Entergy

Entergy Nuclear-South
River Bend Station
5485 U.S. Highway 61
P.O. Box 220
St. Francisville, LA 70775
Tel 225 381 4374
Fax 225 381 4872
phinnen@entergy.com

Paul D. Hinnenkamp
Vice President, Operations
River Bend Station

RBG-45950

May 14, 2002

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

SUBJECT: River Bend Station, Unit 1
Docket No. 50-458
License Amendment Request
LAR 2002-17, River Bend Nuclear Station Proposed Amendment of Facility Operating License to Remove Operating Mode Restrictions for Performing Emergency Diesel Generator Testing

Dear Sir or Madam:

Pursuant to 10CFR50.90, Entergy Operations, Inc. (Entergy) hereby requests the following amendment for River Bend Station, Unit 1. EOI requests modification of the River Bend Technical Specifications to revise several of the Surveillance Requirements (SRs) pertaining to testing of the Division 3 standby diesel generator (DG) and manual transfer test for offsite circuits. The proposed change would modify specific restrictions associated with these SRs that prohibit performing required testing in Modes 1, 2 or 3. The affected SRs are SR 3.8.1.8, SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.16, SR 3.8.1.17, SR 3.8.1.18, and SR 3.8.1.19.

The proposed change has been evaluated in accordance with 10CFR50.91(a)(1) using criteria in 10CFR50.92(c) and it has been determined that this change involves no significant hazards considerations. The bases for these determinations are included in the attached submittal.

The proposed change does not include any new commitments. The NRC has approved similar Technical Specification changes for other plants. For example, Perry and Clinton have each received similar license amendments on February 24, 1999, and October 2, 2000, respectively. Grand Gulf Nuclear Station has requested similar changes by letters dated November 15, 2001 and February 19, 2002.

Entergy Operations, Inc. requests that the effective date for this Technical Specification change to be within 30 days of approval. Although this request is neither exigent nor emergency, your prompt review is requested. RBS has identified this change as affecting activities planned during the upcoming refueling outage (RF11) and on that basis requests approval of this proposed change by January 31, 2003. The requested approval date and implementation period will enable RBS to optimize refueling outage planning and activities.

A001

If you have any questions or require additional information, please contact Greg Norris at 225-336-6391.

I declare under penalty of perjury that the foregoing is true and correct. Executed on May 14, 2002.

Sincerely,

Paul D. Hinnenkamp
Vice President, Operations
River Bend Station, Unit 1

PDH/GPN

Attachments:
1. Analysis of Proposed Technical Specification Change
2. Proposed Technical Specification Changes (mark-up)
3. Changes to TS Bases pages (For Information Only)

cc: U. S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011

NRC Senior Resident Inspector
P. O. Box 1050
St. Francisville, LA 70775

U.S. Nuclear Regulatory Commission
Attn: Mr. David J. Wrona MS O-7D1
Washington, DC 20555-0001

Mr. Prosanta Chowdhury
Program Manager – Surveillance Division
Louisiana Department of Environmental Quality
Office of Radiological Emergency Plan and Response
P. O. Box 82215
Baton Rouge, LA 70884-2215

Attachment 1

RBG-45950

Analysis of Proposed Technical Specification Change

SR 3.8.1.13: Revise to remove the MODE restriction from the Note for the Diesel Generator 1C only. This SR requires demonstrating that the DG automatic trips are bypassed on an actual or simulated ECCS initiation signal.

SR 3.8.1.16: Revise to remove the MODE restriction from the Note for the Diesel Generator 1C only. This SR requires verifying each DG synchronizes 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 returns to ready-to-load operation.

SR 3.8.1.17: Revise to remove the MODE restriction from the Note for the Diesel Generator 1C only. 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).

SR 3.8.1.18: Revise to remove the MODE restriction from the Note for the Diesel Generator 1C only. This SR verifies that the sequence time is within ± 10% of design for each load sequence timer.

SR 3.8.1.19: Revise to remove the MODE restriction from the Note for the Diesel Generator 1C only. This SR verifies, for Division 3, on an actual or simulated loss of offsite power in conjunction with an actual or simulated Emergency Core Cooling System (ECCS) initiation signal, the de-energization of emergency buses and that the DG auto-starts from standby configuration.

The MODE restrictions for SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.16, SR 3.8.1.17, SR 3.8.1.18 and SR 3.8.1.19 will remain applicable to Diesel Generator 1A and Diesel Generator 1B. The change will be affected by adding "not applicable to DG 1C" to the current Note.

The proposed changes to SRs 3.8.1.8, 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, 3.8.1.19 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 outage critical path time.

The Note in SR 3.8.1.8, currently read as follows: "This surveillance shall not be performed in Modes 1 or 2. However, credit may be taken for unplanned events that satisfy this SR." The Note for this SR will be revised to remove the mode restrictions from the first part of the note such that 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 3.8.1.8 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."

In summary, Entergy proposes to amend Technical Specification (TS) 3.8.1, "AC Sources - Operating" to remove the MODE restriction pertaining to the testing of the manual transfer of the unit power supply from normal to alternate offsite circuits in SR 3.8.1.8, and to make specific MODE restriction changes applicable to testing of the High Pressure Core Spray (HPCS) Diesel Generator 1C (DG 1C), only, within SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.11, SR 3.8.1.12, SR

3.8.1.13, 3.8.1.16, SR 3.8.1.17, SR 3.8.1.18 and SR 3.8.1.19. The changes will be affected by clarifying the current Notes to make them not applicable to Diesel Generator 1C.

These changes will allow the performance of all SRs for the Division 3 DG during any MODE of plant operation. This will allow greater flexibility in scheduling these SR and will allow the performance during non-outage times. Having a completely tested Emergency Core Cooling System available for the duration of a refueling outage will reduce the amount of system re-alignments and operator workload during an outage.

Since the proposed changes can provide significant reductions in outage critical path time, EOI is respectfully requesting review and approval of these amendments by January 31, 2003. This would support scheduling of these SRs before or after the outage 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 (TS) Bases Control Program."

3.0 BACKGROUND

River Bend 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 RBS consists of the offsite power sources and the onsite standby power sources, i.e., diesel generators (DGs) 1A, 1B and 1C. 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 River Bend Station 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 has two 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 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. A detailed description of the offsite power network and circuits to the onsite Class 1E ESF buses is found in Updated Safety Analysis Report, (USAR) Chapter 8.

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 on an ESF bus degraded voltage or under-voltage 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.

A detailed description of the onsite power network is found in Updated Safety Analysis Report, Chapter 8, section 8.3 " Onsite Power System".

The HPCS diesel generator 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 diesel generator starts automatically on a LOCA signal from the plant protection system or undervoltage 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 failure of this unit will not negate the capability of other power sources. There is no provision for automatic paralleling of the HPCS diesel generator with the auxiliary power or with standby power sources. Provisions for manual paralleling with normal power sources are made for loading the diesel generator during the exercise mode. A synchronous check relay is provided to prevent breaker closure during paralleling unless the busses are synchronized within the tolerances of the relay. If a LOCA signal occurs while the HPCS diesel generator is running in parallel with the normal bus, the diesel generator breaker will automatically trip. At least one interlock is provided to avoid accidental paralleling. There is no sharing of the HPCS power system with other standby diesel generators.

The HPCS is designed and constructed to allow all active components to be tested during normal plant operations. 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. These features, along with the design of the electrical distribution system, allow Entergy to make this request to remove the remaining restrictions from testing the HPCS DG.

By virtue of this request the HPCS DG and the HPCS System can almost be completely tested during normal plant operations. This on-line testing will minimize system manipulations and reduce operator workload during refueling outages. Having completed this testing during normal operations will eliminate approximately 12 hours of Operator intensive testing during an outage.

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 3.8.1.8, 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 River Bend 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 unavailable for responding to an accident during portions of the testing. DG unavailability during the proposed on-line testing is summarized in Section 4.9 Table 1. 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

River Bend 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 River Bend Station (RBS) 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. RBS 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 RBS Plant Administrative Procedure, ADM-0096 "Risk Management Program Implementation and On-line Maintenance Risk Assessment", 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 RBS equipment and allows the site to evaluate the adverse effects of other maintenance activities and its impact on DG maintenance.

4.4 Online Testing versus Outage Testing (SR 3.8.1.11, 12, 16 and 19)

The current Limiting Condition for Operations (LCO) for the HPCS DG is 72 hours but due to the relationship between the DG and the HPCS system, the Technical Specifications allow up to 14 days of inoperability if the Reactor Core Isolation Cooling system is not inoperable. This LCO provides ample time for the performance of the SR requested in this change request. The actual time needed to perform these SRs is approximately 12 hours. By virtue of the HPCS being a stand-alone system with its dedicated DG and independent distribution system, there is minimal opportunity for the performance of these SR 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 isn't any real potential for this testing to create a perturbation on the grid. Completed Division 3 test results have shown that the important bus voltage parameters stay within prescribed limits.

In comparing the Technical Specification requirements for ECCS and AC Sources during MODES 1, 2, or 3 and MODES 4 or 5, the requirements are more restrictive during MODES 1, 2, or 3. Due to the more restrictive criteria during MODES 1, 2, or 3, performing the testing during these MODES is supported by other ECCS systems if something should occur during the test.

As described in the USAR, Section 6.3.4.2.1 "HPCS Testing", 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, or 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.

4.5 Testing Pursuant to SR 3.8.1.8

SR 3.8.1.8 verifies the manual transfer of the unit power supply from the normal offsite circuit to the required alternate circuit. This is a manual operation only that is performed by synchronizing the alternate source to the divisional switchgear, closing the alternate source breaker, and then opening the normal supply breaker. The process is reversed to return to the normal source. Operators performing this test monitor running and incoming voltages during the synchronization to ensure that they are matched prior to breaker operation. This evolution has little impact on plant loads and the DGs are unaffected by the performance of this test. The power system loading during such testing is within the rating of all transformers, switchgear, and breakers.

4.6 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.

During operation at River Bend, the emergency buses are normally tied to the preferred station service transformers fed from the switchyard. This is the same configuration maintained during plant shutdown when the load reject testing is currently conducted. 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.

Historical bus voltage data from testing performed pursuant to these SR's for Division 3 DG full load reject 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 stabilizes within one second. Thus, the voltage transient experienced by loads on the affected bus is minor.

4.7 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 form in Section 4.9 Table 1.

4.8 Testing Pursuant to SR 3.8.1.17 and SR 3.8.1.18

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.

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.

SR 3.8.1.18 verifies the sequence timing is within ± 10% of design for each load sequence timer. This timing data is collected during performance of the HPCS Loss of Offsite Power/LOCA surveillance per SR 3.8.1.19. The requested change to the Mode restrictions of SR 3.8.1.18 for the Division 3 DG will permit continued performance of this surveillance requirement during performance of the related SRs.

4.9 Risk Assessment

During certain portions of the surveillances the Division 3 DG would not be able to immediately respond to an accident. Division 3 DG unavailability during the performance of the proposed on-line DG testing is summarized in Table 1, with the longest unavailability time of 8.0 hours. Based on this, the greatest Incremental Conditional Core Damage Probability (ICCDP) per RG 1.177 is determined as follows:

For the average maintenance model (as referenced in RG 1.177), the base core damage frequency for RBS is 3.39E-6 per year, based upon Revision 3A of the RBS Level 1 PRA which is being implemented Spring 2002. Estimates of the equivalent yearly core damage probability when the Division 3 DG is out of service (for the whole year) was made utilizing the Equipment Out Of Service (EOOS) software. It is also assumed that the Division 3 service water pump discharge valve, SWP-MOV40C, is OOS. This effectively makes the Division 3 service water pump unavailable. The HPCS injection valve, E22-MOVF004 is also assumed OOS, which effectively makes the HPCS pump OOS. Both the injection valve and the service water pump are considered unavailable while the Division 3 DG is OOS. With all three components OOS

and using EOOS the core damage frequency is 1.71E-5/yr. The Risk Achievement Worth (RAW) for the combination is 5.0.

Average CDF Increase

The average at-power CDF with the additional out of service time for all three components is computed by adding the CDF for the additional period during which they are out of service with the CDF for the remainder of the year. The change in CDF is calculated as follows:

$$\Delta CDF_{At-Power} = \frac{T_{Div3}}{T_{Year}}(CDF_{Div3}) + \left[1 - \frac{T_{Div3}}{T_{Year}}\right](CDF_{Base}) - CDF_{Base}$$

where,

CDF_{Div3} is the estimated yearly CDF with Division 3 DG, SWP-MOV40C, and E22-MOVF004 out of service.

T_{Div3} is the additional out of service time for the Division 3 DG, SWP-MOV40C, and E22-MOVF004 due to the proposed on line testing. This is estimated to be a total of 12 hours per cycle. On a yearly basis this number is 8 hours per year with the assumption of an 18 month cycle.

T_{Year} is the number of hours in a year (8760 hours).

CDF_{Base} is the baseline annual average CDF with the current average unavailability of the Division 3 DG and SWP-P2C. The Level 1 PRA model does not contain an unavailable basic event for MOVs. It only contains fail to open and fail to remain open basic events. In some cases there are fail to close basic events.

Therefore, the ΔCDF associated with this change is:

$$\Delta CDF_{At-Power} = \frac{8hrs}{8760hrs}(1.71E-5/yr) + \left[1 - \frac{8hrs}{8760hrs}\right](3.39E-6/yr) - 3.39E-6/yr$$

$$= 1.25E-8/yr$$

This value for ΔCDF is significantly smaller than the RG 1.174 guidance of less than 1.0E-6/year for very small CDF increases.

TABLE 1
DG Unavailability During Surveillance Testing

	Surveillance Test Procedure/Description	**Applicable CPS Technical Specification**	**Associated Unavailability**	**Comments regarding unavailability**
1	STP-309-0603 Div. III 18 Month ECCS Test	SR 3.8.1.13b	4.0 hrs/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	STP-309-0603 Div. III 18 Month ECCS Test	SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.17	8.0 hrs/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/cycle**	

ICCDP

The incremental conditional core damage probability (ICCDP) can be computed using the definition in RG 1.177. In terms of the above defined parameters, the definition of ICCDP associated with Division 3 DG out of service is as follows:

$$ICCDP_{Div3} = \frac{T_{Div3}}{8760hrs/yr}\left(CDF_{Div3} - CDF_{Base}\right)$$

The total increase on out of service time (12 hours) is used for this calculation.

$$ICCDP = \frac{12hrs}{8760hrs/yr}\left(1.71E-5/yr - 3.39E-6/yr\right)$$

$$= 1.88E\text{-}8$$

This value for ICCDP is significantly smaller than the RG 1.177 guidance of 5.0E-7 for a small quantitative impact.

<u>ΔLERF and ICLERP</u>

Calculation of ΔLERF and ICLERP are not necessary as these two are a fraction of ΔCDF and ICCDP and both ΔCDF and ICCDP are below the respective ΔLERF and ICLERP significance guidance from RG 1.174 and RG 1.177.

PSA Quality

The PSA model for RBS was first developed for the Individual Plant Examination (IPE) that was submitted to the NRC by letter RBG-38077 dated February 1, 1993 , in response to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities." The NRC staff issued its Safety Evaluation Report (SER) for the RBS IPE by letter RBC-47152 October 17,

1996, wherein the NRC staff concluded that the RBS IPE submittal met the intent of Generic Letter 88-20. No major weaknesses were identified.

An independent assessment of the RBS PSA, using the Self-Assessment Process developed as part of the Boiling Water Reactor Owners' Group (BWROG) PSA Peer Review Certification Program, was completed to ensure that the RBS PSA was comparable to other PSA programs in use throughout the industry. To this end, a PSA Certification Team completed an inspection and review of the RBS PSA in April 1998 and completed a PSA Certification Report in October 1998. Included in the PSA Certification review were the models and methodology used in the RBS PSA. The quality of the PSA and completeness of the PSA documentation were also assessed. The certification team found that the RBS PSA is fully capable of addressing issues such as those associated with extending the Division I and Division II EDG AOT from 72 hours to 14 days with a few enhancements. The RBS PSA has also benefited from subsequent plant reviews of the other BWR-6 plants. Additional information on the PSA Certification review has been provided to the NRC in RBS letters RBG-45832, "License Amendment Request (LAR) 2001-027, Emergency Diesel Generator Extended Allowed Outage Time" and RBG-45934, "Supplement to Amendment Request LAR 2001-027, Emergency Diesel Generator Extended Allowed Outage Time, TS 3.8.1."

External Events

Fire

As stated in NUREG-1407, the IPEEE was meant to be a vulnerability screening analysis rather than a full scope probabilistic risk assessment. While PSA techniques were used to develop core damage frequencies associated with internal fires, the results from the IPEEE are still screening analyses and therefore are not directly comparable to the CDF results from the IPE. The CDF values generated for the IPEEE are intended to show that the CDF is low enough that a vulnerability does not exist. The evaluation of external events and internal fires contains some very large uncertainties. In many cases, these uncertainties led to the application of conservative assumptions to bound the accident and prove that no vulnerabilities exist.

Taking the Division 3 DG, the HPCS pump, and the Division 3 Standby Service Water pump OOS for eight hours to complete the surveillances in Table 1 will not increase the unavailability of those components significantly. Therefore, it is reasonable to assume that the core damage frequency due to a fire will not change significantly because of the additional time that those components are OOS during the year. Therefore, fire risk impact is expected to be non-risk significant.

The Technical Specification LCO times are 14 days for the HPCS pump and 30 days for the Division 3 Standby Service Water pump. If the HPCS pump and the Standby Service Water pump are not operable then the Division 3 DG is not required to be operable. If these components are OOS for only 8 hours for the surveillance tests then the OOS time falls well within the LCO of 14 days. An 8 hour unavailability corresponds to an increase in unavailability on a yearly basis of 0.001. This is small compared to the NRC "Green" performance indicator for HPCS of 1.5% or the "Green" performance indicator for Emergency AC Power availability of 2.5%.

Seismic

Per the RBS IPEEE, "RBS is classified in NUREG-1407 as a reduced scope plant of low seismicity; therefore, emphasis was placed on conducting detailed seismic walkdowns." Since RBS did not perform a seismic PSA analysis for the IPEEE; the seismic LOOP initiator frequency was not previously determined. The likelihood of a seismic event at River Bend is on the order of 1E-5/yr (Ref. NUREG-1488). Maximum ground acceleration for both horizontal and vertical motion for the safe shutdown earthquake (SSE) is 0.1 g (RBS USAR Section 2.5.2.6). 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, Vol. 4, Rev. 1, Part 3, "Analysis of Core Damage Frequency, Peach Bottom Unit 2 External Events," estimates the median peak ground acceleration at which these ceramic insulators are lost to be approximately 0.25 g. Using this value, the conclusion can be reached that the seismic LOOP initiator is over an order of magnitude less than the LOOP initiating event frequency times the 4 hour non-recovery probability for AC power used in the base PSA model.

Industry experience also supports this conclusion. At least in recent history, seismic events appear to be a relatively minor contributor to the industry LOOP frequency. Evidence of this is provided in EPRI Report TR-110398, "Losses of Offsite Power at U.S. Nuclear Plants – Through 1997." This report records no LOOP events caused by seismic events, even though the database includes over a thousand years of unit operating experience and includes a period of time that had noteworthy earthquakes.

5.0 REGULATORY ANALYSIS

5.1 Applicable Regulatory Requirements/Criteria

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met. The application provides sufficient information to demonstrate that the request does not alter compliance with any applicable regulatory requirement or criteria. The River Bend Station USAR Chapter 8 Section 8.3.1.2 provides an analysis of the plant design against the applicable regulatory requirements. This change request affects the description of compliance to GDC 18 provided in USAR Section 8.3.1.2.2.1 in that Entergy is now proposing to perform the functional test during normal operations. Entergy has carefully reviewed the requirements of GDC 18 and has determined that it only defines that the electrical system be designed such that testing can be performed and does not stipulate when testing should be conducted.

Entergy has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the TS, and do not affect conformance with any GDC differently than described in the SAR.

5.2 No Significant Hazards Consideration

The proposed change will revise Technical Specification (TS) 3.8.1, "AC Sources – Operating" to modify Surveillance Requirements (SRs) pertaining to the testing of the Division 3 standby diesel generator (DG) and manual transfer test for offsite circuits. Specifically, changes will revise Technical Specification (TS) 3.8.1, "AC Sources – Operating" in order to modify specific

MODE restrictions for performance of Surveillance Requirements (SR) for the High Pressure Core Spray (HPCS) Diesel Generator 1C (DG 1C) and the SR which verifies the manual transfer of the unit power supply from the normal offsite circuit to the required alternate circuit. This would allow the performance of all SRs for the DG 1C during any MODE of plant operation. This will allow greater flexibility in scheduling these SRs and will allow the performance during non-outage times. Having a completely tested Emergency Core Cooling System available for the duration of a refueling outage will reduce the amount of system re-alignments and operator workload during an outage.

Entergy Operations, Inc. has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The DG and its 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 DG to respond to a design basis accident will not be adversely impacted by these proposed changes. The capability of the DG 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. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   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. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   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 DG do not affect the operability requirements for the DG, as verification of such operability will continue to be performed as required. Continued verification of operability supports the capability of the DG to perform its 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, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment(s) present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.3 Environmental Considerations

The proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

Attachment 2

RBG-45950

Proposed Technical Specification Changes (mark-up)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts from standby conditions and achieves: a. For DG 1A and DG 1B, steady state voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz, in ≤ 10 seconds. b. For DG 1C: 1. Maximum of 5400 V, and 66.75 Hz, and 2. Steady state voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz, in ≤ 13 seconds.	184 days
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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTE---------- 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 following load rejection, the engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is lower.	(Not applicable to DG 1C) 18 months
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. ---------- Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 4784 V for DG 1A and DG 1B and ≤ 5400 V for DG 1C during and following a load rejection of a load ≥ 3030 kW and ≤ 3130 kW for DGs 1A and 1B and ≥ 2500 kW and ≤ 2600 kW for DG 1C.	(Not applicable to DG 1C) 18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	(Not Applicable to DG 1C)
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions I and II; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ 3740 V and ≤ 4580 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ----------	(Not Applicable to DG 1C)
	Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. For DG 1C during the auto-start maintains voltage ≤ 5400 V and frequency ≤ 66.75 Hz; b. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves voltage ≥ 3740 V and ≤ 4580 V; c. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and d. Operates for ≥ 5 minutes.	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; and b. Generator differential current.	(Not applicable to DG1C) 18 months
SR 3.8.1.14	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG operating at a power factor ≤ 0.9, operates for ≥ 24 hours: a. For DG 1A and DG 1B loaded ≥ 3030 kW and ≤ 3130 kW; and b. For DG 1C: 1. For ≥ 2 hours loaded ≥ 2750 kW and ≤ 2850 kW, and 2. For the remaining hours of the test loaded ≥ 2500 kW and ≤ 2600 kW.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 1 hour loaded ≥ 3000 kW and ≤ 3100 kW for DG 1A and DG 1B, and ≥ 2500 kW and ≤ 2600 for DG 1C, or operating temperatures have stabilized, which ever is longer. Momentary transients outside of the load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts and achieves, in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	18 months
SR 3.8.1.16	----------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: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	(Not Applicable to DG 1C) 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.	(Not applicable to DG1C) 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 sequence time is within ± 10% of design for each load sequencer timer.	(Not applicable to DG 1C) 18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. 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, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions I and II; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, 2. energizes auto-connected emergency loads, 3. achieves steady state voltage ≥ 3740 V and ≤ 4580 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	18 months

(Not Applicable to DG 1C)

(continued)

Attachment 3

RBG-45950

Changes to Technical Specification Bases Pages

(For Information Only)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.4 and SR 3.3.5.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.5.1.4 and SR 3.3.5.1.5 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

(continued)

(Except for Division III which can be tested in any operational condition)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

The pump flow rates are verified with a pump differential pressure that is sufficient to overcome the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. The Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves in the flow path to their required positions. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

(Except for Division III which can be tested in any operational condition)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7

See SR 3.8.1.2

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit. The 18 month Frequency of the Surveillance is based on engineering judgment taking into consideration the 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 on the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. ~~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.~~ 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 corrective 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The referenced load for DG 1A is the 917.5 kW low pressure core spray pump; for DG 1B, the 462.2 kW residual heat removal (RHR) pump; and for DG 1C the 1995 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. 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 River Bend Station the lower value results from the first criteria. The 18 month frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

(Note 1 is not applicable to DG 1C)

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. 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 corrective 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

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 1.108 (Ref. 9) and is intended to be consistent with expected fuel cycle lengths.

(Note is not applicable to DG 1C)

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

2) Post corrective 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 1A and DG 1B. For DG 1C, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(Note 2 is not applicable to DG 1C)

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 corrective 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 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds for DG 1A and DG 1B and 13 seconds for DG 1C) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the 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.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 1A and DG 1B. For DG 1C, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. The reason for Note 2 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. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(Note 2 is not applicable to DG 1C)

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 corrective 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 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

are bypassed on an ECCS initiation test signal and critical protective functions trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide alarms on abnormal engine conditions. These alarms provide the operator with necessary information to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against 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.

(The Note is not applicable to DG 1C)

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 corrective 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 1.108 (Ref. 9), paragraph 2.a.(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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the respective DG to each required offsite power source can be made and that the respective DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the undervoltage logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

Portions of the synchronization circuit are associated with the DG and portions with the respective offsite circuit. If a failure in the synchronization requirement of the Surveillance occurs, depending on the specific affected portion of the synchronization circuit, either the DG or the associated offsite circuit is declare inoperable.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), and takes into consideration plant conditions required to perform the Surveillance.

(The Note is not applicable to DG 1C)

This SR is 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 corrective 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.13. The intent in the requirement associated with SR 3.8.1.18.b is to show that the emergency loading is not affected by the DG operation in 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.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(8); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

(Note is not applicable to DG 1C)

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

2) Post corrective 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 logic. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the bus power supply due to high motor starting currents. The 10% load sequence time tolerance ensures that sufficient time exists for the bus power supply to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. (Note that this surveillance requirement pertains only to the load sequence timer itself, and not to the interposing logic which comprises the remainder of the circuit.) 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 1.108 (Ref. 9), paragraph 2.a.(2); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

(Note is not applicable to DG 1C)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge 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 3.8.1.18 (continued)

2) Post corrective 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 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.12, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system 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.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

(Note 2 is not applicable to DG 1C)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 1A and DG 1B. For DG 1C, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from

(continued)