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November 15, 2001

U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Document Control Desk

Subject: Grand Gulf Nuclear Station Proposed Amendment of Facility Operating License to Remove Operating Mode Restrictions for Performing Emergency Diesel Generator Testing
Grand Gulf Nuclear Station
Docket No. 50-416
License No. NPF-29

GNRO-2001/00083

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90, Entergy Operations Inc., (EOI) hereby requests amendment of Facility Operating License for Grand Gulf Nuclear Power Station (GGNS). Specifically, EOI requests modification of the GGNS Technical Specifications to revise several of the Surveillance Requirements (SRs) pertaining to testing of the standby emergency diesel generators (DGs). The proposed change would remove the restriction associated with these SRs that prohibits performing the required testing during Modes 1, 2 or 3. The affected SRs are SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.13 and SR 3.8.1.17.

Essential details and information to support this request are provided in the Attachments to this letter. Attachment 1 provides a description and justification for the requested TS changes. Attachment 1 also contains the evaluation for no significant hazards consideration, wherein it is concluded that, based on an evaluation of the proposed changes against the criteria of 10CFR50.92, no significant hazards consideration is involved. Attachment 1 also provides an evaluation against the 10 CFR 51.22 criteria for environmental considerations. The Technical Specification pages annotating the proposed changes are provided in Attachment 2, and the marked-up Technical Specification Bases pages are provided for information in Attachment 3.

Since the proposed changes can provide significant reductions in outage critical path time, GGNS is respectfully requesting review and approval of these amendments by August 01, 2002. Once approved, the amendment will be implemented within 60 days. This would support scheduling of the SRs before or after the outage (based on the due dates for the SRs) such that planning for the outage can be finalized with the noted SRs removed from the outage scope. It should be noted that the NRC has approved similar Technical Specification changes for other plants. For example, Perry (February 24, 1999) and Clinton (October 2, 2000) have each received similar license amendments. This letter contains no new commitments.

If you have any questions or require additional information, please contact Mr. Lonnie F. Daughtery at (601) 437-2334.

I declare under penalty of perjury that the forgoing is true and correct. Executed on November 15, 2001.

Yours truly,

William A Eaton

WAE/LFD

attachments:

1. Analysis of Proposed Technical Specification Change
2. Proposed Technical Specification Changes (mark-up)
3. Changes to Technical Specification Bases Pages (proposed mark-up)
4. Tabulation of DG Unavailability During Surveillances

cc: (See Next Page)

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1.0 DESCRIPTION

This letter requests amendment of Facility Operating License NPF-29 for Grand Gulf Nuclear Power Station (GGNS). Specifically, EOI requests modification of the GGNS Technical Specifications (TS) to revise several of the Surveillance Requirements (SRs) pertaining to testing of the standby emergency diesel generators (DGs). The proposed change would remove the restriction associated with these SRs that prohibits performing the required testing during Modes 1, 2 or 3. The affected SRs are as follows:

- SR 3.8.1.9: This SR requires demonstrating that the diesel generator (DG) can reject its largest load while maintaining margin to the overspeed trip.

- SR 3.8.1.10: This SR requires demonstrating that the DG can reject its full load without the DG tripping or its output voltage exceeding a specific limit.

- SR 3.8.1.13: This SR requires demonstrating that the DG (non-critical) automatic trips are bypassed on an actual or simulated ECCS initiation signal and that (critical) trips are not bypassed.

- SR 3.8.1.17: This SR requires demonstrating that the DG automatic switchover from the test mode to ready-to-load operation is attained upon receipt of an ECCS initiation signal (while maintaining availability of the offsite source).

Since the proposed changes can provide significant reductions in outage critical path time, GGNS is respectfully requesting review and approval of these amendments by August 01, 2002. This would support scheduling of the SRs before or after the outage (based on the due dates for the SRs) such that planning for the outage can be finalized with the noted SRs removed from the outage scope.

The proposed changes to the Technical Specifications are reflected in the annotated TS pages provided in Attachment 2. Associated changes to the TS Bases are indicated in Attachment 3. The proposed TS Bases changes are for information only and will be controlled by TS 5.5.11, "Technical Specifications Bases Control Program."

2.0 PROPOSED CHANGE

TS 3.8.1 delineates requirements for AC power sources, including the DGs, while in Modes 1, 2, and 3. The proposed change concerns several of the Surveillance Requirements (SRs) pertaining to the DGs.

The proposed changes to SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, and 3.8.1.17 will allow performance of the testing during Modes 1, 2 or 3 such that the testing will no longer have to be performed during plant outages. This will help to reduce the complexity of work and testing activities during refueling outages and potentially will reduce outage critical path time.

Specifically, Note 1 for SR 3.8.1.9 and SR 3.8.1.10, currently read as follows: "This surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR." The Notes for SR 3.8.1.13 and 3.8.1.17 are identical except they also include MODE 3. The Note for each of these SRs will be revised to remove the mode restrictions from the first part of the note such that the Note (or the affected portion of the Note) would be reduced to the following: "Credit may be taken for unplanned events that satisfy this SR."

The proposed changes to TS Bases for SR 3.8.1.9 and SR 3.8.1.10 removes the sentence that states: "The reason for [the Note] is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems." The proposed change to TS Bases for SR 3.8.1.17 removes the statement: "The reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems."

The following statement is proposed to be added to the TS Bases for each of the above SRs: "Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related systems are aligned to another offsite source. This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations." The proposed change to TS Bases for SR 3.8.1.13 removes the statement; "The reason for the Note is that performing the Surveillance removes a required DG from service."

3.0 BACKGROUND

Grand Gulf Nuclear Station (GGNS) Technical Specification (TS) 3.8.1, "AC Sources - Operating," specifies requirements for the Electrical Power Distribution System AC sources. The Class 1E AC Electrical Power Distribution System AC sources at GGNS consists of the offsite power sources and the onsite standby power sources, i.e., diesel generators (DGs) 11, 12, and 13. As required by 10 CFR 50, Appendix A, GDC 17, the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system at GGNS supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus. Each ESF bus is capable of being supplied by either of three separate and independent offsite sources of power. Each ESF bus also has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the GGNS switchyard from the transmission network. Three electrically and physically separated circuits (of which only the 500 kV sources are credited for meeting LCO requirements at this time due to reliability concerns with the 115 kV source) provide AC power to each of the 4.16 kV ESF buses. The offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power network and circuits to the onsite Class 1E ESF buses is found in Updated Safety Analysis Report, (UFSAR) Chapter 8, section 8.2 " Offsite Power System".

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically upon receipt of a loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation"). In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident such as a LOCA. Transfer is accomplished by first opening the incoming offsite feeder breakers and subsequently closing the DG feeder breaker when the generator has reached rated speed and voltage. This arrangement lessens the likelihood that the offsite source (i.e., grid) and the onsite sources remain paralleled during periods of degraded grid conditions. A detailed description of the onsite power network is found in Updated Safety Analysis Report, Chapter 8, section 8.3 " Onsite Power System".

For Divisions I and II, prior to auto connecting the DG to the ESF bus (i.e., closing DG output breaker), the breakers connecting the buses to the offsite sources are opened and all bus loads except ESF 480 volt load center feeders are tripped. The same signal that initiates the tripping of the offsite feeder breakers also causes all loads to be stripped from the 4.16 kv bus. Loads are sequenced back onto the bus following closure of the DG output breaker to the ESF bus, in a predetermined sequence in order to prevent overloading the standby emergency power source. Load shedding and sequencing for Divisions I and II is discussed in detail in the UFSAR Section 8.3.1.1.3.

For Division III (High Pressure Core Spray - HPCS) loads are not shed and thus not required to be sequenced back onto the bus. However, the design of the HPCS system ensures that the offsite and onsite source will not continue to operate in a parallel mode following receipt of either a LOCA or LOP signal. When in parallel operation the occurrence of a LOCA signal will cause, the HPCS DG output breaker to trip open. It will not be automatically closed unless the preferred offsite source of power is lost similar to the Division I and II designs. Following the receipt of a LOP signal, the offsite feeder breakers will trip open and the HPCS DG output breaker will automatically close.

Presently, the above SRs are required to be performed while the plant is shut down. For SRs 3.8.1.9 and 3.8.1.10 this is enforced by a note preceding each of the SRs in the Technical Specifications, which states in part that the surveillance shall not be performed in Mode 1 or 2. The TS Bases state that the reason for this restriction is to prevent unnecessary perturbations to the electrical distribution systems which could challenge steady state operation and thus plant safety systems if the SR was performed with the reactor critical.

SRs 3.8.1.13 and 3.8.1.17 are restricted from being performed in Modes 1, 2 or 3, as these surveillances are preceded by a similar note. The TS Bases for SR 3.8.1.13 state that the reason for the Note is to prevent the DG from unnecessarily being removed from service with the reactor in Mode 1 or Mode 2. The TS Bases for SR 3.8.1.17 state that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Based on reconsideration of the need and reason for the SR notes, GGNS is proposing to modify the note to remove the Mode 1 and Mode 2 restrictions for performance of SR 3.8.1.9 and SR 3.8.1.10, and to remove the Mode 1, Mode 2 and Mode 3 restrictions from SR 3.8.1.13 and SR 3.8.1.17.

4.0 TECHNICAL ANALYSIS

4.1 General Basis

Although the TS Bases, as currently written, state that the reason for the SR Note (for SRs 3.8.1.9 and 3.8.1.10) is to preclude the potential for perturbations of the electrical distribution system during plant operation, reconsideration of this basis has determined that the noted concern is unwarranted with respect to requiring the affected SRs to be performed only during shutdown conditions. This conclusion is based on (1) the Grand Gulf AC power supply and associated protection features (2) industry and plant experience with the performance of testing required per the affected SRs, (3) administrative controls that minimize plant risks during performance of the affected testing, and (4) the low probability of a significant voltage perturbation during such testing.

Such testing only makes the DG(s) unavailable for responding to an accident during portions of the testing. DG unavailability during the proposed on-line testing is summarized in Attachment4. The risk of performing the noted required surveillances during plant operation is not significantly greater than the risk associated with the performance of other DG surveillances required by the Technical Specifications but which are not prohibited from being performed during plant operation. Surveillance Requirements 3.8.1.9, 3.8.1.10, and 3.8.1.17 are performed by paralleling the DG in test with offsite power, similar to the existing monthly run of the DG, which is conducted with the plant on line. Further, performance of the required testing at power would not result in a challenge to any plant safety system.

4.2 Administrative Controls for On-line Maintenance

Grand Gulf Nuclear Station Technical Specifications impose requirements/restrictions on the amount of equipment allowed out of service at any given time. Required Action B.2 of TS 3.8.1, "AC Sources-Operating," requires identification of inoperable required features that are redundant to required features supported by the inoperable diesel generator. This Required Action is applicable throughout the entire period of diesel inoperability. Inoperable features on the redundant division can then cause entry into other more severe Required Actions, thus providing further incentive not to make another DG inoperable. Additionally, the Safety Function Determination Program (SFDP) pursuant to TS 5.5.10 requires that the loss of safety function be protected against.

The GGNS approach to performing maintenance requires that we use a protected division concept. This means that without special considerations we only allow work on one division at a time. This administrative control provides additional assurance that only one division at a time is worked on and it helps eliminate inadvertent work on the other division.

GGNS procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities and degraded grid conditions, when paralleling a DG with offsite power. For example, during testing, only one DG is operated in parallel with offsite power at a time. This configuration provides for sufficient independence of the onsite power sources from offsite power while still enabling testing to demonstrate DG operability. In this configuration, it is possible for only one DG to be affected by an unstable offsite power system. (Even then, it may be possible for operator action to be taken to manually reset the affected lockout relay so that the DG can be restarted.) Even if this unlikely scenario were to occur, plant safe shutdown capability would still be assured with the two remaining DGs.

4.3 On-line Risk Management

The GGNS Plant Administrative Procedure "01-S-18-6 Risk Assessment of Maintenance Activities" provides procedural requirements to conduct risk assessment for all maintenance performed while in MODES 1, 2 or 3. The purpose of this procedure is to ensure that a process is in place to assess the overall impact of maintenance on plant risk and to manage the risk associated with equipment unavailability. This program implements the requirements of 10CFR50.65 (a) (4) Maintenance Rule. This program uses a risk evaluation tool to assess the potential risk implications of planned or emergent work activities. This tool warns Planning & Scheduling/Outage personnel that plant risk goals are being approached or would be exceeded if work was allowed to be performed. These administrative controls contained in the above procedure minimize any potential to allow work on redundant DGs. The risk evaluation tool is a comprehensive modeling of important GGNS equipment and allows the site to evaluate the adverse effects of other maintenance activities and its impact on DG maintenance.

4.4 Testing Pursuant to SR 3.8.1.9 and SR 3.8.1.10

For performance of the load rejection tests per SRs 3.8.1.9 and 3.8.1.10, the typical approach taken is to load the tested DG to the required load (via offsite power) and then open the DG output breaker. An alternate method for performing SR 3.8.1.9 is to trip the associated largest single load. Opening of the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. This evolution has little impact on plant loads. The power system loading during such testing is within the rating of all transformers, switchgear, and breakers, both before and after the load rejection, and as further explained below, performance of the load rejection SRs does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus.

Data from testing performed pursuant to these SRs is recorded via temporarily installed recorders at GGNS. Analysis of bus voltage traces taken from previous tests has shown that the voltage drop, which occurs, is such that voltage during the "transient" remains well above the minimum required voltage for plant loads, and typically recovers well within two seconds. Thus, the voltage "transient" experienced by loads on the affected bus is minor.

In addition, the probability for a grid disturbance to occur during the timeframe of a test performed per SR 3.8.1.9 or SR 3.8.1.10 is low since the occurrence of a grid disturbance is independent of the testing. Regardless, protective relaying for the diesel generator would be available to protect the diesel generator while it is connected to the grid. In addition, the protection instrumentation (required to be Operable per TS 3.3.8.1, "Loss of Power (LOP) Instrumentation") for sustained grid low-voltage conditions would be available to respond to such a condition.

4.5 <u>Testing Pursuant to SR 3.8.1.17</u>

The performance of the test mode override test per SR 3.8.1.17 ensures that the availability of the DG under accident conditions is unaffected during the performance of the surveillance test. This test is typically performed in conjunction with the load rejection tests (while the DG is paralleled with the offsite source) by simulating a LOCA signal to the DG start circuitry, which causes the DG output breaker to open, as the DG is returned to a ready-to-load condition. Similar to the tests performed for SRs 3.8.1.9 and 3.8.1.10, opening the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. Consequently, performance of testing pursuant to SR 3.8.1.17 does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus.* In addition, similar to testing performed for SRs 3.8.1.9 and 3.8.1.10, the power system loading for this test is within the rating of the affected transformers, switchgear, and breakers, both before and after the load rejection.

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* As noted in the Bases for this SR, the intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by DG operation in the test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. On this basis, performance of routine testing required pursuant to SR 3.8.1.17 does not require separating the bus from offsite power. Consequently, performance of this surveillance does not require removing an offsite circuit from service, as currently implied in the Bases for this SR. Therefore, as noted previously, the Bases will be revised accordingly.

4.6 Testing Pursuant to SR 3.8.1.13

Performance of testing required per SR 3.8.1.13 to verify that non-emergency automatic trips are bypassed and that emergency automatic trips will trip the DG in an emergency, while at power, is justified on the basis that: (1) this SR is not performed with the DG paralleled to offsite power, and (2) unavailability of the DG during the conduct of this test is minimal. DG unavailability mainly occurs when the DG is tripped in response to the emergency trips and then verified to be tripped prior to resetting the trips. Manual action is required to reset the emergency trips so that the DG can then be available to start in an actual emergency situation. Since the test is conducted with the DG unloaded and isolated from its respective emergency bus, there is no impact to the electrical distribution system. Therefore, there is no mechanism for challenging continued steady state operation.

The test is performed by verifying that the non-emergency automatic trips do not trip the DG (i.e., the associated lockout relay is not tripped). The only jumpers and signal simulation required is executed at the relay level in the DG control circuitry such that only the associated DG is affected during this surveillance. DG inoperability for performance of this testing during plant operation is provided in tabular from in Attachment4.

4.7 Risk Assessment

During certain portions of the surveillances the DG would not be able to immediately respond to an accident. DG unavailability during the performance of the proposed on-line DG testing is summarized in Attachment4, with the longest unavailability time of 8.0 hours.
Based on this, the greatest Incremental Conditional Core Damage Probability (ICCDP) in RG 1.177 is determined as follows:

For the average maintenance model (as specified in RG 1.177), the base core damage frequency determined for GGNS is 5.46E-6 per year. Of the three diesel generators, the Division 3 DG has the largest risk achievement worth. The core damage frequency with the Division 3 DG out of service is 2.9E-5. Therefore, the largest delta core damage frequency (CDF) for this proposal occurs with the Division 3 DG out of service and is 2.35E-5 (2.9E-5 – 5.46E-6 = 2.35E-5). Using this value with the longest interval of 8.0 hours yields an ICCDP of 2.15E-8 (2.35E-5 times 8/8760 = 2.15E-8). This is significantly smaller than the Tier 1 acceptance guideline of 5E-7, which is defined as small in RG 1.177.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

Pursuant to 10 CFR 50.90, Entergy Operations Inc. Energy Company, (EOI) hereby requests amendment of Facility Operating License for Grand Gulf Nuclear Power Station (GGNS). Specifically, EOI requests modification of the GGNS Technical Specifications to revise several of the Surveillance Requirements (SRs) pertaining to testing of the standby emergency diesel generators (DGs). The proposed change would remove the restriction associated with these SRs that prohibits performing the required testing during Modes 1, 2 or 3. The affected SRs are as follows:

- SR 3.8.1.9: This SR requires demonstrating that the diesel generator (DG) can reject its largest load while maintaining margin to the overspeed trip.
- SR 3.8.1.10: This SR requires demonstrating that the DG can reject its full load without the DG tripping or output voltage exceeding a specific limit.
- SR 3.8.1.13: This SR requires demonstrating that the DG (non-critical) automatic trips are bypassed on an actual or simulated ECCS initiation signal and that (critical) trips are not bypassed.
- SR 3.8.1.17: This SR requires demonstrating that the DG automatic switchover from the test mode to ready-to-load operation is attained upon receipt of an ECCS initiation signal (while maintaining availability of the offsite source).

In accordance with 10CFR 50.92, a proposed change to the operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed change would not: (1) involve a significant increase in the probability or consequences of any accident previously evaluated, (2) create the possibility of a new or different kind of accident from any accident previously evaluated, or (3) involve a significant reduction in a margin of safety. The proposed change has been evaluated against each of these criteria, and it has been determined that the change does not involve a significant hazard because:

(1) The proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

The DGs and their associated emergency loads are accident mitigating features, not accident initiating equipment. Therefore, there will be no impact on any accident probabilities by the approval of the requested amendment.

The design of plant equipment is not being modified by these proposed changes. As such, the ability of the DGs to respond to a design basis accident will not be adversely impacted by these proposed changes. The capability of the DG's to supply power in a timely manner will not be compromised by permitting performance of DG testing during periods of power operation. Additionally, limiting testing to only one DG at a time ensures that design basis requirements for backup power is met, should a fault occur on the tested DG. Therefore, there would be no significant impact on any accident consequences.

Based on the above, the proposed change to permit certain DG surveillance tests to be performed during plant operation will have no effect on accident probabilities or consequences.

(2) The proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

No new accident causal mechanisms would be created as a result of NRC approval of this amendment request since no changes are being made to the plant that would introduce any new accident causal mechanisms. Equipment will be operated in the same configuration with the exception of the plant mode in which the testing is conducted. This amendment request does not impact any plant systems that are accident initiators; neither does it adversely impact any accident mitigating systems.

Based on the above, implementation of the proposed changes would not create the possibility of a new or different kind of accident from any accident previously evaluated.

(3) The proposed change does not involve a significant reduction in the margin of safety.

Margin of safety is related to the confidence in the ability of the fission product barriers to perform their design functions during and following an accident situation. These barriers include the fuel cladding, the reactor coolant system, and the containment system. The proposed changes to the testing requirements for the plant DGs do not affect the operability requirements for the DGs, as verification of such operability will continue to be performed as required (except during different allowed Modes). Continued verification of operability supports the capability of the DGs to perform their required function of providing emergency power to plant equipment that supports or constitutes the fission product barriers. Consequently, the performance of these fission product barriers will not be impacted by implementation of this proposed amendment.

In addition, the proposed changes involve no changes to setpoints or limits established or assumed by the accident analysis. On this and the above basis, no safety margins will be impacted. Therefore, implementation of the proposed changes would not involve a significant reduction in a margin of safety.

Based upon the above analysis, the proposed change will not increase the probability or consequences of any accident previously evaluated, create the possibility of a new or different kind of accident from any accident previously evaluated, or involve a significant reduction in the margin of safety. Therefore, the proposed change meets the requirements of 10 CFR 50.92(c) and involves no significant hazard consideration.

5.2 Applicable Regulatory Requirements/Criteria

The license application provided sufficient information to demonstrate that the request does not alter compliance with any applicable regulatory requirement or criteria. The specific change requested only alters when certain surveillances may be performed, which has no impact on the design or safety function of the diesel generators or off-site power systems.

The Grand Gulf Nuclear Station's Updated Safety Analysis Report Chapter 8 Section 8.3.1.2 provides an analysis of the plant design against the various applicable regulatory requirements and criteria. A review of the submittal against 10 CFR 50, Appendix A, GDC 17 and 18 and Regulatory Guide 1.9 Revision 3, as the principal requirements, revealed continued compliance with regulations.

6.0 ENVIRONMENTAL CONSIDERATION

The proposed license amendment was evaluated against the criteria of 10 CFR 51.22 for environmental considerations. Since the proposed change involves no change to the design or operation of the facility, the proposed change (1) does not significantly increase individual or cumulative occupational radiation exposures, (2) does not significantly change the types or significantly increase the amount of effluents that may be released offsite, and (3) as discussed in this enclosure, does not involve a significant hazards consideration. Based on the foregoing, it has been concluded that the proposed Technical Specification change meets the criteria given in 10 CFR 51.22(c)(9) for categorical exclusion from the requirement for an Environmental Impact Statement.

ATTACHMENT 2 TO GNRO-2001/00083

PROPOSED TECHNICAL SPECIFICATION CHANGES
(MARK-UP)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.8	------------------NOTE------------------ This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. -- Verify manual transfer of unit power supply from the normal offsite circuit to required alternate offsite circuit.	 18 months
SR 3.8.1.9	------------------NOTES------------------ 1. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 2. If performed with DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. -- Verify each DG rejects a load greater than or equal to its associated single largest post accident load and engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed setpoint or 15% above nominal, whichever is lower.	 18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	-----------------NOTE----------------- This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. -------------------------------------- C Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 5000 V during and following a load rejection of a load ≥ 5450 kW and ≤ 5740 kW for DG 11 and DG 12 and ≥ 3300 kW for DG 13.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.13	-------------------NOTE------------------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- Verify each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; b. Generator differential current; and c. Low lube oil pressure for DG 11 and DG 12.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.17	-------------------NOTE------------------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency loads from offsite power.	18 months
SR 3.8.1.18	------------------NOTE-------------------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- Verify interval between each sequenced load block is within ± 10% of design interval for each automatic load sequencer.	18 months

(continued)

ATTACHMENT 3 TO GNRO-2001/00083

CHANGES TO TECHNICAL SPECIFICATION BASES PAGES
(PROPOSED MARK-UP)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

2) tripping its associated single largest load with the DG solely supplying the bus.

If this load were to trip, it would result in the loss of the DG. As required by IEEE-308 (Ref. 13), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For the Grand Gulf Nuclear Station the lower value results from the first criteria.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

INSERT A

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. NOTE 1 STATES: Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the 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.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load, i.e., maximum expected accident load, without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

INSERT A

This SR has been modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

INSERT A

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

The SR is modified by a Note. The reason for the Note is that performing the Surveillance removes a required DG from service. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the 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.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3) requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to the continuous rating of the DG, and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. An exception to the loading requirements is made for DG 11 and DG 12. DG 11 and DG 12 are operated for 24 hours at a load greater than or equal to the maximum expected post accident load. Load carrying capability testing of the Transamerica Delaval Inc. (TDI) diesel generators (DG 11 and DG 12) has been limited to a load less than that which corresponds to 185 psig brake mean effective pressure (BMEP). Therefore, full load testing is performed at a load ≥ 5450 kW but < 5740 kW (Ref. 15). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

INSERT A

~~This SR has been modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.~~ Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the 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.

SR 3.8.1.18

Under accident conditions, loads are sequentially connected to the bus by the load sequencing panel. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the bus power supplies due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the bus power supplies to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

(continued)

INSERT A

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related systems are aligned to another offsite source. This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

DG Unavailability During Surveillance Testing

	Surveillance Test Procedure/ Description	**Applicable CPS Technical Specification**	**Associated Unavailability**	**Comments regarding unavailability**
1	06-OP-1P75-R-3&4 (Division 1, 2 DG 11/12 Trips and Response to ECCS initiation Signal	SR 3.8.1.13	4.0 hrs/DG/cycle	Unavailability estimate is based on the average time to install LOCA signal and to conduct testing. The DG remains unavailable until the tests are completed.
2	06-OP-1P81-R-0001 (HPCS DG Trips and Response to ECCS Initiation Signal and 100% Load Reject	SR 3.8.1.13	4.0 hrs/DG/cycle	Unavailability estimate is based on the average time to install LOCA signal and to conduct testing. The DG remains unavailable until the tests are completed.
3	06-OP-1P75-R-3&4 & 06-1P81-R-0001 (Reject of Largest Load Test, Response to ECCS Initiation Signal and 100% Load Reject Test)	SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.17	8.0 hrs/DG/cycle	Unavailability estimate is based on the average time to install LOCA signal and to bar engine and check for moisture and complete testing.
			Total Unavailability Hours per cycle **12 hrs/DG/cycle**	Item 1 describes testing on Division I and II DG and item 2 describes testing on Division III DG. Item 3 describes testing on all three Divisions, therefore adding items 1 and 3 or 2 and 3 gives the total for unavailability hours per DG.