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December 17, 1996

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

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Supplemental Information Regarding Oconee
Emergency Power Engineered Safeguards
Functional Test Amendment Request

On December 11, 1996, Duke Power Company submitted an amendment to Facility Operating License Nos. DPR-38, DPR-47, and DPR-55 for Oconee Nuclear Station Units 1, 2, and 3, respectively. The amendment consists of proposed changes to the Updated Final Safety Analysis Report (UFSAR) regarding a one-time emergency power engineered safeguards (ES) functional test.

During conference calls with Duke Power on December 12, 1996, and December 13, 1996, the NRC requested additional information regarding the December 11, 1996, Duke Power submittal. Attachment 1 provides Duke Power's response to the information requested by the staff. Attachment 2 contains an administrative revision to the proposed UFSAR change such that the supplemental information in this submittal is included by reference.

A001/1

Please address any questions to Ed Burchfield at (864) 885-3292 or Michael Bailey at (864) 885-4390.

Very truly yours,

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ATTACHMENT 1

Supplemental Information Regarding The Oconee Emergency Power Engineered Safeguards Functional Test

The NRC identified twelve areas where additional information is necessary to support the review of the license amendment submitted by Duke Power Company on December 11, 1996. This attachment lists each NRC request followed by the Duke Power Company response.

Question 1: Please describe in detail the plant configuration for the fueled units at the time of the test. Details such as RCS temperature, pressure, PORV setpoint, steam generator temperature, and pressure should be indicated. The submittal is vague with respect to the pressurizer having a nitrogen cover gas or a steam bubble.

Response: The test proposed in the December 11, 1996, submittal will be conducted with Oconee Unit 3 defueled and with fuel in the core on Oconee Units 1 and 2. The proposed test will involve brief interruptions of decay heat removal to Units 1 and 2. Although highly unlikely, Duke Power has thoroughly analyzed the consequences of an extended loss of decay heat removal. The results of this analysis are described in detail in the response to Question 2.

The plant configuration for the test will be conservative with respect to the initial conditions assumed in the loss of decay heat removal safety analysis. These conditions are specified in the test procedure. The Reactor Coolant System (RCS) temperature will be less than or equal to 100°F and RCS pressure will be less than 50 psig. Since LTOP conditions apply on Units 1 and 2, the PORV will be operable with a setpoint of 475 psig. The pressurizer will have a nitrogen cover gas and an initial level less than or equal to 100 inches. The LPI System will be providing decay heat removal via either the non-load shed A or B LPI pumps. The main feeder buses for Units 1 and 2 will initially be powered by their respective startup transformers from the switchyard. Steam generator temperature will be less than or equal to 100°F and steam generator level will be greater than or equal to 75% operating range. The steam generators will be depressurized at nearly atmospheric pressure.

Unit 3 will be defueled with the reactor vessel head off. The temperature in both spent fuel pools is currently less than 100°F. In preparation for this response and to estimate the spent fuel conditions at the revised test date of January 2, 1997, a revised analysis of the time to boil in the spent fuel pools was performed. Assuming an initial temperature of 100°F, the Units 1 and 2 spent fuel pool will begin boiling at approximately 103 hours and the Unit 3 spent fuel pool will begin boiling at approximately 31 hours. Assuming an initial temperature of 110°F, the Units 1 and 2 spent fuel pool will begin boiling at approximately 94 hours and the Unit 3 spent fuel pool will begin boiling at approximately 29 hours.

Question 2: The submittal indicates that a loss of decay heat removal analysis has been performed. Please provide details with regard to the assumptions chosen. Please include details such as initial RCS temperature and if the steam generator cooling is considered. Explain why offloading the core or flooding the refueling cavity on the fuel units is not justified as a measure to prevent an increase in the probability of core damage given the unusual alignment and the potential for unforeseen circumstances associated with the test.

Response: Duke Power performed a loss of decay heat removal thermal hydraulic analysis for Units 1 and 2 using methods reviewed and approved by the NRC as described in Duke topical report DPC-NE-3000. The analysis determined the plant response in the event that decay heat removal by the LPI System cannot be restored for 24 hours. Initial conditions for the analysis are as follows:

- RCS temperature = 100°F
- RCS pressure = 50 psig
- Pressurizer level = 100 inches (scale is 0-400 inches)
- Nitrogen cover gas in the pressurizer
- No reactor coolant pumps in operation
- 15% steam generator tube plugging
- Steam generators in reduced wet layup at 75% operating range
- Steam generator temperature = 100°F
- Steam generator pressure = atmospheric

* Decay heat corresponding to 75 days after shutdown (assumed that the test would start on December 19, 1996)

Boundary conditions for the analysis are as follows:

* No feedwater addition
* Operator action to open the atmospheric dump valves within 13 hours

In the unlikely event that decay heat removal by LPI is interrupted for an extended time during the test, natural circulation will develop and primary and secondary side temperatures will increase until the secondary side reaches saturation at approximately 13 hours. By this time, operator action is credited to open the manual atmospheric dump valves.

The RCS temperature and pressure responses are given in Figures 1 and 2, respectively. RCS temperature and pressure gradually increase until the secondary side reaches saturation. Since the steam generators provide sufficient decay heat removal, the primary side stabilizes near the saturation temperature corresponding to the secondary side pressure. The RCS average temperature stabilizes at approximately 220°F with RCS pressure remaining below 130 psig. Therefore, no voiding in the RCS is predicted and the RCS is greater than 100°F subcooled. Pressurizer level (Figure 3) follows the same general trends as RCS temperature and pressure. Pressurizer level increases from 100 inches to approximately 225 inches. It should be noted that Page 13 of the December 11, 1996, submittal stated that the volume increase to heat up to boiling would increase pressurizer level from 100 to approximately 180 inches. This statement is incorrect in that no boiling is predicted and pressurizer level increases to about 225 inches as opposed to 180 inches.

Figures 4 and 5 show the steam generator temperature and inventory response, respectively. Steam generator pressure increases a few psi once the generators reach saturation and steaming through the atmospheric dump valves is initiated.

Duke Power's analysis indicates that steady-state natural circulation cooling can be established following a loss of

LPI decay heat removal, provided that adequate steam generator levels and steaming capability exist. No operator action is required other than to open the manual atmospheric dump valves prior to 13 hours. Since the peak RCS pressure is less than 130 psig, a large margin exists to the PORV lift setpoint of 475 psig. Therefore, there is a high level of assurance that the PORV will not be challenged. Duke Power's analysis demonstrates that at least 24 hours is available before feedwater addition to the steam generators must be initiated or decay heat removal via LPI must be restored. Thus, ample time is available to prevent the onset of boiling in the primary system.

Insufficient storage capacity exists to offload both the Units 1 and 2 cores into the spent fuel pool. Therefore, it is not possible to conduct the test with all three units defueled. In addition, Duke has considered the possibility of removing the reactor vessel head and flooding the fuel transfer canal during the performance of the test. Because of the redundant and diverse means of decay heat removal provided by the two trains of LPI and natural circulation of the RCS through the steam generators, removal of the reactor vessel head and flooding of the fuel transfer canal is not necessary. The loss of decay heat removal thermal hydraulic analysis indicates that adequate time is available to restore the LPI system to service if a problem occurred during the test. Also, the removal of decay heat from Units 1 and 2 via natural circulation can be established without any power from the main feeder buses.

Question 3. The submittal states that long term steam generator cooling can be established by opening the atmospheric dump valves and feeding the generators with either the TDEFW pumps or the SSF pumps. Please provide some of the details regarding the basis for this statement and include the equilibrium or steady state RCS temperature and pressure calculated and what actions the operators would be required to make. Be sure to include any possible inventory loss from the PORV opening if RCS pressure exceeds the LTOP setpoint and the availability of motive steam for the TDEFW pumps.

Response: Duke Power's response to Question 2 addresses the primary and secondary side response to a loss of LPI decay heat removal. The only actions required by the operators

are to open the atmospheric dump valves. These valves are manual valves which are easily accessible on the turbine deck and are not affected by a loss of power. The predicted RCS pressure response (Figure 3) indicates that the peak pressure should not exceed approximately 130 psig. Thus, significant margin to the PORV lift setpoint of 475 psig exists and no inventory loss from the PORV should occur.

Duke Power's December 11, 1996, submittal did not credit the turbine driven emergency feedwater (TDEFW) pump as a source of feedwater. This is because the steam supply from the Auxiliary Steam System will not be at the recommended pressure for operation of the TDEFW pump. The contingency plans will rely on restoration of power to the motor driven emergency feedwater pumps or use of the Standby Shutdown Facility (SSF) auxiliary service water (ASW) pump. The SSF provides a diverse and independent means of feedwater for the steam generators. The SSF ASW pump is powered by the SSF diesel generator and can be placed in operation within 10 minutes. The SSF ASW pump provides ample flow to supply feedwater to all three units. Since over 24 hours exists before addition of feedwater or LPI is necessary, Duke believes that adequate contingencies exist to safely conduct the test.

Question 4: Will the PORV be functional and operable throughout the course of the testing?

Response: The PORV on Unit 1 and Unit 2 will be operable for the duration of the testing. The motive power for the PORV and for the wide range RCS pressure instrumentation is fed from the DC battery buses and the battery backed AC vital inverters.

Question 5: What is the potential of losing compressed air during the testing? The submittal states that there are "no valves in the HPI, LPI, or RCS systems which are expected to open during the test." What are the consequences of losing compressed air on one of the fueled units with regard to valve positioning? Could RCS inventory be lost if compressed air is lost? Could there be an inadvertent injection of water into the RCS due to compressed air being lost?

Response: The performance of this test does not interrupt power to the primary (normally operating) compressor and therefore a loss of instrument air is not likely. The backup compressors, which only run when the primary compressor is shut down, will have power interrupted for a brief period (less than one hour). If the primary compressor is lost during this time frame, the backup diesel air compressor can be quickly started to supply compressed air. The diesel compressor is maintained for emergency operation and the operators are trained on starting and connecting it to the instrument air system.

A review of the Loss of Instrument Air Abnormal Procedure and the plant lineup for the test identified no pneumatic boundary valves that, upon a loss of instrument air, would result in a loss of RCS inventory or inadvertent injection into the RCS on the fueled units.

Question 6: Please describe how the testing may adversely affect instrumentation available to the operators during the test. Particular attention should be placed on source range nuclear instrumentation, RCS and pressurizer level, RCS temperature and pressure, and DHR and cooling water flow.

Response: Instrumentation which is important to the operators during shutdown conditions receives power from batteries through inverters. During the test, the battery chargers will momentarily lose power. Once the emergency power system energizes the main feeder buses, the battery chargers will be reenergized. Thus, the instrumentation which encompasses the parameters listed in the NRC's question will be available to the operators during the test.

Question 7: The submittal states that, "it is conceivable that some components may fail due to previously undetected defects," however, "redundant components will not be challenged or exposed to the transients of the transfer tests." Please list the components that will not be challenged during the test and what functions will remain available if defects occur with regard to decay heat removal, low pressure injection, and high pressure injection.

Response: Unit 1 has three LPI pumps. Any one of the three LPI pumps is capable of providing adequate decay heat

removal. All three LPI pumps will be available prior to initiating the test. One LPI pump will be in service at the beginning of each power transfer and will restart from the emergency power source. In the highly unlikely event this pump fails during the power transfer transient, either of the two remaining pumps can be started and placed into service from the Unit 1 control room.

Unit 2 also has three LPI pumps. The test configuration for Unit 2 is the same as for Unit 1 with the exception that the LPI pump that is in service will not lose power during Tests 12.3 and 12.4.

There are three low pressure service water (LPSW) pumps for the shared Units 1 and 2 LPSW System. Any one of the three LPSW pumps provides all the service water flow necessary for decay heat removal on both Units 1 and 2. During tests 12.1, 12.2, 12.5, and 12.6, two of the three LPSW pumps will be operating prior to the power transfer and will restart after the power transfer. If both of these pumps should fail to restart, the third LPSW pump can be restarted and provide sufficient flow for decay heat removal on both Units 1 and 2.

During Tests 12.3 and 12.4, one of the two operating LPSW pumps will be powered from Unit 2 and will not be affected by the power transfer.

For the Units 1 and 2 spent fuel pool (SFP), three spent fuel cooling (SFC) pumps and four recirculating cooling water (RCW) pumps will be available for decay heat removal. During Tests 12.1, 12.2, 12.5, and 12.6, the Units 1 and 2 SFC System will lose power. The SFC and RCW pumps do not automatically restart when power is restored to the main feeder buses. As stated in the response to Question 1, boiling in the SFP could occur approximately 103 hours following a loss of decay heat removal. This provides considerable time for the operators to manually restart these pumps once a stable source of power is supplying the main feeder buses, as directed by the test procedure.

During Tests 12.3 and 12.4, one of the three SFC pumps and two of the four RCW pumps will not lose power as these pumps are powered from the Unit 2 main feeder buses.

For the Unit 3 SFP, three SFC pumps, two RCW pumps, and two condenser circulating water (CCW) booster pumps will be available for decay heat removal. During Test 12.1 and 12.2, all three SFC pumps and the four support pumps (two RCW and two CCW booster pumps) will lose power during the power transfer. These pumps will not automatically restart. The operator will be directed to restart these pumps per the test procedures once a stable source of power is supplying the main feeder buses. Approximately 31 hours will exist to perform this function prior to the initiation of boiling in the Unit 3 SFP.

During tests 12.3, 12.4, 12.5, and 12.6, two of the three SFC pumps will have jumpers installed so that these pumps automatically restart when power is restored to the Unit 3 main feeder buses. These pumps will be started to ensure emergency power loads during the test will be comparable to the loads during a design basis accident. Should these two SFC pumps fail to restart during the power transfer transient, the third SFC pump would be available to provide spent fuel cooling. The operators would be instructed to restart this pump (and its support pumps) per the test procedure.

Question 8: Will the fueled units maintain containment integrity during the entire tests?

Response: All reactor building penetrations will be intact or adequate contingencies will be in place to provide closure prior to core boiling in the event of an extended loss of DHR. As described in the response to Question 2, over 24 hours exist to complete this function if LPI decay heat removal is lost. In the event of a loss of decay heat removal, existing abnormal procedures instruct the operators to verify that all reactor penetrations are isolated. No maintenance is currently scheduled on the fueled units that would breach a reactor building penetration during the test. Containment integrity, as defined by the Technical Specifications, will not be established during the test.

Question 9: The submittal states that, "there is no susceptibility to a LOCA on the shutdown units" and supports this statement by stating that there will be no seal injection, normal makeup, emergency makeup, or letdown flows. Please provide more information regarding the basis

for this statement considering the potential loss of compressed air, loss of power, or other potential failures. What will the condition of the reactor coolant pump seals be during the test and what will occur if steam generator cooling is initiated?

Response: With Units 1 and 2 at cold shutdown conditions, there is no requirement for reactor coolant pump seal injection, normal makeup, emergency makeup, or normal letdown. Decay heat removal will be provided by the LPI System in a closed loop mode. Loss of compressed air is not anticipated during this test as the primary instrument air compressor will not have its power supply affected during the test. In addition, in the unlikely event compressed air is lost, no loss of RCS inventory will occur. This is because isolation by the relevant RCS boundary valves is not impacted by a loss of air. The loss of LPI decay heat removal analysis described in the response to Question 2 predicts substantial margin to the PORV lift setpoint of 475 psig. Should steam generator cooling be necessary, equilibrium RCS conditions would be approximately 220°F and less than 130 psig. At these conditions, the integrity of the reactor coolant pump seals will not be challenged and no seal cooling is necessary.

Question 10: The submittal states that most UFSAR analyzed accidents (LOOP/LOCA) are not "postulated for cold shutdown units." Considering this test results in an increased possibility of a loss of power, should this be analyzed prior to the test to detect unanticipated problems (i.e., water hammer, relief valve cycling).

Response: Duke Power has thoroughly analyzed the potential consequences of a loss of power. As described in the response to Question 2, requiring the steam generators to be in reduced wet layup provides an ample heat sink should power be lost. Over 24 hours exists before feedwater would need to be added to the generators or LPI decay heat removal would need to be initiated. As described earlier, the test alignment for Units 1 and 2 should result in no inventory addition or loss from the RCS.

Question 11: Describe in greater detail contingency plans and recovery measures should an unforeseen circumstance occur. For example, what actions are required to put the

redundant components, not subject to the testing, into service to initiate decay heat removal, LPI, or HPI. Should the HPI and LPI be isolated from the RCS, please include what actions are necessary to un-isolate these injection lines.

Response: The LPI pumps at Oconee are also used to provide decay heat removal while shutdown. These pumps will not be isolated from the RCS during the test. Should any Unit 1 or 2 pump(s) providing decay heat removal fail during the power transient, then the redundant pumps, as described in response to Question 7, can be started by manual operator actions in the Unit 1 and 2 control rooms. Guidance to restart the LPI pumps and/or LPSW pumps is provided in the test procedure. The LPI System can be used as a makeup source with the operation of one valve outside the control room. Also, these valves are located outside of the reactor building and are easily accessible.

The HPI pumps are isolated from the RCS due to LTOP concerns whenever the RCS is intact and less than 325°F. HPI would be available a backup makeup source in the event of an RCS leak. Guidance is provided for the use of HPI as a makeup source in the Loss of Decay Heat Removal Abnormal Procedure. Operation of four valves outside the control room will be required to align the HPI System to the RCS. These valves are located outside of the reactor building and are easily accessible.

Question 12: Depending upon the results, it may be necessary to repeat portions of the test. What are Duke Power's plans with respect to repeating portions of the test? Is there an upper bound on the number of times a test would be repeated?

Response: Duke Power will have pre-test and post-test briefings for each of the six portions of the test. The post-test briefing will assess the test results with respect to the acceptance criteria. If it is necessary to repeat a portion of the test, the status of the Oconee units will be evaluated to determine if a retest can be safely conducted. Duke Power does not intend to perform a portion of the test more than three times without reviewing the test plan with the NRC.

ATTACHMENT 2

The proposed UFSAR change is being revised to delete the reference to the November 21, 1996, letter and to add a reference to the December 17, 1996, letter. The letters dated December 11, 1996, and December 17, 1996, contain all of the information that pertains to the license amendment request.

UFSAR Change to Page 14-7

A one-time emergency power ES functional test which involves the three Oconee units during shutdown conditions has been evaluated. The scope of the test is described in Duke letters to the NRC dated December 11, 1996 and December 17, 1996. This test will verify certain design features of the emergency power system in an integrated fashion. Oconee Unit 3 will be defueled and Oconee Units 1 and 2 will be at cold shutdown with fuel in the reactor core during the performance of the test.