March 14, 2003

Mr. Paul D. Hinnenkamp
Vice President - Operations
Entergy Operations, Inc.
River Bend Station
P. O. Box 220
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION, UNIT 1 - ISSUANCE OF AMENDMENT RE: REMOVAL OF OPERATING MODE RESTRICTIONS FOR PERFORMING EMERGENCY DIESEL GENERATOR TESTING (TAC NO. MB5093)

Dear Mr. Hinnenkamp:

The U. S. Nuclear Regulatory Commission (Commission) has issued the enclosed Amendment No. 133 to Facility Operating License No. NPF-47 for the River Bend Station, Unit 1. The amendment consists of changes to the Technical Specifications (TSs) in response to your application dated May 14, 2002, as supplemented by letters dated February 12 and 28, 2003.

The amendment modifies the surveillance requirements pertaining to the testing of the Division 3 standby emergency diesel generator (EDG). The change allows performance of required surveillance tests for the Division 3 EDG during any mode of plant operation (previously allowed only in modes 4 (Cold Shutdown) and 5 (Refueling)).

A copy of our related Safety Evaluation is enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Michael Webb, Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-458

Enclosures: 1. Amendment No. 133 to NPF-47
2. Safety Evaluation

cc w/encls: See next page

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**No legal objection
*SE Input Provided - no major changes made

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DATE	3/10/2003	3/12/03	3/10/03	11/20/02	14 March 2003	3/14/03

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ENTERGY GULF STATES, INC. **

AND

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-458

RIVER BEND STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 133
License No. NPF-47

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

   A. The application for amendment by Entergy Gulf States, Inc.* (the licensee) dated May 14, 2002, as supplemented by letters dated February 12 and 28, 2003, 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, as amended, 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 license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

---

* Entergy Operations, Inc. is authorized to act as agent for Entergy Gulf States, Inc., and has exclusive responsibility and control over the physical construction, operation and maintenance of the facility.

**Entergy Gulf States, Inc., has merged with a wholly owned subsidiary of Entergy Corporation. Entergy Gulf States, Inc., was the surviving company in the merger.

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-47 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 133 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. EOI 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 30 days from 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: March 14, 2003

ATTACHMENT TO LICENSE AMENDMENT NO. 133

FACILITY OPERATING LICENSE NO. NPF-47

DOCKET NO. 50-458

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
3.8-8	3.8-8
3.8-9	3.8-9
3.8-10	3.8-10
3.8-11	3.8-11
3.8-12	3.8-12
3.8-13	3.8-13
3.8-14	3.8-14

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 133 TO

FACILITY OPERATING LICENSE NO. NPF-47

ENTERGY OPERATIONS, INC.

RIVER BEND STATION, UNIT 1

DOCKET NO. 50-458

1.0 INTRODUCTION

By application dated May 14, 2002, as supplemented by letters dated February 12 and 28, 2003, Entergy Operations, Inc. (Entergy or the licensee) requested changes to the Technical Specifications (TSs) for the River Bend Station, Unit 1 (RBS). The supplemental letter dated February 12, 2003, provided additional information that clarified the application and the supplemental letter dated February 28, 2003, withdrew the requested change to the Note associated with Surveillance Requirement (SR) 3.8.1.8 to remove the Mode restrictions placed upon the manual transfer test for offsite circuits. The supplemental letters did not expand 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 June 25, 2002 (67 FR 42824).

The proposed changes would modify the TS SRs pertaining to the testing of the Division 3 standby emergency diesel generator (EDG) (EDG 1C, which is an independent source of onsite alternating current (AC) power dedicated to the high pressure core spray (HPCS) system). Specifically, Entergy requested to revise portions of TS 3.8.1, "AC Sources - Operating" to allow performance of the required surveillance tests for EDG 1C during any mode of plant operation, rather than as currently allowed only in Modes 4 (Cold Shutdown) and 5 (Refueling). The proposed changes impact tests performed to meet the following SRs and would apply only to EDG 1C:

– SR 3.8.1.9 --- Demonstrate that the EDG can reject its largest load while maintaining margin to the overspeed trip

– SR 3.8.1.10 --- Demonstrate that the EDG can reject its full load without tripping or its output voltage exceeding a specified limit

– SR 3.8.1.11 --- Verify the de-energization of emergency buses and EDG auto-start from standby configuration on an actual or simulated loss of offsite power (LOOP) signal

– SR 3.8.1.12 --- Verify EDG auto-start from standby configuration on an actual or simulated emergency core cooling system (ECCS) initiation signal

- SR 3.8.1.13 --- Demonstrate that the EDG automatic trips are bypassed on an actual or simulated ECCS initiation signal
- SR 3.8.1.16 --- Verify EDG synchronization with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power, transfer of all loads to offsite power source, and return to ready-to-load operation
- SR 3.8.1.17 --- Demonstrate that the EDG 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)
- SR 3.8.1.18 --- Verify that the load sequence time is within ± 10 percent of design for each load sequence timer
- SR 3.8.1.19 --- Verify the de-energization of emergency buses and that the EDG auto-starts from standby configuration on an actual or simulated LOOP in conjunction with an actual or simulated ECCS initiation signal.

2.0 REGULATORY EVALUATION

The U.S. Nuclear Regulatory Commission (NRC) staff finds that the licensee, in Section 5 of its submittal dated May 14, 2002, identified the applicable regulatory requirements. The regulatory requirements that the staff applied in its review of the application included General Design Criterion (GDC)-17, "Electric Power Systems," of Appendix A to Title 10 of the *Code of Federal Regulations* (CFR) Part 50 which 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 test ability to perform its safety function, assuming a single failure; the offsite system is required to supply power to the onsite electric distribution system by two physically independent circuits. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as the result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

The staff also considered GDC-18, "Inspection and Testing of Electric Power Systems," which requires that electric power systems important to safety be designed to permit appropriate inspection and testing.

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 4 and 5 of Attachment 1 to the licensee's submittal dated May 14, 2002. 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.

As described by the licensee's application dated May 14, 2002, the Class 1E AC distribution system at RBS supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kiloVolt (kV) Engineered Safety Feature (ESF) bus. Each ESF bus has two separate and independent offsite sources of power. Each ESF bus also has a dedicated onsite EDG. The ESF system of any two of the three divisions provides 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 RBS switchyard from the transmission network. From the switchyard, two electrically and physically separated circuits provide AC power to each 4.16 kV ESF bus. 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.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated EDG. An EDG 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 on an ESF bus degraded voltage or under-voltage signal. 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 LOCA.

The HPCS EDG has the capability to restore power quickly to the HPCS bus, in the event offsite power is unavailable, and to provide all required power for the startup and operation of the HPCS system, one standby service water pump motor, and miscellaneous auxiliaries associated with it. The HPCS EDG starts automatically on a LOCA signal from the plant protection system or under voltage on the HPCS 4.16 kV bus, and will be automatically connected to the HPCS bus when the plant preferred AC power supply is not available. The system has a full-flow test line to either the suppression pool or the condensate water storage tank, which allows testing without injecting into the reactor vessel.

3.1 Deterministic Evaluation

The proposed changes are based on the finding of both deterministic and probabilistic risk assessment. Although the licensee has demonstrated, based on a probabilistic safety assessment basis, that performing on-line surveillance testing at power would result in no significant increase in risk, the staff also reviewed the amendment from a deterministic approach as follows:

3.1.1 <u>SR 3.8.1.9 and SR 3.8.1.10</u>

SR 3.8.1.9 requires, at least once per 18 months, verification of each EDG's capability to reject a load greater than or equal to its associated single largest post accident load and, following load rejection, vertification that engine speed is maintained less than nominal plus 75 percent of the difference between nominal speed and the overspeed trip setpoint or 15 percent above nominal, whichever is lower. SR 3.8.1.10 requires, at least once per 18 months, verification that each EDG, operating at a power factor ≤ 0.9, does not trip and voltage is maintained ≤ 4784 Volts (V) for EDG 1A and EDG 1B, and ≤ 5400 V for EDG 1C during and following rejection of a load ≥ 3030 kiloWatts (kW) and ≤ 3130 kW for EDGs 1A and 1B, and ≥ 2500 kW and ≤ 2600 kW for EDG 1C. At the present time, these SRs contain Notes that prohibit performance of these SRs during Modes 1 and 2. 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 licensee proposes to perform these tests for the HPCS EDG during Modes 1 and 2.

The licensee states that, to perform these tests, the typical approach taken is to load the tested EDG to the required load (via offsite power) and then open the EDG output breaker. An alternate method for performing SR 3.8.1.9 is to trip the associated largest single load. Opening of the EDG output breaker separates the EDG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. The licensee indicates that the historical bus voltage data obtained from testing performed pursuant to these SRs for the Division 3 EDG has shown that the voltage drop which occurs is such that the voltage during the transient remains well above the minimum required voltage for plant loads and stabilizes within one second.

The staff requested that the licensee clarify to the staff how the perturbation during power operation is comparable to the previous test results, which were performed during shutdown when system voltages were relatively higher. In addition, the staff requested the licensee to demonstrate that the voltage drop on the safety bus after load rejection is well above the setpoints of degraded and loss of voltage relays.

The licensee provided their response in a supplemental letter dated February 12, 2003. The licensee stated that it has performed these surveillances in Mode 1 for unplanned events and found no indication of excess perturbation to the electrical distribution system that could challenge continued steady state operation. In addition, the licensee performed an on-line load reject analysis at the worst case anticipated grid voltage under double contingency grid conditions with RBS off-line per the latest system study. The grid voltage included the LOCA loading on the standby buses. In this extreme case, there was considerable margin between the final bus voltage and the degraded voltage setpoint. The licensee stated that there is a delay time of approximately one minute on the degraded voltage relay to allow the grid to recover. The loss of voltage relay has a three second time delay, whose calibration is checked every eighteen months. The loss of voltage relay is set at approximately 73 percent bus voltage. Thus, even with the worst case anticipated grid voltages, the expected bus voltage would remain above the degraded and under voltage relay setpoints.

Based on the above discussion and past performance of these tests, the staff concludes that the expected drop in bus voltage due to the proposed tests would still maintain the available voltage significantly above these settings, and that conducting these tests at power (Modes 1 and 2) will not cause significant perturbations in the electrical system or present any threat to the safety of the plant; therefore, the proposed changes are acceptable.

3.1.2 <u>SR 3.8.1.11 and SR 3.8.1.19</u>

SR 3.8.1.11 requires, at least once per 18 months, verification on an actual or simulated LOOP signal that each EDG automatically starts from standby conditions and supplies permanently connected and auto-connected shutdown loads for $\geq$ 5 minutes. SR 3.8.1.19 requires, at least once per 18 months, verification on an actual or simulated LOOP signal in conjunction with an actual or simulated ECCS initiation signal, respectively, that each EDG supplies permanently connected and auto-connected emergency loads for $\succ$ 5 minutes. At the present time, these SRs contain Notes that prohibit performance of these SRs during Modes 1, 2, or 3. The stated reason for the Notes is that performing the surveillances would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. The licensee proposes to perform these tests for the HPCS EDG during Modes 1, 2, or 3.

The licensee states that the HPCS can be tested at full flow with condensate storage tank water at any time during plant operation, except when the reactor vessel water level is low, when the condensate level in the condensate storage tank is below the reserve level, or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCS is being tested, the system returns automatically to the operating mode. Further, because the HPCS is a stand-alone system with its dedicated EDG and independent distribution system, there is minimal opportunity for the performance of these SRs to have any impact on other safety-related plant equipment and, due to the minimal size of the loads associated with the HPCS system, there is not any real potential for this testing to create a perturbation on the grid.

Since SR 3.8.1.11 and SR 3.8.1.19 require de-energization of the emergency bus, the staff was concerned that performing these surveillances during power operation would unnecessarily remove a required offsite power circuit from service or could perturb the electrical distribution system. The staff requested the licensee to clarify to the staff how LOOP and safety injection signals will be generated without disturbing plant operation. Also, since these surveillances require operation of the HPCS pump, the staff requested the licensee to clarify how HPCS will be operated during these tests without disturbing plant operation.

The licensee provided their response by supplemental letter dated February 12, 2003. The licensee stated that, due to the minimal size of the loads associated with the HPCS system, there is minimal potential for creating a perturbation on the grid. Test signals during the surveillance are generated by connecting an ECCS Test Switch to the HPCS Logic Test Receptacle on panel H13-P625. This panel is the HPCS instrumentation cabinet in the main control room. Additional test signals, such as service water pump initiation and loss of power signal are generated using calibration units for a specific function, and by manually tripping the HPCS bus supply breaker. The control logics associated with these tests are Division 3 only, and do not impact other divisional components.

The HPCS system is a stand alone system with a dedicated EDG and independent distribution system. The HPCS is designed and constructed to allow all active components to be tested during normal plant operation. The system has a full flow test line to either the suppression pool or the condensate water storage tank which allows testing without injecting into the reactor vessel. The only component that would not be tested during plant operation would be the HPCS injection motor operated valve (MOV). During testing, the HPCS pump is operated in test return configuration with its reactor vessel injection pathway isolated. During current off-line testing, this is done with the injection path manually isolated. As the manual isolation is located in the drywell, on-line testing would be performed with the injection line MOV closed and de-energized. This testing would be similar to quarterly in-service testing that is already performed during plant operation.

Based on the above discussion and past performance of these tests, the staff concludes that conducting these tests at power is not more challenging to plant stability than performance of the periodic HPCS system test, which is conducted quarterly during power operation. Therefore, the operation of the HPCS during the performance of these SRs will not disrupt power operation or cause any significant perturbations in the electrical system. Therefore, the proposed changes are acceptable.

3.1.3 SR 3.8.1.12 and SR 3.8.1.16

Currently, SR 3.8.1.12 requires, at least once per 18 months, verification on an actual or simulated ECCS initiation signal, that each EDG auto-start from standby configuration and operate for $\geq$ 5 minutes. SR 3.8.1.16 requires, at least once per 18 months, verification that each EDG can be synchronized with the offsite power source while loaded with emergency loads, and upon a simulated restoration of offsite power, transfer all loads to an offsite power source, and return to ready-to-load operation. At the present time, these SRs contain Notes that prohibit performance of these SRs during Modes 1, 2, or 3. For SR 3.8.1.12, the stated reason for the Note is that, during power operation with the reactor being “critical,” performance of this SR could cause perturbations to the electrical distribution system that could challenge continued, steady state operation. For SR 3.8.1.16, the stated reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. The licensee proposed to perform these tests for the HPCS EDG during Modes 1 or 2 for SR 3.8.1.12 and Modes 1, 2, or 3 for SR 3.8.1.16. The licensee provided the following justification for its request.

The licensee states that, since the HPCS system is a stand alone system with a dedicated EDG and independent distribution system, there is minimal opportunity for the performance of these SRs to have any impact on other safety-related plant equipment. Also, due to the minimal size of the loads associated with the HPCS system, there is minimal potential for creating a perturbation on the grid. Completed test results have shown that the important bus voltage parameters stay within prescribed limits. Therefore, the proposed changes are acceptable.

Based on the above discussion and past performance of these tests, the staff concludes that conducting these tests at power is not more challenging to plant stability than performance of the periodic HPCS system test, which is conducted quarterly during power operation. Therefore, the operation of the HPCS during the performance of these SRs will not disrupt power operation or cause any significant perturbations in the electrical system.

3.1.4 SR 3.8.1.13

Currently, SR 3.8.1.13 requires, at least once per 18 months, verification that the automatic trips for each of the EDGs are bypassed on an actual or simulated ECCS initiation signal, except engine overspeed and generator differential current, and that emergency automatic trips will trip the DG in an emergency. At the present time, this SR contains a Note that prohibits performance of this SR during Modes 1, 2, or 3. The stated reason for the Note is that performing the surveillance unnecessarily removes a required EDG from service. The licensee proposes to perform this test for HPCS DG during Modes 1, 2, or 3. The licensee provided the following justification.

The licensee stated that this test is performed by verifying that the non-emergency automatic trips do not trip the EDG (i.e., the associated lockout relay is not tripped). The only jumpers and signal simulation required is executed at the relay level in the EDG control circuitry such that only the associated EDG is affected during this surveillance. Further, this SR is not performed with the EDG paralleled to offsite power, and the unavailability of the EDG during the performance of this test is minimal. EDG unavailability mainly occurs when the EDG 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 EDG can then be available to start in an actual emergency situation. Since the test is conducted with the EDG 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.

Based on the above, the staff concludes that since this test is conducted with the EDG unloaded and isolated from the bus, performance of this SR during power operation will not pose any threat to the safety of the plant or cause any perturbations in the electrical system. Therefore, the proposed change is acceptable.

3.1.5 <u>SR 3.8.1.17 and SR 3.8.1.18</u>

Currently, SR 3.8.1.17 requires, at least once per 18 months, verification that, with an EDG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by returning the EDG to ready-to-load operation and automatically energizes the emergency loads from offsite power. SR 3.8.1.18 requires, at least once per 18 months, verification that the sequence timing is within ± 10 percent of design for each load sequencer timer. At the present time, these SRs contain Notes that prohibit performance of these SRs during Modes 1, 2, or 3. The stated reason for the Notes is that performing the surveillances would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. The licensee proposes to perform these tests for the HPCS EDG during Modes 1, 2, or 3. The licensee provided the following justification for this request.

The licensee states that, during performance of the test mode override test per SR 3.8.1.17, the availability of the EDG under accident conditions is unaffected. This test is typically performed in conjunction with the load rejection tests (while the EDG is paralleled with the offsite source) by simulating a LOCA signal to the EDG start circuitry, which causes the EDG output breaker to open as the EDG is returned to a ready-to-load condition. Similar to the tests performed for SR 3.8.1.9 and SR 3.8.1.10, opening the EDG output breaker separates the EDG 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 EDG is separated from the bus.

SR 3.8.1.18 verifies the sequence timing is within ±10 percent of the design for each load sequence timer. The licensee states that this timing data is collected during performance of the HPCS LOOP/LOCA surveillance per SR 3.8.1.19. The requested change to the Mode restrictions of SR 3.8.1.18 for Division 3 EDG will permit continued performance of this surveillance requirement during performance of the related SRs.

Based on the above information, the staff concludes that conducting these tests at power will not cause any significant perturbation to the electrical distribution system, or pose any threat to the safety of the plant operation; therefore, the performance of these SRs during power operation is acceptable.

3.1.6 Other Compensatory Measures/Restriction

The licensee's approach to perform maintenance uses a protected division concept. This means that, without special consideration, it only works 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.

In addition, the RBS procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, and degraded grid conditions when paralleling an EDG with offsite power. For example, during testing, only one EDG 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 EDG to be affected by an unstable offsite power system. Even if this unlikely scenario were to occur, plant safe shutdown capability would still be assured with the two remaining EDGs.

RBS TSs 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 the licensee to declare required features as inoperable when redundant required features are inoperable. 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 EDG inoperable. Additionally, the Safety Function Determination Program requires that the loss of safety function be protected against in accordance with TS 5.5.10.

Additionally, the RBS Plant Administrative Procedure, ADM-0096, "Risk Management Program Implementation and On-Line Maintenance Risk Assessment," provides procedures for conducting risk assessment for all maintenance activities 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 10 CFR 50.65(a)(4), "Requirements for monitoring the effectiveness of maintenance at nuclear power plants." This program uses a risk evaluation tool to assess the potential risk implications of planned or emergent work activities. This tool warns Planning and 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 EDGs.

3.1.7 Deterministic Conclusion

Based on the above considerations, the staff concludes that the licensee has provided sufficient assurance that performing SRs 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.13, 3.8.1.16, 3.8.1.17, 3.8.1.18, and 3.8.1.19 while at power will not create a transient that could cause any perturbation on the RBS electrical distribution system, disrupt power operation, and challenge the safety systems. For the same reasons, the staff also concludes that the proposed changes do not affect RBS's compliance with the requirements of GDC-17 and GDC-18; therefore, the proposed changes for the HPCS EDG are acceptable from a deterministic standpoint.

3.2 Risk Assessment Evaluation

The proposed on-line surveillance tests have the potential to increase risk by making the HPCS EDG unavailable to respond to an accident during testing. In addition, on-line testing could cause accident initiating events and safety equipment failure. Therefore, in evaluating the risk information submitted by the licensee, guidance provided in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and in RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," was followed. This guidance includes the assessment of the risk impact of the proposed change to ensure that the Commission's Safety Goal Policy Statement is satisfied and the plant risk does not increase unacceptably during any periods safety equipment is taken out of service for testing and/or maintenance. In addition, RGs 1.174 and 1.177 provide guidance for identifying and addressing potentially high risk configurations associated with the proposed changes, as well as guidance for implementing the proposed changes in accordance with an overall configuration risk management program (CRMP).

3.2.1 Quality of Risk Assessment

Entergy reviewed the various steps of the procedures followed in performing the surveillance tests for each of the SRs impacted by the proposed changes. The objective of this review was to (1) investigate the potential for accident initiating events as a result of the tests during plant operation at power, and (2) investigate the unavailability of equipment to perform its safety function during the proposed on-line testing. Such information, which was used in the assessment of the risk impact of the proposed TS changes, is summarized below:

– The proposed on-line surveillance tests make the HPCS EDG unavailable for responding to an accident only during portions of the testing. It was estimated that the HPCS EDG will be unavailable for a total of 12 hours while surveillance tests are conducted. Since the required frequency of the subject tests is once every 18 months, the unavailability of the HPCS EDG will increase by about eight hours per year.

– Accident initiating events, resulting from the proposed allowance to perform the HPCS EDG surveillance tests while the plant is operating at power, are unlikely as indicated by historical experience of similar tests (e.g., monthly EDG run tests are conducted on line by paralleling the EDG in test with offsite power). The performance of these tests do not cause any significant perturbations to the electrical distribution system due to (1) the configuration of the AC power supply and associated protection features, (2) industry and plant experience with the performance of similar on-line testing, (3) administrative controls that minimize plant risks, and (4) the low probability of a significant voltage perturbation during the very short interval of such tests. In addition, due to the minimal size of the loads associated with the HPCS system, there is not any real potential for the tests to create a perturbation on the grid. Furthermore, completed Division 3 test results have shown that the important bus voltage parameters stay within prescribed limits.

The risk impact of the proposed changes was assessed using the plant's probabilistic risk assessment (PRA) model with an eight-hour yearly increase in the HPCS EDG unavailability. The quality of the RBS PRA has been independently assessed according to the Boiling Water Reactor Owner's Group Peer Certification Program and found adequate for addressing issues associated with similar requests, such as issues associated with extending the Division 1 and 2 EDG completion time from 72 hours to 14 days. In addition, the dominant risk contribution of the HPCS EDG is associated with a small number of well understood station blackout accident sequences. Therefore, the overall quality of the plant PRA does not have a significant impact on the quality of the submitted risk assessment. Since the assessed risk impact is associated with internal events only, qualitative arguments are made to show that any contributions to risk from external events would not change significantly the results of the risk assessment. The staff finds that the submitted risk assessment is of adequate quality to be used in the risk-informed decision making regarding the proposed TS changes.

3.2.2 Risk Impact of the Proposed Change

An acceptable approach to risk-informed decision making is to show that the proposed changes to the TS meet several key principles (RG 1.174). One of these principles is to show that the proposed change results in an increase in risk, in terms of core damage frequency (CDF) and large early release frequency (LERF), which is small and consistent with the Commission's Safety Goal Policy Statement. Acceptance guidelines for meeting this principle are presented in RG 1.174.

The licensee used its PRA model of the plant and calculated an increase in CDF associated with the proposed changes of about 1.3E-8/year. This increase is significantly smaller than the RG 1.174 guidance of less than 1.0E-6/year for very small CDF increases. Consequently, the increase in LERF was not calculated since it is less than 1.3E-8/year (which is significantly smaller than the RG 1.174 guidance of less than 1.0E-7/year for very small LERF increases).

In addition to the increases in CDF and LERF, the incremental conditional core damage probability (ICCDP) and the incremental conditional large early release probability (ICLERP) were assessed. These quantities are a measure of the increase in probability of core damage and large early release, respectively, during portions of the test (i.e., 12 hours every 18 months) when the HPCS EDG will be unavailable.

- ICCDP: ~2E-8
- ICLERP: less than 2E-8

These values are smaller than the RG 1.177 guidance of 5E-7 for ICCDP and 5E-8 for ICLERP, respectively, outlined in RG 1.177.

3.2.3 Avoidance of High Risk Plant Configurations

The licensee provides a discussion in its submittal on existing requirements and restrictions, imposed when on-line testing and maintenance activities are performed on the electrical distribution system, which ensure that high risk plant configurations are avoided.

- 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 an inoperable EDG.

- RBS administrative controls provide for use of a “protected division concept” which, without special considerations, allows work on one division at a time.

- Procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, and degraded grid conditions when paralleling an EDG with offsite power. Such precautions include a provision that only one EDG at a time be operated in parallel with offsite power. This configuration provides sufficient independence of the onsite power sources from offsite power since only one EDG can be affected by an unstable offsite power system.

The staff finds that these requirements, restrictions, and precautions are adequate for preventing high risk plant configurations.

3.2.4 Risk-Informed Configuration Risk Management

The intent of the risk-informed configuration risk management is to ensure that plant safety is maintained and monitored when equipment is taken out of service to perform maintenance or testing. Licensees have programs in place to comply with 10 CFR 50.65(a)(4) to assess and manage risk from proposed maintenance activities. These programs can support licensee decision making regarding the appropriate actions to control risk whenever a risk-informed TS is entered.

3.2.5 Probabilistic Conclusion

The proposed changes in tests, performed to meet SRs of the HPCS EDG, will allow the HPCS EDG system to be almost completely tested during normal plant operation (currently allowed only in Modes 4 and 5). The staff expects the licensee to implement the proposed changes in accordance with existing requirements, and impose restrictions when on-line testing (listed in Section 3.2.3 above) and maintenance activities are performed on the electrical distribution system consistent with its procedures for complying with the requirements of 10 CFR 50.65(a)(4). The staff concludes that the results and insights of the risk analysis support the proposed changes.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Louisiana State official 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 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 42824, published June 25, 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

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