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See Reports

SUBJECT: Forwards response to 970422 RAI re Oconee emergency power sys.Techincal rept, "Ultrasonic Exam of Oconee Unit 3 Safe End 3A1 & Unit 2 2A1 Piping," also encl.

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DUKE POWER

May 22, 1997

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 the Oconee Emergency Power System

In a letter dated July 8, 1996, the NRC issued for comment draft reports from the Office of Nuclear Reactor Regulation (NRR) and the Office for Analysis and Evaluation of Operational Data (AEOD). These draft reports contain analyses and recommendations regarding the testing, operation, design and reliability of the Oconee emergency power system and Standby Shutdown Facility (SSF). The July 8, 1996, NRC letter states that no vulnerabilities were identified as a result of the NRR and AEOD reviews in the draft reports which require immediate corrective action.

In a meeting with the NRC on September 19, 1996, Duke Power presented its understanding of the open issues and recommendations from the NRC draft reports, along with Duke Power's plan for disposition of the issues. During the meeting, the NRC clarified Duke Power's understanding of several of the open issues. In order to address the clarifications that were obtained during the meeting, Duke Power requested, in a letter dated October 1, 1996, an extension of the submittal date for the written response to the NRC draft reports until October 31, 1996.

In a letter dated October 31, 1996, Duke Power submitted its understanding of the open issues and recommendations that are contained in the NRC draft reports, along with Duke Power's plans for disposition of these issues. In addition, Duke Power provided general comments about the draft reports and updates/clarifications to information in the draft reports.

A001 1/1

The NRR Staff reviewed the Duke Power submittal and requested additional information in a letter dated April 22, 1997. In Attachment 1, Duke Power provides a response to the NRR Staff's questions.

If there are any questions regarding this submittal, please contact Michael Bailey at (864) 885-4390.

Very Truly Yours,

J W Hampton

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

MEB

Attachment

cc w/attachment:

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NRR

ATTACHMENT 1

REQUEST FOR ADDITIONAL INFORMATION
DUKE POWER COMPANY
OCONEE NUCLEAR STATION ELECTRICAL DISTRIBUTION SYSTEM

Question 1

The response to open issue No. 7 states that operating Oconee unit shutdown loads (approximately 2 MW) are block loaded on the Lee combustion turbines, and additional loads are then manually started until approximately 5 MW is obtained. The shutdown loads, therefore, are apparently deenergized prior to initiation of the test in order to subsequently block load them on the Lee combustion turbine. This conflicts with the response to question A8 in the Duke Power responses to staff questions dated January 31, 1996. That response states that 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. Please clarify which of these responses is accurate.

a) If the shutdown loads are indeed briefly deenergized during the Lee test, then readdress the staff's original question relative to your January 31, 1996 response. The question was: if this degree of loading can be obtained on the Lee combustion turbines during startup, why can't the same test be performed on the Keowee units?

Response to Question 1

Both of the previous responses which were provided by Duke are correct. The Oconee shutdown loads are not deenergized when they are block loaded onto a Lee Combustion Turbine (CT). The process for connecting a Lee CT to an isolated 100 kV transmission line and for block loading a Lee CT is described below.

The Lee CT is started and paralleled to the 100 kV Duke grid at no load. With the Lee CT connected to the 100 kV Duke grid at no load, the transmission line from Lee to CT5 is isolated from the Duke grid. This is the standard method for connecting the Lee CT to CT5 at Oconee via an isolated transmission line.

To block load a Lee CT, Oconee loads are connected to the standby source which is supplied by the 100 kV Duke grid through CT5. The breaker isolating the 100kV transmission line from the 100 kV Duke grid is opened which instantaneously block loads the Lee CT with the Oconee loads. Thus, the Lee CT is block loaded with Oconee loads without the Oconee loads being deenergized.

Question 2

The response provided to open issue No. 9 appears to contradict the information in calculation KC-UNIT 1-2-0098 (Keowee Governor Mechanical Single Failure Analysis) dated September 29, 1993 and calculation KC UNIT 1-2-0106, Rev 1 (Keowee Power Operating Restrictions for NSM-52966) dated May 4, 1995. The information in the referenced calculations indicates that, when the partial shutdown solenoid is deenergized, the wicket gates are limited to 25 percent open, and when the solenoid is energized there is no limit on the wicket gates. The calculations also indicate that on an emergency start from standby there is initially no limit on gate position, then Keowee speed switch 14/1 operates at 52 rpm to limit the gate position to 25 percent, and speed switch 13/1 operates at 122 rpm to remove the gate limit and return control to the governor. The response to open issue No. 9 however indicates that on an emergency start the partial shutdown solenoid energizes initially to allow the gates to open to 50 percent and the gate limit is set at 50 percent. Please clarify.

a) It also appears from this response that the monthly test performed to meet technical specifications is actually a modified normal start, since the auto synchronizer is turned off. Are there any other differences between that start and the normal start?

b) Is the voltage and frequency the only acceptance criteria specified for the monthly test? What is the specified voltage and frequency acceptance criteria? Is the start time to specified voltage and frequency monitored, and what is its acceptance criteria?

c) What are the reasons and difficulties associated with performing an emergency start test on a monthly basis instead of a modified normal start? The modified normal start does not test emergency start gate limit operation, immediate closure of the field circuit breaker, or emergency start relay contacts.

d) The response to open issue No. 9 indicates that the combination of existing and proposed technical specifications results in three emergency start tests from a dead stop, and four from a running Keowee unit every two years. Are these numbers consistent with those provided in the response to open issue No. 44? That response indicates that the Keowee units are emergency started (both standby and hot started) three times per 18 months and a total of 13 times over a three-year period.

e) The response to issue No. 9 also indicates that under current technical specifications there is an 18-month emergency power switching logic (EPSL) functional test

that is performed with a "start from dead stop on an ONS unit." What is the relationship of this test to the EPSL functional test provided to the staff in the January 31, 1996 Duke letter? The test provided to the staff was not a Keowee start from dead stop but rather an emergency start from generating to the grid. How many EPSL functional tests are from a dead stop and how many from generating to the grid? Are any of the Keowee starts from dead stop performed as a black start?

Response to Question 2

This question asks whether the following statements are correct;

A. 1) When the partial shutdown solenoid is deenergized, gate limit is 25%.

2) When the partial shutdown solenoid is energized, there is no gate limit.

3) On emergency start from standby, there is no gate limit initially.

4) At 52 rpm, gate limit is 25%.

5) At 122 rpm, gate limit is removed and control returned to the governor.

B. 1) On emergency start, the partial shutdown solenoid energizes to allow gate opening to 50%

2) At the same time, gate limit is 50%.

RESPONSE

A1) The statement is correct. The information in calculation KC-0098 specifically addresses failure of the partial shutdown solenoid alone. It is correct that there is a gate limit set of about 25% when the solenoid fails.

A2) The statement is correct. During emergency operation, once the unit has reached about 122 rpm, the gate limit is removed, or set to 100% gate.

A3) The statement is not correct. The gate limit setting is about 50%. When the Keowee unit receives the emergency start signal, the partial shutdown solenoid is energized and a gate limit of 50% is imposed immediately.

A4) The statement is correct for an emergency start. Prior to the Keowee unit reaching about 52 rpm, the gate limit is 50%. At the actuation of the speed switch, about 52

rpm, the partial shutdown solenoid is deenergized and the default gate limit (25%) discussed in A1 is the limit.

A5) The statement is correct. At about 122 rpm, the speed switch is actuated and the gate limit goes to 100%.

B1) The statement is correct. The gates are allowed to drive to 50% open and is controlled by the gate speed. The time for the gate to open to 50 % is faster than the Keowee unit acceleration to 52 rpm. Thus, the gates open to 50% prior to the unit reaching 52 rpm.

B2) The statement is correct. When the partial shutdown solenoid is energized, as is the case when an emergency start occurs, the gate limit is set at about 50%.

Since the answers above have been piecemeal in the explanation of gate limits, a detailed description of the sequence of events that occur during a Keowee unit start is provided below.

For a normal start, at t=0 the gate limit is 0%. When the Keowee unit receives the start signal, the partial shutdown solenoid is deenergized and the gate limit is about 25%. When the generator output breaker is closed, the gate limit goes to about 50%. As the Keowee unit is loaded, the operators manually change the gate limit to a level slightly above that required for the desired MW output.

For an emergency start from standby, at t=0 the gate limit is 0%. When the Keowee unit receives an emergency start signal, the partial shutdown solenoid is energized and the gate limit goes to about 50%. When the Keowee unit reaches about 52 rpm, the partial shutdown solenoid is deenergized and the gate limit is about 25%. When the Keowee unit reaches about 122 rpm, the partial shutdown solenoid is energized and the gate limit is driven to 100%.

For an emergency start from an operating unit, at t=0 the gate limit is as set by the operator (i.e. about 60% gate for 80 MW). When the emergency start signal is received, a signal is sent to the governor to raise the gate limit to 100%. Since the governor is also getting a signal that the speed is too high due to the load rejection, the gates are driven closed even though the limit is increased.

Part 2a

The question asks if there are other differences between the monthly Technical Specification start and normal starts other than the Auto Synchronizer being turned off.

RESPONSE:

Yes. During the performance of PT/0/A/0620/09, the unit is placed in REMOTE. This is so the Oconee operators may start Keowee for the test. The unit is normally in LOCAL.

The Auto Synchronizer is placed in MANUAL in order to allow time to read the generator output voltage and frequency before the unit synchronizes to the grid. The Auto Synchronizer is then placed in AUTO during the test and the unit continues on its normal sequence of operation.

Part 2b

The question asks:

A) Are voltage and frequency the only acceptance criteria for the monthly test?

B) What is the specified voltage and frequency acceptance criteria?

C) Is the start time to the voltage and frequency monitored?

D) What is the start time acceptance criteria?

RESPONSE:

A) No.

Other acceptance criteria are:

1) The ability for the Keowee hydro units to successfully automatically start from the Oconee Control Room,
2) The ability of the Keowee hydro units to synchronize through the 230KV overhead to the startup transformers, and
3) The ability of the Keowee hydro units to energize the underground path.

B) The Keowee output voltage is within 13.5 to 14.9 KV, and the Keowee generator frequency is within 57 to 63 Hz.

C) No. Time to reach the voltage and frequency are not required since this test is equivalent to the start test in Reg. Guide 1.9, rev.3, 2.2.1. This is also

consistent with NUREG-1430 SR 3.8.1.2. The timed start test of the Keowee hydro units is performed during the annual emergency start test.

D) Not applicable for the Keowee monthly start surveillance. In the annual emergency start test, the acceptance criteria is to obtain rated voltage and frequency in $\leq$ 23 seconds.

Part 2c

This question asks what the reasons for not performing and difficulties with performing a monthly emergency start test?

RESPONSE:

The reasons for not performing monthly emergency start tests are as follows:

A) Performing an emergency start exactly as an actual start would occur would produce unwarranted and excessive generator thrust bearing wear, because the pumps which provide bearing lubrication are not on at t=0.

B) Performing emergency starts places more strain on the unit wicket gate assemblies and turbine and generator guide bearings due to the increased acceleration of the unit.

C) Monthly emergency start tests are comparable to diesel generator fast start tests. These tests are not required monthly by either Reg. Guide 1.9 or NUREG-1430.

D) Aside from the annual emergency start test, each Keowee unit undergoes approximately 3 additional emergency starts per year. (See response to Part 2d)

E) This would be additional work for the Operations group. Also, additional scheduling would be required for the test and additional support would be needed from other groups.

Part 2d

The question asks whether the following statements are correct, 7 emergency starts every 2 years, or 13 emergency starts every 3 years.

RESPONSE

The following is a list of tests which cause emergency starts of Keowee:

PT/0/A/0620/016 starts both Keowee units from standby annually. It also emergency starts the units from a running no-load condition annually. Thus, there are 2 emergency starts annually credited for this test. This includes both ES channels which can start Keowee.

PT/1/A/0610/01J starts both Keowee units from standby on a refueling (18 month) basis.

PT/2/A/0610/01J starts both Keowee units from an initial condition of grid generation on a refueling (18 month) basis.

PT/3/A/0610/01J starts both Keowee units from an initial condition of grid generation on a refueling (18 month) basis.

PT/0/A/0610/022 starts both Keowee units from an initial condition of grid generation on a refueling (18 month) basis.

The Technical Specification rewrite submitted by a Duke letter dated February 27, 1997 requires verification of Keowee to supply emergency power from an initial condition of commercial power generation (SR 3.7.1.12). It also calls for a load rejection response test (SR 3.7.1.13). These tests are to be conducted on a refueling (18 month) frequency. This will probably be performed in one test. In addition, this test may be incorporated with existing tests.

Using the preceding information, the following number of emergency start tests are performed:

PT/0/A/0620/016 - 2 tests annually which results in 4 tests every 2 years or 6 tests every 3 years,

PT/1/A/0610/01J - 1 test on a refueling frequency for 1 test every 2 years or 2 tests every 3 years,

PT/2/A/0610/01J - 1 test on a refueling frequency for 1 test every 2 years or 2 tests every 3 years,

PT/3/A/0610/01J - 1 test on a refueling frequency for 1 test every 2 years or 2 tests every 3 years, and

PT/0/A/0610/022 - 1 test on a refueling frequency for 1 test every 2 years or 2 tests every 3 years.

Addition of the above information yields 8 tests every 2 years and 14 tests every 3 years. One test is subtracted from the above totals due to the fluctuation of the refueling schedules. This results in 7 tests every 2 years and 13 tests every 3 years. Thus, the numbers of tests which are listed in Open Issues #9 and #44 are correct.

It should be noted that forced outages and other operational considerations can result in changes in the scheduling of the refueling outages which may result in changes in the above estimates of tests.

Part 2e

The question asks:

A) What is the relationship to the EPSL test provided which starts Keowee from grid generation, to the referenced test which starts Keowee from a dead stop?

B) How many EPSL tests are from a dead stop and how many from grid generation?

C) Are there any Keowee starts from a dead stop performed as a black start?

RESPONSE

A) There are 3 EPSL tests, one for each Oconee unit. Of these 3 EPSL tests, 1 test starts Keowee from a dead stop, while the other 2 tests start Keowee from grid generation. The tests are all basically the same. One test also verifies over frequency protection on the SK breaker by load rejection. One test also verifies the transfer from Lee to Keowee.

B) There is 1 EPSL test performed from a dead stop and 2 EPSL tests performed from grid generation.

C) During the performance of PT\1\A\0610\01J, the underground Keowee unit's auxiliaries are briefly deenergized. In the past, this test was performed with the underground Keowee unit at a dead stop condition which resulted in a black start of the associated Keowee

unit. This test was revised to be performed with the underground Keowee unit connected to the 230 kV Duke grid which results in a black run of the associated Keowee unit.

Question 3

Are any of the Oconee Technical Specification electrical tests referenced in the most recent October 31, 1996 Duke letter going to be eliminated in the Technical Specification 3.7 rewrite? If so, which ones and why?

Response to Question 3

The Oconee electrical Technical Specifications which are referenced in the Duke letter dated October 31, 1996 will not be eliminated by the Technical Specification 3.7 rewrite.

Question 4

In the response to open issue No. 28 it is indicated that analysis conducted to evaluate the past operability of the electrical system concluded that all required safety functions would have been accomplished with the voltage at 11.9 kV. In the same response it is stated:

> Due to different system loading, it is expected that the voltages required at the terminals of the Keowee generator to assure proper operation of safety loads will vary, depending on which failure scenario is being analyzed. The minimum generator voltage that bounds all cases and scenarios for the Keowee analysis is 13.5 kV.

It is not clear what the differences are that would lead to the conclusion that "all required safety functions would have been accomplished" with the Keowee generator at 11.9 kV, and also conclude that "[t]he minimum generator voltage that bounds all cases and scenarios for the Keowee analysis is 13.5 kV." Please clarify. Also, please list the full complement of failure scenarios that are referred to in the above quotation.

Response to Question 4

The response to issue No. 28 in the Duke letter dated October 31, 1996 stated that "analysis conducted to evaluate the past operability of the system concluded that all required safety functions would have been accomplished with the associated failure". The specific failure referred to here is a voltage adjust control failure that results in the Keowee terminal voltage decreasing to 11.9kV. No other single failures were postulated (i.e. unscheduled loads, control circuits, etc.) for this specific voltage adjust failure case.

Calculation OSC-5952 analyzes many different cases or scenarios for the Keowee underground path. They include:

1. Simultaneous loading of three Oconee LOOP units,
2. One LOCA unit followed by two LOOP units loading,
3. A LOCA unit loading with an additional failure of the Keowee voltage regulator not switching into automatic,
4. A LOCA unit with an additional failure resulting in an unscheduled large load simultaneously loading with the LOCA, and
5. LOCA unit loading with a failure of the Keowee voltage adjust circuit resulting in 11.9kV Keowee terminal voltage.

For these bounding cases, a Keowee terminal voltage of 13.5kV is used except for specific failure mode cases as discussed above. With the Keowee voltage at a minimum of 13.5kV, all of the different cases conclude proper operation of the safety equipment. Thus, this value of Keowee voltage bounds the different cases or scenarios. A lower Keowee terminal voltage may yield favorable results for some of the different cases (i.e. like 11.9kV for case #5 above). However, the 13.5kV value is acceptable for all scenarios. This voltage of 13.5kV is the minimum value verified during the Keowee periodic surveillances.

Question 5

It's not clear in the response to open issue No. 29 what Duke Power's final position is. The response states that procedure PT/O/A/0620/09, Keowee Hydro Operation, does not put the Keowee unit through a load run; but it doesn't indicate why it is not a load run. It references a one-time load run test that was run in August 1996, and states that the test data demonstrates that monthly load runs of Keowee are not necessary in light of the fact that Keowee is frequently operated to the grid. However, the final paragraph in the response states that normal operation of Keowee verifies the first two surveillance requirements (synchronization and load acceptance) in standard tech specs, and Duke plans to trend data monthly on Keowee operation to the grid in order to verify proper heat exchanger operation. Please indicate why PT/O/A/0620/09 does not meet the criteria of a load run, and what combination of existing Keowee operation and additional verification will be used to demonstrate the load run criteria is met by the Keowee Hydro units.

Response to Question 5

The question asks:

A) Why does PT/0/A/0620/09 not meet the criteria of a load run?

B) What combination of existing operation and additional verification will be used to demonstrate the load run criteria is met by Keowee?

RESPONSE:

A) PT/0/A/0620/09 does not require the Keowee units to run for 1 hour or more. According to Reg. Guide 1.9, revision 3, a load run is valid if the unit runs at least 1 hour.

B) Reg. Guide 1.9, revision 3, states that a load run has the following attributes:

1) Run at 90 to 100% of rating,

2) Run for at least 1 hour, and

3) Attain temperature equilibrium.

For Keowee, attribute 1) is not really applicable. The emergency loads for Keowee are so much less than the rated capacity that Keowee can operate at much less than 90% of rating and still perform its function. The criteria for Keowee, as defined in Oconee System Engineering Manual 4.3, is a load greater than 11.5 MVA. This criteria is based on NSAC-108, D.3.

Attribute 3) is the problematic one for Keowee. Due to the size of the units, the operating characteristics, and the motive force, it takes Keowee several hours to attain temperature equilibrium. This is the reason that the August 1996 load run test was referenced in the Duke letter dated October 31, 1996. This test ran the Keowee hydro units for about 40 hours straight in order to obtain a variety of data. Based on that data, the assumption that operating Keowee at higher loads results in greater equilibrium temperatures was confirmed. This conclusion indicates that there is no reason to run the units at low loads to determine heat exchanger problems. Also, the time requirements for reaching equilibrium can be met by normal grid operation. Based on these factors, the following actions demonstrate the load run criteria is met by Keowee.

1) Normal system generation usually occurs in excess of 1 time each month. This is trended monthly.

2) Normal system generation occurs for periods in excess of 1 hour. This is trended monthly.

3) Normal system generation allows trending of temperatures at rates of increase in excess of emergency operation conditions. This allows for ample opportunity to find adverse trends.

Question 6

The response to open issue No. 30 indicates that the LOCA signal is verified in step 12.35 of the EPSL functional test that was provided to the staff in a January 31, 1996 Duke letter. It further states that subsequent steps 12.36, 12.37, 12.38, and 12.39 demonstrate that this LOCA signal is providing the emergency start to the Keowee units. In fact, it appears from the procedure that at step 12.35 both Keowee units are already operating. Please verify that the LOCA signal of step 12.35 does not actually start the Keowee units but rather is used to verify logic actuation, contact closure, etc., necessary for the emergency start of the Keowee units. If this is not accurate explain specifically what steps 12.35 through 12.39 are verifying.

Response To Question 6

In the Unit 2 EPSL Functional Test procedure provided to the NRR Staff in a Duke letter dated January 31, 1996, the Keowee hydro units were emergency started from an initial grid generation mode during steps 12.17.2 and 12.17.3. The Keowee units were operating in the emergency mode, as a result of the main feeder bus logic, just prior to step 12.35. This was noted in the first paragraph of response to open issue #30 in Duke's submittal dated October 31, 1996.

Step 12.35 provides the engineered safeguards (LOCA) signal to the Keowee emergency start logic. The subsequent procedure steps 12.36 through 12.39 verify that the Keowee units remain operating in the emergency mode as a result of the LOCA signal actuation. Step 12.38 specifically tries to reset the Keowee emergency start logic; but, verification of the alarms in step 12.39 ensures that the emergency start logic is not reset due to the LOCA signal being present. Steps 12.35 through 12.39 verify the logic necessary for the emergency start of the Keowee units and functionally shows that the Keowee units continue to operate through this logic.

Question 7

The item 8 comment in attachment 2 notes that a single breaker failure will not cause the lockout of both Keowee units during periods of dual Keowee unit grid generation and a simultaneous ground fault. It states that both ACB 1 and 2 would need to fail in order to lockout both Keowee units in

the postulated scenario. These statements are made with regard to a statement made in the NRR report that "[a] subsequent single failure of a safety-related breaker to clear a fault on the overhead emergency power path could potentially cause the lockout of both Keowee units if they were generating to the grid."

The circuit breaker the staff was referring to in the NRR report is not ACB 1 or 2 but rather an OCB in the switchyard. The failure postulated was a failure of a Switchyard OCB to isolate a ground fault in the switchyard or on a transmission line, outside the Keowee differential zone of protection. Such an uncleared ground fault would be seen by the ground fault protection scheme (59G relay) of both Keowee Hydro units when they were generating to the grid and cause both units to trip. Please respond whether this scenario is accurate.

Response To Question 7

The potential to lock out both Keowee units due to a switchyard ground fault and concurrent breaker (switchyard PCB) failure is precluded by the existing switchyard breaker failure protective relaying. This protection is designed to trip backup breakers if the primary breaker fails to trip.

Analysis OSC-5093 evaluated if there was a potential for damage to the Keowee units due to a loss of stability. This analysis was performed by assuming a failure in the 230kV switchyard, outside of the Keowee overhead line, and an additional switchyard PCB failing to trip and isolate the fault. The results indicated that the breaker failure logic would respond to trip backup breakers before the critical clearing time to ensure the Keowee units would remain stable. In addition, the results of this analysis indicated that the breaker failure protection will trip the required backup breakers well before the time delay for the generator neutral ground protection relay actuation time.

The failure of PCB 8 or 9 to trip would require ACB-1 and 2 to trip. This scenario results in the longest time for a ground fault to remain connected to Keowee. The following is a summary of the system response to these postulated failure scenarios.

The analysis in OSC-5093 assumed a fault on the transmission line between PCB-7 and 8 and also assumed a PCB-8 breaker failure. This study concluded that ACB-1 and 2 would be tripped by PCB-8 breaker failure protective relaying in less than 0.40 seconds. The minimum operate time for the Keowee units 59G relay is 0.80 seconds. Thus, the breaker failure scheme would isolate the fault well before the generator neutral ground protection relay actuation.

Similarly, a fault on the Yellow Bus side of PCB-9 would yield the same results as the scenario which is described above. The breaker failure scheme would isolate the fault well before the generator neutral ground protection relay actuation.

Question 8

The item 13 comment in attachment 2 indicates that the diesel generator hot restart test is not applicable for the Keowee units because the concern associated with the diesel generator's ability to start at high diesel temperatures does not exist at Keowee.

We recognize that the Keowee Hydro units do not necessarily have the same vulnerabilities as diesel units, but are there other vulnerabilities that might be peculiar to the Hydros relative to hot starting? We note that in the response to open issue No. 30 Duke has indicated that a hot restart test was performed as part of a load run test on August 22-23, 1996.

Response to Question 8

The hot restart test which was performed on August 23, 1996 verified that there are no specific vulnerabilities associated with the Keowee hydro units hot starting. The test results were consistent with previous emergency start tests with regards to achieving nominal speed and voltage within the proper time frame. This test was conducted at the peak lake temperature after about 40 hours of continuous operation of both units.

Diesel engines typically have cylinder exhaust gas temperatures in the 900° F range with oil temperatures in the 215° F range and engine coolant temperatures of 185° F. Clearances for various engine parts are 0.010″ for valve stem to guide, 0.027″ for connecting rod bearing to crankpin, 0.020″ for piston to cylinder head clearance, and 0.022″ for piston to liner. With the shutdown of the diesel engine, the oil and water systems cease flow as the engine coasts to a stop. The external lube oil pump flow is on the order of 20 gpm versus 200 gpm for the engine driven pump. With exhaust gas temperatures of 900° F, and the loss of 90% of the cooling flow, materials may expand enough to create interferences.

Keowee has a maximum lake water temperature of 85° for motive force and cooling water. During the August 23, 1996, maximum temperatures were about 105° F for the generator air coolers, about 125° F for the thrust bearing oil, and about 135° F for the guide bearing oil. All of these temperatures are below the temperatures for the diesel. Clearances for various

parts are 0.75″ for runner to discharge ring, 0.38″ for runner to inner head cover, 0.013″ for guide bearings to shaft, and 0.80″ for the mean generator stator to rotor air gap. When the hydro unit is shutdown, cooling water continues to circulate at full flow until the unit reaches a dead stop. Oil flow in the turbine guide bearings is continuous whether the unit is running or not. Since operating temperatures are much lower, cooling water and oil flows continue, and clearances are the same or larger, there are no vulnerabilities associated with the Keowee hydro units relative to a hot restart.

Question 9

The item 15 comment in attachment 2 indicates that as a result of NSM ON-52966 the reclosure timers for the Keowee ACBs are set at 8.2 to 8.8 seconds, and the acceptance criterion is that they be greater than 4 seconds. What is the basis for the acceptance criterion? Why is there no upper bound on the acceptance criterion?

Response to Question 9

The reclosure timers (52-1TD and 52-2TD) for the Keowee ACBs are set at 8.5 seconds with an acceptable limit of ± 0.3 seconds. This results in an acceptable range of 8.2 to 8.8 seconds. If these relays are found outside of the 8.2 to 8.8 second range during the surveillance test, engineering is notified for evaluation of this out of tolerance device.

The minimum acceptable design basis setting for these timers is 3.64 seconds. The 3.64 seconds is the maximum amount of time, including tolerances, for non-essential loads (i.e. Reactor Coolant Pumps) to trip from loss of voltage on the overhead path. For conservatism, the annual Keowee Emergency Start Test lists the minimum acceptable time as 4 seconds.

The maximum acceptable design basis setting for these timers is 23 seconds. This is consistent with the maximum required time for the Keowee units to be available to deliver emergency power.

Question 10

The item 16 comment in attachment 2 states that during the standby bus source undervoltage sensing test, each logic chain is actuated to ensure that the resulting retransfer to startup signal is achieved. It indicates that the two-of-three verification is not necessary for the standby bus undervoltage logic since a single failure is necessary in order to require actuation of this logic.

It's not clear what portion of the undervoltage sensing logic

this test verifies and does not verify. How many logic chains are there, and is the two-of-three undervoltage signal provided to each logic chain? What types of failures would the test not capture and how is the test conducted?

Response to Question 10

The undervoltage sensing circuits for the Standby Source are verified for each Oconee Unit. Each undervoltage sensing circuit, one per phase for each Standby Bus, is initiated individually and the associated computer points and alarms are verified. This test verifies that all relays in the undervoltage sensing circuit operate as required. The undervoltage sensing circuits for the three phases of a Standby Bus are arranged in a two out of three configuration which is a part of the retransfer to startup logic. Each of the two retransfer to startup logic channels require the undervoltage sensing circuits to be initiated for two of the three phases of both Standby Buses. During each Unit's Emergency Power Switching Logic Functional test, while Oconee loads are being supplied by the Standby Source, power is removed from the Standby Buses and the loads are verified to retransfer back to the Startup Source. This transfer verifies both Standby Buses' undervoltage sensing circuits since the retransfer function requires that both Standby Buses undervoltage sensing circuits operate. The retransfer function is required only to mitigate a single failure which makes the Standby Source unavailable. Therefore, a second failure would be required for the retransfer to startup function to fail when called upon.

Question 11

Item 57 in attachment 2 of the Duke letter, indicates that item 18 in the NRR draft report (page 27) incorrectly states that there is no similar technical specification requirement at Oconee for the standard diesel generator test of reaching rated voltage and frequency within a specified time. It comments that the annual emergency start test verifies that Keowee can obtain the rated voltage and frequency within the test acceptance limits.

We note that the subject standard technical specification test referred to in the NRR draft report is a ten-year test of the simultaneous start capability of both diesel generators. Is the annual emergency start test of the Keowee units referred to in the comment to item 57 a test of the simultaneous start capability of both Keowee units? If both units are not emergency started simultaneously from a standby condition in that test, it is not comparable to the subject ten-year test. Is a simultaneous emergency start from standby periodically performed on both Keowee units?

Response to Question 11

The question asks:

A) Is the annual emergency start test in item 57 of the Duke letter dated October 31, 1996 a simultaneous start of both Keowee units?

B) If both units are emergency started from standby, is that comparable to the 10 year test?

C) Is a simultaneous emergency start from standby periodically performed on the Keowee units?

RESPONSE

A) Yes. PT/0/A/0620/16 annually performs a simultaneous emergency start from standby of both Keowee units.

B) Yes. The existing test is comparable to the 10 year test.

C) Yes. PT/0/A/0620/16 annually performs a simultaneous emergency start of both Keowee units from standby.

Question 12

The final portion of the response to open issue No. 1 discusses the electrical loading that would occur if ECCS actuation signals were received during a three unit Oconee LOOP. It indicates that if an ECCS actuation were to occur, only one additional HPI pump would be started in each unit, over and above the other HPI pumps and essential loads that were energized by other automatic features during the LOOP event. The response states that the load associated with these additional HPI pumps is smaller than the Oconee LOOP or LOCA loads that are currently analyzed to be block loaded onto an overhead or underground Keowee unit. It concludes, therefore, that the emergency power system would perform its intended function and is bounded by the current analyses.

It's not clear why the fact that the load of the HPI pumps is less than the entire LOOP or LOCA load, leads to the conclusion that the current analyses bounds the subject scenario. Is this indicating that, because the loads are staggered during the event, the voltage transients seen are less than those analyzed? If so, how does the final steady-state load during this scenario compare to the analyses in terms of voltage and CT4 or CT5 loading capability. Has a 3 unit LOCA/LOOP event been analyzed, or does the conservatism used in the CYME analyses bound the 3 unit LOCA/LOOP event?

Response to Question 12

Response to issue No. 1 in the Duke letter dated October 31, 1996 addresses the hypothesis of an ECCS actuation due to overcooling following a three unit LOOP instead of concurrent with a three unit LOOP. As noted in the response to issue No. 1 in the October 31, 1996 letter, Duke Power does not believe an overcooling event that results in an ECCS actuation will occur following a three unit LOOP.

For a 3 unit LOOP scenario, the three LOOP units would load on the overhead path after about 15 seconds following the LOOP event. If the ECCS actuation is assumed to subsequently occur, only ES channels 1 and 2 would actuate. ES channels 1 and 2 would actuate the 4kV HPI pump motors. LPI, LPSW, RBCU and RBS motors are actuated by ES channels 3 through 8. In addition, only one HPI pump motor from each unit would start if ES channels 1 and 2 were to actuate subsequent to the LOOP. The other two HPI pumps per unit would already be operating as a result of the Loop actuation.

From a steady state load perspective, the additional load of one HPI pump per unit to the three LOOP units is bounded by the previously analyzed loading of a three unit LOOP and LOCA which includes actuation of ES channels 1 through 8. Based on the above information, it is concluded that the existing analyses evaluate a scenario which is more conservative.

The additional load of one HPI pump per unit is approximately 1800 hp (i.e. 3 X 600 hp). If each of the three additional HPI motors are assumed to simultaneously start, the existing analysis shows that acceptable results exist for a loading in excess of approximately 3000 hp (a LOOP unit equivalent load) to a Keowee unit which is already supplying Oconee loads. Thus, the existing analysis also bounds this scenario from a starting transient perspective.

The CT4 and CT5 loadings do not apply to this particular scenario. If a failure of the overhead path were assumed, then CT4 or CT5 loading would apply. However, the conclusions are no different from the conclusion which is stated above for the overhead emergency power path.

A three unit LOCA/LOOP event is the basic design basis event which is analyzed in each of the emergency power source calculations (i.e. Keowee and Lee).

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DUKE POWER

May 22, 1997

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

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Justification for Continued Operation of
Oconee Unit 1 as a Result of Oconee Unit 2
HPI Line Leak
Supplemental Information
NRC TAC No. M98454

On May 13, 1997, the staff faxed Duke Power eleven additional questions related to the recent weld crack on the Unit 2 High Pressure Injection (HPI) System A1 injection line. These questions were discussed in a meeting with the staff on May 14, 1997. On May 16, 1997, Duke Power submitted a letter which committed to responding to the first three of the eleven questions by May 23, 1997. Duke Power has completed the responses to the first four questions and they are provided in Attachment 1. Responses to the remaining seven questions will be submitted to the staff within the next two weeks.

At the May 14, 1997, meeting with the staff and during subsequent telephone conversations with the staff, additional information was requested regarding responses to the questions in the May 5, 1997, staff request for additional information on the HPI System. Attachment 2 provides supplemental information for Questions 1d, 2a, 4e, and 4f of the May 5, 1997, staff letter.

Please address any questions to J. E. Burchfield, Jr. at (864) 885-3292.

Very Truly Yours,

J. W. Hampton
Site Vice President

J. W. Hampton
Site Vice President

Attachment

xc: L. A. Reyes, Region II
Regional Administrator

M. A. Scott, Region II
Senior Resident Inspector

D. E. LaBarge, ONRR
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Attachment 1
NRC Request for Additional Information
May 13, 1997 Questions (1-4)

Question 1:

Did the ultrasonic inspection performed in 1982 determine that there were no flaws in the pipe to safe-end weld and adjacent piping in HPI/MU 2A1 line in Oconee 2 and in the pipe to safe-end welds in the 4 HPI and HPI/MU lines in Oconee 1?

Response:

References:

1. Babcock & Wilcox 177 Fuel Assembly Owner's Group Safe End Task Force Report on Generic Investigation of HPI/MU Nozzle Component Cracking, B& W Document #77-1140611-00 (1982-1983)

Verbal feedback from the B & W inspectors indicate that all of the Oconee Units 1, 2, & 3 pipe to safe end welds, adjacent pipe base material, and safe-end base material were UT'd in 1982 by B&W technicians in the aftermath of the 1982 Crystal River pipe to safe end weld failures. However, no records of these inspections have been located to date. Reference 1 describes the inspections performed on all the Oconee Units as a result of the Crystal River pipe to safe end weld failures. The report notes that a combination of radiographic and ultrasonic inspection techniques were used to detect flaws in the safe-end, nozzle, adjacent piping, and associated welds for all of the Oconee Units. There were no anomalies (i.e. loose thermal sleeve, flaws, etc.) detected in the 2A1 nozzle and associated components noted in the report. There were also no anomalies noted for any of the Unit 1 HPI/MU nozzles. Listed on the next page is a matrix of activities performed on the Oconee HPI Injection Nozzles from 1982 to the present:

OCONEE NUCLEAR STATION

MATRIX OF ACTIVITIES PERFORMED ON HPI INJECTION NOZZLES

ACTIVITY / NOZZLE#	REPLACED PIPE-SAFE END WELD	INSTALLED SOCKET WELD	REPLACED THERMAL SLEEVE	REPLACED SAFE END	RE-ROLLED EXISTING THERMAL SLEEVE
1A1					
1A2		1982			
1B1					
1B2					
2A1	1997	1982/1997	1997	1997	
2A2	1982	1982	1982	1982	
2B1	1982			1982	1982
2B2	1982		1982	1982	
3A1	1997	1997	1997	1997	
3A2	1982	1982	1982	1982	
3B1	1982			*	1982
3B2					

* Safe End was not replaced at time thermal sleeve was re-rolled.

Question 1(b):

How were these inspections qualified?

Response:

ASME Code Section XI requirements for UT qualification were minimal at the time of the inspections. Methods for detecting cracking in the safe end and adjacent piping were developed at Crystal River. A 35-45 degree shear wave was employed, based on the methods developed at Crystal River, to detect axial cracking in the safe end and adjacent piping. These processes were sufficient to detect cracks at both Crystal River and Oconee.

Question 2:

Did the UT inspections of Oconee 1, 2, and 3 HPI/MU lines after 1982 include the pipe-to-safe end region? If they included the pipe-to-safe end region, did they discover any evidence of cracking?

Response:

The pipe to safe end region was not subjected to UT inspection after 1982.

Question 3:

Have any of the UT inspections detected a crack? In particular, have the UT inspection techniques been able to find the cracks in Units 2 and 3.

Response:

Yes, the 2A1 piping to safe-end weld and safe end exhibited cracks in the 1997 UT inspections. This specimen was destructively analyzed at the FTI Lynchburg metallurgical laboratory, but was analyzed from a crack cause standpoint as opposed to a UT comparison standpoint.

The 3A1 safe-end and the 2A1 piping also exhibited cracks in the 1997 UT inspections. The 3A1 components were sent to Lynchburg with a primary objective of comparing UT flaw detection with the metallurgical laboratory results. The safe-end has been analyzed thus far and Attachment 1A, Technical Report of the Ultrasonic Examination of the Oconee 3A1 Nozzle Safe-End and 2A1 Piping, provides the results of this comparison.

It can be seen from this information that safe-end flaws in the range of .110″ to .15″ in depth can be detected, but improvements in the reliability of the technique are needed. Cracks equal to or greater than .05″ in depth can be detected in the piping.

The techniques used to perform the 3A1 safe-end UT were qualified in accordance with ASME Section XI Appendix VIII, 1992 Edition with 1993 Addenda. Details of Duke Power's Section XI Appendix VIII qualification can be accessed through the Electric Power Research Institute (EPRI) NDE Center in Charlotte, North Carolina. During much of the Unit 3 inspections, an NRC inspector was observing the performance of the UT.

Duke Power is continuing to evaluate the metallurgical results as they are received in order to develop optimum inspection procedures and intervals for the nozzle components. We anticipate a final metallurgical report by June 15, 1997.

Question 4:

Based on the RT inspections, which radiographs of the Oconee Units 1, 2, and 3 safe-ends indicate there was a gap between the safe end and the thermal sleeve and which indicate there were no gaps?

Response:

See the chart on pages 5-7.

Question 4(b):

When the radiographs were 're-read' in 1997, did the findings change (and how)?

Response:

Previous to 1997, the acceptance criterion for the radiographic examinations was evidence of an intact thermal sleeve. Based on current findings, that acceptance criterion was invalid. Current acceptance criteria for the radiographic examinations are evidence of an intact thermal sleeve and no change in the gaps (if existing) between the thermal sleeve and the safe-end at the rolled-in portion of the thermal sleeve. Based on this change in the acceptance criteria, the 're-reading' of the radiographs indicated problems with the 3A1 nozzle (gap through the rolled in portion).

OCONEE UNITS 1,2, & 3

HPI NOZZLES - DESIGN INFORMATION AND THERMAL SLEEVE GAP DATA

NOZZLE	VINTAGE	THERMAL SLEEVE DESIGN	THERMAL SLEEVE ROLL	YEAR	ROLL AREA (IN.)	TOTAL GAP (IN.)	CHANGE	COMMENTS
1A1	ORIGINAL	DOUBLE	SEE NOTE 2	N/A	1.875	0	0	NO GAPS NOTED IN ANY RT
1A2	ORIGINAL	DOUBLE	SEE NOTE 2	N/A	1.875	0	0	NO GAPS NOTED IN ANY RT
1B1	ORIGINAL	DOUBLE	SEE NOTE 2	N/A	1.875	0	0	NO GAPS NOTED IN ANY RT
1B2	ORIGINAL	DOUBLE	SEE NOTE 2	1983	1.875	0.8125	0	BASELINE RT, NO CHANGE IN GAP SINCE 1983
2A1	ORIGINAL	SINGLE	CONTACT EXPANDED	1983	2.25	0	0	BASELINE RT, NO CHANGE UNTIL 1996
				1996	2.25	1.75	1.75	SEE NOTE 1
				1997	2.25	2.25	0.5	THROUGH GAP
	REPLACED 1997	MODIFIED SINGLE	HARD ROLLED					
2A2	REPLACED 1982	MODIFIED SINGLE	HARD ROLLED LESS THAN DESIGN	1983	2.75	1.125	0	BASELINE RT
				1986	2.75	1.5	0.375	
				1989	2.75	1.25	-0.25	
				1996	2.75	1.25	0	
				1997	2.75	1.25	0	

OCONEE UNITS 1,2, & 3

HPI NOZZLES - DESIGN INFORMATION AND THERMAL SLEEVE GAP DATA

NOZZLE	VINTAGE	THERMAL SLEEVE DESIGN	THERMAL SLEEVE ROLL	YEAR	ROLL AREA (IN.)	TOTAL GAP (IN.)	CHANGE	COMMENTS
2B1	ORIGINAL	SINGLE	HARD RE-ROLLED IN 1982	1983	1.875	0	0	BASELINE RT
				1985	1.875	N/A	N/A	RT'D WRONG NOZZLE
				1988	1.875	0	0	
				1989	1.875	0.5	0.5	
				1996	1.875	0.5	0	
				1997	1.875	0.5	0	
2B2	REPLACED 1982	MODIFIED SINGLE	HARD ROLLED	N/A	1.875	0	0	NO GAPS NOTED IN ANY RT
3A1	ORIGINAL	SINGLE	CONTACT EXPANDED	1984	2.25	0.25	0	BASELINE RT
				1985	2.25	1.3125	1.0625	SEE NOTE 1
				1987	2.25	1.3125	0	
				1988	2.25	1.625	0.3125	
				1989	2.25	1.4375	-0.1875	
				1996	2.25	2.25	0.8125	THROUGH GAP
				1997	2.25	2.25	0	THROUGH GAP
	REPLACED 1997	MODIFIED SINGLE	HARD ROLLED					
3A2	REPLACED 1982	MODIFIED SINGLE	HARD ROLLED	N/A	2.25	0	0	NO GAPS NOTED IN ANY RT

OCONEE UNITS 1,2, & 3

HPI NOZZLES - DESIGN INFORMATION AND THERMAL SLEEVE GAP DATA

NOZZLE	VINTAGE	THERMAL SLEEVE DESIGN	THERMAL SLEEVE ROLL	YEAR	ROLL AREA (IN.)	TOTAL GAP (IN.)	CHANGE	COMMENTS
3B1	ORGINAL	SINGLE	HARD RE-ROLLED IN 1982	1984	2.25	1.125	0	BASELINE RT
				1985	2.25	0.9375	-0.1875	
				1987	2.25	0.75	-0.1875	
				1988	2.25	0.625	-0.125	
				1989	2.25	0.25	-0.375	
				1996	2.25	0.25	0	
				1997	2.25	1.125	0.875	
3B2	ORGINAL	SINGLE	CONTACT EXPANDED	1984	2.25	0	0	BASELINE RT
				1985	2.25	0	0	
				1987	2.25	0	0	
				1988	2.25	0.375	0.375	
				1989	2.25	0	-0.375	
				1996	2.25	0	0	
				1997	2.25	0.375	0.375	

NOTES:

1. SHOULD HAVE INVESTIGATED CAUSE OF GAP GROWTH AT THIS TIME.
2. OUTER SLEEVE CONTACT EXPANDED TO SAFE END, INNER SLEEVE CONTACT EXPANDED TO OUTER SLEEVE

DEEFINITIONS:

HARD RE-ROLL: Original sleeve design that was re-rolled to a 5% wall reduction.
HARD ROLL: New sleeve was mechanically thinned to a 5% wall reduction.
CONTACT EXPANDED: Sleeve was expanded from the ID until contact was achieved between OD of thermal sleeve and ID of safe end.