Entergy

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G3NO-2008-00014

November 5, 2008

U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Attention: Document Control Desk

DOCKET: No. 52-024

SUBJECT: Responses to NRC Requests for Additional Information, Letter No. 12 (GG3 COLA)

REFERENCE: NRC Letter to Entergy Nuclear, *Request for Additional Information Letter No. 12 Related to the SRP Sections 8.2 and 8.3 for the Grand Gulf Combined License Application*, dated October 7, 2008 (ADAMS Accession No. ML082810107).

Dear Sir or Madam:

In the referenced letter, the NRC requested additional information on sixteen items to support the review of certain portions of the Grand Gulf Unit 3 Combined License Application (COLA). The responses to the following Requests for Additional Information (RAIs) are provided in Attachments 1 through 16 to this letter as follows:

1. RAI Question 08.02-1, Capacity and Capability of Offsite Power System
2. RAI Question 08.02-2, Industry Standards for Switchyard
3. RAI Question 08.02-3, Multiple Facility Contingencies
4. RAI Question 08.02-4, Confirm Switchyard Voltage Limits
5. RAI Question 08.02-5, Testing and Surveillance Program
6. RAI Question 08.02-6, Grid Frequency Variation
7. RAI Question 08.02-7, GDC-5 Applicability
8. RAI Question 08.02-8, GDC-4 Applicability
9. RAI Question 08.02-9, GDC-2 Applicability

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10. RAI Question 08.02-10, BTP 8-5 Applicability
11. RAI Question 08.02-11, BTP 8-6 Applicability
12. RAI Question 08.02-12, Station Ground Grid Description
13. RAI Question 08.02-13, Surge and Lighting Protection Description
14. RAI Question 08.02-14, Effect of Addition of Unit 3 on Unit 1 Operation
15. RAI Question 08.02-15, Routing of Normal/Alternate Preferred Switchyard Control Power
16. RAI Question 08.03.02-1, SBO Response Procedures and Training

Should you have any questions, please contact me or Mr. Tom Williamson of my staff. Mr. Williamson may be reached as follows:

Telephone: (601) 368-5786

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E-Mail Address: twilli2@entergy.com

This letter contains commitments as identified in Attachment 17.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 5, 2008.

Sincerely,

WKH/ghd

Attachments:
1. Response to RAI Question No. 08.02-1
2. Response to RAI Question No. 08.02-2
3. Response to RAI Question No. 08.02-3
4. Response to RAI Question No. 08.02-4
5. Response to RAI Question No. 08.02-5
6. Response to RAI Question No. 08.02-6
7. Response to RAI Question No. 08.02-7
8. Response to RAI Question No. 08.02-8
9. Response to RAI Question No. 08.02-9
10. Response to RAI Question No. 08.02-10
11. Response to RAI Question No. 08.02-11
12. Response to RAI Question No. 08.02-12
13. Response to RAI Question No. 08.02-13
14. Response to RAI Question No. 08.02-14
15. Response to RAI Question No. 08.02-15
16. Response to RAI Question No. 08.03.02-1
17. Regulatory Commitments

cc (email unless otherwise specified:

Mr. T. A. Burke (ECH)
Mr. S. P. Frantz (Morgan, Lewis & Bockius)
Mr. B. R. Johnson (GE-Hitachi)
Ms. M. Kray (NuStart)
Mr. P. D. Hinnenkamp (ECH)

NRC Project Manager – GGNS COLA
NRC Director – Division of Construction Projects (Region II)
NRC Regional Administrator - Region IV
NRC Resident Inspectors' Office: GGNS

**ATTACHMENT 1**

**G3NO-2008-00014**

**RESPONSE TO NRC RAI LETTER NO. 12**

**RAI QUESTION NO. 08.02-1**

## RAI QUESTION NO. 08.02-1

### NRC RAI 08.02-1

Since all Grand Gulf units share the same switchyard, the offsite power system provided for Grand Gulf should have sufficient capacity and capability to safely shutdown all units. Operational experience as documented in various NRC generic communications (e.g., NRC Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients" NRC Information Notice 98-07, "Offsite Power Reliability Challenges from Industry Deregulation," and NRC Information Notice 95-37, "Inadequate Offsite Power Voltages During Design-Basis Events") have shown the need to demonstrate that the offsite power system operation can support equipment important to safety in order to avoid plant transients.

For example, NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," states that, "For NPPs licensed in accordance with the GDC in Appendix A to 10 CFR Part 50, the design criteria for onsite and offsite electrical power systems are provided in GDC 17... which requires, among other things, that an offsite electric power system be provided to permit the functioning of certain SSCs important to safety in the event of anticipated operational occurrences."

The staff requests that the applicant discuss the capacity and capability of the offsite system (i.e., the 500 kV lines and associated switchyard equipment) to mitigate the consequences of anticipated abnormal operational occurrences associated with unit operation.

### Entergy Response

The transmission network for the Grand Gulf Nuclear Station was evaluated under a System Impact Study (SIS) for interconnection of Unit 3 by the Southwest Power Pool (SPP), the Independent Coordinator of Transmission (ICT) for Entergy Transmission. The SIS, referenced in FSAR Section 8.2.2.1.1, was performed to verify load flow capability, short circuit capability, and system stability of the local transmission system in the vicinity of the Grand Gulf switchyard. The study was performed in accordance with the Entergy Open Access Tariff, which meets North American Electric Reliability Corporation (NERC) criteria. Individual cases are run to NERC Contingency Categories A, B, and C. This level of detail meets the specific requirements of Entergy Transmission Planning Guidelines and assures that the local transmission system, including the Grand Gulf switchyard, continues to be a reliable power source. This methodology also meets criteria provided by NERC and that referenced in Standard Review Plan 8.2, Section III.F.

For the SIS, General Electric-Hitachi (GEH) provided the estimated generator output and the plant operating load. The SIS followed specific criteria, such as:

- Loss of the GGNS unit
- Loss of any generating unit on the Entergy transmission grid
- Loss of any major transmission circuit

- Loss of any large load or block of load

These criteria are considered bounding for the anticipated abnormal operational occurrences identified in DCD Chapter 15.2.6. The Chapter 15 anticipated operating occurrences (AOO) include:

- Loss of feedwater heating
- Closure of one turbine control valve
- Generator load rejection with turbine bypass
- Generator load rejection with a single failure in the turbine bypass system
- Turbine trip with turbine bypass
- Inadvertent isolation condenser initiation

Specific upgrades to the transmission system were recommended by the SIS to ensure that Entergy interconnection criteria are met with the interconnection of Unit 3. The upgrades include expanding the existing 500 kV switchyard to accommodate Unit 3 and an additional 500 kV transmission line. Additionally, other transmission configuration changes are planned in order for the grid to accommodate the new 500 kV line and Unit 3. These upgrades are required to be installed prior to interconnecting Unit 3. Upon completing these system upgrades, the SIS finds that the transmission system is capable of accepting the interconnection of Unit 3 and of operating with the contingencies evaluated.

The DCD does not presently contain limits for voltage and frequency variation for site-specific offsite power systems. Analysis of the as-built onsite power system is performed to determine the load requirements during design basis operating modes. This analysis, in part, specifies required power, voltage, frequency, and interrupting capability necessary for the offsite power system to support safety-related load operation during design basis operating modes. This analysis will be accomplished as part of a site-specific ITAAC and will ensure that each as-built offsite circuit has sufficient capacity and capability. The exact wording of these ITAAC will be finalized and incorporated into the COLA following final development of the GDC 17 interface requirements that will be included in the DCD. These interface requirements are under development by GEH in response to DCD RAI 14.3-394 S1.

**Proposed COLA Revision**

None

ATTACHMENT 2

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-2

## RAI QUESTION NO. 08.02-2

### NRC RAI 08.02-2

COL Section 8.2.2.1.2, "Transmission System Monitoring and Analysis," discusses inspection, maintenance, and monitoring of switchyard components. The staff requests that the applicant discuss the industry (FERC, NERC, and IEEE) standards that will be followed for switchyard protection system, monitoring, maintenance and testing.

### Entergy Response

Monitoring, maintenance, and testing of the switchyard protection system are performed under NERC's Standard PRC-005-1, "Transmission and Generation Protection System Maintenance and Testing," Standard PRC-008-0, "Under Frequency Load Shedding Equipment Maintenance Program," and Standard PRC-017-0, "Special Protection System Maintenance and Testing."

### Proposed COLA Revision

FSAR Section 8.2.1.2.2 will include the information provided in this response as indicated in the attached draft markup.

**Markup of Grand Gulf COLA**

The following markup represents Entergy's good faith effort to show how the COLA will be revised in a future COLA submittal in response to the subject RAI. However, the same COLA content may be impacted by revisions to the ESBWR DCD, responses to other COLA RAIs, other COLA changes, plant design changes, editorial or typographical corrections, etc. As a result, the final COLA content that appears in a future submittal may be somewhat different than as presented herein.

Routine periodic switchyard testing activities include:

- Circuit breaker profile or timing tests
- Relay testing
- Battery discharge testing
- PT testing
- CCVT testing
- Arrester testing

Monitoring, maintenance and testing of the protection system is performed under NERC's Standard PRC-005-1, "Transmission and Generation Protection System Maintenance and Testing," Standard PRC-008-0, "Under Frequency Load Shedding Equipment Maintenance Program," and Standard PRC-017-0, "Special Protection System Maintenance and Testing."

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8.2.2.1 RELIABILITY AND STABILITY ANALYSIS

Replace this section with the following.

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GGNS COL 8.2.4-9-A
GGNS COL 8.2.4-10-A

Entergy is a member of the Southeastern Electric Reliability Council (SERC). The guidelines of SERC provide assurance that transmission systems that are part of the interconnected network are planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. These guidelines, along with North American Electric Reliability Corporation transmission planning guidelines, were followed in the design of the off-site power system to support Unit 3, and are adhered to during the ongoing operation of the plant.

In the history of its operation Unit 1 has not experienced a complete loss of off-site power source availability. Only one brief storm-related concurrent loss of the GGNS 500 kV Switching Station transmission source lines, Baxter Wilson and Franklin, occurred during this period. This event resulted in an upgrade of the carrier and protective relay schemes for these lines to provide greater availability of these sources to the station.

8.2.2.1.1 System Impact Study

A System Impact Study was conducted to assess the effect of Unit 3 on the reliability of the EES and to analyze the reliability of the off-site power supply for Unit 3.

ATTACHMENT 3

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-3

## RAI QUESTION NO. 08.02-3

### NRC RAI 08.02-3

Section 8.2.2.1.1 states that, "The analysis included worst case disturbances, as a result of a single event, such as loss of the largest generation capacity supplying the grid; removal of the largest load from the grid; and loss of the most critical transmission line." As referenced in SRP Section 8.2, operating experience has indicated that Palo Verde Nuclear Generating Station lost offsite power and all three units tripped on June 14, 2004. As a result of this operating experience, the staff requests the applicant to clarify whether the stability analysis identified for the Grand Gulf switchyard included tripping of both nuclear units. If the stability analysis did not include tripping of both nuclear units, then the staff requests that the applicant provide a discussion (including failure mode and effect analysis) of why an event similar to Palo Verde will not cause the loss of both units at Grand Gulf Station; or, provide a discussion illustrating that there will be no impact to grid stability should such an event occur.

### Entergy Response

The System Impact Study (SIS) referenced in COLA FSAR Section 8.2.2.1 was performed to verify load flow capability, short circuit capability, and system stability of the local transmission system in the vicinity of the Grand Gulf switchyard. The study was performed in accordance with NERC criteria. Individual cases are run to NERC Categories A, B, and C for No Contingency evaluations, N-1 evaluations, and N-2 evaluations, respectively. This level of detail meets the specific requirements of the Entergy Electric System (EES) and assures that the local transmission system, including the Grand Gulf switchyard, will continue to be a reliable power source. Grid studies are performed at least every three years and incorporate updated grid configurations and conditions. They also include multiple contingencies such as the unit trip combined with other concurrent transmission/generation contingencies to verify and confirm the adequacy of the grid sources following such events.

NERC Category B includes N-1 contingencies such as a single line-to-ground fault or a three-phase fault on a single transmission circuit, transformer, or generator with normal clearing. NERC Category C includes N-2 contingencies such as:

- Successive single line-to-ground faults or three-phase faults with normal clearing,
- Loss of two circuits on a common tower, or
- Single line-to-ground faults with delayed clearing on a single transmission circuit, transformer, or generator.

The reviewer asks to clarify that the analysis addressed multiple facility contingencies. The reviewer also included an example of a multiple facility contingency event as a trip of three nuclear units. NERC Category C is considered multiple facility contingencies. A NERC Category C case only considers tripping a single generator in conjunction with a stuck breaker or protection system failure. NERC Category D is considered an extreme event analysis and exceeds N-2. Analysis of a transmission system to NERC Category D is considered unusual. NERC Category D includes a case for loss of all generating units at a single station. The local transmission system that includes the Grand Gulf switchyard has not been evaluated for loss of all generating units as this is considered to be an extreme case and is outside of the requirements of Entergy Transmission planning.

A review of NRC Standard Review Plan (SRP) Section 8.2, Subsection III.1.F indicates that grid stability analyses should consider normal conditions, N-1 events, and N-2 events. Specifically, the SRP states that "the analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line. This could be the total output of the station, the largest station on the grid, or possibly several large stations if these use a common transmission tower, transformer, or a breaker in a remote switchyard or substation." The generating units at Grand Gulf do not use common transmission towers, transformers, or breakers. Therefore, extreme events represented in NERC Category D analyses are not applicable to Grand Gulf.

RG 1.206, Section C.III.8.2.1 states that a COL applicant should perform a failure modes and effects analysis (FMEA) of the switchyard components to assess the possibility of simultaneous failure of both offsite circuits as a result of a single failure. This analysis was completed and is discussed in FSAR Section 8.2.1.2.1.1.

With respect to reviewing operating experience, RG 1.206, Section C.III.1.9.4, states that COL applicants are required to demonstrate how operating experience insights from NRC generic communications issued after the most recent revision to the applicable SRP (March 2007) and 6 months before the submission of the COL application have been incorporated into the plant design. Operating experience from NRC generic communications prior to March 2007 is included into the applicable SRP section and, hence, requires no separate evaluation other than that required by the SRP. The FMEA and the offsite power stability analysis performed for Grand Gulf Unit 3 meets the acceptance criteria in SRP Section 8.2. Hence, no additional analysis is required.

In reference to the potential for the loss of both Grand Gulf Units in response to "an event similar to Palo Verde", the Entergy Transmission 500 kV system in the Grand Gulf area uses independent line relays, DC control power sources, and breaker trip coils that are not shared in the primary and backup protective relay systems (reference FSAR Sections 8.2.1.2.1.1 and 8.2.1.2.1.2). Either the primary or backup protective relay systems are independently capable of isolating a fault, such as a line fault similar to the "Palo Verde event" initiator, even if one protective relay system, control power supply, or breaker trip coil does not function. Therefore, the Grand Gulf Units are not susceptible to "an event similar to Palo Verde" from a single protective relay failure in response to a line fault.

**Proposed COLA Revision**

None

**ATTACHMENT 4**

**G3NO-2008-00014**

**RESPONSE TO NRC RAI LETTER NO. 12**

**RAI QUESTION NO. 08.02-4**

## RAI QUESTION NO. 08.02-4

### NRC RAI 08.02-4

Section 8.2.2.1 established maximum and minimum switchyard voltage limits of 525 kV and 491 kV. The staff requests that the applicant explain how these limits are established. In addition, please confirm that these voltage limits are acceptable for auxiliary power system equipment operation including safety-related battery chargers and safety-related uninterruptible power supplies during different operating conditions. The confirmation should include the following (assumptions, acceptance criteria, and summary of results) load flow analysis (bus and load terminal voltages of the station auxiliary system), short circuit analysis, equipment sizing studies, protective relay setting and coordination, motor starting with minimum and maximum grid voltage conditions. A separate set of calculations should be performed for each available connection to offsite power supply. In addition, please include a discussion of how the results of the calculations will be verified.

### Entergy Response

The Grand Gulf Unit 1 500 kV offsite power voltage must remain within the range 491 kV and 525 kV under post accident conditions. These minimum and maximum voltages were also used as the Unit 3 requirement because both units will use the same offsite power.

The maximum and minimum switchyard voltage limits of 525 kV and 491 kV referenced in FSAR Section 8.2.2.1 are based on current Unit 1 requirements for the Entergy Transmission system for the Grand Gulf 500 kV switchyard buses. The DCD does not presently contain limits for voltage and frequency variation that need to be met by site-specific offsite power systems. Analyses of the as-built onsite power system will be performed to determine the load requirements during design basis operating modes. This analysis will, in part, specify required power, voltage, frequency, and interrupting capability necessary for the offsite power system to support safety-related load operation during design basis operating modes. This analysis will be accomplished as part of a site-specific ITAAC and will ensure that each as-built offsite circuit has sufficient capacity and capability. The exact wording of these ITAAC will be finalized and incorporated into the COLA following final development of the GDC 17 interface requirements that will be included in the DCD. These interface requirements are under development by General Electric-Hitachi in response to DCD RAI 14.3-394 S1.

### Proposed COLA Revision

None

**ATTACHMENT 5**

**G3NO-2008-00014**

**RESPONSE TO NRC RAI LETTER NO. 12**

**RAI QUESTION NO. 08.02-5**

## RAI QUESTION NO. 08.02-5

### NRC RAI 08.02-5

Section 8.2.2.1.2 states that compliance with GDC 18 is achieved by designing testability and inspection capability into the system and then implementing a comprehensive testing and surveillance program. The staff requests that the applicant provide details regarding the testing and surveillance program for offsite power system components with respect to GDC 18.

### Entergy Response

The Grand Gulf offsite AC power system is designed for testability and inspection capability in accordance with GDC 18, as stated in DCD Sections 8.1.5.2.4 and 8.2.2.1.2.

The switchyard power circuit breakers, disconnects, and transmission line protective relaying are routinely inspected and tested to ensure continued reliable operation. Routine maintenance on power circuit breakers is performed to verify the manufacturer's tolerances for operation are not exceeded. Calibration checks of the protective relay systems in the switchyard are performed on routine intervals not to exceed two fuel cycles. Functional checks of relay and control equipment is also made on a two fuel-cycle interval. These inspections and test provide compliance with GDC 18 for the offsite power system components.

Monitoring, maintenance, and testing of the switchyard protection system are performed under NERC's Standard PRC-005-1, "Transmission and Generation Protection System Maintenance and Testing," Standard PRC-008-0, "Underfrequency Load Shedding Equipment Maintenance Program," and Standard PRC-017-0, "Special Protection System Maintenance and Testing."

### Proposed COLA Revision

FSAR Section 8.2.1.2.2, "Testing and Inspection," will be added for switchyard testing activities as indicated in the attached draft markup.

**Markup of Grand Gulf COLA**

The following markup represents Entergy's good faith effort to show how the COLA will be revised in a future COLA submittal in response to the subject RAI. However, the same COLA content may be impacted by revisions to the ESBWR DCD, responses to other COLA RAIs, other COLA changes, plant design changes, editorial or typographical corrections, etc. As a result, the final COLA content that appears in a future submittal may be somewhat different than as presented herein.

dual cable tray systems in the control building and dual cable trenches in the transformer area.

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8.2.1.2.1.3 Transmission System Operator Agreement

GGNS SUP 8.2-1 Prior to fuel load, the licensee will establish an agreement with the Transmission System Operator (TSO) to address switchyard and transmission interface issues, including the following items:

- Exclusion Area control, switchyard access, and security
- Operation of equipment and activities performed in the switchyard
- Maintenance of switchyard equipment
- Coordination of planned plant outages and activities directly affecting power supply to GGNS
- Review and approval of changes which might affect compliance with regulatory requirements and commitments which could affect off-site power supply to GGNS
- Procedures and training on the critical need for power at GGNS during emergencies

Entergy Mississippi Inc. is responsible for the maintenance of the GGNS switchyard and transmission equipment.

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GGNS SUP 8.2-3 8.2.1.2.2 Testing and Inspection

Transmission lines are inspected via an aerial inspection program approximately twice per year. The inspection focuses on such items as right-of-way encroachment, vegetation management, conductor and line hardware condition, and the condition of supporting structures.

Routine periodic switchyard inspection activities include:

- Inspections of circuit breakers and batteries
- Inspection of substation equipment
- Infrared scans

Routine periodic switchyard testing activities include:

- Circuit breaker profile or timing tests
- Relay testing
- Battery discharge testing
- PT testing
- CCVT testing
- Arrester testing

Monitoring, maintenance and testing of the protection system is performed under NERC's Standard PRC-005-1, "Transmission and Generation Protection System Maintenance and Testing," Standard PRC-008-0, "Underfrequency Load Shedding Equipment Maintenance Program," and Standard PRC-017-0, "Special Protection System Maintenance and Testing."

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8.2.2.1 RELIABILITY AND STABILITY ANALYSIS

Replace this section with the following.

---

GGNS COL 8.2.4-9-A
GGNS COL 8.2.4-10-A

Entergy is a member of the Southeastern Electric Reliability Council (SERC). The guidelines of SERC provide assurance that transmission systems that are part of the interconnected network are planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. These guidelines, along with North American Electric Reliability Corporation transmission planning guidelines, were followed in the design of the off-site power system to support Unit 3, and are adhered to during the ongoing operation of the plant.

In the history of its operation Unit 1 has not experienced a complete loss of off-site power source availability. Only one brief storm-related concurrent loss of the GGNS 500 kV Switching Station transmission source lines, Baxter Wilson and Franklin, occurred during this period. This event resulted in an upgrade of the carrier and protective relay schemes for these lines to provide greater availability of these sources to the station.

8.2.2.1.1 System Impact Study

A System Impact Study was conducted to assess the effect of Unit 3 on the reliability of the EES and to analyze the reliability of the off-site power supply for Unit 3.

ATTACHMENT 6

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-6

## RAI QUESTION NO. 08.02-6

### NRC RAI 08.02-6

Section 8.2.2.1.1 states that grid frequency must be maintained between 57 and 61.8 Hz. The staff requests that the applicant discuss how the auxiliary power system studies consider the combined effect of frequency and voltage variation on the operation of auxiliary power system equipment including safety-related battery chargers and safety-related UPS.

### Entergy Response

The maximum and minimum switchyard frequency limits referenced in FSAR Section 8.2.2.1 are based on current Unit 1 requirements for the Entergy Transmission system for the Grand Gulf 500 kV switchyard buses.

The DCD does not presently contain limits for voltage and frequency variation that need to be met by the site-specific offsite power systems. Analyses of the as-built onsite power system will be performed to determine the load requirements during design basis operating modes. This analysis will, in part, specify required power, voltage, frequency, and interrupting capability necessary for the offsite power system to support safety-related load operation during design basis operating modes. This analysis will be accomplished as part of a site-specific ITAAC and will ensure that each as-built offsite circuit has sufficient capacity and capability. The exact wording of these ITAAC will be finalized and incorporated into the COLA following final development of the GDC 17 interface requirements that will be included in the DCD. These interface requirements are under development by General Electric-Hitachi in response to DCD RAI 14.3-394 S1.

### Proposed COLA Revision

None

ATTACHMENT 7

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-7

## RAI QUESTION NO. 08.02-7

### NRC RAI 08.02-7

FSAR Chapter 1, Table 1.9-201, "Conformance with Standard Review Plan," for SRP Section 8.2, indicates GDC-5 is not applicable. The ESBWR DCD, Rev. 4, Section 8.2.2.2 states that the ESBWR Reference Plant is designed as a single-unit plant; therefore, GDC-5 is not applicable. However, the staff notes that Grand Gulf Unit 3 switchyard is shared with Grand Gulf Unit 1; and therefore, GDC-5 is applicable. The staff requests that the applicant address this issue and provide a discussion on how they meet GDC-5.

### Entergy Response

GDC 5 states that "(s)tructures, systems, and components important to safety (emphasis added) shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units." The offsite power system for an ESBWR is not important-to-safety [safety-related or safety-significant Regulatory Treatment of Non-Safety Systems (RTNSS)] based on the system classifications and risk analysis performed in the ESBWR DCD. Specifically:

- DCD Table 3.2-1, "Classification Summary," specifies that the switchyard is non-safety class.
- DCD Section 8.2.1.2, "Offsite Power System," states that the offsite power system is a non-safety-related system.

Furthermore, in SECY-94-084, "Policy and Technical Issues Associated With the Regulatory Treatment Of Non-Safety Systems In Passive Plant Designs," the staff determined to resolve the electrical distribution issues on passive advanced light water reactor (ALWR) designs by evaluating the AC power system features using the process defined for resolving RTNSS. The ESBWR DCD has evaluated offsite power for RTNSS and determined that it does not warrant treatment as RTNSS. DCD Section 19A.4.3.4 states that structures, systems, and components (SSCs) within the ESBWR design scope for preventing a loss of preferred power (LOPP) initiating event are not risk-significant and do not warrant additional regulatory oversight. Analysis of the Grand Gulf offsite power system has shown that its reliability (as measured by overall LOPP frequency) is within that assumed for the standard ESBWR plant probability risk analysis (refer to Entergy Letter dated 10/1/08 response to RAI 19-2).

The certified AP1000 DCD, another passive plant, also considers GDC 5 not applicable to offsite power (refer to AP1000 DCD, Revision 16, Table 8.1-1).

Based on the ESBWR DCD system classifications, offsite power is not important to safety and, therefore, Entergy has concluded that GDC 5 is not applicable to the offsite power system. If the NRC staff believes the DCD classification for offsite power is not appropriate, Entergy believes the staff should pursue this issue with General Electric-Hitachi.

Therefore, the applicability statement for SRP Section 8.2, Acceptance Criteria 3 (GDC 5) in FSAR Table 1.9-201 is correct as written.

**Proposed COLA Revision**

None

ATTACHMENT 8

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-8

## RAI QUESTION NO. 08.02-8

### NRC RAI 08.02-8

FSAR Chapter 1, Table 1.9-201, "Conformance with Standard Review Plan," for SRP Section 8.2, indicates GDC-4 is not applicable. However, RG-1.206 call for the applicant to demonstrate conformance with GDC-4. The staff requests that the applicant provide a discussion on how they meet GDC-4 or provide regulatory basis for not meeting GDC-4.

### Entergy Response

GDC 4 states that "(s)tructures, systems, and components important to safety (emphasis added) shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents." The offsite power system for an ESBWR is not important-to-safety [safety-related or safety-significant Regulatory Treatment of Non-Safety Systems (RTNSS)] based on the system classifications and risk analysis performed in the ESBWR DCD. Specifically:

- DCD Table 3.2-1, "Classification Summary," specifies that the switchyard is non-safety class.
- DCD Table 8.1-1 specifies that GDC 4 is not applicable to the offsite power system.
- DCD Section 8.2.1.2, "Offsite Power System," states that the offsite power system is a non-safety related system.

Furthermore, in SECY-94-084, "Policy and Technical Issues Associated With the Regulatory Treatment Of Non-Safety Systems In Passive Plant Designs" the staff determined to resolve the electrical distribution issues on passive advanced light water reactor (ALWR) designs by evaluating the AC power system features using the process defined for resolving RTNSS. The ESBWR DCD has evaluated offsite power for RTNSS and determined that it does not warrant treatment as RTNSS. DCD Section 19A.4.3.4 states that structures, systems and components (SSCs) within the ESBWR design scope for preventing a loss of preferred power (LOPP) initiating event are not risk-significant and do not warrant additional regulatory oversight. Analysis of the Grand Gulf offsite power system has shown that its reliability (as measured by overall LOPP frequency) is within that assumed for the standard ESBWR plant probability risk analysis (refer to Entergy Letter dated 10/1/08 response to RAI 19-2).

The certified AP1000 DCD, another passive plant, also considers GDC 4 not applicable to offsite power (refer to AP1000 DCD, Revision 16, Table 8.1-1).

Based on the ESBWR DCD system classifications, offsite power is not important to safety, and, therefore, Entergy has concluded that GDC 4 is not applicable to the offsite power system. If the NRC staff believes the DCD classification for offsite power is not appropriate, Entergy believes the staff should pursue this issue with General Electric-Hitachi.

Nevertheless, the offsite power system and offsite transmission network are of robust design in accordance with Entergy transmission system standards that employ "good utility practices", and are based, in part, on consensus industry standards ( IEEE, ANSI, etc.) for performance requirements relative to exposure to various environmental conditions. The offsite power system and offsite transmission network are also designed to meet the requirements of the National Electrical Safety Code (NESC).

Therefore, the applicability statement for SRP Section 8.2, Acceptance Criteria 2 (GDC 4) in FSAR Table 1.9-201 is correct as written.

**Proposed COLA Revision**

None

ATTACHMENT 9

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-9

## RAI QUESTION NO. 08.02-9

### NRC RAI 08.02-9

FSAR Chapter 1, Table 1.9-201, "Conformance with Standard Review Plan," for SRP Section 8.2, indicates that GDC-2 is not applicable. However, RG-1.206 calls for the applicant to demonstrate conformance with GDC-2. The staff requests that the applicant clarify their conformance with GDC-2 as it relates to structures, systems, and components of the offsite power systems being capable of withstanding the effects of natural phenomena (excluding seismic, tornado, and flood) without the loss of the capability to perform their safety functions or provide regulatory basis for not conforming to GDC-2.

### Entergy Response

GDC 2 states that "(s)tructures, systems, and components important to safety (emphasis added) shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions." The offsite power system for an ESBWR is not important-to-safety [safety-related or safety-significant Regulatory Treatment of Non-Safety Systems (RTNSS)] based on the system classifications and risk analysis performed in the ESBWR DCD. Specifically:

- DCD Table 3.2-1, "Classification Summary," specifies that the switchyard is non-safety class and Seismic Category NS.
- DCD Table 8.1-1 specifies that GDC 2 is not applicable to the offsite power system.
- DCD Section 8.2.1.2, "Offsite Power System," states that the offsite power system is a non-safety related system.

Furthermore, in SECY-94-084, "Policy and Technical Issues Associated With the Regulatory Treatment Of Non-Safety Systems In Passive Plant Designs" the staff determined to resolve the electrical distribution issues on passive advanced light water reactor (ALWR) designs by evaluating the AC power system features using the process defined for resolving RTNSS. The ESBWR DCD has evaluated offsite power for RTNSS and determined that it does not warrant treatment as RTNSS. DCD Section 19A.4.3.4 states that structures, systems, and components (SSCs) within the ESBWR design scope for preventing a loss of preferred power (LOPP) initiating event are not risk-significant and do not warrant additional regulatory oversight. Analysis of the Grand Gulf offsite power system has shown that its reliability (as measured by overall LOPP frequency) is within that assumed for the standard ESBWR plant probability risk analysis (refer to Entergy Letter dated 10/1/08, response to RAI 19-2).

The certified AP1000 DCD, another passive plant, also considers GDC 2 not applicable to offsite power (refer to AP1000 DCD, Revision 16, Table 8.1-1).

Based on the ESBWR DCD system classifications, offsite power is not important-to-safety, and, therefore, Entergy has concluded that GDC 2 is not applicable to the offsite power system. If the NRC staff believes the DCD classification for offsite power is not appropriate, Entergy believes the staff should pursue this issue with General Electric-Hitachi.

Nevertheless, the offsite power system and offsite transmission network are of robust design in accordance with Entergy transmission system standards that employ "good utility practices", and are based, in part, on consensus industry standards ( IEEE, ANSI, etc.) for performance requirements relative to exposure to various environmental conditions, such as wind, precipitation (e.g., rain, ice and snow), lightning and temperature variation. The offsite power system and offsite transmission network are also designed to meet the requirements of the National Electrical Safety Code (NESC).

Therefore, the applicability statement for SRP Section 8.2, Acceptance Criteria 1 (GDC 2) in FSAR Table 1.9-201 is correct as written.

**Proposed COLA Revision**

None

**ATTACHMENT 10**

**G3NO-2008-00014**

**RESPONSE TO NRC RAI LETTER NO. 12**

**RAI QUESTION NO. 08.02-10**

## RAI QUESTION NO. 08.02-10

### NRC RAI 08.02-10

COL application, Chapter 1, Table 1.9-201, "Conformance with Standard Review Plan," for SRP Section BTP 8-5, indicates that BTP 8-5, "Supplemental Guidance for Bypass and Inoperable Status Indication for Engineered Safety Features System," is not applicable. However, the ESBWR DCD, Rev. 4, Section 8.3.2.2.2 indicates that BTP ICSB 21, "Supplemental Guidance for Bypass and Inoperable Status Indication for Engineered Safety Features System," is applicable. Please note that BTP ICSB 21 has been renamed as BTP 8-5. The staff requests that the applicant modify Table 1.9-201 to indicate BTP 8-5 is applicable.

### Entergy Response

BTP 8-5 is not applicable to Grand Gulf Unit 3. The ESBWR is designed in accordance with ICSB 21, which is the predecessor to BTP 8-5, as indicated in DCD Table 8.1-1 and Section 8.3.2.2.2. Additionally, BTP 8-5 does not provide guidance on any site-specific design, operational aspects of the facility, or siting information in the FSAR that supplements the Site Safety Analysis Report. Therefore, FSAR Table 1.9-201 will be revised to clarify the basis for concluding that BTP 8-5 is not applicable.

### Proposed COLA Revision

FSAR Table 1.9-201 will be revised as shown in the attached draft markup.

**Markup of Grand Gulf COLA**

The following markup represents Entergy's good faith effort to show how the COLA will be revised in a future COLA submittal in response to the subject RAI. However, the same COLA content may be impacted by revisions to the ESBWR DCD, responses to other COLA RAIs, other COLA changes, plant design changes, editorial or typographical corrections, etc. As a result, the final COLA content that appears in a future submittal may be somewhat different than as presented herein.

GGNS COL 1.9-3-A

**TABLE 1.9-201 (Sheet 27 of 60)**
**CONFORMANCE WITH STANDARD REVIEW PLAN**

| SRP Section | Title | Rev | Date | Specific Acceptance Criteria | Evaluation |
|---|---|---|---|---|---|
| BTP 8-5 | Supplemental Guidance for Bypass and Inoperable Status Indication for Engineered Safety Features Systems | Rev. 3 | Mar-07 | | Not applicable. The ESBWR ~~does not rely on safety-related AC power systems. However,~~is designed in accordance with ICSB-21, the predecessor to BTP 8-5, as stated in DCD Table 8.1-1 and DCD Section 8.3.2.2.2. Also refer to DCD Table 7.1-1 for conformance to RG 1.47 and Bypass and Inoperable Status Indication (BISI) for all safety-related systems. |
| BTP 8-6 | Adequacy of Station Electric Distribution System Voltages | Rev. 3 | Mar-07 | | Not Applicable - ~~The use of batteries/inverters in the supply arrangement of the ESBWR Class 1E busses results in independence from off-site power with respect to the voltage on the 1E busses.~~The ESBWR is designed in accordance with PSB 1, the predecessor to BTP 8-6, as stated in DCD Table 8.1-1 and DCD Section 8.3.1.1.2. |
| BTP 8-7 | Criteria for Alarms and Indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status | Rev. 3 | Mar-07 | | Not applicable. The ESBWR does not use safety-related diesel generators. |
| 9.1.1 | Criticality Safety of Fresh and Spent Fuel Storage and Handling | Rev. 3 | Mar-07 | II.1 | Conforms |
| 9.1.2 | New and Spent Fuel Storage | Rev. 4 | Mar-07 | II.1, II.2, II.3, II.4, II.5, II.6, II.7 | Conforms |

ATTACHMENT 11

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-11

# RAI QUESTION NO. 08.02-11

## NRC RAI 08.02-11

COL application, Chapter 1, Table 1.9-201, "Conformance with Standard Review Plan" for SRP Section BTP 8-6, indicates that BTP 8-6, "Adequacy of Station Electric Distribution System Voltage," is not applicable. However, the ESBWR DCD, Rev. 4, Section 8.3.1.1.2 indicates that BTP PSB 1, "Adequacy of Station Electric distribution System Voltage," is applicable. Please note that BTP PSB 1has been renamed as BTP 8-6. The staff requests that the applicant modify Table 1.9-201 to indicate BTP 8-6 is applicable.

## Entergy Response

BTP 8-6 is not applicable to Grand Gulf Unit 3. The ESBWR is designed in accordance with PSB 1, which is the predecessor to BTP 8-6, as indicated in DCD Table 8.1-1 and Section 8.3.1.1.2. Additionally, BTP 8-6 does not provide guidance on any site-specific design, operational aspects of the facility, or siting information in the FSAR that supplements the Site Safety Analysis Report. Therefore, FSAR Table 1.9-201 will be revised to clarify the basis for concluding that BTP 8-6 is not applicable.

## Proposed COLA Revision

FSAR Table 1.9-201 will be revised as shown in the attached draft markup.

**Markup of Grand Gulf COLA**

The following markup represents Entergy's good faith effort to show how the COLA will be revised in a future COLA submittal in response to the subject RAI. However, the same COLA content may be impacted by revisions to the ESBWR DCD, responses to other COLA RAIs, other COLA changes, plant design changes, editorial or typographical corrections, etc. As a result, the final COLA content that appears in a future submittal may be somewhat different than as presented herein.

GGNS COL 1.9-3-A

**TABLE 1.9-201 (Sheet 27 of 60)**
**CONFORMANCE WITH STANDARD REVIEW PLAN**

| SRP Section | Title | Rev | Date | Specific Acceptance Criteria | Evaluation |
|---|---|---|---|---|---|
| BTP 8-5 | Supplemental Guidance for Bypass and Inoperable Status Indication for Engineered Safety Features Systems | Rev. 3 | Mar-07 | | Not applicable. The ESBWR ~~does not rely on safety-related AC power systems. However,~~is designed in accordance with ICSB-21, the predecessor to BTP 8-5, as stated in DCD Table 8.1-1 and DCD Section 8.3.2.2.2. Also refer to DCD Table 7.1-1 for conformance to RG 1.47 and Bypass and Inoperable Status Indication (BISI) for all safety-related systems. |
| BTP 8-6 | Adequacy of Station Electric Distribution System Voltages | Rev. 3 | Mar-07 | | Not Applicable - ~~The use of batteries/inverters in the supply arrangement of the ESBWR Class 1E busses results in independence from off site power with respect to the voltage on the 1E busses.~~The ESBWR is designed in accordance with PSB 1, the predecessor to BTP 8-6, as stated in DCD Table 8.1-1 and DCD Section 8.3.1.1.2. |
| BTP 8-7 | Criteria for Alarms and Indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status | Rev. 3 | Mar-07 | | Not applicable. The ESBWR does not use safety-related diesel generators. |
| 9.1.1 | Criticality Safety of Fresh and Spent Fuel Storage and Handling | Rev. 3 | Mar-07 | II.1 | Conforms |
| 9.1.2 | New and Spent Fuel Storage | Rev. 4 | Mar-07 | II.1, II.2, II.3, II.4, II.5, II.6, II.7 | Conforms |

ATTACHMENT 12

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-12

## RAI QUESTION NO. 08.02-12

### NRC RAI 08.02-12

The ESBWR DCD, Rev. 4, Section 8.2.3 states that a station ground grid is provided consisting of a ground mat below grade at the switchyard that is connected to the foundation embedded loop grounding system provided for the entire power block and associated buildings. However, the Grand Gulf Station ground grid consists of switchyard ground grid, existing Unit 1 ground grid and new Unit 3 ground grid. The staff requests that the applicant discuss the interface and impact of station grounding due to addition of Unit 3 ground grid to the existing station ground consisting of switchyard and Unit 1 grounding. Please also provide a summary description of the existing grounding system at the Grand Gulf and the proposed grounding of the Unit 3 to achieve a single point ground at the site.

### Entergy Response

A description of the Unit 3 station ground grid is provided in DCD Chapter 8, Appendix 8A, Section 8A.1, "Station Grounding and Surge Protection." This DCD section includes a system description and analysis of regulatory guidance and applicable codes and standards used in the design.

The Unit 3 grounding system, including the Unit 3 offsite power system and the portion of the Grand Gulf switchyard upgraded to accommodate Unit 3, is designed to IEEE-80, "Guide for Safety in AC Substation Grounding," IEEE-81, "Guide for Measuring Earth Resistivity, Grounding Impedance, and Earth Surface Potentials of a Ground System" and IEEE-665, "Guide for Generation Station Grounding." Detailed design verifies the adequacy of the Unit 3 grounding station and offsite power system and evaluates the interface with Unit 1 to ensure that the Grand Gulf Unit 3 grounding system meets these standards for the addition of Unit 3 and the offsite power system for Unit 3, including the portion of the Grand Gulf switchyard upgraded to accommodate Unit 3.

The grounding systems for Grand Gulf Unit 1 onsite and offsite power distribution systems are as described in the Unit 1 FSAR Section 8.3.1.1.6.4.

### Proposed COLA Revision

None

ATTACHMENT 13

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-13

## RAI QUESTION NO. 08.02-13

### NRC RAI 08.02-13

SRP 8.2 (III.1.I) identifies the need to address provisions for surge protection and lightning protection. However, staff review of Chapter 8 has not identified that these issues were addressed. The staff requests that the applicant provides a discussion about the surge protection and lightning protection with respect to the offsite power system or justify an alternative approach.

### Entergy Response

DCD Appendix 8A is incorporated by reference into the Grand Gulf Unit 3 COLA FSAR with the supplements noted in FSAR Appendix 8A.2. Details of station grounding and surge protection are addressed in DCD Appendix 8A.1.

The lightning protection system covers all major plant structures, including the Unit 3 offsite power system and the portion of the Grand Gulf switchyard upgraded to accommodate Unit 3. It is designed to reduce the potential for direct lightning strikes to buildings, electric power equipment, and instruments. Lightning protection is provided in accordance with Regulatory Guide (RG) 1.204, "Guidelines for Lightning Protection of Nuclear Power Plants."

The design for surge protection and lightning protection include NFPA-780, "Standard for the Installation of Lightning Protection Systems," and IEEE-C62.23, "IEEE Application Guide for Surge Protection of Electric Generating Plants." Surge arrestors are applied in compliance with IEEE C62.11, "IEEE Standard for Metal-Oxide Surge Arrestors for AC Power Circuits," and IEEE C62.22, "IEEE Guide for Application of Metal-Oxide Surge Arrestors for AC Systems." Surge arrestors are maintained according to NEMA requirements and manufacturer's recommendations.

### Proposed COLA Revision

FSAR Table 1.9-204 will be revised as shown in the attached draft markup to add IEEE Standards C62.11 and 62.22. (Note: IEEE C62.23 is currently listed in DCD Table 1.9-22; DCD Table 1.9-22 is incorporated by reference into the grand Gulf Unit 3 FSAR.)

FSAR Section 8.2.1.2.1.1 will be revised to discuss surge suppression and lightning protection as shown in the attached draft markup.

**Markup of Grand Gulf COLA**

The following markup represents Entergy's good faith effort to show how the COLA will be revised in a future COLA submittal in response to the subject RAI. However, the same COLA content may be impacted by revisions to the ESBWR DCD, responses to other COLA RAIs, other COLA changes, plant design changes, editorial or typographical corrections, etc. As a result, the final COLA content that appears in a future submittal may be somewhat different than as presented herein.

GGNS SUP 1.9-1

**TABLE 1.9-204 (Sheet 4 of 6)**
**INDUSTRIAL CODES AND STANDARDS**

| Code or Standard Number | Year | Title |
|---|---|---|
| Factory Mutual | | |
| Data Sheet 7-42 | 2006 | Guidelines for Evaluating the Effects of Vapor Cloud Explosions Using a TNT Equivalency Method |
| | 2007 | Approval Guide |
| **Institute of Electrical and Electronics Engineers (IEEE)** | | |
| C2 | 2007 | National Electric Safety Code |
| C62.11-1999 | 1999 | IEEE Standard for Metal-Oxide Surge Arrestors for AC Power Circuits |
| C62.22-1997 | 1997 | IEEE Guide for Application of Metal-Oxide Surge Arrestors for AC Systems |
| **National Fire Protection Association (NFPA)** | | |
| NFPA 10 | 2007 | Standard for Portable Fire Extinguishers |
| NFPA 11 | 2005 | Standard for Low-, Medium-, and High-Expansion Foam |
| NFPA 13 | 2007 | Standard for the Installation of Sprinkler Systems |
| NFPA 14 | 2007 | Standard for the Installation of Sandpipe and Hose Systems |
| NFPA 15 | 2007 | Standard for Water Spray Fixed Systems for Fire Protection |
| NFPA 16 | 2007 | Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems |
| NFPA 20 | 2007 | Standard for the Installation of Stationary Pumps for Fire Protection |
| NFPA 24 | 2007 | Standard for the Installation of Private Fire Service Mains and their Appurtenances |
| NFPA 25 | 2008 | Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems |
| NFPA 30 | 2008 | Flammable and Combustible Liquids Code |

The nominal voltage of the 500 kV grid is 510 kV. The maximum and minimum voltages of the 500 kV grid are 525 kV and 491 kV, respectively. The recorded voltages in the past years indicate no voltage excursions outside these limits.

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8.2.1.2.1 Switchyard

Replace the second, third, fourth, fifth, and sixth paragraphs of DCD Section 8.2.1.2.1 with the following sections.

8.2.1.2.1.1 Transmission Switchyard

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GGNS COL 8.2.4-2-A

Unit 3 is connected to the GGNS 500 kV Switching Station.

GGNS COL 8.2.4-10-A

The Unit 1 portion of the GGNS 500 kV Switching Station is extended to the north to accommodate the Unit 3 interconnection to the grid. The GGNS Switching Station has two 500 kV main buses running in the north-south direction. The electrical configuration of the off-site power system is shown in Figure 8.2-202. The general arrangement of the GGNS Switching Station and its connection to the plant and the grid are shown in Figure 8.2-203.

The switchyard is extended with rigid tubing supported on insulators and galvanized towers and pedestals. The bus arrangement is in a double bus configuration at 30 feet and 55 feet height above ground. The buses are designed to withstand a maximum fault on any section. This is the maximum limiting force-loading that the buses would be subjected to.

The layout of the switchyard is designed as a double-bus double-breaker or breaker-and-a-half configuration. The breaker switching configuration provides for the isolation of any faulted line without affecting the operation of any other lines. This scheme also provides for isolation of any one breaker on the 500 kV East/ West bus for inspection and maintenance without affecting the operation of any of the connecting lines or any other connection to the buses. The design provides for the isolation of any breaker, without limiting the operation of the unit or the transmission lines connecting to the 500 kV grid. Each bus in the Unit 3 section of the switchyard has sufficient capacity to carry its load under any postulated switching sequences. The upgrade of the Unit 1 section of the switchyard conforms to the new bus rating.

<u>The switchyard uses surge suppressors on the high and low sides of the main transformers, UATs and RATS. The design for surge protection and lightning protection include NFPA-780, "Standard for the Installation of Lightning Protection Systems," and IEEE-C62.23, "IEEE Application Guide for Surge Protection of Electric Generating Plants." Surge arrestors are applied in compliance with IEEE C62.11, "IEEE Standard for Metal-Oxide Surge Arrestors for AC Power Circuits"</u>

and IEEE C62.22, "IEEE Guide for Application of Metal-Oxide Surge Arrestors for AC Systems." Surge arrestors are maintained according to NEMA requirements and manufacturer's recommendations.

The switchyard is designed with a completely redundant protective relay scheme.

---

GGNS COL 8.2.4-6-A

GGNS COL 8.2.4-7-A

GGNS COL 8.2.4-10-A

There are two sources of ac auxiliary power from the 6.9 kV Plant Investment Protection (PIP) buses for the normal preferred switchyard power center and alternate preferred switchyard power center, as shown on DCD Figure 8.1-1. The switchyard auxiliary power system is designed with adequate equipment, standby power, and protection to provide maximum continuity of service for operation of the essential switchyard equipment during both normal and abnormal conditions. There are two independent sets of 125 V DC batteries, chargers, and DC panels for the switchyard relay and control systems DC supply requirements. Each charger is powered from a separate ac source with an automatic switchover to the alternate source, in the event the preferred source is lost. The distribution systems for the two battery systems are physically separated. This separation includes dual cable tray systems in the control building and dual cable trenches in the new portion of the switchyard.

High speed circuit breakers with adequate operating and interrupting rating are provided. The 500 kV circuit breakers are equipped with two independent trip coils for tripping by a separate set of protective relays. In addition, the circuit breakers are provided with breaker failure schemes. The protective relay systems are redundant. These systems are overlapping such that each high voltage component is covered by at least two sets of protective relays. The primary and backup relay systems are supplied from separate current inputs, separate DC circuits for control from each 125 V DC battery, and are connected to separate trip coils of the power circuit breakers.

In case of a spurious relay trip, or a trip due to a fault on one of the off-site circuits, the switchyard buses will continue to stay energized. There is adequate capacity in the system and the switchyard equipment to meet the auxiliary power requirements of Unit 3.

---

GGNS COL 8.2.4-10-A

Failure analysis shows that a single fault in any section of a 500 kV bus is cleared by the adjacent breakers and does not interrupt operation of the remaining part of the 500 kV switchyard bus or the connection of the unaffected transmission lines. Only those elements connected to the faulted section are interrupted.

The transmission line relay protection circuits continuously monitor the conditions of the off-site power system and are designed to detect and isolate faults with maximum speed causing minimal disturbance to the system.

ATTACHMENT 14

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-14

## RAI QUESTION NO. 08.02-14

### NRC RAI 08.02-14

COL Section 8.2.1.1 states that the GGNS 500 kV switching station is common to Units 1 and 3. The staff requests that the applicant confirm that they will be performing an evaluation regarding any effects on the operation (minimum and maximum grid voltage, degraded voltage, etc.) of the existing nuclear units due to addition of Unit 3 to the existing grid.

### Entergy Response

It is inappropriate for the applicant for the GGNS Unit 3 Combined License (Docket Number 05200024) to make commitments for the licensee of GGNS Unit 1 (Docket Number 05000416). The GGNS Unit 3 applicant does confirm that it will coordinate with the GGNS Unit 1 licensee to ensure that the GGNS Unit 1 licensee is fully aware of the potential impacts from the design and operation of GGNS Unit 3. Specifically, this would include potential impacts from using a common switchyard (e.g. minimum and maximum grid voltage, degraded voltage, etc.).

Managerial and administrative controls are used to provide assurance that the effects from GGNS Unit 3 operation on the operation of GGNS Unit 1 are appropriately evaluated in accordance with applicable regulations. For example, the GGNS Unit 1 licensee (Docket Number 05000416) is subject to the requirements of 10 CFR 50.59 and 10 CFR 50.71; therefore, switchyard changes would be evaluated to the extent that they affect the GGNS Unit 1 licensing basis and/or facility FSAR.

### Proposed COLA Revision

None

ATTACHMENT 15

G3NO-2008-00014

RESPONSE TO NRC RAI LETTER NO. 12

RAI QUESTION NO. 08.02-15

## RAI QUESTION NO. 08.02-15

### NRC RAI 08.02-15

COL Section 8.2.1.2.1.1 states that there are two sources of power from 6.9 kV Plant Investment Protection (PIP) buses for the normal preferred switchyard power center and alternate preferred switchyard power center as shown on the ESBWR DCD, Rev. 4, Figure 8.1-1. The ESBWR DCD, Rev. 4, Section 8.2.3 requires that these cables are routed in separate raceways. The staff requests that the applicant confirm that two sources of ac power from the 6.9 kV Plant Investment Protection buses for normal preferred switchyard power center and alternate preferred switchyard power center are routed in separate raceways.

### Entergy Response

DCD Section 8.2 is incorporated by reference into the Grand Gulf Unit 3 COLA FSAR with the supplements noted in FSAR Section 8.2; this includes DCD Section 8.2.3. Therefore, if alternate preferred and normal preferred control, instrumentation, and miscellaneous power cables are located underground in the same duct bank, they are routed in separate raceways, as specified in DCD Section 8.2.3.

### Proposed COLA Revision

None

**ATTACHMENT 16**

**G3NO-2008-00014**

**RESPONSE TO NRC RAI LETTER NO. 12**

**RAI QUESTION NO. 08.03.02-1**

# RAI QUESTION NO. 08.03.02-1

## NRC RAI 08.03.02-1

Supplement (GGNS SUP 8.3.2) to Section 8.3.2.1.1 states that training and procedures to mitigate a station blackout (SBO) event are implemented in accordance with Sections 13.2 and 13.5. According to NUMARC 87-00 which is endorsed by RG 1.155, the SBO response procedures include (1) Station Blackout Response Guidelines, (2) AC Power Restoration, and (3) Severe Weather Guidelines. The staff requests that the applicant confirm that their specific SBO procedures and training will cover all three of the above identified procedures.

## Entergy Response

The training and procedures addressed in FSAR Section 8.3.2.1.1 will include the three topics listed in the RAI. Training of licensed and non-licensed plant personnel as well as plant procedures are discussed in the COLA FSAR Sections 13.2 and 13.5 respectively; however, these discussions do not specifically address SBO events. In general, training is described in the FSAR in sufficient detail to assure plant staff receives adequate training for responding to all plant events, both normal and abnormal, and such training would encompass an SBO event. As recommended by NUMARC 87-00, the FSAR will be revised to indicate that procedures will include:

1. Station blackout response guidelines,
2. AC power restoration, and
3. Severe weather guidelines.

## Proposed COLA Revision

FSAR Section 8.3.2.1.1 will be revised as indicated in the attached draft markup.

**Markup of Grand Gulf COLA**

The following markup represents Entergy's good faith effort to show how the COLA will be revised in a future COLA submittal in response to the subject RAI. However, the same COLA content may be impacted by revisions to the ESBWR DCD, responses to other COLA RAIs, other COLA changes, plant design changes, editorial or typographical corrections, etc. As a result, the final COLA content that appears in a future submittal may be somewhat different than as presented herein.

## 8.3 ON-SITE POWER SYSTEMS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

### 8.3.1.1 DESCRIPTION

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Insert the following as the first paragraph.

GGNS SUP 8.3-1 An intermediate switchyard is utilized to transition off-site power from the GGNS 500-kV Switching Station to the Unit 3 main power transformers, the 500/13.8-6.9-kV UATs and the 500/13.8-6.9-kV RATs. This intermediate switchyard contains the generator circuit breaker, supply circuit breakers to the UATs and a supply circuit breaker to the RATs.

---

### 8.3.2.1.1 SAFETY-RELATED STATION BATTERIES AND BATTERY CHARGERS

**Station Blackout**

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Add the following paragraph at the end of the Station Blackout section.

GGNS SUP 8.3-2 Training and procedures to mitigate an SBO event are implemented in accordance with Sections 13.2 and 13.5, respectively. As recommended by NUMARC 87-00 (Reference 8.3-201), SBO event mitigation procedures address SBO response (e.g., restoration of on-site standby power sources), AC power restoration (e.g., coordination with transmission system load dispatcher), and severe weather guidance (e.g., identification of site-specific actions to prepare for the onset of severe weather such as a an impending tornado), as applicable. The ESBWR is a passive design and does not rely on off-site or on-site AC sources of power for at least 72 hours after an SBO event, as described in DCD Section 15.5.5, Station Blackout. In addition, there are no nearby large power sources, such as a gas turbine or black start fossil fuel plant, that can directly connect to the station to mitigate the SBO event. Restoration from an SBO event will be contingent upon power being made available from any one of the following sources:

- ~~Either of the station~~Any of the standby or ancillary diesel generators
- Restoration of any one of the three 500 kV transmission lines described in Section 8.2

## 8.3.5 REFERENCES

8.3-201 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, NUMARC 87-00, Revision 1, August 1991.

# ATTACHMENT 17

# G3NO-2008-00014

# REGULATORY COMMITMENTS

**REGULATORY COMMITMENTS**

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

| COMMITMENT | TYPE (Check one) | | SCHEDULED COMPLETION DATE (If Required) |
|---|---|---|---|
| | ONE-TIME ACTION | CONTINUING COMPLIANCE | |
| An analysis of the onsite power system will be accomplished as part of a site-specific ITAAC and will ensure that each as-built offsite circuit has sufficient capacity and capability. The exact wording of these ITAAC will be finalized and incorporated into the COLA following final development of the GDC 17 interface requirements that will be included in the DCD. | ✓ | | Future COLA submittal |
| FSAR Section 8.2.1.2.2 will include the information provided in this response as indicated in draft markup contained in Attachment 2. | ✓ | | Future COLA submittal |
| Analyses of the as-built onsite power system will be performed to determine the load requirements during design basis operating modes. This analysis will, in part, specify required power, voltage, frequency, and interrupting capability necessary for the offsite power system to support safety-related load operation during design basis operating modes. This analysis will be accomplished as part of a site-specific ITAAC and will ensure that each as-built offsite circuit has sufficient capacity and capability. The exact wording of these ITAAC will be finalized and incorporated into the COLA following final development of the GDC 17 interface requirements that will be included in the DCD. | ✓ | | Future COLA submittal |
| FSAR Section 8.2.1.2.2, "Testing and Inspection," will be added for switchyard testing activities as indicated in the draft markup contained in Attachment 5. | ✓ | | Future COLA submittal |

| COMMITMENT | TYPE (Check one) | | SCHEDULED COMPLETION DATE (If Required) |
|---|---|---|---|
| | ONE-TIME ACTION | CONTINUING COMPLIANCE | |
| FSAR Table 1.9-201 will be revised as shown in the draft markup contained in Attachment 10. | ✓ | | Future COLA submittal |
| FSAR Table 1.9-201 will be revised as shown in the draft markup contained in Attachment 11. | ✓ | | Future COLA submittal |
| FSAR Table 1.9-204 will be revised as shown in the draft markup contained in Attachment 13 to add IEEE Standards C62.11 and 62.22. (Note: IEEE C62.23 is currently listed in DCD Table 1.9-22; DCD Table 1.9-22 is incorporated by reference into the grand Gulf Unit 3 FSAR.) | ✓ | | Future COLA submittal |
| FSAR Section 8.2.1.2.1.1 will be revised to discuss surge suppression and lightning protection as shown in the draft markup contained in Attachment 13. | ✓ | | Future COLA submittal |
| FSAR Section 8.3.2.1.1 will be revised as indicated in the draft markup contained in Attachment 16. | ✓ | | Future COLA submittal |