September 10, 2002

Mr. William A. Eaton
Vice President, Operations GGNS
Entergy Operations, Inc.
P. O. Box 756
Port Gibson, MS 39150

SUBJECT: GRAND GULF NUCLEAR STATION, ISSUANCE OF AMENDMENT RE: REMOVAL OF OPERATING MODE RESTRICTIONS FOR PERFORMING HIGH PRESSURE CORE SPRAY EMERGENCY DIESEL GENERATOR TESTING (TAC NO. MB4261)

Dear Mr. Eaton:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 155 to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1 (GGNS). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated February 19, 2002, as supplemented by letter dated July 17, 2002.

This amendment revises TS 3.8.1, "AC Sources - Operating," to remove all current Mode restrictions associated with testing the High Pressure Core Spray Diesel Generator 13 during normal operation. The proposed changes remove the restriction associated with Surveillance Requirements (SRs) that prohibit performing the required testing in Modes 1, 2, or 3. The specific SRs addressed in this amendment are: SR 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19.

A copy of our safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission’s next biweekly *Federal Register* notice.

Sincerely,

/RA/

David Jaffe, Senior Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-416

Enclosures:
1. Amendment No. 155 to NPF-29
2. Safety Evaluation

cc w/encls: See next page

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*SE input provided - no major changes made.

ACCESSION NUMBER: ML022280173 * * See previous concurrences

OFFICE	PDIV-1/PM	PDIV-1/LA	SPSB/SC**	EEIB/SC*	OGC**	PDVI-1/SC
NAME	DJaffe	MMcAllister forDJohnson	MRubin	CHolden	RWeisman	RAGramm
DATE	9/10/02	9/10/02	8/27/02	8/8/02	9/9/02	9/19/02

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ENTERGY OPERATIONS, INC.

SYSTEM ENERGY RESOURCES, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

ENTERGY MISSISSIPPI, INC.

DOCKET NO. 50-416

GRAND GULF NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 155
License No. NPF-29

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment filed by Entergy Operations, Inc. (the licensee) dated February 19, 2002, as supplemented by letter dated July 17, 2002, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment; and paragraph 2.C.(2) of Facility Operating License No. NPF-29 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 155 , are hereby incorporated into this license. Entergy Operations, Inc. shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance, and shall be implemented within 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Robert A. Gramm, Chief, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: September 10, 2002

ATTACHMENT TO LICENSE AMENDMENT NO. 155

FACILITY OPERATING LICENSE NO. NPF-29

DOCKET NO. 50-416

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3.8-9	3.8-9
3.8-10	3.8-10
3.8-13a	3.8-13a
3.8-15	3.8-15

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 155 TO FACILITY OPERATING LICENSE NO. NPF-29

ENTERGY OPERATIONS, INC., ET AL.

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

1.0 INTRODUCTION

By application dated February 19, 2002, as supplemented by letter dated July 17, 2002 (References 7.1 and 7.2, respectively), Entergy Operations Inc., et al. (EOI, Entergy, or the licensee), submitted a request for changes to the Grand Gulf Nuclear Station, Unit 1 (GGNS), Technical Specifications (TSs.) The supplemental letter dated July 17, 2002, provided clarifying information that did not change the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on April 30, 2002 (67 FR 21288).

This amendment would revise TS 3.8.1, "AC [Alternating Current] Sources - Operating," to remove all current Mode restrictions associated with testing the High Pressure Core Spray (HPCS) Diesel Generator (DG) 13 (HPCS DG or DG 13) during normal operation. The proposed changes would remove the restriction associated with Surveillance Requirements (SRs) that prohibits performing the required testing in Modes 1, 2, or 3. The specific SRs addressed in this amendment are: SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19.

2.0 REGULATORY EVALUATION

General Design Criterion (GDC)-17, "Electric Power Systems," of Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 requires, in part, that nuclear power plants have an onsite and offsite electric power system to permit the functioning of structures, systems, and components important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure, and the offsite system is required to be supplied by two physically independent circuits. In addition, these criteria require provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of a loss of power from the unit, the offsite transmission network, or the onsite power supplies. GDC-18, "Inspection and Testing of Electric Power Systems," requires that electric power systems important to safety be designed to permit appropriate inspection and testing.

Offsite power is supplied to the GGNS switchyard from the transmission network. Three electrically and physically separated circuits provide AC power to each of the 4.16 kiloVolt (kV) Engineered Safety Features (ESF) buses. The offsite AC electrical power sources are, to the extent practical, designed and located so as to minimize the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

The onsite standby power source for each 4.16 kVs 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. In the event of a loss of preferred power, the ESF electrical loads automatically connect to the DGs in sufficient time to provide for a 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*., the grid, and the onsite sources remain paralleled during the period of degraded grid conditions.

For Division I and II, prior to auto-connecting the DG to the ESF bus (*i.e.*, closing the DG output breaker), the breakers connecting the buses to the offsite sources are opened and all bus loads other than the 480 Volt (V) ESF load center feeders are tripped. The same signal that initiates the tripping of the offsite feeder breaker 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.

For Division III (HPCS DG), 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 power sources will not continue to operate in a parallel mode following receipt of either a LOCA or loss-of-offsite power (LOOP) 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, similar to the Division I and II designs, the preferred offsite source of power is lost. Following the receipt of a LOOP signal, the offsite feeder breaker will trip open and the HPCS DG output breaker will automatically close.

The staff finds that the licensee, in Sections 3 and 5.1 of Reference 7.1, identified the applicable regulatory requirements. The regulatory requirements that the staff considered in reviewing the proposed amendment are: 10 CFR Part 2, Section 2.101; 10 CFR 50.59; 10 CFR Part 50, Appendix A, GDC-17; 10 CFR Part 50, Appendix A, GDC-18; 10 CFR 50.90 regarding changes to TSs; and 10 CFR 50.92 for no significant hazards consideration.

3.0 TECHNICAL EVALUATION

The NRC staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendment, which are described in Sections 3, 4, and 5 of Reference 7.1. The detailed evaluation below will support the conclusion that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

3.1 Deterministic Evaluation

The HPCS power system is a self-contained system. The loads supplied by this system are only loads associated with Division III of the emergency core cooling system (ECCS). They consist of the HPCS pump, HPCS standby service water (SSW) pump, related motor operated valves, diesel support equipment, and Division III direct current equipment. Therefore, during the performance of the surveillance tests addressed in Reference 7.1, only Division III equipment is directly affected.

At the present time, SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19 contain Notes that prohibit performance of these SRs during Modes 1, 2, or 3. The stated reason for the Notes is that during power operation with the reactor being "critical," performance of these SRs could cause perturbations to the electrical distribution system that could challenge continued, steady state operation.

The staff requested that the licensee respond to the following questions:

1. Describe how SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19 are performed and state why performing these SRs during power operation does not cause any significant perturbation to the electrical distribution. In addition, describe how the LOOP and Spray Initiation (SI) signals are generated without disturbing operation.

2. SRs 3.8.11 and 3.8.19 require verification, on an actual or simulated LOOP signal and an actual or simulated LOOP in conjunction with an actual or simulated ECCS initiation signal, respectively, that HPCS DG supplies permanently connected and auto-connected loads for ≥ 5 minutes. Describe how the HPCS pump will be operated during these tests without disturbing plant operation.

3. SR 3.8.1.12 required that, on an actual or simulated ECCS initiation signal, emergency loads be auto-connected to the offsite power system. Describe how the HPCS pump will be operated from the offsite power system without disturbing plant operation.

The licensee provided their response in Reference 7.2, as described in Sections 3.1.1 through 3.1.5, herein.

3.1.1 SR 3.8.1.11

SR 3.8.1.11 requires, among other requirements, verification that on an actual or simulated LOOP signal the HPCS DG auto-starts from the standby condition and supplies power to permanently-connected and auto-connected loads for ≥ 5 minutes. SR 3.8.1.11 is performed with the bus lined up to ESF Bus 21 with breaker 152-1705 closed. During the surveillance, the HPCS pump is started and it recirculates water back to the suppression pool. A LOOP is simulated by tripping open the offsite power feeder breaker (152-2902). The Division III DG starts and restores bus voltage in less than 10 seconds. Flow is then adjusted to establish maximum current. All HPCS auxiliaries required during an emergency are verified to be operating. The HPCS pump is stopped after five minutes have elapsed.

3.1.2 SR 3.8.1.12

SR 3.8.1.12 requires, among other requirements, verification that on an actual or simulated ECCS initiation signal, each DG automatically starts from the standby condition and the emergency loads are automatically connected to the offsite power system. The licensee stated (Reference 7.2) that SR 3.8.1.12 is a simulation of a LOCA and can be performed when lined up to any of the ESF transformers. The LOCA signal is inserted by arming and depressing the

HPCS Manual Initiation Pushbutton. This causes the HPCS pump, the DG, and all associated auxiliaries to start. The pump is verified to run for ≥ 5 minutes. The HPCS pump and DG are then stopped.

3.1.3 <u>SR 3.8.1.16</u>

SR 3.8.1.16 requires verification that, upon simulated restoration of offsite power, each DG can be synchronized with the offsite power source while loaded with emergency loads, the loads can be transferred to the offsite power source, and the DG is then verified to return to a ready-to-load condition. This is performed following the LOOP test of SR 3.8.1.11. After the DG has started and accepted load following the LOOP test, the DG is synchronized to the offsite power. The DG load is reduced to about 350 kilo Watts (kW), effectively transferring the loads to the offsite power source. The DG output breaker is then tripped open and the DG is verified not to trip. The parameters required to demonstrate a ready-to-load condition are then verified and the DG is stopped.

3.1.4 <u>SR 3.8.1.19</u>

SR 3.8.1.19 requires, among other things, verification that on an actual or simulated LOOP signal in conjunction with an actual or simulated ECCS initiation signal, each DG, including the HPCS DG, automatically starts from standby condition and supplies power to permanently connected and automatically connected loads for ≥ 5 minutes. The licensee stated (Reference 7.2) that SR 3.8.1.19 simulates LOOP in conjunction with LOCA and is performed with bus 17AC lined up to ESF Transformer 12 and with Breaker 152-1704 closed. A signal simulating a LOCA (high drywell pressure) is inserted into the HPCS logic by use of a test switch. The offsite feeder breaker 152-1904 is simultaneously tripped to complete the LOOP/LOCA simulation. The HPCS auxiliaries required during an emergency are verified to be running. The HPCS pump is then overridden off to allow valve logic testing. The LOCA signal is reset. Another LOCA signal (low reactor water level) is then inserted into the HPCS logic using the test switch. The HPCS is verified to restart. After all required testing is complete, the HPCS pump and DG are stopped.

3.1.5 <u>Discussion - Deterministic Evaluation</u>

The licensee stated in Reference 7.2 that during the SR tests HPCS is operated on either the minimum flow line or the test return line. Both of these lines return to the suppression pool. This is not an abnormal mode of operation, as the system is designed to allow full flow testing in any mode of operation (Reference 7.3, Updated Final Safety Analysis Report, Sections 6.3.4.2.1, 7.3.1.1.1.3.9, and 7.3.2.1.2.3.1.10). Also, the licensee stated in Reference 7.2 that HPCS is tested quarterly to meet inservice testing (IST) SRs. During the IST, the pump is run at full flow conditions (approximately 7200 gallons per minute) for approximately 20 minutes. When performing SRs 3.8.1.19 and 3.8.1.12 on-line, the actual injection of the HPCS system into the reactor during the online test will be prevented by opening the breaker to the HPCS injection valve. During performance of SR 3.8.1.11, the HPCS system does not get an injection signal. A control room operator is typically assigned to perform the surveillance. The operator is cognizant of, and directs all activities associated with this testing, in accordance with the appropriate surveillance procedure. The restorations of all safety-related functions, including restoration of the injection valve to the “operable” status, are independently verified.

In response to the question as to why performing the above SRs during power operation does not cause any significant perturbation to the electrical distribution system, the licensee explained, in Reference 7.2, that the total emergency load for the HPCS bus is less than 3 megawatts. The HPCS pump starting load for SR testing on-line would not be significantly different from the starting load for the licensee's quarterly IST. Starting and stopping of a pump this size would be a normal load for the power grid. The normal power sources for the HPCS system are connected to the grid via the station service transformers upstream of the main generator output breakers and do not use the generator directly. GGNS has neither startup transformers nor fast bus transfers. The service transformers are only loaded to about half their capacity, of which the 3-megawatt load of HPCS is only a small portion (< 2 percent). As such, the load is very much like any other load on the grid and does not directly affect other onsite loads. During power operations, the voltage at the ESF buses is nearly equal to or only slightly more than the nominal value. One reason for this is the relatively low loading factor for the station service transformers. These transformers are only loaded to about half of their capacity. One reason for this is that according to Reference 7.3, Section 8.2.4, "Operating Limits," the nominal operating voltage at the 500 kV bus is 496 kV. This establishes the margin between the available bus voltages and the degraded voltage trips at 90 percent for the other divisions. The time delay features of Division I and II under voltage sensors (nine seconds for 90 percent degraded voltage) are designed to allow small, brief perturbations to settle out well before actual trips would occur. Any transients resulting from the performance of a load rejection test would be expected to be less than two seconds in duration and less than 2 percent in magnitude.

For any of the subject SRs, the LOOP and LOCA signals are generated only in the HPCS logic and only on the HPCS AC power supply (bus 17AC). The divisional logic trains of Division III prevent any interaction with the Division I and II trains. The LOOP signals generated by de-energizing bus 17AC do not affect the other two ESF trains. The Division III (HPCS) bus is completely independent from the Division I and II buses.

Based on the foregoing, the NRC staff concludes that the performance of SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19 is not more challenging to plant stability than performance of the IST which is conducted quarterly during power operation. Therefore, the operation of the HPCS, during the performance of these SRs, will not disrupt power operation.

3.1.6 Other Compensatory Measures/Restrictions

The licensee's approach to perform maintenance uses a protected division concept. This means that without special consideration, it allows work on only one division at a time. This administrative control provides additional assurance that only one division at a time is worked on, and helps eliminate inadvertent work on the other division.

In addition, the GGNS procedures contain precautions to minimize the 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 if this unlikely scenario were to occur, safe plant shutdown capability would still be assured with the two remaining DGs.

The GGNS TSs impose restrictions on the 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 the required features supported by the inoperable DG. 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 licensee’s Safety Function Determination Program, TS 5.5.10, requires protection against loss of safety function.

Additionally, the GGNS Plant Administrative Procedure 01-S-18-6 (Reference 7.4) provides procedures for conducting risk assessment for all maintenance performed while in Modes 1, 2, or 3. The purpose of Reference 7.4 is to ensure that a process is in place to assess the overall impact on plant risk and to manage the risk associated with equipment unavailability. This program implements the requirements of the Maintenance Rule, 10 CFR 50.65(a)(4). This program uses an Equipment-Out-Of-Service risk evaluation tool to assess the potential risk implications of planned or emerging work activities, and warn Planning and Scheduling/Outage personnel that plant risk goals are being approached or would be exceeded if work were allowed to be performed. The administrative controls contained in Reference 7.4 minimize any possibility of allowing work on redundant DGs. The risk evaluation tool contains a comprehensive model of important GGNS equipment and allows the licensee to evaluate the adverse effects of other maintenance activities and their impacts on DG maintenance. The administrative controls contained in Reference 7.4 minimize any potential to allow work on redundant DGs.

3.1.7 Conclusion-Deterministic Evaluation

Based on the above considerations, the staff concludes that the licensee has provided sufficient assurance that performing SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19 while at power, will not create a transient that could cause a perturbation on the GGNS electrical distribution system, disrupt power operation, or challenge the safety systems. For the same reasons, the staff also concludes that the proposed changes do not affect GGNS’s compliance with the requirements of GDC-17 and GDC-18. Therefore, the proposed changes are acceptable from a deterministic standpoint.

3.2 Probabilistic Risk Evaluation

The requested change (removal of Mode restrictions for testing the HPCS DG) is limited to Division III-related components due to the complicated nature of the surveillance tests involved for Division I and II. The licensee states that the risk of performing the required surveillance tests during power operation is not significantly greater than the risk associated with the performance of other DG surveillance tests required by the TSs but which are not prohibited from being performed during plant operation.

The following sections provide the probabilistic safety assessment (PSA or PRA) insights.

3.2.1 Internal Events

3.2.1.1 Tier 1

For the 24-hour HPCS DG test proposal at power, the licensee computed the annualized change in (Delta) Core Damage Frequency (CDF) for GGNS to be 6.45E-8/reactor-year (r-yr) (Reference 7.1), which is very small according to the guidelines of Regulatory Guide (RG) 1.174 (Reference 7.6). The annualized Delta Large Early Release Frequency (LERF), which is a fraction of the annualized Delta CDF, would also be very small according to the RG 1.177 (Reference 7.7) guidelines of less than 1.0E-7/r-yr.

The licensee computed the Incremental Conditional Core Damage Probability (ICCDP) to be 3.22E-8, which is significantly smaller than the Reference 7.7 guideline of 5.0E-7, indicating a very small quantitative impact. The Incremental Conditional Large Early Release Probability (ICLERP) is a fraction of the ICCDP, and is therefore small when compared to the Reference 7.7 guideline of 5.0E-8.

The above values of Delta CDF, ICCDP, and the acceptably small values of Delta LERF and ICLERP are reasonable and acceptable to the staff. There is also an unquantified risk reduction when the SR testing is not performed during the plant shutdown.

3.2.1.2 Tier 2

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, only one DG could be affected by an unstable power source system, although the licensee's analysis indicates that such instability is unlikely. 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. If this unlikely scenario were to occur, safe plant shutdown capability would still be assured with the two remaining DGs.

3.2.1.3 Tier 3: On-Line Risk Management

As stated in Section 3.1.6 above, Reference 7.4 provides procedures for conducting risk assessment for all maintenance performed while in Modes 1, 2, or 3. This accounts for assessment of the overall impact on plant risk, management of the risk associated with equipment unavailability, and implementation of the requirements of the Maintenance Rule, 10 CFR 50.65(a)(4). This would minimize any possibility of allowing work on redundant DGs and also would minimize the adverse effects of other maintenance activities and their impacts on DG maintenance.

3.2.1.4 PSA Quality

The original GGNS Individual Plant Examination was developed by the licensee with the assistance of Science Applications International Corporation and was submitted to the staff in 1992. It was revised in 1997, renamed, and issued as Reference 7.8, which used the results from PRA Model "GGNS PSA, Revision 1." An independent assessment of Reference 7.8 has been completed to ensure that it was comparable to other PSAs in use throughout the industry. This assessment applied the Self-Assessment Process developed as part of the Boiling Water Reactor Owners' Group (BWROG) PSA Peer Review Certification Program. The PSA Certification Team, which was a group of industry and utility experts selected by the BWROG, completed an inspection and review of the GGNS PSA in August 1997 and completed a PSA Peer Review certification report in October 1997 (Reference 7.9). The models and methodology used in Reference 7.9 were included in the PSA peer review certification. The quality of the PSA and completeness of the PSA documentation were also assessed. The Certification Team found that Reference 7.8 is fully capable of addressing issues requiring risk significance determination with a few enhancements.

Because the proposed changes to the TS for on-line SR testing of HPCS DG testing have only a small impact on total DG unavailability, according to the licensee, any enhancements made to the GGNS PSA are not expected to significantly impact the overall conclusions of the above evaluations. For the same reason, the staff has made the same conclusion.

3.2.2 External Events

By application dated November 15, 1995, the licensee submitted its Individual Plant Examination for External Events (IPEEE) for GGNS (Reference 7.10). In the IPEEE, fire was addressed using "Fire PRA" methods developed and described later in Reference 7.11 (GGNS was the pilot plant for the Electric Power Research Institute Guide), seismic impact was addressed using a "seismic margins" methodology, and other events were addressed by conforming to NUREG-0800 (Reference 7.12). EOI received the staff Safety Evaluation for the IPEEE by letter dated March 16, 2001, in which the staff concluded that seismic events, fires, high winds, floods, and other events were adequately addressed. Of the events considered, seismic and fire are the initiators with the most potential for an induced LOOP. LOOP is relevant to the proposed changes because of the potential increase in HPCS DG unavailability. The following paragraphs provide the detailed discussion of the external events evaluated by the staff.

3.2.2.1 Seismic

GGNS was identified in NUREG-1407 (Reference 7.13) as a reduced scope plant of low seismicity; accordingly, emphasis was placed on conducting seismic inspections for the IPEEE. Thus, the licensee did not make a direct determination of the LOOP due to seismic events as an initiator frequency, but estimated it as follows:

> ...Ceramic insulators for offsite power transformers tend to be the most vulnerable components in the offsite power system during a seismic event. NUREG/CR-4550 [Reference 7.14],...estimates the median peak ground acceleration at which these ceramic insulators are lost to be approximately 0.25 g. NUREG-1488 [Reference 7.15],...provides an estimate for annual probability of exceedance for peak ground acceleration of approximately 2E-5 for GGNS and a ground acceleration of 0.25 g....

The licensee thus estimates the seismic LOOP initiator frequency as 2.3E-3/yr. Even if the likelihood of non-recovery of offsite power were somewhat greater, given a seismic event, the seismic LOOP contribution would still be bounded by the normal LOOP scenario.

Based on this estimate and the relatively slight changes to the internal events PSA model, the licensee concludes that the impact of the proposed changes to seismic risk is very small. For the same reasons, the staff has made the same conclusion.

3.2.2.2 Fire

While the licensee uses PSA techniques to develop CDFs associated with internal fires, the IPEEE results are the results of screening analyses and therefore are not directly comparable to the CDF results from the internal event's PSA. The CDF values generated for the IPEEE were intended to show that the CDF is low enough that the vulnerability does not exist. The licensee did not develop the Fire PSA to the same level of detail as the internal events PSA. Therefore, the Fire CDF reported in the IPEEE should not be combined with, or directly compared with the internal events analysis. A review of the Fire PSA scenarios indicates that approximately 14.6 percent of the Fire CDF (1.3E-6/r-yr) is associated with a fire-induced LOOP event. This compares with a 42.5 percent contribution (2.3E-6/r-yr) from LOOP initiators for the base internal events PSA. These frequencies are relatively close, and since additional DG out-of-service time would primarily impact LOOP scenarios, the effect of the proposed change on Fire CDF would be expected to be similar to the impact on the corresponding internal events PSA CDF.

The staff concludes that, since the impact of the proposed change (removal of Mode restrictions for testing the HPCS DG) on internal events risk is well within the RG guidelines, there is no need for a quantitative evaluation of the impact on fire risk, which should also be within the RG guidelines.

3.2.2.3 High Winds and Tornados

Reference 7.10 states that all safety-related structures, other than the SSW system components, are protected against high winds, tornado wind loads, and tornado-generated missiles. The guidance in Reference 7.13 states that if a plant meets the Reference 7.12 criteria, high winds and tornados can be screened out as significant contributors to total CDF. The licensee made use of fairly recent tornado data for 10 years (1985 thru 1994). For the SSW components, a frequency assessment of tornado-generated missiles was performed. The licensee estimated this frequency to be 7.7E-9/r-yr. This frequency is substantially lower than the Reference 7.13 criterion of 1.0E-6/r-yr.

The staff concludes that the risk due to high winds and tornado-generated missiles is acceptable, conforming to the Reference 7.13 guidelines.

3.2.2.4 Conclusions - External Events

Based on discussions in Sections 3.2.2.1 through 3.2.2.3 above, the staff concludes that the external events results were reasonably complete and adequate considering the design and operation of the plant. The staff thus concludes that the aspects of seismic events, fires, and high winds and tornados (including missiles) were adequately addressed, and other external events were not of substantial consequence.

3.2.3 Conclusion - Probabilistic Risk Evaluation

The staff has reviewed the proposed amendment to remove the Mode restriction for performance of SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19 from a probabilistic assessment perspective. The staff concludes that the available risk insights and findings support the proposed change.

The staff concludes that the impact on plant risk of allowing the GGNS HCPS DG to undergo testing without Mode restrictions is very small for both internal and external events. The staff concludes that the proposed 24-hour HPCS DG testing without Mode restrictions is acceptable from a risk perspective.

3.3 TS Changes

The licensee has proposed to revise the TSs to reflect the deletion of Mode restrictions from SRs pertaining to testing of the HPCS DG to allow SR testing during reactor operation. The changes remove the restrictions in SRs 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19 that prohibit conducting the required testing of the DGs during reactor operating Modes 1, 2, or 3.

Based on the evaluation discussed in Sections 3.1 and 3.2 of this safety evaluation, the staff concludes that the above-described changes to the TSs are acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the State of Mississippi was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (67 FR 21288 published April 30, 2002). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES

7.1 GNRO-2002/00006, William A. Eaton (Entergy) letter to NRC, "License Amendment Request, Removal of Operating MODE Restrictions for Performing High Pressure Core Spray Emergency Diesel Generator Testing (LBDC-2002/003) Grand Gulf Nuclear Station, Unit 1," dated February 19, 2002.

7.2 GNRO-2002/00061, William A. Eaton (Entergy) letter to NRC, "Grand Gulf Nuclear Station, Unit 1, Supplement to Amendment Request, Response to Request for Additional Information Concerning High Pressure Core Spray Testing," dated July 17, 2002.

7.3 Grand Gulf Nuclear Station, Updated Final Safety Analysis Report (UFSAR).

7.4 GGNS Plant Administrative Procedure No. 01-S-18-6, "Risk Assessment of Maintenance Activities."

7.6 U.S. Nuclear Regulatory Commission, Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998.

7.7 U.S. Nuclear Regulatory Commission, Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998.

7.8 Entergy Operations Inc., Grand Gulf Nuclear Station Engineering Report No. GGNS-97-0014, "GGNS PRA Update Summary and Results Report," Rev. 0, July 30, 1997.

7.9 Engineering and Research, Inc., Report No. C1029701-3130/3, "Grand Gulf PSA Peer Review Certification Report," October 30, 1997.

7.10 GGNS Individual Plant Examination for External Events (IPEEE), November 1997.

7.11 Electric Power Research Institute, Technical Report 105928, "Fire PRA Implementation Guide," December 1995.

7.12 NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," 1975.

7.13 NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

7.14 NUREG/CR-4550, Vol. 4, Revision 1, Part 3, “Analysis of Core Damage Frequency, Peach Bottom Unit 2, Internal Events,” February 1999.

7.15 NUREG-1488, “Revised Livermore [Lawrence Livermore Laboratory] Seismic Hazard Estimates for Sixty-nine Nuclear Power Plants East of the Rocky Mountains,” July 1999.

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Date: September 10, 2002

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