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Jerry C. Roberts
Director
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GNRO-2002/00056

June 20, 2002

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

SUBJECT: Grand Gulf Nuclear Station, Unit 1
Docket No. 50-416
Supplement to Amendment Request
Emergency Diesel Generator Extended Allowed Outage Time, TS 3.8.1.

REFERENCE: Letter GNRO-2002/0007 from William A. Eaton to USNRC, "License Amendment Request, Emergency Diesel Generator Extended Allowed Out-of-Service Time (AOT) - TS 3.8.1, AC Sources - Operating, LDC 2001-192," dated January 31, 2002.

Dear Sir or Madam:

By the above referenced letter, Entergy Operations, Inc. (Entergy) proposed a change to the Grand Gulf Nuclear Station (GGNS) Technical Specifications (TSs) to extend the allowed out-of-service time for a Division I or Division II Emergency Diesel Generator (EDG) from 72 hours to 14 days (TAC No. MB3973).

On May 10 and 16, Entergy and a member of your staff held calls to discuss the amendment request. As a result of the calls, five questions were determined to need formal response. Entergy's response to the questions is contained in Attachment 1.

In addition, on June 3, 2002, the staff requested an additional commitment. The application submitted by the above referenced letter noted that the evaluation of the extended AOT risk impacts was performed using an interim model. Entergy had made a special effort to ensure that the aspects of the interim model that were potentially sensitive to the EDG maintenance unavailability were adequate to evaluate risk impacts of the extended AOT. However, the staff requested that Entergy also evaluate the risk metrics using the updated risk model, when available, and provide a summary of the results to the staff. Entergy commits to provide this information.

There are no technical changes proposed. The original no significant hazards considerations included in the original application referenced above is not affected by any information contained in the supplemental letter. There are two new commitments contained in this letter as summarized in Attachment 2.

A001

If you have any questions or require additional information, please contact Ron Byrd at 601-368-5792.

I declare under penalty of perjury that the foregoing is true and correct. Executed on June 20, 2002.

Sincerely,

J. C. Roberts
Director, Nuclear Safety Assurance
Grand Gulf Nuclear Station, Unit 1

JCR/RWB/bab

Attachments:
1. Response to Request For Additional Information
2. List of Regulatory Commitments

cc: Mr. Ellis W. Merschoff
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U. S. Nuclear Regulatory Commission
Region IV
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U. S. Nuclear Regulatory Commission
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Dr. E. F. Thompson (w/a)
State Health Officer
State Board of Health
P.O. Box 1700
Jackson, Mississippi 39205

Mr. T. L. Hoeg, GGNS Senior Resident
Mr. D. E. Levanway (Wise Carter)
Mr. L. J. Smith (Wise Carter)
Mr. N. S. Reynolds
Mr. H. L. Thomas

Attachment 1

To

GNRO-2002/00056

Response to Request for Additional Information Related to License Amendment Request, EDG Extended AOT

Response to Request for Additional Information Related to License Amendment Request, EDG Extended AOT

Question 1:

Discuss and provide information on the reliability and availability of offsite power sources relating to the proposed change. The discussion should include duration, cause, date and time of each loss-of-offsite power (partial or complete) event.

Response:

Information regarding grid stability is being provided to the NRC staff in response to questions concerning the GGNS Appendix K Measurement Uncertainty Recovery 1.7% Power Uprate request (TAC No. MB3972). The stability analysis shows continued stable performance at the new GGNS power output level. A portion of that response is provided below.

Grid stability analyses for GGNS have been performed in accordance with the guidance of NUREG-0800, Section 8.2.III.1.f.

For the Dynamic Stability Study, the analysis tripped GGNS and applied faults which lasted up to 15 cycles. Only one case, during an off-peak condition, went unstable after 14 cycles which is not considered a problem since it is beyond the time for back up breakers to respond assuming a failed or stuck breaker in conjunction with the fault occurring (typically, back up breakers trip within 7 cycles). The 11 MW electrical power uprate difference between the analysis (1350 MW) and the new calculated peak (1361 MW) will have negligible impact on how the turbine generator will react to a fault, since this modification does not change any of the parameters or controls on the turbine generator. The 11 MW will also have negligible impact on how the grid reacts to the turbine generator tripping, since the 500 kV system has the capacity to account for this additional generation loss. Entergy Transmission Planning was contacted about this power uprate and they did not require additional studies since it was purely a steam increase.

For the Steady State Stability Study, the analysis assumed multiple failures over and beyond the NUREG requirements for the 500 kV line and it met the 0.975 per unit requirement for minimum voltage. The cases which are required to credit the 500 kV lines as a valid GDC-17 source during an accident do not take credit for the station's generation capacity. Therefore it was concluded that the 11 MW difference will have no impact on the steady state stability studies.

As noted in the application for this TS amendment, a loss of offsite power frequency of 0.035/year was used in the GGNS Probabilistic Safety Analysis (PSA). This frequency was obtained from industry data in NSAC/166, "Losses of Off-Site Power at U.S. Nuclear Power Plants". The data covers the period from 1980 through 1990. Examination of data from EPRI 000000000001000158, "Losses of Off-site Power at U.S. Nuclear Power Plants—Through 1999," indicates that the assumed loss of offsite power frequency of 0.035/year from NSAC/166 is slightly conservative.

Within this industry data is one GGNS event (LER 1991-005) which occurred at 9:32 a.m. on June 17, 1991. A failure of a B phase 500kV switchyard breaker caused a trip of the unit and a power loss to one of the 500kV service transformers. The event is classified as a Type III loss of offsite power category. A Type III event is one where the unit trips off-line with a loss of feed

through the unit auxiliary transformer but off-site power remains available or can be made available from another source through a fast transfer or manual switching from the control room. These type events do not represent a complete loss of all off-site power. In this event, the unit trip and power loss to the 500kV service transformer resulted in the loss of preferred power feed to two ESF buses. The two ESF buses were transferred to the 115kV offsite power source. GGNS is only required to have two of its three off-site sources available to meet Technical Specification requirements for preferred sources and as such still retained full off-site power availability. Since offsite power was still available to the ESF buses from two additional off-site sources (via manual switching in the Control Room), this event was classified as a Loss of the Power Conversion System (PCS) initiator in the GGNS PSA rather than a loss of offsite power initiator. The GGNS Main One line Diagram showing the ESF bus power supply options can be viewed in GGNS FSAR Figure 8.1-001.

Question 2:

It is the NRC staff's understanding that the purpose of the requested amendment is to allow an increased outage time during plant power operation for performing EDG inspection, maintenance, and overhaul, which would include disassembly of the EDG. EDG operability verification after a major maintenance or overhaul may require a full load rejection test. If a full load rejection test is performed at power, please address the following:

(a) What would be the typical and worse-case voltage transients on the 4160-V safety buses as a result of a full-load rejection?

(b) If a full-load rejection test is used to test the EDG governor after maintenance, what assurance would there be that an unsafe transient condition on the safety bus (i.e., load swing or voltage transient) due to improperly performed maintenance or repair of a governor would not occur?

(c) Using maintenance and testing experience on the EDG, identify possible transient conditions caused by improperly performed maintenance on the EDG governor and voltage regulator. Discuss the electrical system response to these transients.

(d) Provide the tests to be performed after the overhaul to declare the EDG operable and provide justification of performing those tests at power.

Response:

The purpose of the requested amendment is to allow an increased outage time during plant power operation for performing EDG inspection, maintenance, and overhaul, which may include disassembly of the EDG. However, the EDG operability verification after a major maintenance or overhaul does not include a full load rejection test, such as Surveillance Requirements (SRs) 3.8.1.9 or 3.8.1.10, unless the speed control or voltage control components are replaced or require corrective maintenance for a problem identified during EDG operation. Both of these situations are infrequent and would be handled as separate tasks outside the scope of routine planned maintenance.

The current TS do not allow a full load reject test to be performed in MODE 1 or 2 except for unplanned events. The TS Bases for SRs 3.8.1.9 and 3.8.1.10 include two examples of unplanned events:

1) unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of required performance is available; and

2) post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

This proposed TS change does not alter the current restrictions or allowances for load reject tests provided by the TS. However, by letter GNRO-2001/00083, dated November 15, 2001, Entergy requested a change to remove this restriction. That request is still pending (TAC No. MB3487). Entergy is addressing voltage transient concerns associated with an on-line load reject test in response to questions on that amendment application. Until the TS restriction is removed by separate amendment, Entergy will not plan elective maintenance that requires a full-load reject test on-line.

Following an on-line overhaul of the EDG, the normal monthly TS SRs (i.e., 3.8.1.2 and 3.8.1.3) would be performed to demonstrate EDG operability. However, prior to performing these final surveillance tests, a series of post-maintenance engine runs at unloaded and varying load conditions is conducted to verify that the EDG is functionally sound.

Precautions are taken following an extended EDG maintenance period to ensure that any improperly performed maintenance on the diesel governor does not introduce possible transient conditions that would adversely challenge the EDG or the safety bus. The primary method of protecting the bus against a possible governor malfunction is to ensure that the governor provides customary stable control before connecting the EDG to the bus. The latter stages of the planned maintenance activities include returning the EDG to governor control in a deliberate and controlled manner.

As further assurance against any possible malfunction, the overspeed trip is also assured to be functional before the first fast start. All of this is done before connecting the EDG to the bus for the first time. Therefore, any deleterious effects of a governor malfunction would be confined to the EDG alone. On a start, an engine overspeed is the only plausible significant consequence of a governor malfunction. A functional overspeed trip assures the protection of the EDG should this occur.

Once governor control is proven, the EDG is connected to the bus, paralleling with the grid, in the same manner as for a monthly surveillance test.

Routine governor maintenance and minor adjustments do not require load rejects to prove their success. The governor's ability to control a fast start, which is only done while disconnected from the bus, is sufficient to demonstrate that the response dynamic remains nominal or the same as demonstrated during the past surveillances.

In summary, the current TS only allow load reject test to be performed during Mode 1 or 2 for unplanned events and a EDG overhaul does not require a load reject to be performed. A

request to remove the restrictions for the on-line load reject is pending under TAC MB3487 and voltage transient conditions are being addressed in that application. Therefore this proposed TS change would not introduce any new load reject tests while on-line. Precautions are taken following major maintenance to ensure that any improperly performed maintenance on the governor or voltage regulator does not adversely challenge the EDG or the safety bus.

Question 3:

What type of communication has been established between the control room operator of Grand Gulf Nuclear Station and the System Load Dispatcher? Is the System Load Dispatcher notified in advance that the EDG is going to be out of service for an extended period of time?

Response:

The communications protocol between GGNS and the Entergy Transmission group is established by formal agreement. The Grand Gulf Control Room is the official contact point at GGNS, 24 hours a day/7 days a week. In addition, there is a dedicated telephone line between the GGNS control room and the Jackson load dispatcher that allows immediate contact if necessary.

Grand Gulf currently does not notify the System Load Dispatcher that an EDG is going to be out of service for an extended period of time. This notification is unnecessary since GGNS is already established as a preferred load and based on the sensitivity the dispatchers maintain toward GGNS with respect to switchyard and grid conditions. During high risk evolutions at GGNS (which includes an EDG out of service for maintenance), maintenance activities in the switchyard on the power lines or transformers which provide offsite power to the plant are avoided.

Question 4:

It is stated that Division III EDG can be cross-connected to either Division I or Division II AC buses to provide an alternate AC power in the event of a station blackout. In this regard provide the following information:

(a) Is this a permanent cross-connection? How long would it take to accomplish this connection?

(b) Demonstrate that Division III EDG has enough capacity to power loads that are needed for a station blackout and loss of offsite power.

(c) Can this EDG be qualified as an alternate AC source according to the recommendation of Regulatory Guide 1.155, "Station Blackout."

Question 4(a):

Is this a permanent cross-connection? How long would it take to accomplish this connection?

Response:

The electrical equipment that enables the cross-connection is permanent and was part of the original plant design. This configuration facilitates the cross-connection from Division III to the Division I or II bus through existing breakers and cables.

The cross-connection is accomplished by defeating the HPCS LOCA automatic initiation signals, defeating the particular Load Shed and Sequencing (LSS) panel for the division to be cross tied, defeating certain interlocks and performing breaker line-ups to load the Division III EDG with the desired loads. The process for performing this evolution is procedurally controlled by Off-Normal Event Procedure 05-1-02-I-4. The procedure contains a table of loads which can be connected without exceeding the Division III D/G capacity. The loads identified are sufficient to address station needs in the event of a station blackout or a loss of offsite power.

The cross-connection can be accomplished within two hours. Additional discussion on the cross-connect time is provided in response to question 4(c). Note that the cross-connection adds a defense-in-depth measure that is not credited in the current Station Blackout (SBO) coping analysis. The ability of GGNS to cope with a four-hour SBO has been evaluated without reliance on this cross-connection capability as described in Appendix 8A of the GGNS UFSAR. The coping evaluation of Appendix 8A is not altered by the proposed change. Additionally, the coping results are not affected by the 1.7% Appendix K power uprate.

Question 4(b)

Demonstrate that Division III EDG has enough capacity to power loads that are needed for a station blackout and loss of offsite power.

Response:

The Division III EDG has a continuous rating of 3300 kW and a 2,000 hour rating of 3474 kW. Off-Normal Event Procedure 05-1-02-I-4 establishes the loads that can be connected to prevent overloading the Division III EDG. The loads allowed by the procedure are provided in Table 1 below:

Table 1
Essential Loads

LOAD	LOAD KW
SSW Pump	997
RHR Pump	803
MOVs	Div. I 187.5 Div. II 190.7
Control Room Standby Fresh Air	20
ESF Battery Charger	110
Drywell Cooler Fans	120
FPCCU Pump	124
SSW O/A Fan	40
Control Room A/C	120
SSW Cooling Tower Fans	244
ESF Switchgear Room Cooler	12
Div. II Instrument Air Compressor	230 (Div. II only)
Safeguard Switchgear/Battery Fans	122
ECCS Room Cooler	8
HPCS EDG Auxiliaries	154
TOTAL	Div. I 3061.5 Div. II 3294.7

Reactor coolant system inventory control during the initial phases of a Station Blackout will be provided by the RCIC system. After the four-hour coping period, decay heat removal utilizing one train of RHR will likely be necessary. Operators may use RHR Shutdown Cooling (SDC) to remove decay heat from the reactor or use Suppression Pool Cooling (SPC) to cool the suppression pool. These loads are included in the list of equipment that is to be connected, including any required support systems. Thus, the Division III EDG is capable of supplying the power to the one RHR pump needed for the RHR system to provide decay heat removal for the postulated scenario. It should be noted that because the subject scenario does not involve a large-scale mass and energy release as for a LOCA, the demands on various systems will be less than for the DBA-LOCA scenarios (which also assume a loss of offsite power). Thus, it is concluded that the Division III EDG is capable of supplying all the loads needed for a SBO or loss of offsite power.

Question 4(c):

Can this EDG be qualified as an alternate AC source according to the recommendation of Regulatory Guide 1.155, "Station Blackout"?

Response:

GGNS complies with the Station Blackout (SBO) Rule, 10CFR50.63 as a four-hour coping plant with no credit taken for the HPCS EDG as an alternate AC (AAC) power supply. In addition, the HPCS system is not relied upon as an injection source to the RPV for the SBO coping analysis. The availability of the HPCS EDG provides additional defense-in-depth capability by providing power to the HPCS pump or by providing alternate power to the other division loads.

Entergy has reviewed the potential for qualifying the HPCS EDG as an AAC source in accordance with NUMARC 87-00. This review indicates that the HPCS diesel generator at GGNS conforms to NUMARC 87-00 with the exception of Appendix B, Criterion B.12, which states:

> *"Unless otherwise governed by technical specifications, the AAC system shall be demonstrated by initial test to be capable of powering required shutdown equipment within one hour of a station blackout event."*

This criterion is met except for the time limitation of one hour. It is anticipated that the cross-connection can be effectively accomplished with the Division 3 EDG ready to power required shutdown equipment within 2 hours. The one-hour AAC criterion was established in Regulatory Guide 1.155 as a provision for the SBO coping analysis. The current licensing basis coping duration (4 hours) of the station blackout event is through use of the RCIC system without taking credit for either the HPCS EDG as an AAC or HPCS injection.

Additionally, since the HPCS system would be available as committed in the application for the amendment, the HPCS EDG would more likely be used initially to power the HPCS pump. It should be noted that the HPCS EDG meets the timing criterion for an AAC as it relates to providing power to just the HPCS system. This otherwise dedicated Division 3 power supply would be available to the HPCS pump within 23 seconds in the event of a loss of power to both Division I and Division II buses. This availability to power HPCS is consistent with the more stringent timing criterion of 10 minutes as stated in Regulatory Guide 1.155 section 3.3.5 criterion 3. Therefore, the cross-connection timing should not be a crucial factor in the first few hours of an SBO for GGNS.

Dedicating personnel to the cross-connection activity when entering the extended maintenance period may be inappropriate for the SBO event considering the coping time available and other response actions that will require operator attention. In addition to power recovery actions, there are other operator actions taken in response to a SBO which are discussed in Appendix 8A of the Updated Final Safety Analysis Report.

In summary, the HPCS EDG cross-connection can be accomplished in a timely manner relative to the coping duration, the alternate loads are within the capability of the EDG and the EDG meets the pertinent criteria for an AAC for the intended application. Therefore, it is reasonable to conclude the HPCS EDG can be used as a source of AC power in the event of a SBO to provide adequate defense-in-depth measures by being available to power the HPCS system or to power other divisional loads.

Question 5

Please provide the unavailability data for the EDG's at Grand Gulf due to maintenance and describe how it is consistent with the objectives and intent of the maintenance rule. Please clarify that since the availability of HPCS EDG is essential during the extended AOT, why is it not listed in the commitment identification form?

Response:

The EDG unavailability data for the EDG's and its consistency with the maintenance rule is addressed on page 14 of Attachment 1 of the application (Letter GNRO-2002/0007 from William A. Eaton to USNRC, dated January 31, 2002). It is Entergy's intent to maintain the HPCS EDG available so that it can be used as either a power source to HPCS or used as an alternate power source to the other divisional loads. To make these intentions clear, Entergy commits to not removing the HPCS EDG from service for planned maintenance while EDG 11 or EDG 12 is out of service for extended maintenance. This commitment is summarized in Attachment 2.

Attachment 2

GNRO-2002/00056

List of Regulatory Commitments

List of Regulatory Commitments

The following table identifies those actions committed to by Entergy in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

COMMITMENT	TYPE (Check one)	
	ONE-TIME ACTION	CONTINUING COMPLIANCE
Entergy will evaluate the risk metrics for the EDG extended AOT using the updated risk model, when available, and provide a summary of the results to the NRC staff.	X	
The HPCS EDG (Division III) will not be taken out of service for planned maintenance while EDG 11 (Division I) or EDG 12 (Division II) is out of service for extended maintenance.		X