inspector
Oconee Nuclear Station

S. D. Ebneter, Regional Administrator
Region II

E. L. Jordan, Chairman
CRGR

ATTACHMENT 1

REQUEST FOR ADDITIONAL INFORMATION ON THE
OCONEE EMERGENCY ELECTRICAL SYSTEM

A. QUESTIONS REGARDING TESTING

Question A1

Provide the specific acceptance criteria (voltage, frequency, time, etc.) for each test identified in the Duke Power Company (Duke) letter of November 17, 1995. Discuss how that criteria relates back to the required design basis operation of the equipment being tested and assures its proper performance during the design basis scenario.

Response to Question A1

For completeness, the tests which are described in response to Request 1 in the Duke letter dated November 17, 1995, are listed below. A description of the specific test acceptance criteria (TAC) and the relationship of the TAC to the design basis follows the list of tests.

1. PT/0/A/0620/16 - Keowee Emergency Start Test
2. PT/0/A/0610/22 - Degraded Grid and Switchyard Isolation Functional Test
3. PT/1,2,3/A/0610/01J - Emergency Power Switching Logic (EPSL) Functional Test
4. Keowee Maximum Load Rejection Test (Post NSM ON-52966 Implementation)
5. TT/0/A/0650/01 - Keowee Black Start Test
6. Keowee Overhead Path & RCP Motor Load Test
7. PT/0/A/0610/19 - 100kV Power Supply Prior To Extended Keowee Outages
8. PT/0/A/0610/06 - 100kV Power Supply From Lee Steam Station
9. PT/0/A/0610/23 - Lee Combustion Turbine-Generator Operation To the Grid Verification
10. Lee Combustion Turbine-Generator & ASW Motor Test.
11. Keowee Low Power Test
12. PT/1,2,3/A/0610/01A - EPSL Normal Source Voltage Sensing Circuit
13. PT/1,2,3/A/0610/01B - EPSL Startup Source Voltage Sensing Circuit

14. PT/1,2,3/A/0610/01C - EPSL Standby Bus Voltage Sensing Circuit

The Keowee Emergency Start Test (Test 1) is associated with Technical Specification (Tech Spec) surveillance 4.6.2. On an annual basis, it verifies Keowee's ability to emergency start upon receipt of a Keowee emergency start signal. In addition, it verifies the ability of the Keowee units to accelerate to rated speed and voltage within a committed time of 23 seconds. This test also demonstrates Keowee's ability to accept loads equivalent to the design basis accident loads for three Oconee units. Finally, this test verifies the setpoint of the Keowee overhead ACB re-closure timers. The acceptance criteria for this test are: (1) each Keowee Unit reaches rated speed (approximately 128.6 RPM) and voltage (13.5 - 14.1kV) in less than 23 seconds of emergency start, (2) statalarms and emergency start initiated lights operate as required per the test procedure (1,3SA14-E4 and 1,3SA15-E4), (3) each Keowee unit supplies greater than or equal to 25 MW to the grid with the load being added at its maximum practical rate, (4) both Keowee units continue to operate until manually shut down, and (5) the reclosure timers actuate within 6.0 - 7.0 seconds (Unit 1) and 4.0 - 5.0 seconds (Unit 2). The reclosure timer setpoints will be changing with the implementation of modification NSM ON-52966.

Criterion 1 demonstrates proper operation of the voltage regulator and speed control governor on each Keowee unit. The failure of equipment which results in inadequate voltage or frequency build-up is detected by this test. The time requirement demonstrates the ability of the emergency power system to support the required emergency core cooling system (ECCS) injection time. In order to actuate the re-transfer to startup logic in a timely manner, the 23 second time requirement is placed on the emergency power system. This ensures that the 48 second ECCS injection requirement is met with an assumed loss of the underground path. Criterion 2 verifies that the appropriate alarms and indications are received. The third criterion demonstrates that Keowee has adequate capacity to supply the accident loads for Oconee. Criterion 4 ensures that the Keowee units operate as expected until shutdown. Criterion 5 verifies that the reclose timers on the Keowee overhead ACBs are set as designed.

The Degraded Grid and Switchyard Isolation Functional Test (Test 2) is identified in the proposed Tech Spec surveillance 3.7.7.1. On a refueling cycle frequency, it verifies proper operation of the degraded grid protection system (DGPS) and the Keowee overhead air circuit breaker (ACB) and switchyard PCB-9 during

switchyard isolation. This test demonstrates Keowee's ability to load reject upon receipt of an emergency start from the switchyard isolation circuitry. In addition, this test demonstrates the ability of the overhead Keowee unit to energize the 230kV yellow bus and the startup transformers (CT1, CT2 and CT3) for each Oconee unit. The acceptance criteria for this test are: (1) the DGPS actuates as designed (i.e. breakers trip/close as expected and appropriate alarms and indication are received), (2) the overhead Keowee unit separates from the grid and energizes the startup transformers from the isolated yellow bus, and (3) the underground Keowee unit energizes the underground path and transformer CT-4.

Criterion 1 demonstrates that the system will perform as expected during the occurrence of a degraded grid condition concurrent with an engineered safeguards actuation. The second and third criteria demonstrate Keowee's ability to energize the emergency power paths during a design basis event (DBE). Energization of the overhead and underground power paths is verified by observation of nominal voltage and frequency on the Oconee control room indication. During the initial performance of this test, the overhead Keowee unit was "black started" from standby. "Black start" implies that the overhead Keowee unit started without AC power available to the Keowee unit's auxiliaries.

The Emergency Power Switching Logic (EPSL) Functional Test (Test 3) is associated with Tech Spec surveillance 4.6.4. On a refueling frequency, this test verifies the ability of the EPSL system to maintain the main feeder busses (MFB) energized by the most reliable power source without operator action. The acceptance criteria are: (1) the EPSL circuitry operates properly per the procedure which is included as Attachment 3, (2) after load shed, all non-load shed equipment breakers remain closed and all load shed equipment breakers are open, (3) the re-closure timers for the non-safety automatically re-closing breakers are 57 - 63 seconds (1X7), 33 - 37 seconds (1X5) and 30 - 34 seconds (1X6), (4) following emergency start both Keowee units reach rated speed (approximately 128.6 RPM) and voltage (13.5 - 14.1kV), (5) the overhead ACBs are open, (6) transformer CT-4 is energized, (7) following a transfer to the standby busses (whether powered from a Lee combustion turbine-generator (CTG) or Keowee underground) the MFB undervoltage relays are reset and a nominal voltage of 4160V is on the MFB, (8) the SL breakers trip upon loss of the Lee line, and (9) after the SL breakers trip, the SK breakers close.

Criteria 1 and 2 demonstrate the ability of the EPSL circuitry and breaker operation to align the Oconee unit auxiliaries to the

appropriate power path. The loss of power sources, which results in the transfer to standby and re-transfer to startup, are actually simulated as during a DBE. Criterion 3 demonstrates that, when required, the non-safety load groups will not load until the appropriate time delay has elapsed. Criteria 4, 5 and 6 demonstrate Keowee's ability to emergency start as a result of the loss of the MFB and the LOCA actuations. Since there is no actual LOOP, the Keowee unit's voltage and frequency are verified to be at their nominal values with the overhead ACBs open and CT-4 energized on the underground path. Criterion 7 demonstrates, regardless of the power source, that the MFBs are reenergized with nominal voltage and the appropriate statalarms are reset. Criteria 8 and 9 demonstrate that the interlocks between the SL and SK breakers are operable. In addition, criteria 8 and 9 demonstrate that the SL breakers will trip and the SK breakers will close to reenergize the standby busses if Lee is lost and a Keowee unit is available. Although verification of the ability of the Keowee unit to "black start" is not part of the acceptance criteria for the test, it should be noted that the Keowee underground unit "black starts" during the Oconee Unit 1 EPSL test. This occurs because the auxiliary loads for the Keowee unit are lost as a result of a simulated LOOP on Oconee Unit 1.

The Keowee Load Rejection Test (Test 4) is associated with the Keowee overfrequency and governor protection modification (NSM ON-52966). An amendment to the Tech Spec is being drafted which will incorporate this test into Tech Spec Section 4.6. On a refueling frequency, this test will verify Keowee's ability to load reject and realign to the appropriate power path within the committed time. The acceptance criterion requires the Keowee units to decelerate to 110 percent nominal speed following a maximum power load rejection condition in less than 22 seconds. The maximum power load rejection will be based on the allowed operating conditions on the day of the test. The allowed operating conditions are contained in the Oconee Selected Licensee Commitment manual. Reestablishment of power to the power paths within the committed time supports the 48 second ECCS injection time which was discussed in Test 1.

A Keowee Black Start Test (Test 5) was a one-time test to re-demonstrate the ability of the Keowee units to emergency start without AC power to the auxiliaries. The acceptance criterion for this test was that the Keowee units started and obtained rated speed and voltage during a Keowee blackout condition. During a LOOP DBE, the Keowee units will start without AC auxiliaries.

A one-time test (Test 6) of the Keowee overhead path with a reactor coolant pump motor load collected data for the certification of a computer model. This test was performed in conjunction with the degraded grid and switchyard isolation functional test (Test 2). Since this test was collecting data, no acceptance criteria were established beyond those associated with Test 2.

The 100kV Power Supply to Extended Keowee Outages Test (Test 7) is associated with Tech Spec surveillance 4.6.6. This test demonstrates annually that a dedicated Lee CTG can energize the Oconee main feeder busses.

The acceptance criteria are: (1) the breakers operate as specified in the procedure, and (2) the standby busses are energized from a dedicated Lee CTG. Oconee control room meters provide indication of the standby bus and MFB nominal voltage readings. A recent revision to this procedure moved the Tech Spec 4.6.6 surveillance requirements to the EPSL Functional Test (Test 3).

The 100kV Power Supply from Lee Steam Station Test (Test 8) is associated with Tech Spec surveillance 4.6.7. This test demonstrates on an 18 month frequency that a Lee CTG can be started and connected to the isolated 100kV line. In addition, the Lee CTG is loaded with Oconee unit loads that are equivalent to the maximum safeguards loads of one Oconee unit (4.8 MVA) within one hour.

The test acceptance criteria are: (1) the breakers operate as specified in the test procedure, (2) the main feeder busses are supplied from an isolated Lee CTG, and (3) the Lee CTG is loaded to greater than or equal to 5 MW within one hour of the notification to Lee that power is required. The Lee CTGs are a manual action power source for Oconee. Criteria 1 and 2 ensure that the dedicated path from Lee to Oconee can be manually aligned. In criterion 3, the one hour requirement is a specific Tech Spec requirement. Operators at Lee verify the proper CTG voltage (14.1kV) and frequency (60 Hz) prior to notifying Oconee that the source is available. The ability of the Lee CTG to satisfactorily carry the load as well as the magnitude of the load are verified at Lee.

The Lee Combustion Turbine-Generator to the Grid Verification Test (Test 9) is associated with Tech Spec Surveillance 4.6.8. It demonstrates annually that the Lee CTGs can supply loads on the system grid equivalent to the safeguard loads of one Oconee unit plus the safe shutdown loads of two Oconee units. The

acceptance criterion for this test is that each Lee CTG operates at greater than or equal to 22MW on the system grid.

A test (Test 10) of a Lee CTG with the auxiliary service water (ASW) pump motor was a one-time test of the Lee CTG via the dedicated 100kV line. The purpose of this test was to collect data for computer model certification. Therefore, no acceptance criteria were established.

The Keowee Low Power Test (Test 11) was performed in conjunction with this past Unit 1 EPSL Functional Test. No further acceptance criteria were established beyond those previously mentioned in Test 3 above. The purpose of this test was to collect data on Keowee while the Keowee units were being loaded during acceleration. In addition, data was collected during steady state load additions and rejections. The data that was collected from this test will be evaluated and the need for future loading tests will be assessed. The preliminary test results are discussed as part of the response to Question A7.

The EPSL Sensing Circuit Tests (Test 12, 13, and 14) are performed on a refueling cycle frequency as prerequisites to the EPSL Functional Test (Test 3). They verify that the normal, startup, and standby bus source undervoltage logic performs as designed. Each two-of-three configuration is verified via test lights. The acceptance criteria are that the lights, relay statalarms and computer points function as required by the procedure.

Question A2

Provide a functional description of the emergency power switching logic (EPSL) and discuss how the EPSL testing described in the November 17, 1995, letter verifies each of those functions. Also, describe how the features in the logic that may not be exercised during a normal performance test (like redundant or protective features) are tested. Provide a copy of the EPSL test procedures.

Response to Question A2

The 4kV Essential Auxiliary Power System Design Basis Document (DBD) contains a functional description of the EPSL logic. A copy of the 4kV DBD was provided to the NRC during a meeting at Oconee on November 8, 1995. In a tabular/matrix form, the DBD also references the design basis requirements of the system to the applicable test which supports the requirements.

The EPSL is functionally tested during each Oconee unit's refueling outage by the EPSL functional test. During the functional test, both channels of the redundant EPSL logic are tested to ensure that the load shed, transfer to standby and retransfer functions occur on the simulation of a loss of power and engineered safeguards. The EPSL design allows a single channel to perform the required functions. The redundancy within the individual EPSL channels is tested during the EPSL functional test. For example, the multiple paths which actuate the load shed relays are verified. Similarly, the multiple paths that can actuate the standby breaker close initiation logic are also demonstrated to perform as intended. The EPSL functional test (Test 3) is discussed in the response to Question A1. In addition, Attachment 3 contains a copy of the EPSL test procedure for one Oconee unit.

Protective relays (e.g. overcurrent, differential, undervoltage, etc.) are tested separately on a periodic basis via their respective maintenance procedure.

Question A3

Are there additional tests, surveillances, or calibrations, separate from those identified in the November 17, 1995, letter, used to support operability of required equipment? If so, identify them.

Response to Question A3

Additional tests, surveillances and calibrations beyond those mentioned in the November 17, 1995, submittal are performed at Oconee in support of equipment operability. Mechanical performance tests, battery tests, DC systems tests and protective relay calibrations are examples of tests performed to support operability of the required equipment. In addition, the operability of the emergency power system is observed as part of the operator rounds which are performed each shift. The testing program at Oconee is extensive and sufficient to ensure that the equipment which is needed to mitigate a design basis accident will perform properly.

The emergency power system testing program has improved from the past. A team that was comprised of engineering, maintenance, and operations representatives was established in 1993 to review the testing adequacy of the emergency power system. The emergency power system testing program has been enhanced as a result of this review. For example, the testing of the normal source to

startup source "slow bus transfer" logic was incorporated into the periodic testing program. Also, functional tests of the bus lockout circuits were added to the testing program on each Oconee unit's main feeder bus and standby bus. Another example of an enhancement to the testing program includes verification of the tripping capability of the individual load undervoltage load shedding relays. In order to illustrate the testing practices at Oconee, a copy of the test matrix from the Keowee Emergency Power DBD is provided in Attachment 4.

For systems which have redundant circuits or components, all of the required design basis functions are tested. An example where each component and channel is verified is the EPSL functional test which is discussed in the response to Questions A1 and A2. If only one of the redundant channels is required to perform the design basis functions, the test verifies the performance of the design basis function instead of operation of each channel separately.

Question A4

Identify the frequency of the periodic tests identified in the November 17, 1995, letter.

Response to Question A4

The following list provides the periodic test procedure numbers, title, and frequency.

PROCEDURE	TITLE	FREQUENCY
PT/1,2,3/A/610/01A	EPSL Normal Source Voltage Sensing Circuit	Refueling
PT/1,2,3/A/610/01B	EPSL Startup Source Voltage Sensing Circuit	Refueling
PT/1,2,3/A/610/01C	EPSL Standby Bus Source Voltage Sensing Circuit	Refueling
PT/1,2,3/A/610/01J	Emergency Power Switching Logic Functional Test	Refueling
PT/0/A/610/22	Degraded Grid and Switchyard Isolation Function Test	Refueling
PT/0/A/610/06	100kV Power Supply From Lee Steam Station	18 Months
PT/0/A/620/16	Keowee Emergency Start Test	Annual
PT/0/A/610/19	100kV Power Supply Prior To Extended Keowee Outages	Annual
PT/0/A/610/23	Lee Gas Turbine Operation To	Annual

Question A5

What failures have been discovered as the result of performing the tests described in the November 17, 1995, letter?

Response to Question A5

The response to Question A1 provides the details of tests that are performed to demonstrate the ability of the power sources, associated controls, and switching logic to perform their design basis functions. The performance of these tests ensures that the emergency power system is rigorously and comprehensively tested. A review of the failures that were discovered during the performance of these tests indicates that few significant failures occurred within the emergency power system during the tests. All of the failures have been investigated and corrected. The only recurring failure involves a problem with the indicating light sockets. Corrective action is in progress to alleviate this problem.

The following list contains the failures discovered during the past 5 years while performing the tests that are discussed in the response to Question A1. The data supports Duke's position that testing is performed at an appropriate level of detail to assure that equipment problems which could impact the ability of a system to perform its intended function are identified and corrected.

EPSL Testing (PT/1,2,3/A/610/01A,B,C,J)

1. Indicating lights did not illuminate because light sockets were bad.
2. Incorrect light bulb had been installed in light socket.
3. Non-safety motor control centers did not transfer to their alternate source.
4. Operator aid computer was lost because of inverter transfer problem.
5. Low pressure injection pump breaker would not close because timing relay coil was open.
6. Startup breaker did not close because slow transfer timing relay coil was open.
7. Power circuit breaker (PCB) 24 trip interposing relay coil was found to be open.

8. Startup breaker failed to close in the test position because the operating rod position indicating contact did not function properly.
9. Operating time for the non-safety STAR relay was out of tolerance.
10. The slow transfer initiation relay did not work properly during a non-LOOP power transfer.

Keowee Emergency Start Test

1. Generator supply breaker failed to close because a pin had been left out during manufacturing.
2. Generator field breaker failed to closed because a latching mechanism was worn.
3. Generator did not reach required voltage because the regulator was set incorrectly.
4. Keowee auxiliary power breakers would not close during test because a modification affected the required closing voltage.

Lee Combustion Turbine-Generator Tests (PT/0/A/610/06, 19, 23)

None

Degraded Grid and Switchyard Isolation Function Test

None

Question A6

How is proper loading and voltage regulator and governor response verified during periodic testing of the Keowee units for the LOCA/LOOP scenario from the standby condition? Based on the information in the November 17, 1995, letter, it is not apparent whether any periodic test has replaced the "J" test that would load a Keowee unit at 11 seconds while the unit is still accelerating. The tests that were identified only load the units while operating at nominal frequency and voltage.

Response to Question A6

Initially, the various functions of the emergency power switching logic were tested separately during each Oconee unit's refueling outage. In order to reduce outage risk and to perform a more integrated test, the various EPSL tests were combined into four tests in 1987. The resulting four EPSL tests were the functional

test, normal source voltage sensing test, startup source voltage sensing test, and standby bus voltage sensing test.

The EPSL functional test is an integrated test which verifies all of the functions that the emergency power switching logic would perform in a design basis event. As part of the EPSL functional test, the ability of a Lee combustion turbine-generator to supply an Oconee unit's main feeder busses on a transmission line which is separated from the Duke grid is verified. This verification allows testing of the SL and SK breaker logic in a more integrated manner since a Lee CTG is energizing the standby busses. Block loading of Keowee while it is accelerating is not possible due to the fact that the standby busses are energized by a Lee CTG. Therefore, the Keowee units are not tested periodically by loading at 11 seconds when the Keowee units are accelerating. We consider this change adequate because testing at steady-state provides reasonable assurance that all of the design basis conditions are met.

Oconee bridges the gap between testing and actual design requirements by using analysis. Since actual design basis loads are not available for functional testing, computer models are used to ensure the full loading capability of the emergency power system. The computer modeling tool which is used at Oconee is the CYME program. The CYME program is capable of dynamically modeling the power source, distribution system, and the electrical loads. Certification testing and analysis for the CYME program have been performed for Keowee and Lee. Further details on the test and model correlations are provided in the November 17, 1995, response to Request 1.

Proper voltage regulator and governor operation is verified as part of the EPSL functional test and Keowee emergency start test. These tests ensure that the Keowee units reach rated speed and voltage. After the Keowee units are loaded, proper operation of Keowee is observed using indications in the Oconee control room. In order to document the stability of the Keowee units, voltage and frequency monitoring of the Keowee unit that is supplying Oconee will be performed periodically with the EPSL functional test.

During this past Unit 1 refueling outage, the "J" test was revised to allow limited loading of Keowee while accelerating. Results of the data collected during this test are described in the response to Question A7 below. In addition, the response to Question B6 contains a description of a modification which will result in the Keowee units being loaded within approximately 90 percent of the nominal voltage and frequency.

Question A7

Provide the results of the recent modified "J" tests. Discuss how the test results support the 11 second loading scenario. Also, provide information to supplement your response in the November 17, 1995, letter to provide details regarding each instance that this test is referenced as providing data necessary to answer the staff's question (for example, in response to request 4).

Response to Question A7

In the Duke response dated November 17, 1995, the modified "J" test was referenced to support the responses to Requests 3, 4, and 5. The modified "J" test results are provided below to supplement the November 17, 1995, response. These test results will be evaluated and the need for future tests while the Keowee units are accelerating will be assessed.

During the Oconee Unit 1 EPSL functional test ("J" test), Keowee Unit 2 was loaded with Oconee Unit 1 shutdown loads while accelerating. After the emergency start signal, the loads were placed on Keowee at approximately 11.8 seconds. When Keowee was initially loaded, the voltage and frequency were at approximately 55 percent rated values and no detectable transient was experienced. The initial loading was approximately 4.8 MVA with the steady state loading at approximately 1.2 MVA.

From the graphs in Attachment 5, no detectable transient was experienced at the time of loading. The Keowee unit acceleration did not change when loaded and it reached rated frequency at approximately 18.5 seconds after the emergency start signal. The voltage continued to rise at the same rate until limited by the Volts/Hertz limiter. Rated voltage was reached at approximately 15.5 seconds after the emergency start signal. All loads accelerated to rated speed and continued to run until shut down.

In addition, the regulator automatic initiate relay energized at approximately 10.5 seconds after the emergency start signal. Considering the 2.5 second time delay, the voltage regulator would have gone into automatic at approximately 13 seconds after the emergency start signal.

Question A8

Test 8, as referenced in the November 17, 1995, letter, shows that a Lee combustion turbine-generator (CTG) is tested by

loading it to the approximate accident loads of an Oconee unit by using non-essential Oconee loads. Test 3 shows that an idling Keowee unit is loaded using actual auxiliary loads of a shutdown Oconee unit. If our assumption that the total load used in Test 3 (approximately 2 MVA) is substantially less than the load used in Test 8 is correct, why isn't the more substantial loading (approximating accident loads) used in Test 8 also used in Test 3? The NRC staff also understands that Test 9 (Lee CTG to the grid verification test) will replace Test 8 in a proposed change to Oconee Technical Specifications. How will the Lee CTG transmission path to Oconee, and the Lee CTG voltage and frequency response, be verified if Test 8 is eliminated?

Response to Question A8

The required loading of a Lee CTG per Technical Specification 4.6.7 is 4.8 MVA. However, the loads which are available during a refueling outage are approximately 2 MVA. To obtain loads equivalent to 4.8MVA, the Lee CTG is loaded during the startup phase of an Oconee unit. During this test, the required startup equipment for the Oconee unit is not lost since the loads are transferred to the Lee CTG without a loss of power. A majority of the Oconee unit's startup loads are load shed during EPSL operation. If the EPSL test was done during the startup phase of the Oconee unit, the startup loads would not be available to load onto a Keowee unit. The load shed circuits can be defeated to allow the startup loads to transfer to a Keowee unit. However, there would be a loss of power during the test as Keowee starts. Therefore, the required startup equipment for the Oconee unit would be lost for a brief period of time. The loading of a Keowee unit with the additional 2-3 MVA during Oconee startup is not justifiable based on the resulting risk to Oconee from the loss of power to the startup equipment.

The second part of the response compares the present and proposed surveillance requirements for the Lee combustion turbine-generators. This comparison will show how the existing test requirements are maintained in the proposed Technical Specifications.

Technical Specification Section 4.6 currently requires verification of the following:

(4.6.6) - Annually and prior to extended Keowee outages, Lee can be started, connected to an isolated 100kV line, and energize the 4160 main feeder buses.

(4.6.7) - Every 18 months, Lee can be started, connected to the isolated 100kV line and carry 4.8 MVA (one Oconee units DBA load) within one hour.

(4.6.8) - Annually, Lee can be started and supply the equivalent of an Oconee LOCA/LOOP unit and two Oconee LOOP units loads on the system grid.

The proposed Technical Specification Section 3.7 requires verification of the following:

(3.7.1.6) - Annually, verify the dedicated 100kV line is OPERABLE by energizing both standby buses by a Lee Gas Turbine.

(3.7.1.4) - Monthly, verify the S breakers are OPERABLE by full cycling.

(3.7.1.7) - Annually, verify Lee can be started, connected to the 100kV line system grid, and supply the equivalent of an Oconee LOCA/LOOP unit loads and two Oconee LOOP units loads within one hour.

Existing Technical Specification surveillance 4.6.6 has been replaced with a surveillance requirement (SR 3.7.1.6) that does not require connection to the main feeder buses. Monthly testing of the S breakers which connect the standby buses and main feeder buses is performed per SR 3.7.1.4. This ensures that voltage can be provided from the standby buses to the main feeder buses during an emergency.

The 18 month loading (equivalent to the ES loads of one Oconee unit) of a Lee gas turbine through the isolated 100kV line within one hour has been combined with the required annual loading (equivalent of an Oconee LOCA/LOOP unit and two Oconee LOOP units loads) on the system grid. This is covered by proposed SR 3.7.1.7.

Operability of the dedicated line is demonstrated by the combination of the proposed Technical Specification surveillances that are described in the paragraphs above. The ability to energize the main feeder buses from a Lee Gas Turbine is verified by proposed SRs 3.7.1.4 and 3.7.1.6. The load capacity verification of the Lee Gas Turbine is performed by SR 3.7.1.7. This testing methodology is consistent with the testing requirements for the Keowee Units.

Question A9

Identify any periodic or one-time-only electrical tests that have been performed on the standby shutdown facility (SSF) and the test acceptance criteria. Identify any electrical surveillances or calibrations used to support operability of required electrical equipment.

Response to Question A9

The design bases for the SSF AC power system is to supply adequate power to SSF loads during design events. The system has few automatic functions required for design basis operation. These automatic functions consist of the tripping of the SSF feeder breakers on Oconee Unit 2 load shed, the SSF generator voltage regulator and the SSF D/G speed control. The diesel generator is manually started, and the power system is manually switched from the normal feeder to the diesel generator (D/G) during design events. All loads started on the system are manually controlled and no load sequencer is provided on the system.

A list of the periodic and the one-time-only electrical tests, surveillances and calibrations for the SSF are shown below:

A. One Time Tests Performed by Manufacturer (MKW Power Systems)

The ability of the SSF D/G to run long term at its continuous rating was demonstrated by the manufacturer's testing. This testing was performed by the manufacturer prior to delivery of the D/G's. In this test, the engine was loaded to its continuous rating for the time that was required to reach engine equilibrium plus an additional 22 hours of operation. "Engine temperature equilibrium" is when the jacket water and lube oil temperatures are within ± 10 °F of the engine manufacturer's normal operating temperatures. This test was followed immediately by a test run of the engine at the "short term rating" (3850 KW) for 2 hours.

In addition, the following block loading and full load tests were performed:

1. A full load rejection test was performed with the following acceptance criteria. The speed after load rejection does not exceed 75 percent of the difference between the nominal speed and the overspeed trip set point, or 15 percent above nominal, whichever is lower.

2. After the generator was loaded with the largest projected load, a representative block load which was 10 percent greater than the largest projected load was applied to the D/G. For the acceptance criteria, the limits specified in OS-347, "SSF Diesel Electric Generating Unit Specification", could not be exceeded. These limits verify that the maximum momentary generator voltage drop after application of each load is not to exceed 20 percent of the rated generator voltage. In addition, the limits ensure that the generator voltage recovers to at least 90 percent of nominal and frequency recovers to at least 98 percent of nominal in less than 40 percent of each load sequence time interval.

3. The largest step load the D/G can accept without exceeding limits specified in OS-347 was determined.

The following tests were conducted on a typical unit to demonstrate the capability of the D/G to start and accept load after receipt of the start signal:

1. Valid starting and loading tests were made with an acceptance criterion of no more than one failure per hundred starts.

2. Immediately following the starting and acceleration to rated speed, a single step load equal to 1750 KW was applied. This step load verified that the D/G output did not exceed the limits stated in OS-347.

3. At least 270 of the 300 test starts were performed with the D/G temperature at or below "warm standby". After a load is applied, the D/G set continues to operate until the jacket water and lube oil temperatures are within ± 10 °F of the normal engine operating temperature for the corresponding load.

4. At least 30 tests were performed with the engine initially at "engine operating temperature equilibrium".

In addition, D/G alarms were tested to verify that they activated within the manufacturer's tolerance.

An additional one-time 24 hour run of the SSF D/G's is planned to demonstrate the D/G's ability to supply power to SSF loads for

the duration of an accident which requires operation of the SSF. Details of the planned test are described below:

1. The SSF D/G will be started using the Diesel Emergency Start push-button.

2. For the duration of the test, the SSF auxiliary service water (ASW) system will be operated at approximately accident flow rates. The SSF D/G will be used to supply power to the SSF ASW system. The flow will be through the SSF ASW pump minimum flow line and the SSF ASW test line.

3. All three Oconee unit's SSF reactor coolant (RC) makeup systems will be operated until shutdown of these systems is required to ensure that containment isolation Technical Specification action statements are satisfied. Full SSF RC makeup system flow will be provided through each Unit's corresponding SSF RC makeup system test line while the SSF RC makeup systems are operating.

4. The SSF diesel service water (DSW) system and the SSF HVAC service water system will be operated and powered from the D/G for the duration of the test.

5. Performance data will be taken to determine when the diesel reaches equilibrium conditions. This information will be used to determine the length of future periodic D/G performance tests.

The performance of this benchmarking one-time test will be coordinated with the benchmarking of the SSF service water system flow model. This test is scheduled for the latter part of the summer to ensure that the SSF heat exchangers are properly challenged. Therefore, the commitment to complete the SSF service water system flow model benchmark is being revised to allow for a more comprehensive test. This commitment will be completed within 90 days following the completion of the 24 hour run.

B. Periodic Tests

1. PT/0/A/400/11 Diesel Engine Performance Test

The ability to start and supply the design basis electrical load is tested quarterly by PT/0/A/400/11. The acceptance criteria ensure that the SSF D/G operates at $\geq$ 3100 KW for $\geq$

60 minutes. In addition, the D/G operation verifies full cycle of D/G fuel oil valves.

2. PT/0/A/600/21 SSF Diesel Generator Test

The ability to start the SSF D/G from the standby mode is tested monthly by PT/0/A/600/21. The acceptance criteria ensure that the SSF D/G starts from the standby mode and runs properly.

3. PT/1,2,3/A/0610/1J EPSL Functional Test

The trip function of the SSF feeder breakers is verified in the EPSL functional test (PT/2/A/0610/1J). The SSF incoming breaker is also tripped by an engineered safeguards signal on any Oconee unit. While the tripping of the SSF breaker is not a design basis requirement, it is verified by PT/1,2,3/A/0610/1J.

C. Surveillances and Calibrations

1. IP/0/A/370/04 SSF RC Makeup Pump Manual Override Circuit Test

This procedure tests the manual override circuitry and verifies that the RC makeup can be successfully started using the "Override SSF RC Makeup Pump Switch".

2. IP/0/A/380/06 SSF Diesels Load and Speed Control

This procedure calibrates the components associated with diesel load and speed control for the SSF D/G's.

3. IP/0/A/380/12 SSF Preventative Maintenance Procedure for D/G Control Relays

This surveillance tests and documents the operability of the relays which are used in D/G control applications.

4. IP/0/A/385/1A SSF 125VDC Batteries DCSF and DCSFS Daily Surveillance

During the daily surveillance, the SSF battery voltage, pilot cell voltage, pilot cell specific gravity, pilot cell electrolyte temperature, pilot cell level, charger output current, and battery room temperature are checked. The pilot cell is rotated weekly to ensure that all cells are checked periodically. Once a week, the electrolyte level on

all cells is checked, and the battery jars and terminal connections are inspected.

5. IP/0/A/385/1B Standby Shutdown Facility 125 VDC Battery Capability Test

This surveillance demonstrates that the SSF batteries are capable of providing the SSF DC system design loads for a period of one hour.

6. IP/0/A/385/1C Instructions for Conducting Equalizing Charge for SSF Batteries

This surveillance provides a procedure for conducting an equalizing battery charge.

7. IP/0/A/385/1D SSF 125 VDC Battery Quarterly Surveillance

The temperature, voltage, and electrolyte level in each battery cell are checked to determine the health of each cell. The acceptance criteria for these checks include cell temperatures not deviating by more than 5 degrees. In addition, the specific gravity (SG) of any cell must be above 1.200, and above the average SG - 0.010. The individual cell voltage must be above 2.12VDC when on a float charge.

8. IP/0/A/385/1E SSF Preventative Maintenance Procedure for Power Conversion Products 35-130-1000 CE Float Charger

This surveillance performs preventative maintenance on the Power Conversion Products 35-130-1000CE Float Charger. The charger provides DC power to the SSF vital and non-vital loads.

9. IP/0/A/385/1G SSF Preventative Maintenance Procedure for Elgar Inverters

Preventative maintenance on SSF Elgar Inverters is performed by this procedure. The two Elgar Inverters provide 120 VAC power to the SSF loads that are necessary to achieve hot shutdown.

10. IP/0/A/2005/004, NEI, PP-EP SVS Static Voltage Regulator Exciter System

This verifies proper operation of the generator voltage regulator. The acceptance criteria verify a maximum voltage drop of 20 percent with a recovery to 90 percent within 18 seconds during an SSF ASW pump start.

11. IP/0/A/4980 Series Relay procedures

The power system is designed with many protective features normally provided on power distribution systems. All protective relays on the system are tested and calibrated periodically by their respective procedures.

B. QUESTIONS REGARDING 11-SECOND LOADING OF KEOWEE UNIT UNDERGROUND PATH

Question B1

How has the CYME analysis, which assumes nominal voltage and frequency, been used to judge the adequacy of the 11-second loading criteria for a Keowee unit underground path which actually begins loading at about 60 percent of nominal voltage and frequency? Since the explanation in the November 17, 1995, letter is very general and qualitative, provide any quantitative insights or assumptions to explain the extrapolation of the CYME results as verification of the 11-second loading case at 60 percent voltage and frequency?

Response to Question B1

The CYME analysis assumes an initial condition of nominal voltage and frequency (60 hertz). This analytical approach is adequate to determine the acceptability of the 11 second loading criterion. During the 11 second loading, the volt/hertz (V/Hz) ratio is equivalent to or better than the steady state V/Hz ratio. This is due to the characteristics associated with motor torque. Motor torque is proportional to the voltage squared and inversely proportional to the frequency squared. Thus, the motors see an accelerating torque at 11 seconds that is equivalent to the torque at nominal conditions.

Question B2

What assumptions were used for motor starting and operating characteristics under constant V/Hz conditions? Has information been solicited from the vendors of those motors regarding performance and reliability under reduced voltage and frequency? If so, provide the vendor conclusions. A constant V/Hz will only be maintained at the Keowee generator terminals. Voltage drops from the generator to the terminals of Oconee equipment will result in proportionately lower voltages than frequency at the terminals of the equipment. Have these voltages been calculated and the results on equipment operation been analyzed? The voltage drops will not all necessarily be proportional to the nominal voltage and frequency case because the paths from the Keowee generator to the Oconee equipment terminals will have different reactance to resistance (X/R) ratios for the nominal

case than for the 60 percent case. Since smaller cables typically have smaller X/R ratios than larger cables, they should have proportionately larger voltage drops than the larger cables during the 60 percent case than during the nominal case.

Response to Question B2

The response to Question B1 provides the motor torque characteristics under constant V/Hz conditions. The motor characteristics were discussed with Westinghouse and Philadelphia Gear Corporation. These letters conclude that loading at reduced voltage and frequency at a constant V/Hz ratio is acceptable without damage to the equipment. Attachment 6 provides the letters which contain the responses from the vendors.

For the second part of the question, it is true that the voltage dip in the smaller cables is proportionally higher for the lower frequencies. However, the voltage drop through the higher X/R ratio transformers is proportionally lower during motor starting. The increase in the voltage drop through the smaller cables is offset by the decrease in the voltage drop through the high X/R ratio transformer. Therefore, the V/Hz ratio at the terminals of the loads (assuming a constant V/Hz ratio at the Keowee Generator) will not be significantly different between the lower frequencies and steady state.

Question B3

Were the effects of potential extended locked-rotor conditions on motors analyzed due to the proportionately lower voltages at 60 percent frequency than at nominal frequency? Were the effects on motor-operated valves (MOVs) and their motor contactors analyzed as well as on constant duty motors? Are the thermal overloads on MOVs bypassed at Oconee? Describe the treatment of thermal overloads at Oconee such as the criteria and method for bypassing or how their settings are determined.

Response to Question B3

As indicated in the Response to Question B1, the motor torque at a lower voltage and frequency (but constant V/Hz) is equivalent to the motor torque at nominal conditions. At the 11 second loading time, the Keowee unit is operating at a less than rated voltage and frequency. In addition, the acceleration time for many of the motors is less than the time that it will take the Keowee unit to reach rated speed following the 11 second loading. Thus, many of the motors will reach synchronous speed before the

Keowee unit reaches rated speed. Since the starting motor torque is equivalent to the torque at nominal conditions and the final motor speed is less, instead of an extended start time, the motor start time is shortened. Premature tripping of the loads during acceleration is not a concern because the overcurrent protective relays operate slightly slower at reduced frequencies and slightly faster at frequencies above nominal.

The motor operated valves (MOVs) were assumed to exhibit the same V/Hz relationship as the constant duty motors. Response to Question B2 provides information on starting loads at reduced frequency and voltage. Our evaluation of the contactor control circuit fusing indicates that the control circuits can draw the rated pickup amperes for at least 10 seconds before blowing the control fuses. A few second delay in the contactor pickup will not cause the circuit protection to prevent the contactor pickup.

For the safety MOVs that are not fed from the Standby Shutdown Facility (SSF), one overload heater is sized for motor protection and is only connected to an alarm. The other overload heaters for the MOV provide cable protection and trip the MOV circuit. For the SSF, one overload heater is sized for motor protection and is only connected to an alarm. The other overload heaters in the SSF MOV circuit are sized at 150 percent of MOV full load amperes. In any case, the circuit overload protection should allow the MOV rated locked rotor current to flow for at least 10 seconds before tripping the control circuit.

Question B4

Have the effects of reduced frequency and voltage at the 11-second loading point been analyzed for electrical equipment other than motors connected to the Oconee AC busses? Has information regarding performance and reliability under these conditions been solicited from the equipment vendors? If so, what were the results or conclusions?

Response to Question B4

Reduced frequency and voltage loading from the Keowee underground path was part of the original Oconee license. The effects and acceptability of this loading have been examined for various pieces and types of equipment. In July of 1971, Duke performed tests on a selective sample of engineered safeguards equipment to confirm the point at which Keowee should be loaded. The equipment tested included a latching relay, timing relays, FVR starters and a motor operated valve (MOV). The tests show that

the Clark size 2 FVR starter is the limiting device. At the rated volts/Hz ratio, the starter failed to operate properly below a frequency of approximately 25 Hz (42 percent of rated). Following discussions with the manufacturers of the equipment, the MOV manufacturer provided additional information that the valves with a loss motion (Hammerblow) design should not be connected to power below a frequency of 30 Hz. At frequencies below 30 Hz, the manufacturer was not assured that the operator could reach a sufficient speed for correct operation when hammerblow occurs.

The effects of reduced frequency and voltage loading was recently considered during the Oconee battery charger replacement modifications. The charger manufacturer was questioned about the effects of reduced frequency and voltage loading on the chargers. As with the previous equipment, the manufacturer indicated that no adverse effects would occur to the battery chargers.

In addition, tests that were performed on a type CO-8 overcurrent protective relay show that the relay operates slightly slower at reduced frequencies and slightly faster at frequencies above nominal. The manufacturer concluded that other types of protective relays (CO-5, CO-11, etc.) would perform similarly. Therefore, premature tripping while the loads are accelerating is not a concern.

Question B5

In a Duke letter dated February 22, 1995, Duke responded to NRC Staff questions on an Oconee Technical Specification revision and provided a timeline for the LOCA/LOOP scenario from Keowee standby start following plant modification no. NSM-ON-52966. On that timeline, does T=0 represent the time that the LOOP signal comes in from the loss of voltage or degraded voltage relays after their respective timers have timed out, or does it represent the time at which a loss of offsite power actually occurs? What are the setpoints of the loss of voltage and degraded voltage relays that sense lost or degraded voltage, and what are their time delays? What is the location point on the system where the voltage is being sensed? Provide the same information for the voltage relays that provide breaker closure permissives?

Response to Question B5

On the referenced LOCA LOOP scenario time line, T=0 represents the actual time that the LOOP occurs. There are no time delays associated with the external grid trouble protection system (EGTPS) logic. On detection of a LOOP, the 230kV switchyard is immediately isolated and Keowee is provided an emergency start signal. The EGTPS undervoltage relays have a tap setpoint of 82 volts which is approximately 70 percent of nominal voltage. These relays sense voltage off the 230kV switchyard red and yellow busses.

For degraded grid, a built in nine (9) second time delay is present in the logic. Following initial LOCA loading, the time delay allows the grid voltage to recover above the degraded grid undervoltage relay reset setpoints. If the voltage does not recover within the defined time, the switchyard isolate logic is initiated. Prior to this time delay, Keowee would have received an emergency start upon the LOCA initiation. The degraded grid undervoltage relays have a setpoint of 111.25 volts which is approximately 96 percent of nominal voltage. The undervoltage relays sense voltage in the 230kV switchyard on the startup transformer bus line for each Oconee unit. A modification that enhances the sensing of the degraded grid undervoltage relays is planned and scheduled.

The Oconee unit normal supply breakers (N breakers) have a voltage close permissive. These breakers can only be closed manually. The voltage close permissive is from the 27N undervoltage relays. The undervoltage relays are Westinghouse type CV-7 relays with a tap setpoint of 105 volts which is approximately 87 percent of nominal voltage. They sense 4kV voltage on the secondary side of the respective Oconee unit normal auxiliary transformer.

The Oconee unit startup supply breakers (E breakers) have a voltage close permissive. These breakers can be manually and automatically closed. The voltage close permissive is from the 27E undervoltage relays. The undervoltage relays are Westinghouse type CV-7 relays with a tap setpoint of 105 volts which is approximately 87 percent of nominal voltage. They sense 4kV voltage on the secondary side of the respective Oconee unit startup auxiliary transformer.

The underground path SK breakers and Oconee unit standby bus breakers (S breakers) each have voltage close permissives. The voltage close permissives are configured to sense voltage on the

line and a deenergized bus. These relays are set to allow closure at approximately 55 percent of nominal voltage.

Question B6

The timelines for the LOCA/LOOP scenario appear to indicate that the Keowee load rejection scenario is the most limiting from the time perspective. If this is the case, it appears that the loading of the underground path for the standby start scenario could be delayed until the Keowee unit is at nominal frequency and voltage and still meet accident time requirements assuming failure of the underground path. Therefore, is it necessary to load the underground unit at 11 seconds?

Response to Question B6

Loading a Keowee unit at 11 seconds was part of the original design basis. However, it is not necessary to load the underground Keowee unit at 11 seconds. The design basis requires that ECCS injection occurs within 48 seconds. In support of this design basis, Keowee should be at rated speed and voltage within 23 seconds. As noted in this question, the load rejection case is more limiting from a time perspective than the start from standby scenario.

Duke has reviewed the possibility of delaying the underground path loading until the voltage and frequency are within approximately 90 percent of their nominal values. The review concluded that the change is feasible. A delay of roughly 5 seconds is incurred by waiting for the Keowee unit to accelerate to approximately 90 percent of nominal voltage and frequency. This delay is within the assumptions of the ECCS analyses, in that the main feeder busses continue to have power within the required time. A modification of this nature is being planned via the normal modification process. The conceptual design for the modification includes the placement of undervoltage and frequency relays on the underground power path. These relays provide a permissive that ensures a Keowee unit is within approximately 90 percent of the nominal voltage and frequency prior to energizing the standby busses. In addition, a speed permissive will be placed on the overhead Keowee ACBs. Currently, undervoltage protection is provided on the overhead power path. The combination of the speed permissive and the existing voltage protection ensures that a Keowee unit is within approximately 90 percent of the nominal voltage and frequency prior to energizing the overhead power path.

Question B7

One of the potential problems that could occur for the loading at 11 seconds is that all equipment may not physically start at 11 seconds but may rather start in a somewhat random fashion according to the voltage and frequency recovery at their terminals. If there are interlocks with other equipment, either direct or through process controls (like pressure or flow permissives), this might result in tripping or locking out of equipment. One mechanism for creating a lockout could be the actuation of circuit breaker anti-pump circuits. Have these possibilities and effects been considered?

Response to Question B7

The possible interlocks between equipment have been considered as part of the Oconee design. The design philosophy of the Oconee fluid systems is such that the suction lines to the required pumps are kept flooded. Therefore, the remaining actions in an accident are the starting of the pump motor and the opening of the discharge valve. Following an engineered safeguard actuation, no interlocks exist that could adversely impact the potential randomness of lower voltage components starting.

Question B8

For the loss of power to the main feeder busses (MFB) following a plant trip (non-LOCA) such as caused by a failure of the startup transformer or a failure to transfer to it, will the Keowee unit underground path reenergize the buses at 60 percent of nominal frequency and voltage or at nominal voltage and frequency? Does the Keowee unit start prior to or following the 20 second MFB delay? What is the magnitude of the MFB load if the loss of MFB scenario occurs and what are the loads that are powered?

Response to Question B8

For the failures described in the question, the Keowee units receive an emergency start signal from the MFB monitor panel after a 20 second time delay. The selected Keowee underground unit powers the standby busses unless a Lee CTG or the Central switchyard is already energizing the standby busses. The Keowee underground unit is loaded at approximately 60 percent of rated voltage and frequency.

In addition, the MFB monitor panel actuates the load shed circuit following the 20 second time delay. This is done in preparation

of a transfer to the standby busses. Following deenergization of the MFB, the non-essential loads are tripped by their individual undervoltage relay. Following actuation of the EPSL load shed logic, these loads are provided an additional trip signal. The non-load shed loads will restart once power is restored. HPI (2 pumps), LPSW (2 pumps) and MDEFW (2 pumps) are examples of 4kV motors that may restart. A total of approximately 4 MVA of load is expected to be supplied by the MFB. This is a combination of the motor loads and house static loads.

C. QUESTIONS REGARDING THE KEOWEE VOLTAGE REGULATOR AND GOVERNOR

Question C1

Provide a description of the differences between normal operation and emergency operation of the Keowee voltage regulator and governor. Include the differences for start, acceleration, generator breaker closure, steady-state operation, load application and load reject.

Response to Question C1

The physical differences in the Keowee voltage regulator operation when operating in the normal and emergency modes are as follows.

1. Upon receipt of an emergency start signal, the field, supply, and field flash breaker close immediately. On a normal startup, the breakers close when the generator speed reaches approximately 50RPM.

2. The auto synchronizer is deenergized by an emergency start signal. If the Keowee unit load rejects on receipt of the emergency start signal, the auto synchronizer is deenergized. The auto synchronizer would not be deenergized on a load rejection for non-emergency start conditions.

3. During acceleration, steady-state operation, and load application, there are no changes between emergency and normal operation of the voltage regulator.

The physical differences in the Keowee governor operation when operating in the normal and emergency modes are as follows:

1. For an emergency start from standby, the immediate gate opening is increased to about 50 percent. This allows the Keowee unit to accelerate to rated speed faster. This gate position is greater than the position which is required to operate the emergency loads. Thus, the Keowee unit continues to accelerate when loaded at 11 seconds.

2. During emergency operation, the compensating dashpot is used to slow the response of the governor in order to avoid speed swings due to rapid load changes. The frequency will be held within the speed droop limits of 5 percent for demands

requiring 100 percent gate change. Emergency loads at normal lake levels require approximately 30 percent gate change. During normal operation, the compensating dashpot is in service except when the operator manually takes on load.

3. During emergency start conditions, the gate limit is extended to 100 percent to assure that emergency power is available during extraordinarily low Lake Keowee levels.

4. The permissives required only for normal operation, such as oil levels and pressures, are blocked to ensure that emergency power is delivered. Several permissives that are applicable to emergency power generation are not blocked.

5. On emergency start, the governor and auto synchronizer interface is blocked to prevent the synchronizer from attempting to control speed.

The differences between normal and emergency operation for the Keowee voltage regulator and governor are tabulated below for convenience.

A. Start differences:

Voltage Regulator	- Excitation Breaker closure
	- Auto Synchronizer
Governor	- Gate Limit
	- Initial Gate Opening
	- Permissives
	- Auto Synchronizer

B. Acceleration differences:

Voltage Regulator	- None
Governor	- Initial Gate Opening

C. Generator (Excitation) Breaker closure:

Voltage Regulator	- Immediate
Governor	- None

D. Steady state operation:

Voltage Regulator	- None
Governor	- Compensating Dashpot

E. Load application:

Voltage Regulator	- None
Governor	- Compensating Dashpot

F. Load Reject (due to emergency start as opposed to grid disturbance):

Voltage Regulator	- Auto Synchronizer
Governor	- Permissives
	- Gate Limit
	- Compensating Dashpot
	- Auto Synchronizer

In emergency conditions, there is a fundamental difference in the function of the voltage regulator and governor. When generating commercial power, the speed and voltage is maintained by the system grid. Thus, the governor and voltage regulator allow the operator to manually control the power output of the machine. The voltage regulator is used to control the reactive power, and the governor is used to control the real power. When The Keowee unit is isolated from the grid, the governor and voltage regulator control the frequency and voltage. In order to maintain voltage and frequency, they must respond to changes in the power requirements.

The differences between normal and emergency governor and voltage regulator operation are minimal. Thus, failures in the governor or voltage regulator will be recognized when the Keowee units are connected to the grid. The loss of the ability to maintain rated voltage or frequency in an emergency would be indicated by a loss of MW or MVAR control during commercial operation.

Question C2

Table C.1-1 in the Keowee Probablistic Risk Assessment (PRA) identifies an event on September 20, 1992, concerning the base adjust and voltage adjust portions of the Keowee voltage regulator. It states that the cause was dirty base adjust contacts, which was corrected by running the base adjuster back and forth a couple of times and spraying the base adjuster with solvent. The staff feels that this problem is similar to one identified by it in question 7 of the NRC November 2, 1995, letter to Duke. This appears to be a credible failure that could result in a low voltage output from Keowee in a range that would result in degraded voltages on Oconee equipment. Provide your comments or conclusion in this regard.

Response to Question C2

As discussed in the PRA analysis (Table C.1.1, page 2), this failure would not have adversely affected the ability of the Keowee unit to supply adequate voltage to the Oconee emergency power system. This failure prevented the voltage regulator from switching to automatic. In an emergency, the Keowee unit would have operated with the regulator in manual. The potential for failures to cause a generator to operate in manual was analyzed in KC-2023 (Analysis of Keowee Voltage Regulator Settings), and no safety concerns were identified.

Question C3

In November 17, 1995 response to the staff's question 6, it is indicated that the minimum excitation limiter (MEL) of the voltage regulator responded to the failure of the volts/hertz limiter card by maintaining field excitation at the minimum excitation limit. What is the corresponding generator output voltage at the setpoint of the minimum excitation limit when Keowee is supplying Oconee loads?

Response to Question C3

When connected to the grid, the generator terminal voltage is controlled by the grid voltage. When considering operation of the minimum excitation limiter (MEL) module, changes in the excitation level during grid operation will not affect the terminal voltage significantly. Excitation control is used to control the generator power factor (pf), or in other words, the amount of VARs the machine supplies to the grid. If the machine is excited such that the no load terminal voltage is above the equivalent grid voltage, the generator would operate as a VARs source to the grid with a lagging pf. If the machine is excited such that the no load terminal voltage is below the equivalent grid voltage, the generator would operate as a VARs sink from the grid with a leading pf.

If a failure or improper operator control causes the excitation to decrease too far, the machine may lose synchronism with the grid. This condition could damage the machine. Thus, the loss of excitation (40) relay is provided to trip the generator and protect it. The Westinghouse regulator system provides the MEL module to prevent failures in the voltage regulator or operator action from decreasing excitation to a point where the machine would trip. This module prevents the operator from inadvertently placing the machine in a dangerous condition. In addition, the

module provides for continued commercial operation with some regulator failures.

As discussed above, the generator terminal voltage is dominated by the grid voltage and will not decrease significantly when excitation is decreased. The MEL compares the generator output voltage and current together. When the unit is operating with a leading power factor, the MEL develops a limit signal. This limit signal is developed by vectorially summing the current and voltage signals in a way that increases the total when the generator goes more and more leading. At the limit, the output of the MEL will take control of the system away from the voltage error detector. This prevents any further reduction in the excitation of the generator.

If the unit is operating isolated from other power sources, the generator terminal voltage will decrease as the excitation decreases. In addition, there are no VAR sources at Oconee significant enough to cause the generator to go leading. Therefore, the Keowee unit continues to operate with a lagging power factor as voltage decreases. Both of these factors cause the MEL module to shift away from the setpoint. Thus, the MEL provides no limit signal to minimize the voltage decrease when the unit is operated as an emergency power source.

Question C4

Is the volts/hertz limiter functional during all Keowee operating modes? In several places where potential governor failures that could result in a low frequency were discussed in the November 17, 1995, letter, it was stated that these failures would also result in a low voltage output from Keowee. Is this due to the action of the volts/hertz limiter?

Response to Question C4

Since a governor failure scenario is assumed by this question, the single failure criterion allows for the assumption that the voltage regulator functions properly. Thus, the voltage regulator is in automatic and the V/Hz limiter is functional. The V/Hz limiter is functional in both modes of operation (commercial and emergency power) unless a regulator failure occurs.

If a governor failure causes the frequency to decrease, the V/Hz limiter takes control of voltage when the frequency decreases to approximately 95 percent or 57 Hz. The V/Hz limiter maintains

the V/Hz ratio at approximately 105 percent as frequency decreases.

Question C5

In the November 17, 1995, response to staff question 10, it was stated that alarms indicating low governor oil pressure, indicative of possible low frequencies, are provided in the Keowee control room. What is the frequency output of the Keowee machines that would correspond to the low governor oil pressure setpoint?

Response to Question C5

The frequency corresponding to the governor oil low pressure setpoints is 60 Hz since no governor failures other than low oil pressure are assumed.

There are alarms for governor oil pressure at 300 psig decreasing and 290 psig decreasing. Neither of these alarms prohibit or shut down an emergency start. Based on the testing performed by the Woodward Governor Company prior to Keowee commercial operation, the wicket gates are capable of being controlled with an oil pressure down to 265 psig. This pressure test was performed using only the governor oil pressure tank. The test concluded when the float valve closed thus isolating the pressure source. The low pressure alarms were established using this test data. At the 290 psig alarm point, the oil pressure allows about 150 percent wicket gate stroke. The following factors need to be considered when evaluating the setpoints.

1. The test did not use the three governor oil pumps per Keowee unit which are powered by the Keowee unit auxiliaries.

2. At normal operating lake levels, operation in the emergency load range of 20.6 MVA requires about 30 percent gate. The 150 percent wicket gate stroke available at 290 psig in the governor oil pressure tank is sufficient capacity for 2.5 full gate strokes for emergency loads.

3. The governor oil pressure tank float valve closure is established at a point that allows shutdown of the Keowee unit in a controlled manner. This implies that control is available for a governor oil pressure at or above 265 psig.

Question C6

The Keowee PRA identified a number of Keowee voltage regulator and governor failures that could result in out-of-tolerance voltages and frequencies being applied to redundant Oconee electrical equipment. These failures, among others, are titled: (a) Keowee Unit 1 Base Adjust is Set Incorrectly, (b) KHU-1 Voltage Adjust Failure Drives Generator Output Too High/Low, (c) Keowee Unit 1 Governor Fails to Position Wicket Gates With Unit Running, and (d) Keowee Unit 1 Governor Fails to Position Wicket Gates During a Hot Start. Although many of these failures would likely drive the output frequency and voltage to a level that would either separate the Keowee unit from the Oconee loads or alarm the condition so that operators could separate the loads, some failures could result in a voltage or frequency that neither initiates an alarm or trip. For example, in the November 17, 1995, response to staff question 10, it appears that a low voltage (above approximately 47 percent) or low frequency on the underground path would not cause an alarm or trip. While the design and modifications made to the Keowee governors, voltage regulators, and generator breaker control have addressed a number of the more likely failure modes and occurrences, it is not clear to the NRC staff that the probability of occurrence of an out-of-tolerance voltage or frequency is sufficiently low relative to the potentially negative effects on multiple and redundant Oconee electrical equipment. Figures 7.2-1, 7.2-3, and 7.2-4 in the Keowee PRA indicate that voltage regulator and governor failures are of relatively high importance for Keowee reliability and unavailability. However, the Oconee PRA does not examine the more negative effects of these failures should out-of-tolerance voltages and frequency be applied to Oconee electrical equipment (equipment tripping, fuse blowing, or other possible damage). The Oconee PRA assumes only that the Keowee power supply is lost. Provide the Duke opinion with appropriate basis on each of the above NRC staff observations.

Response to Question C6

The emergency power system has been analyzed for all credible voltage regulator failures that could cause the voltage to decrease without a complete collapse. The bounding cases consist of a failure which would drive the voltage adjuster motor to the low limit and a failure of the voltage regulator which causes operation in manual. Driving the voltage adjuster motor to the low limit causes the voltage to decrease to 85 percent of rated voltage (11.7KV). Operation of the Keowee unit with the voltage regulator in manual is conservatively assumed to cause the field current to remain constant at the rated no load level. The

analyses performed to evaluate these failures conclude that all required loads start and operate on the failed Keowee unit. These analyses are documented in OSC-5952.

The Keowee governor has been analyzed for all credible failures that could cause the frequency to decrease or increase. The bounding case with the governor is the loss of the permanent magnet generator signal to the governor flyball motor. This failure is addressed by modification NSM ON-52966. The analysis of this failure indicates that the Keowee unit either trips or operates within the allowed range of frequency. This analysis is documented in KC-0098.

One major difference between Keowee and other emergency diesel generators is the amount of run time on the Keowee units. Emergency diesel generators run approximately 40 hours per year, while the Keowee units may run that much in a month. The differences between normal and emergency operation for the Keowee governor and voltage regulator are not significant. Therefore, failures or potential failures are revealed during normal operation. The past Keowee operating record supports Duke's position that failures which result in a degraded voltage or frequency are of a very low probability.

The Keowee PRA did not explicitly include degraded operation of the Keowee generators. Failures of the Keowee generators result in sufficient deviation from the required operating parameters. Thus, the Keowee generators are either manually or automatically separated from Oconee. The likelihood of the Oconee loads remaining connected to a degraded Keowee unit is small enough to ignore in the analysis.

In considering the impact of the Keowee failures on the Oconee AC power system, a failure mode of similar consequences is modeled in the existing study. A common cause failure (CCF) of breakers N1 and N2 to open results in the complete loss of power to the Oconee loads. The value assigned to the common cause failure of the N breakers to open is 3.0E-05. The failure to recover probability is 0.05 and the total LOOP frequency is about 9.0E-02. The resulting contribution to the loss of AC power from this event is 1.4E-07 (approximately 0.2 percent of the total). This event is assumed to render all plant equipment except the SSF unavailable. When combined with the failure of the SSF (approximately 0.2), the contribution to core damage frequency (CDF) is 3.0E-08 (approximately 0.03 percent of the total CDF).

The range of failure probabilities for the Keowee voltage regulator, turbine, and governor components in the KPRA is from

approximately 2.0E-05 to 2.0E-03. If 10 percent of the failure probability for a particular failure mode is assumed to result in operation with degraded voltage or frequency, then a typical value for this failure probability could be 1.0E-04. If the failure to recover is estimated at 0.1 and the failure of the SSF is 0.2, then the total contribution to CDF is approximately 1.8E-07 (approximately 0.2 percent of the total CDF). For the example given, there is significant margin in the values before any appreciable contribution to the CDF is observed. If the failure probabilities are smaller than given in the example, then the impact may be less than the CCF of the N breakers.

An accurate calculation of the contribution to CDF from degraded failure modes of the Keowee voltage regulator, turbine, or governor is difficult due to the lack of observed failures in the modes of concern. An example is given where the failure rates are assumed based on the failures that have been experienced. This example shows the contribution to CDF to be small. An increase of an order of magnitude in the CDF contribution over that given in the example produces only a moderate increase in the calculated CDF for Oconee.

Duke believes that the probability of the above described failures is very low. However, it is acknowledged that the consequences of these postulated failures are not easily quantified. Therefore, Duke will implement modifications to monitor and alarm voltages and frequencies below the acceptable ranges. These alarms will promptly alert the operators of unusually low voltages or frequencies. Operator response guidelines will be implemented at Keowee and Oconee to assure that, in the very unlikely event of such a failure, voltage and frequency are restored to their nominal values. These modifications will be installed using our normal modification process.

D. GENERAL QUESTIONS

Question D1

Identify the procedures available to operators covering emergency operation of Keowee, the Standby Shutdown Facility, the Oconee Switchyard, and the Lee CTGs. Describe, in general terms, the operations addressed by each procedure. How often are operators trained and tested on these procedures?

Response to Question D1

The procedures that are available to the Oconee operators for emergency operations of the electrical systems include the following:

1. AP/1,2,3/1700/11, Loss of Power

   Content: This procedure provides guidance to place and maintain the plant in a safe condition if the main feeder busses (MFBs) are or have been deenergized. Guidance is provided to manually energize (if required) the MFBs from any available transformer (Main, Startup, CT-4, or CT-5). Once power to the MFBs is regained, this procedure provides guidance for proper verification of the load shed circuit and for regaining necessary plant loads. If the MFBs are powered by CT-4 or CT-5, the transformer is checked to ensure that the transformer limits are not exceeded when plant loads are regained. In addition, guidance is provided for verification of the switchyard isolation circuit (if required) and recovery of the Oconee 230 kV switchyard.

   Training: All licensed operators at Oconee receive training on this procedure annually in requalification training. Specific critical tasks are trained on a two year frequency.

2. AP/0/A/1700/25, SSF Emergency Operating Procedure

   Content: This procedure provides the guidance which is needed for emergency operation of the SSF systems that are required to maintain Hot Shutdown of all three Oconee units following a station fire, blackout, sabotage event, or flood. The guidance

covers emergency operation of the SSF diesel, SSF RC makeup pump(s), and the SSF auxiliary service water pump. Also, proper operation of the SSF support systems is verified by this procedure.

Training: All licensed operators at Oconee receive training on this procedure at least once every two years in requalification training.

3. OP/O/A/1107/03, 100 KV Power Supply (Lee Combustion Turbine)

Content: This procedure provides the guidance for isolation of the dedicated 100 KV transmission line from the Duke grid. Also, the procedure coordinates the actions of Oconee and Lee Steam Station when energizing the Oconee standby busses from a Lee combustion turbine-generator via transformer CT-5. Lee Steam Station personnel receive guidance for placing the combustion turbine-generator in service in OP/O/A/1107/03A, "ONS AND LEE STEAM STATION PROCEDURE FOR FURNISHING EMERGENCY POWER OR BACKUP POWER TO OCONEE."

Training: All licensed operators at Oconee receive training on this procedure at least once every two years in requalification training.

The procedures that are available for the operating personnel of the Keowee Hydro Station and a general description of each procedure are listed below:

1. AP/0/A/2000/001, Keowee Hydro Station - Natural Disaster

Content: This procedure provides the instructions for an inspection of the Keowee Hydro Station and surrounding structures following an earthquake or natural disaster. The inspection includes each level in the station, the main step-up transformer area, and the exterior of the building. Assistance would be requested from area operating personnel to inspect the intake and spillway structures, Keowee Dam, Oconee Intake Dam, and Little River Dam and dikes. This information would be documented in the procedure and communicated to the Oconee Operations Shift Manager, Charlotte coordinator, Keowee Supervisor, Keowee Security, and Keowee Utility Supervisor (responsible for dam inspections).

Training: Training is provided to individuals when initially classified as an operator. Re-trainng is provided on the procedure every 2 years. This re-training consists of performance of the associated training and qualification (T&Q) guide. Oconee operators do not train on this procedure.

2. AP/0/A/2000/002, Keowee Hydro Station - Emergency Start

Content: This procedure provides guidance for the proper responses following a Keowee Emergency Start. The procedure concentrates on the verification of the operation of both Keowee units and the establishment of auxiliary power for the long term operation of each unit. In the event a Keowee unit(s) fails to start, connect to an available auxiliary power source, or supply emergency power to Oconee Nuclear Station (ONS), guidance for manual actions are provided to perform these actions.

Training: Training is provided to individuals when initially classified as an operator. Re-trainng is provided on the procedure annually. The annual training consists of performance of job performance measures (JPM) which were created to address the "critical" activities necessary for the proper execution of the procedure. Additionally, all ONS licensed operators are trained on the JPMs. During annual re-qualification training, the ONS licensed operators are randomly selected for performance of the Keowee JPMs.

Question D2

What alarms exist at the Oconee and Keowee sites to alert operators to the fact that a battery charger has been lost? Are there any battery chargers at Oconee or Keowee (e.g., the battery chargers in the Oconee 230 kV switchyard or at the SSF) that, if lost, would not cause an alarm in a manned control room? What procedures exist to direct or guide operator actions needed to restore each of the battery chargers that cause an alarm when lost? In particular, are there procedures in place to direct or guide operators to start the SSF diesel generator if the normal power source to the SSF battery chargers is lost? Are there any batteries at Oconee or Keowee that could discharge without operator knowledge as a result of a lost battery charger? If a

system is equipped with a standby battery charger (e.g., the 230 kV switchyard has a standby battery charger), will the loss of the standby battery charger initiate an alarm if this device is operating in place of the primary charger?

In order to evaluate the timeliness of operator actions needed to restore a lost battery charger, the staff must understand the sizing criteria for battery selection and the battery's current load profile (or the maximum time for which the battery is expected to be capable of supplying its loads). In this regard, provide the sizing criteria used to select the two 230 kV switchyard batteries, the two SSF batteries and the two Keowee batteries, and the expected load profile for each battery. Provide sufficient information to verify that these batteries can be expected to perform adequately for the required duration after their respective battery chargers have been lost. Based on this information, provide your conclusions regarding the adequacy of operator actions needed to restore a lost battery charger within the required coping duration.

Response to Question D2

Part 1: Are there any battery chargers at Oconee or Keowee (e.g., the battery chargers in the Oconee 230 kV switchyard or at the SSF) that, if lost, would not cause an alarm in a manned control room? Are there any batteries at Oconee or Keowee that could discharge without operator knowledge as a result of a lost battery charger?

Failures of battery chargers in the 125Vdc and 250Vdc Power systems at Oconee, the 230kV and 525kV switchyards, Keowee, and the SSF are alarmed in a manned control room. None of the 125Vdc or 250Vdc batteries can discharge due to loss of a battery charger without knowledge of an operator.

For most of the DC systems, battery trouble alarms, DC system trouble alarms, and/or dedicated charger trouble alarms are driven by charger internal contacts which monitor the status of the charger. Battery trouble alarms or DC system trouble alarms provide indication of other items, such as bus undervoltage, breaker status, etc. in addition to charger status.

Specific information on how each charger is alarmed is given below. Note that these alarm configurations reflect existing system design and are subject to change as enhancements are made to the alarm systems.

Failure of a charger at Keowee will generate a battery trouble and a charger trouble alarm in the Keowee control room and in the Oconee Unit 2 control room.

Failure of a charger in the 230kV switchyard 125Vdc system will generate a battery trouble alarm in the Oconee Unit 1 control room.

Failure of a charger in the 525kV switchyard 125Vdc system will generate a battery trouble alarm in the Oconee Unit 1 control room.

Failure of a charger in the 125Vdc vital instrumentation and control system will generate a battery trouble alarm and a DC system trouble alarm in the appropriate Oconee unit control room.

Failure of a charger in the 250Vdc power battery system will generate a battery trouble alarm and charger alarm in the appropriate unit control room.

In the SSF 125Vdc system, the charger internal status contacts generate an alarm in the SSF control room, which is not continuously manned. However, DC bus undervoltage generates an alarm in the SSF equipment room. This alarm also rolls to an alarm station which is continuously monitored by security personnel. This undervoltage alarm is set just below battery open circuit voltage and will provide indication of battery discharge associated with a failure of the battery charger.

Part 2: What procedures exist to direct or guide operator actions needed to restore each of the battery chargers that cause an alarm when lost?

Each charger is provided with connection to one or more battery/ DC system trouble and/or charger trouble alarms as described above. The actions taken by operations in response to battery trouble, DC system trouble, or charger trouble alarms are governed by a separate alarm response procedure for each alarm. In general, the operators are instructed to assess the cause of the alarm (when there are several inputs to a battery or DC system trouble alarm) using local indications. If the operator determines that there is indeed a charger problem, the alarm response procedure instructs the operator to align the standby charger or make other changes to the system alignment using the appropriate procedure.

Failure of a battery charger at Keowee or the SSF requires slightly different actions. The Keowee control room is not

continuously manned, but the Keowee Hydro Station is continuously manned. Upon receipt of an alarm from Keowee in the Oconee control room, Oconee operators are directed by procedure to contact the Keowee operators to determine the cause of the alarm and determine availability of the Keowee Unit. Keowee personnel will then respond to the alarm by verifying that it is valid and placing the standby charger in service.

For the SSF, the security alarm response procedure requires that the Security Shift Supervisor notify operations whenever the DC bus undervoltage alarm is received. Operations will investigate the alarm in the SSF equipment room. The alarm response procedure then directs operations to align the standby battery and battery charger to the Distribution Center.

Part 3: Are there any procedures in place to direct or guide operators to start the SSF diesel generator if the normal power source to the SSF battery Charger is lost?

Loss of power to the charger will require that the SSF be declared inoperable and will cause all three units to enter an action statement as required by Technical Specification 3.18.5. Therefore, alarm response procedures do not specifically call for operation of the SSF diesel generator to provide power for a battery charger. Upon loss of power to the SSF, operations procedures currently instruct the Oconee Unit 2 control room to reset load shed and to close the 4160V switchgear breaker supplying SSF switchgear OTS1. Load shed will be reset very soon after an event occurs, just after verification that ES switchgear, motor control centers, and battery chargers are energized and main feeder bus transfer switches are placed in manual. SSF power recovery will be the first action taken after load shed is reset in Oconee Unit 2.

Part 4: If a system is equipped with a standby battery charger (e.g., the 230 kV switchyard has a standby battery charger), will the loss of the standby battery charger initiate an alarm if this device is operating in place of the primary charger?

All of the above systems are equipped with a standby charger. When the standby charger is in service, the standby charger internal contacts are automatically aligned to control the appropriate battery trouble alarms. On the systems where dedicated charger trouble alarms are also provided, the standby charger alarms are enabled by procedure when the charger is placed in service.

Part 5: Provide the sizing criteria used to select the two 230kV Switchyard Batteries, the two SSF batteries, and the two Keowee batteries, and the expected load profile for each battery.

230kV Switchyard 125Vdc System

Each 230kV switchyard 125Vdc battery is sized to carry the entire load of 125Vdc system during an event for one hour without battery chargers. A single battery could be called upon to operate all of the 230kV switchyard equipment when one battery is out of service and the distribution centers are tied as allowed by Tech Spec 3.7.2(e).

Calculations show that the emergency load profile under this alignment consists of current required to support switchyard isolate during the first minute after loss of charger power (less than 350 amps), followed by 58 minutes of steady state load (less than 60 amps), followed by current required to support an isolation of the red bus by action of the red bus differential circuit during the last minute of the hour (less than 310 amps). These loads include corrections for 80 percent capacity, 60° F electrolyte temperature, and load growth where appropriate. These currents are all expressed at 125Vdc, and actual system currents may be slightly different due to the change in battery voltage during the discharge. The load profile is of course subject to change as loads are added and removed from the system.

During non-emergency conditions, a single battery would be expected to carry less than 60 amps. Since this is comparable to the load profile under emergency conditions, each battery could be expected to support the system for at least one hour after a charger failure under non-emergency conditions. This is sufficient time for the standby charger to be aligned using the alarm response procedures described above.

The 230kV switchyard batteries are each capable of delivering 204 amps for a period of one hour with an average end-of-discharge voltage of 1.75 volts per cell.

Keowee 125Vdc System

Each Keowee 125Vdc battery is sized to start and run both Keowee units for a period of one hour without battery chargers. A single battery could be called upon to start and run both units when one battery is out of service and the DC distribution centers are tied as allowed by Tech Spec 3.7.2(e). Under normal conditions, with both batteries in service, each battery will

carry approximately half of its design load. The Keowee batteries are each capable of delivering 975 amps for a period of one hour with an average end-of-discharge voltage of 1.75 volts per cell.

The emergency load profile under this alignment consists of the current required to start and run two units for a period of one hour without battery chargers. The existing system calculation shows that this load is less than 2200 amps for one minute and less than 170 amps for the remainder of one hour, including corrections for 80 percent capacity, 60°F electrolyte temperature, and 10 percent load growth. These currents are all expressed at 125Vdc, and actual system currents may be slightly different due to the change in battery voltage during the discharge. The load profile is of course subject to change as loads are added and removed from the system.

During non-emergency conditions, a single battery would be expected to carry less than 170 amps. As this is comparable to the load profile under emergency conditions, each battery could be expected to support the system for at least one hour. This is sufficient time for the standby charger to be aligned using the alarm response procedures described above.

SSF 125Vdc System

The SSF 125Vdc batteries are each sized to start and run the SSF diesel generator, its auxiliaries, and other SSF equipment without battery chargers for a period of one hour. Normally, one battery and charger are connected to the DC distribution center and the other battery and charger are kept as standby equipment, although Tech Spec 3.18.5 requires that only one battery and charger be operable. Existing calculations show that the emergency load profile consists of less than 850 amps for 15 minutes, and less than 650 amps for the remainder of one hour, including corrections for 80 percent capacity, 60°F electrolyte temperature, and 10 percent load growth. The load profile is of course subject to change as loads are added and removed from the system.

During non-emergency conditions, a single battery would be expected to carry less than 650 amps. As this is less load than under emergency conditions, the battery could be expected to support the system for at least one hour. This is sufficient time for the standby charger and battery to be aligned using the alarm response procedures described above.

The SSF batteries are each capable of delivering 1050 amps for a period of one hour with an average end-of-discharge voltage of 1.81 volts per cell.

Question D3

Summarize the methodology for implementation of the Maintenance Rule at the Lee Station.

Response to Question D3

The Lee/Central power (LCP) system will be included in the Oconee maintenance rule as a risk significant system. The LCP system is defined as the onsite portion of the Lee auxiliary power source which includes transformer CT-5 and the 4160V SL breakers.

The LCP system will be considered available when the following conditions are met:

1. The 100kV transmission line is capable of being separated from the Duke Power system within 1 hour and delivering power through transformer CT-5 and breakers SL1 and SL2 to the Oconee standby bus.

2. At least two Lee CTGs are available to provide power to Oconee. A Lee CTG would be considered available if it can reach rated speed and voltage within one hour.

The following will be considered failures for reliability monitoring:

1. Lee is asked to provide power to transformer CT-5 within 1 hour and CT-5 is not energized within that time. This includes the failure to separate from the Central switching station.

2. A Lee CTG supplying power to transformer CT-5 trips.

3. The standby bus cannot be energized through the SL breakers from transformer CT-5 upon demand.

4. A failure of a Lee CTG not supplying power to Transformer CT-5 which results in the unavailability of the LCP system.

Oconee and Lee operating personnel will communicate daily to discuss the status of the three Lee CTGs. Lee will provide Oconee

a monthly report of the CTG activities. Lee will notify Oconee immediately when less than two CTGs are available to supply power to Oconee.

ATTACHMENT 2

LIST OF COMMITMENTS

This list of commitments outlines the various commitments made as part of the response to the NRC's questions. Detailed information on each commitment is contained in the referenced response.

A. NEW

1. Perform a one-time 24 hour run of the SSF diesel generator. (Question A9)

2. Modify the permissives on the emergency power path to delay loading of the Keowee units until the voltage and frequency are within approximately 90 percent their nominal values. (Question B6)

3. Install voltage and frequency monitoring on the Keowee units to alarm when the voltage or frequency are below the acceptable values. (Question C6)

4. Include the Lee/Central power system in the Oconee maintenance rule as a risk significant system. (Question D3)

B. EXISTING

1. Periodically, monitor the voltage and frequency of the Keowee unit supplying Oconee during the EPSL functional test. (Question A6)

2. Evaluate the test results from the Oconee Unit 1 EOC16 "J" test and determine if any future testing while the Keowee units are accelerating is necessary. (Question A7)

C. REVISED

1. The SSF service water system flow test will be benchmarked against data taken during the one-time 24 hour run on the SSF diesel generator. This commitment will be completed within 90 days following completion of the 24 hour run. (Question A9)

ATTACHMENT 3

EMERGENCY POWER SWITCHING LOGIC
FUNCTIONAL TEST