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GNRO-2011/00043

June 8, 2011

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

SUBJECT: Request for Additional Information Regarding
Extended Power Uprate
Grand Gulf Nuclear Station, Unit 1
Docket No. 50-416
License No. NPF-29

REFERENCES:
1. Email from A. Wang to F. Burford, dated May 10, 2011, GG EPU Containment and Ventilation Branch Request for Additional Information (ME4679) (Accession No. ML111300156)
2. License Amendment Request, Extended Power Uprate, dated September 8, 2010 (GNRO-2010/00056, Accession No. ML102660403)

Dear Sir or Madam:

The Nuclear Regulatory Commission (NRC) requested additional information (Reference 1) regarding certain aspects of the Grand Gulf Nuclear Station, Unit 1 (GGNS) Extended Power Uprate (EPU) License Amendment Request (LAR) (Reference 2). Attachment 1 provides responses to the additional information requested by the Containment and Ventilation Branch.

No change is needed to the no significant hazards consideration included in the initial LAR (Reference 2) as a result of the additional information provided. There are no new commitments included in this letter.

If you have any questions or require additional information, please contact Jerry Burford at 601-368-5755.

I declare under penalty of perjury that the foregoing is true and correct. Executed on June 8, 2011.

Sincerely,

M. A Krupa

MAK/FGB/dm

Attachments:
1. Response to Request for Additional Information, Containment and Ventilation Branch

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Attachment 1

GNRO-2011/00043

Grand Gulf Nuclear Station Extended Power Uprate

Response to Request for Additional Information

Containment and Ventilation Branch

Response to Request for Additional Information
Containment and Ventilation Branch

By letter dated September 8, 2010, Entergy Operations, Inc. (Entergy) submitted a license amendment request (LAR) for an Extended Power Uprate (EPU) for Grand Gulf Nuclear Station, Unit 1 (GGNS). By letter dated March 31, 2011 (GNRO-2011/00021, NRC ADAMS Accession No. ML110900586), Entergy provided responses to the initial questions from the Containment and Ventilation Branch. Subsequently, the U.S. Nuclear Regulatory Commission (NRC) staff has determined that the following additional information requested (RAI) by the Containment and Ventilation Branch is needed for the NRC staff to complete their review of the amendment. Entergy's response to each item is also provided below.

While responding to RAI #3, it was identified that the values for peak drywell pressure for the Design Basis Accident (DBA) Loss of Coolant Accident (LOCA) current licensed thermal power (CLTP) with EPU model and DBA LOCA EPU with EPU model were incorrect in EPU LAR Attachment 5, Table 2.6-1, *GGNS Containment Performance Results*. The correct value for peak drywell pressure for both of these is 27.0 psig. In addition, the value for the peak containment pressure for the DBA LOCA CLTP with EPU model should be 14.8 psig rather than 14.7 psig as reflected in the Table 2.6-1. Changes to EPU LAR Attachment 5, Figure 2.6-4, *Short-Term DBA LOCA MSLB Pressure Response at EPU,* and Figure 2.6-5, *Short-Term DBA LOCA MSLB Differential Pressure Response at EPU* were also identified. The peak drywell pressure and bubble pressure at vent clearing are revised to 27.0 psig and 20.2 psid, respectively on Figure 2.6-4. Also on Figure 2.6-4, the time of occurrence for the peak drywell pressure and peak wetwell pressure is revised to 3.19 seconds and 2.94 seconds, respectively. The value for the peak drywell - containment differential pressure on Figure 2.6-5 is changed to 23.8 psid at a time of occurrence of 1.73 seconds. The revised values have no impact on the DBA LOCA evaluation.

<u>RAI # 1</u>

With regards to Entergy letter dated March 31, 2011, Attachment 1, response to RAI No. 1(d), describe the Fire Safe Shutdown (FSSD) analyses for which the initial conditions are given in two columns of the table. In the description include the computer code used, the sequence of events, time of operator actions, and the results. How are these analysis related to the results described in Table 2.5-1, "Appendix R Fire Event Evaluation Results," of Power Uprate Safety Analysis Report (PUSAR).

<u>Response</u>

The limiting Appendix R FSSD event was analyzed for both 102.46% CLTP and EPU conditions. A summary of the EPU evaluation of this event is in EPU LAR Attachment 5, Section 2.5.1.4.2 and the results are presented in Table 2.5-1. Two FSSD cases were analyzed at EPU conditions, as shown in the response to RAI 1.d of the March 31, 2011 letter. The first case represents the design Appendix R fire event and the second case is a net positive suction head (NPSH) confirmation case. One FSSD case at 102.46% CLTP condition (core thermal power of 3994 MWt) using the initial conditions same as the first EPU case was performed as a benchmark to the current analysis basis.

The initial conditions for Appendix R analysis are described in the following table.

Item	Parameter	Unit	FSSD EPU (Appendix R)	FSSD EPU (NPSH)
1	Core Thermal Power	MWt	4408	4408
2	Rated Core Flow	Mlbm/hr	112.5	112.5
3	Initial Dome Pressure	psia	1060	1060
4	Initial Water Level (above vessel zero)	inch	565.7	565.7
5	Decay Heat	N/A	ANS 5.1-1979 with SIL 636	ANS 5.1-1979 with SIL 636
6	Initial Suppression Pool (SP) Temperature	^{o}F	95	100
7	Initial Wetwell (WW) Pressure	psia	15.7	14.6
8	Initial SP Water Volume at low water level (LWL)	ft^3	133750	133750
9	Initial Containment Airspace Volume at LWL	ft^3	270000	270000
10	Initial WW Temperature	^{o}F	95	100
11	Initial WW Relative Humidity	%	20	100
12	Initial Drywell (DW) Temperature	^{o}F	135	140
13	Initial DW Pressure	psia	17.7	14.3[(1)]
14	Initial DW Relative Humidity	%	20	90
15	Residual Heat Removal (RHR) Heat Exchanger K-value	Btu/sec-^{o}F	486	486
16	RHR Flow Rate	gpm	6600	6600
17	RHR Pump Horsepower (1 pump)	hp	1000	1000
18	Service Water Temperature	^{o}F	90	90
19	Safety Relief Valve (SRV) Capacity at Reference Pressure	lbm/hr psig	925000 1241	925000 1241

(1) In the March 31, 2011 response to RAI 1(d), the initial drywell pressure was reported as -0.3 psig incorrectly. The initial drywell pressure used in the EPU NPSH case was 14.3 psia (or -0.4 psig).

The containment results of these cases at EPU conditions are shown in the following table.

	FSSD EPU (Appendix R)	FSSD EPU (NPSH)	Design Limit
Maximum DW Pressure, psia	19.5	16.4	44.7
Maximum DW Temperature, °F	225.9	234.0	330
Maximum WW Pressure, psia	19.3	17.0	29.7
Maximum WW Temperature, °F	144.9	149.2	185
Maximum SP Temperature, °F	178.5	181.4	185/210(1)

(1) The design limit of 185°F included on EPU LAR Attachment 5, Table 2.5-1 and carried forward to this table is the current design limit. For EPU implementation, this design limit is increased to 210°F (refer to EPU LAR Attachment 5B, Section 2.6.5.1).

The sequence of events for FSSD EPU design Appendix R case is described in the following table. The sequence of events for FSSD EPU (Appendix R) and FFSB EPU (NPSH) cases is the same through the first 90 minutes; in the NPSH case, the peak suppression pool temperature of 181.4°F is reached in approximately 2.9 hours.

Time	Events
0 seconds	Reactor trips automatically, or is tripped by the operator due to fire. Offsite power is lost. All unprotected shutdown systems are lost due to the fire. All high pressure systems are considered conservatively unavailable.
0-5 seconds	Main steam turbine trip, loss of reactor feedwater and MSIV closure occurs due to fire or due to loss of offsite power (LOOP).
35 seconds	SRVs open due to high reactor pressure and subsequently close as reactor pressure drops. SRVs cycle several times maintaining the reactor high pressure until the operator can initiate a corrective action.
~14.3 minutes	When reactor level reaches 373 inches above vessel zero, the operator manually opens 6 SRVs, starts one RHR pump and aligns RHR in the low pressure coolant injection (LPCI) mode.
~18.5 minutes	The water level in the hot/average channel drops below top of active fuel (TAF) for approximately 100 seconds (core uncovery). A brief core heatup does not result in the peak cladding temperature exceeding the initial steady-state temperature of 597°F.
~19.2 minutes	LPCI starts injecting into the core.
~26.5 minutes	Reactor vessel water level is restored above TAF in the downcomer region.
30 minutes	Alternate shutdown cooling mode is initiated to remove long-term decay heat.
~1.5 hours	Cold shutdown is reached
~3.3 hours	The peak suppression pool temperature of 178.5°F is reached.

The values of the peak cladding temperature and maximum operator action time to open automatic depressurization system (ADS) valves in the LAR Attachment 5 Table 2.5-1 are calculated by using SAFER and GESTR-LOCA codes. The other values in the Table 2.5-1 are containment analysis results and are calculated using SHEX code. The EPU containment results in the Table 2.5-1 are the limiting results from two EPU cases described in the above table.

As shown in the above tables, the key peak values are below the respective design limits. Therefore, the applicable acceptance criteria for Appendix R event are met.

RAI # 2

With regards to Entergy letter dated September 8, 2010, Attachment 5B, Section 2.6.1.1, and Table 2.6-1:

(a) Describe the limiting ASDC analysis for which the results are documented in Table 2.6-1.

(b) Provide a comparison of the EPU sequence of events with the current licensing basis sequence of events documented in UFSAR Table 15.2-13 and justify differences.

(c) Provide a comparison of the EPU input parameters for the evaluation of ASDC with the current licensing basis input parameters documented in UFSAR Table 15.2-14 and justify differences.

Response

As described in GGNS Update Final Safety Analysis Report (UFSAR) Section 5.4.7.1.5, in the event either of the two shutdown cooling suction valves from the reactor vessel cannot be opened following a reactor scram, an alternate shutdown cooling process must be implemented. This cooling mode is called alternate shutdown cooling (ASDC), in which the operator uses the RHR system via the LPCI configuration, after depressurization, to flood the vessel to the main steam line so as to allow continuous flow from the vessel through the SRVs to the suppression pool.

a. Footnote 5 of Table 2.6-1 identifies the ASDC analysis results for limiting peak bulk pool temperatures and notes they are more limiting, compared to the DBA LOCA results in the table.

   The current ASDC analysis is described in UFSAR Section 15.2.9. This scenario begins with a LOOP event and the resulting plant scram. It includes a single active component failure of an Emergency Diesel Generator (EDG) which causes loss of power to one of the two in-series AC-motor operated shutdown cooling recirculation loop suction valves to the redundant RHR cooling loops; thereby causing the loss of the RHR shutdown cooling function. Manual operator action to open this valve is assumed to fail. Reactor water level is maintained early in the event by High Pressure Core Spray (HPCS) which responds when the reactor pressure vessel (RPV) water reaches low-low level.

   Due to the assumed failure of an EDG, only a single RHR heat exchanger is available for long-term shutdown and suppression pool cooling. The operator is anticipated to take action to initiate use of the RHR heat exchanger at 10 minutes.

At a suppression pool temperature of 120°F, the analysis of record for this event assumes a blowdown of the RPV via the ADS at approximately 42 minutes. By 68 minutes, the blowdown is completed and a transition to shutdown cooling would be initiated. Assuming the transition to shutdown cooling fails, the scenario then assumes RHR realignment into the ASDC configuration, which is assumed to take 35 minutes.

For the EPU analysis, the operator will sustain a controlled reactor cooldown at the rate of 100°F/hour for times when suppression pool temperature exceeds 110°F, but is conservatively assumed not before 10 minutes following initiation of the event. Then, at 35 hours, the operator manually shuts down the suppression pool cooling in preparation for establishing cold shutdown. Presuming that normal shutdown cooling is not achievable, in 35 minutes, RHR in LPCI mode is initiated. The vessel is flooded above the main steam line elevation and provides liquid recirculation flow to the suppression pool via the ADS SRVs. Cold shutdown is achieved when the RPV liquid bulk temperature is indicated to be below 200°F.

b. A comparison of sequence of events for the ASDC analysis is shown in the following table:

Approx. Elapsed Time	**Events (from UFSAR Table 15.2-13 and supporting analysis)**	**Approx. Elapsed Time**	**Events (from analysis EPU LAR Attachment 5 Section 2.6.1.1 -ASDC)**
0 min	Reactor at 105% initial steam flow CLTP - 105% of OLTP (original licensed thermal power)	0 min	Reactor at EPU steam flow EPU power - 117% of OLTP.
0 min	Loss of diesel generator (LOOP and scram)	0 min	Loss of diesel generator (LOOP and scram)
0 min	Suppression Pool (SP) temperature alarm activated	0 min	SP temperature alarm activated
7.5 min	SP temperature reaches 110°F. Operator scram if not previously occurring		
10 min	SP cooling initiated	10 min	SP cooling initiated
		~17.8 min	SP temperature reaches 110°F. Operators initiate controlled reactor cooldown at 100°F/hour
42 min	Full blowdown initiated via ADS when SP temperature reaches 120°F maximum.		
68 min	Blowdown to 100 psi completed. (Initiate isolation of SP cooling.)		

Approx. Elapsed Time	Events (from UFSAR Table 15.2-13 and supporting analysis)	Approx. Elapsed Time	Events (from analysis EPU LAR Attachment 5 Section 2.6.1.1 -ASDC)
98 min	Open RHR shutdown cooling suction valve. Assumed to fail.		
103 min	Redirect RHR pump discharge from pool to vessel via LPCI line. (35 minutes (103-68) to accomplish CIC+ADS)		
		2.86 hours	Feedwater flow begins as reactor pressure drops below 100 psig.
~3.4 hours	SP temperature peaks (UFSAR Figure 15.2-14a)		
		3.83 hours	SP temperature peaks
		35 hours	Operator manually shuts down SP cooling mode, in preparation for normal shutdown cooling (NSDC).
		35 hours, 35 minutes	RHR in LPCI mode initiated to flood vessel and provide liquid recirculation flow to SP via ADS valves.

As can be seen above, the primary difference in the sequence of events is that in the EPU analysis the operator monitors the condition of the reactor / containment and pursues a controlled reactor shutdown according to the allowed reactor depressurization rate.

The EPU analysis conservatively assumes a 100°F/hour depression vs. ADS actuation for blowdown. Also, it conservatively accounts for feedwater addition as reactor pressure is reduced. The operators do not secure suppression pool cooling in an attempt to achieve cold shutdown until after 35 hours, since suppression pool temperature is high. Normal shutdown cooling is attempted at 35 hours, and alternate shutdown cooling achievable thereafter, assuming failure of NSDC, in the similar time frame, to assure cold shutdown within the required 36 hour limit.

c. A comparison of input parameters for ASDC is provided in the following table:

Parameter	From UFSAR Table 15.2-14	Used in EPU Analysis
Initial Power (% of 3833 MW)	105	117
Suppression Pool Mass (lbm)	8.66×10^6	8.30×10^6
RHR (KHX value) (Btu/Sec/°F)		
Pool cooling	540	540
Cooled water to vessel	511	540
Initial vessel condition		
Pressure (psia)	1060	1066
Temperature (°F)	552	552.4
Initial primary fluid inventory (lbm)	6.71×10^5	7.40×10^5
Initial pool temperature (°F)	95	95
Service water temperature, (°F)	90	90
Vessel heat capacity (Btu/lbm/°F)	0.123	0.123
HPCS on - water level (ft)		
On	40.93	39.58
Off	49	49
HPCS flow rate, (gpm)	7450	8175

As part of the EPU analysis, a review of the plant parameters was conducted. This review accounts for refinements in some values (e.g., suppression pool mass, initial primary fluid inventory) apart from changes in order (e.g., initial power) because of EPU. The parameters used in the ASDC analysis were selected to make the analysis generally more conservative.

<u>RAI # 3</u>

With regards to PUSAR Figure 2.6-4, discuss the reasons for the three pressure peaks within the first 5 seconds of the main steam line break (MSLB) LOCA analyses pressure response.

<u>Response</u>

The first peak of Figure 2.6-4 is occurring at 1.15 seconds after initiation of the event. At 1.11 seconds the second row of horizontal vents clears and the flow rate of air from the drywell to the wetwell becomes great enough to completely mitigate and reverse the pressurization of the drywell such that drywell pressure begins to decrease. The air from the drywell enters the wetwell airspace, causing wetwell pressure to increase. Thus, the rapid decrease in drywell pressure that occurs at just after 1.15 seconds, which creates the first peak, is due to the clearing of the second row of horizontal vents.

The second peak of Figure 2.6-4 is occurring at 1.77 seconds after initiation of the event. At 1.44 seconds, the third row of horizontal vents clears. Flow from the drywell now increases again, but by now much of the flow includes steam and liquid from the drywell airspace. So the impact of this clearing of the bottom vents is not as drastic as that of the first opening of the middle vents, and it takes a little longer for drywell pressurization to turn around and begin to decrease, thus resulting in this second peak of drywell pressure.

The third peak of Figure 2.6-4 is occurring at 3.13 seconds after initiation of the event. Air flow from the drywell to the wetwell has rapidly pressurized the wetwell airspace above the suppression pool, which sets up a differential pressure between the airspace below the hydraulic control unit (HCU) floor and the airspace above the HCU floor. Air and vapor below the HCU floor begins to flow to the airspace above the HCU floor through the openings in the HCU floor, which provides some resistance to this flow. As all of the air initially in the drywell is eventually purged to the wetwell airspace, the pressurization of the wetwell airspace below the HCU floor reaches a maximum, and continued airflow to the containment airspace above the HCU floor causes the pressure in the wetwell airspace to decrease until the two containment airspaces, that above the HCU floor and that below the HCU floor, finally equalize. The drywell pressure at this time is following the wetwell pressure by a margin equal to the static head of the horizontal vents, so as the pressure in the wetwell airspace below the HCU floor peaks and begins to decrease again, so does the pressure in the drywell, which results in the third and final peak in drywell pressure.

The above behavior is typical of Mark III containments, as described in NEDO-20533 (EPU LAR Attachment 5, Reference 50).

RAI # 4

With regards to letter dated March 31, 2011, response to RAI No. 1(b), provide the reasons for differences in the model for the MSLB area in the EPU analysis from the current licensing basis break area model given in UFSAR Figure 6.2-9. Explain the methodology used for calculating these flow areas as a function of time.

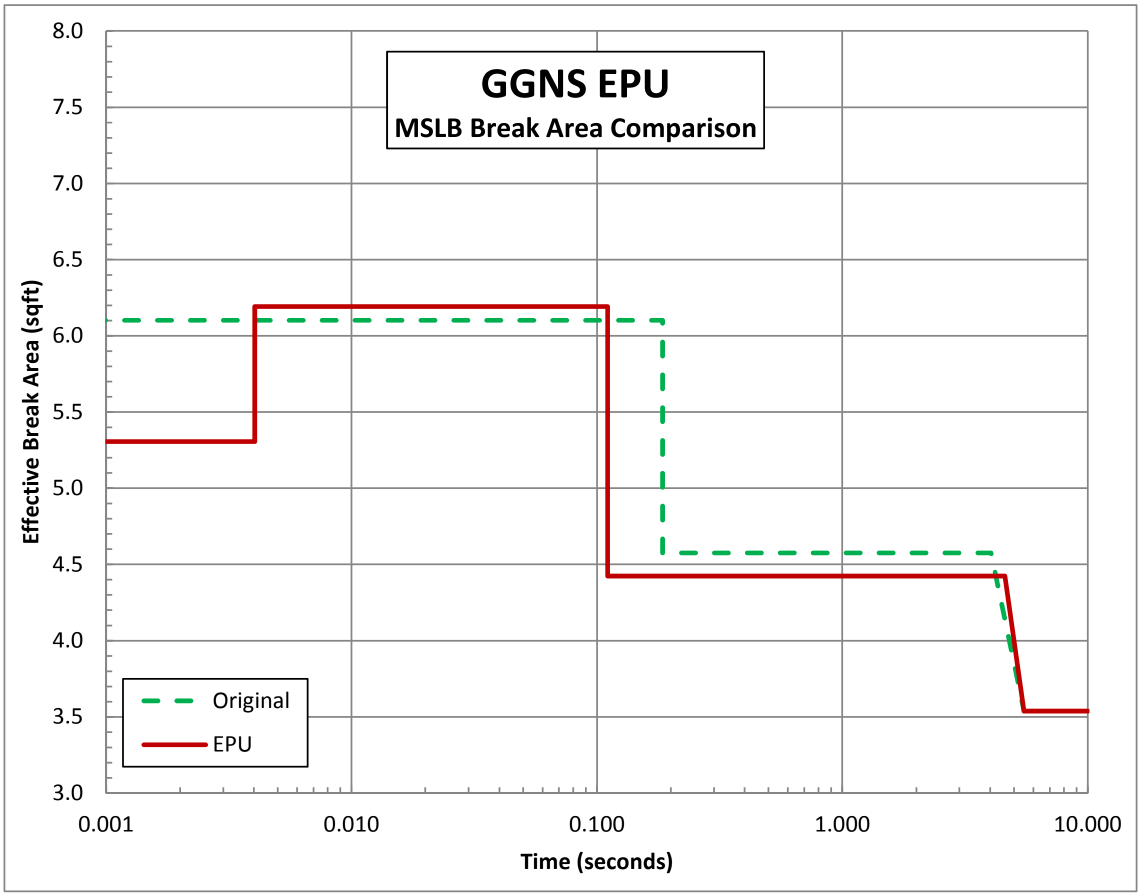
Response

The most significant reason for the change in break area used in the EPU analysis as compared with the original analysis illustrated in the GGNS UFSAR Figure 6.2-9 is a change in the flow area of the Main Steam Line Flow Limiter. In the original analysis, the flow limiter area was assumed to be 1.037 sq ft, which was based on preliminary design information. As-built drawings indicate the internal diameter of the GGNS flow limiter is 12.747 inches, giving a flow area of 0.8862 sq ft.

The original analysis used a nozzle safe end area of 3.538 sq ft, a main steam line area of 3.449 sq ft, and a flow limiter area of 1.037 sq ft. The original analysis also assumed main steam isolation valve (MSIV) closure began at 0.5 seconds and achieved full closure at 5.5 seconds. The original analysis included a flow multiplier of 0.75 applied to the reactor-side break area, but did not include such flow multiplier for the main steam line-side break area. This flow multiplier is used during the time that flow from the break is experiencing a pressure wave that travels from the break location back to the source.

For the EPU analysis, current plant drawings show the nozzle safe end area to be unchanged from the original analysis, 3.538 sq ft. But current drawings indicate the main steam line flow area to be the same as that of the nozzle safe end, or 3.538 sq ft, instead of the 3.449 sq ft used in the original analysis. As mentioned above, current as-built drawings also indicate that the main steam flow limiter area is 0.8862 sq ft, instead of 1.037 sq ft used in the original analysis. In addition, the EPU analysis includes use of the 0.75 flow multiplier on the main steam line-side break area as well as on the reactor-side break area during the times that lines are experiencing the pressure wave back to their sources. The EPU analysis also includes MSIV closure begins at 0.5 seconds and achieves full closure at 5.5 seconds, just as in the original analysis.

The following figure provides a graphic comparison of the effective break areas assumed in the original and in the EPU analyses. Please note that the reduction in break size at approximately 0.11 seconds is correctly reflected below. The table that was provided in response to Item 1.d in the March 31, 2011 response had misplaced the decimal point and incorrectly shown this time step as 0.0110394 seconds.



RAI # 5

With regards to letter dated March 31, 2011, response to RAI 8, for the short term analysis, provide the reasons for using initial drywell pressure of 1.5 psig instead of using the scram setpoint drywell pressure of 2.5 psig or the maximum drywell pressure of 3.5 psig. What value of relative humidity was used in the analysis. In the case where higher than the minimum value of 20-percent was used, provide the justification.

Response

GGNS Technical Specification 3.6.1.4 requires that the differential pressure between the containment and secondary containment be no more than 1.0 psid. Since the secondary containment is maintained at a partial vacuum relative to the surrounding atmosphere pressure during normal operation, the pressure in the containment during normal operation will not be much above atmospheric pressure. However, for the analysis a bounding normal operating pressure in the wetwell of 1.50 psig was assumed.   GGNS does not require and does not typically operate with a significant differential pressure between the drywell and wetwell airspaces. Therefore the analysis is not performed with an initial drywell pressure higher than the initial wetwell pressure.

The initial drywell relative humidity assumed in the analysis was that of the minimum value of 20-percent, which is conservative for this analysis.