CALPINE CORPORATION

717 TEXAS AVENUE, SUITE 1000
HOUSTON, TX 77002

NYSE CPN

December 12, 2011

Mr. Alfred C. Dumaual, PhD
Air Permits Section (6PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RECEIVED
11 DEC 13 PM 5:08
AIR PERMITS SECTION
6PD-R

RE: Response to Request for Additional Information
Deer Park Energy Center LLC
Deer Park, Harris County, Texas

Dr. Dumaual:

On behalf of Deer Park Energy Center LLC, Calpine Corporation is hereby submitting this response to the October 28, 2011 request for additional information for the pending Deer Park Energy Center application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas (GHG) emissions. The questions asked in the letter are duplicated below followed by a response:

1. *Within footnote 1 of Table 3-1, entitled Annual GHG Emission Calculations- New Combined Cycle Combustion Turbine Deer Park Energy Center LLC, the annual firing rate information is noted to be contained in the TCEQ PSD permit application. Please provide a copy of the TCEQ PSD permit application and any subsequent correspondence that may be relevant to the GHG permit application, if any. Additionally, please provide specific detailed calculations to support the Annual Heat Input factor (i.e., seasonal averages and base load percentages).*

   An electronic copy of the TCEQ PSD application was emailed to Stephanie Kordzi of EPA Region 6 on October 20, 2011 and is also included with this transmittal. This application includes the specific detailed calculations to support the heat input factor. The natural gas firing rates for the turbine and duct burners provided on Table 3-1 of the GHG application were obtained from Table B-3A, in Appendix B, of the TCEQ PSD application. While facility operation will be dynamic throughout the normal operating range, the projected annual fuel consumption was based on three specific conditions:

   - Base load turbine operation with low duct firing (6,760 hrs)
   - Base load turbine operation with peak duct firing (1,500 hrs)
   - Base load with power augmentation and peak duct firing (500 hrs)

2. *Within footnotes 3 and 4 of Table 3-3, entitled GHG Emission Calculations - Natural Gas Piping, and Table 3-4, entitled Gaseous Fuel Venting during Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement, the CO_2 and CH_4 emissions appear to be based on a specific natural gas analysis. Please provide a copy of the data and/or analysis to support the use of the emission factor. Is the sample data representative of the natural gas composition throughout the operation of this facility?*

   A copy of the typical natural gas analysis is attached. We are not anticipating any significant changes to the methane and CO_2 content of the natural gas composition throughout the operation of the facility.

3. *The permit application provides an explanation of why Carbon Capture and Sequestration (CCS) was determined to not be technically feasible. Within Section 5.1.2.1, it is noted that the amine absorption technology for CO_2 capture is not yet commercially available for power plant gas turbine exhausts. The statement appears to rely upon an August 2010 report entitled "Report of the Interagency Task Force on Carbon Capture and Storage." Please provide any additional information that was used to support this analysis, i.e., vendor(s) statement.*

   The elimination of carbon capture and sequestration as potential control for this project was based on the absence of a proven sequestration site and the lack of CO2 transport infrastructure (pipeline), in addition to the lack of commercial availability of amine absorption technology. The specific statement regarding the availability of amine absorption is based on the August 2010 report and the fact that there are currently no instances where CO_2 capture technology has been deployed on a natural-gas-fired combined cycle plant. Potential amine technology vendors were not contacted for this application.

4. *Please provide a basis and documentation to support the base heat rate compliance margins listed on page 40 of the permit application.*

   To determine an appropriate heat rate limit for the permit, the following compliance margins were added to the base heat rate limit:

   - A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
   - A 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
   - A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

   Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also estimated an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. A 48,000-operating-hour degradation curve provided by Siemens reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately 5%. The degradation curves describe the amount of "recoverable" and "non-recoverable" degradation. The former includes degradation that can be recovered through compressor water washing, filter changes, instrumentation calibration and auxiliary equipment maintenance. The latter includes degradation that cannot be restored upon a maintenance overhaul.

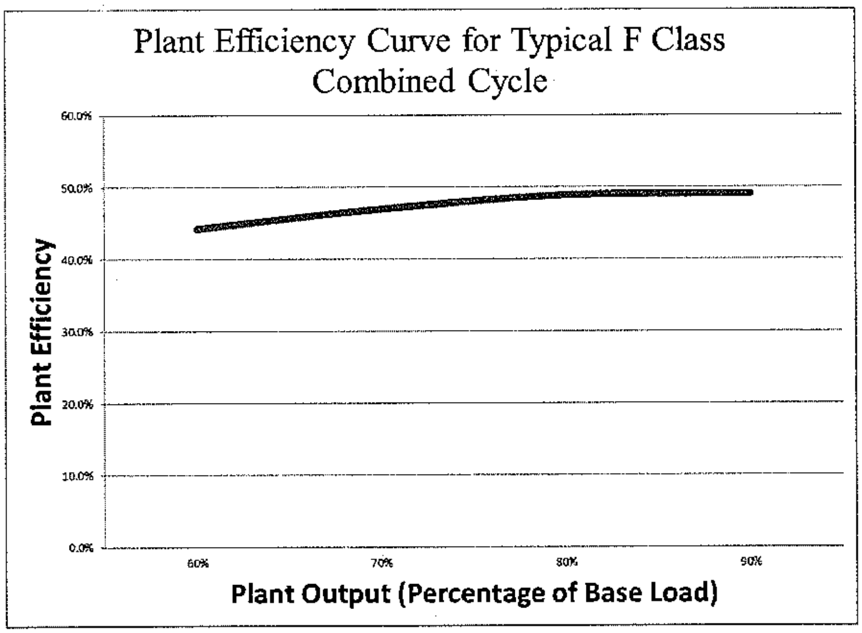
The manufacturer's degradation curves only account for anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, Deer Park Energy Center proposes that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate.

Finally, in addition to the heat rate degradation from normal wear and tear on the turbines, the Deer Park Energy Center is also providing a reasonable compliance margin based on potential degradation in other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). Deer Park Energy Center proposes a 3% degradation rate to account for these factors. The other elements of the combined cycle plant include the following:

- Degradation in Turbine Exhaust Flow: The gas turbine manufacturer's degradation curves predict potential recoverable and non-recoverable degradation in gas turbine exhaust flow over the 48,000 maintenance cycle. This degradation in exhaust flow could result in a direct reduction in the ability of the steam turbine to generate power, which could further degrade the plant's overall efficiency. While degradation in the exhaust flow is expected to be partially offset by degradation in exhaust temperature (which rises over the maintenance cycle), this offset is not expected to make up for anticipated degradation in the reduction in steam turbine power as a result of reduced exhaust flow.
- Degradation in Performance of Steam Turbine and Other Equipment: Degradation in the performance of the heat recovery steam generator, steam turbine, heat transfer, cooling tower, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

5. *The efficiency is noted to range from 30%-50% (HHV). Please provide an efficiency and loading curve and other benchmarking data for the new turbine that supports describing the unit as the "current state-of-the-art" electrical generating equipment*

   The application states that the typical efficiency range *for fossil fuel technologies* is 30% - 50%. Modern combined cycle natural gas-fired facilities such as that proposed for the Deer Park Energy Center operate at approximately 45% to 50% efficiency during normal operation. As an example of combined cycle efficiency, the chart below shows average performance across a load range from 60% to 100% unit output.



6. *The existing facility consists of 4 Siemens 501 F CTG/HRSG trains, one STG and associated ancillary equipment. With this application, the facility is expanding to add a fifth natural gas-fired unit rated at 180 MW (nominal), and a duct burner-fired HRSG. The facility is located in a nonattainment area and the permit application will be reviewed for nonattainment NSR. The determination whether a significant change is a major modification is defined in Part 52.21 and the March 2011 PSD and Title V Permitting Guidance for Greenhouse Gases A major modification occurs when the "net emission increase", as in 40 CFR 52.21(b)(3)(i), is significant for GHG and is comprised of a sitewide two step analyses: Step 1 of the applicability analysis considers only the emissions increases from the proposed modification itself. Step 2 of the applicability analysis, which is often referred to as "contemporaneous netting,"*

considers all creditable emissions increases and decreases. Please provide a Step 2 analysis as detailed in the GHG permitting guidance document.

The contemporaneous netting step of the PSD applicability analysis was not submitted with the GHG application for the following reasons:

- There were no contemporaneous projects which resulted in decreases of GHG emissions. Since the current project triggers PSD applicability for GHG emissions by itself, the contemporaneous increases do not affect PSD applicability for GHG emissions.
- The GHG PSD applicability analysis is different from the PSD applicability analysis for criteria pollutants (NO_X, CO, SO_2, VOC, PM_{10}, $PM_{2.5}$) in that there is no dispersion modeling analysis required for GHG emissions. For criteria pollutants, dispersion modeling to determine the impact area above a defined significant impact level (SIL) includes both the project increase and contemporaneous emission changes. Since there is no dispersion modeling required for GHG PSD applications, contemporaneous emission changes of GHG emissions are not needed for a modeling analysis.
- For contemporaneous projects which occurred prior to the initial applicability date of the PSD Tailoring Rule, January 1, 2011, emission changes of GHG emissions were not previously calculated. Those projects would have to be re-visited to calculate GHG emission increases. Since the past GHG emission increases for this project are not needed to determine PSD applicability or for inclusion in a dispersion modeling analysis, we request that the Step 2 analysis requirement be waived for this project.

Should you have any questions regarding this information, please contact Calpine's technical contact for this application, Ms. Jan Stavinoha, at jstavinoha@calpine.com or by telephone at (713) 570-4814.

Sincerely,

Patrick Blanchard

Patrick Blanchard
Director, EHS
Calpine Corporation

cc: Ms. Jan Stavinoha, P.E., Calpine Corporation
Mr. Larry Moon, P.E., Zephyr Environmental Corporation

CALPINE CORPORATION

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Patrick Blanchard
Director EHS
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February 3, 2012

RECEIVED
12 FEB -7 AM 11:29
AIR PERMITS SECTION
6PD-R

Dr. Alfred C. Dumaual, PhD
Air Permits Section (6PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Response to Request for Additional Information
Deer Park Energy Center LLC
Deer Park, Harris County, Texas

Dr. Dumaual:

On behalf of Deer Park Energy Center LLC, Calpine Corporation hereby submits this revision to the above referenced pending greenhouse gas (GHG) application for the construction of an additional natural gas fired combustion turbine generator with a duct fired heat recovery steam generator at the Deer Park Energy Center located in Deer Park, Harris Country, Texas.

As we discussed in our meeting on December 15, 2011, Calpine is proposing a phased construction plan for the new turbine at the Deer Park Energy Center. The original application represented emissions based on a Model 501F FD3 turbine. However, in order to ensure that the project can be available for commercial operation by the summer of 2014, Calpine is proposing a Siemens Model FD2 initial phase operations with subsequent modification to FD3 performance. The FD3 upgrade includes improvements to the turbine blades and vanes and improved compressor seals that allow the turbine to regain generation capacity that is lost in the summer months due to hot ambient conditions. Start of construction for the FD3 upgrade would occur within 18 months of completion of construction for the initial project.

Since the Model FD2 version of the turbine has a lower maximum fuel firing rate at warm ambient conditions, the turbine heat input for Turbine Case 2B (95° ambient temperature with power augmentation on) and Case 4B (95° ambient temperature with power augmentation off) are lower than for the Model FD3. Attached is a emission calculation Table 3-1A (Annual GHG Emission Calculations - New Combined Cycle Combustion Turbine, FD2 Scenario) which shows the annual GHG emissions for the Siemens Model FD2. The emission calculation Table 3-1 submitted with the original application shows the annual GHG emissions for the Siemens Model FD3. As shown on the calculation tables, the annual CO_2e emissions associated with the Siemens Model FD2 are 18,013 tons less than those for the Siemens Model FD3.

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Should you have any questions regarding this application, please contact Calpine's technical contact for this application, Ms. Jan Stavinoha, at jstavinoha@calpine.com or by telephone at (713) 570-4814.

Sincerely,

Patrick Blanchard
Director, EHS
Calpine Corporation

Enclosure

cc: Mr. Larry Moon, P.E., Zephyr Environmental Corporation

Table 3-1A

Annual GHG Emission Calculations - New Combined Cycle Combustion Turbine

Siemens FD-2 Scenario

Deer Park Energy Center LLC

Annual GHG Emissions Contribution From Natural Gas Fired CTG5/HRSG5

EPN	Annual Heat Input[1] (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions[3] (tpy)	Global Warming Potential[4]	CO_2e (tpy)
CTG5/HRSG5	17,577,640.5	CO_2		1,044,614	1	1,044,614
		CH_4	1.0E-03	19	21	407
		N_2O	1.0E-04	2	310	601
			Totals	**1,044,635**		**1,045,622**

Note

1. *The following annual firing rate information is from Tables A-3A and A-4A, in Appendix A of the PSD application submitted to TCEQ on 02/03/2012.*

Operating Mode	CTG Data Case Number	Annual Operating Hours hr/yr	Turbine Heat Input MMBtu/hr	Duct Burner Heat Input MMBtu/hr	Total Hourly Heat Input MMBtu/hr	Total Annual Heat Input MMBtu/yr
Base Load, 70 °F Ambient, Avg Duct Burner Firing	9b	6760	1,827.5	110	1,937.5	13,097,214.5
Base Load, 90 °F Ambient, Peak Duct Burner Firing	4b	1500	1,602.8	595	2,197.8	3,296,743.5
Base Load, 90 °F Ambient, Peak Duct Burner Firing, Power Augmentation	2b	500	1,712.4	655	2,367.4	1,183,682.5
		8760				**17,577,640.5**

2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

3. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (Fc \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = *CO_2 emitted from combustion, tons/yr*

Fc = Carbon based F-factor, 1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = *1/385 scf CO_2/lbmole at 14.7 psia and 68 °F*

MW_{CO2} = *Molecule weight of CO_2, 44.0 lb/lbmole*

4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

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April 2, 2012

Dr. Alfred C. Dumaual, PhD
Air Permits Section (6PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Response to Request for Additional Information
Deer Park Energy Center LLC
Deer Park, Harris County, Texas

Dr. Dumaual:

On behalf of Deer Park Energy Center LLC (Deer Park), Calpine Corporation hereby submits additional information with regard to the pending Greenhouse Gas (GHG) application for the above referenced facility, in response to your request via voice mail on March 26, 2012. In your voice mail, you requested information on how Deer Park proposes to demonstrate compliance with CO_2 emission limits.

Deer Park proposes to demonstrate compliance with CO_2 emission limits by monitoring the quantity of fuel combusted in the electric generating unit and performing periodic fuel sampling as specified in 40 CFR 75.10(3)(ii) (refer to procedure below). Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculate CO_2 mass emissions.

The four existing natural gas-fired turbines at Deer Park utilize fuel flow meters and monthly GCV sampling in order to comply with the Acid Rain quality assurance and monitoring requirements of 40 CFR 75, Appendix D. The proposed natural gas-fired turbine will also comply with the fuel flow metering and GCV sampling requirements of Appendix D. Deer Park proposes to determine a site-specific Fc factor using the ultimate analysis and Gross Calorific Value in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, §3.3.6.

The procedure for estimating CO_2 Emissions specified in 40 CFR 75.10(3)(ii) is as follows:

Affected gas-fired and oil-fired units may use the following equation:

$$W_{CO2} = (Fc \times H \times Uf \times MW_{CO2})/2000$$

Where:

W_{CO2} = *CO_2 emitted from combustion, tons/hr*

MW_{CO2} = *molecular weight of CO_2, 44.0 lb/lbmole*

Fc = Carbon Based Fc-Factor, (1040 scf/MMBtu for natural gas *<u>or a site-specific Fc factor</u>)*

H = Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5)

Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F

The requirements for fuel flow monitoring and quality assurance in 40 CFR 75 Appendix D are as follows:

Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))

Gross Calorific Value (GCV): determine the GCV of pipeline natural gas at least once per calendar month (40 CFR 75, Appendix D, §2.3.4.1)

This approach is also consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

Furthermore, the recently proposed NSPS Subpart TTTT –Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units ((40 CFR §60.5535(c)) allows electric generating units firing gaseous fuel and liquid fuel oil to determine CO_2 mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using a site specific Fc factor determined in accordance with 40 CFR 75, Appendix F. Therefore, Deer Park's proposed CO_2 monitoring method is consistent with the proposed NSPS Subpart TTTT.

It is Deer Park's position that the proposed methodology for determining compliance with CO_2 emissions is consistent with the requirements of 40 CFR 75, 40 CFR 98, and the proposed NSPS Subpart TTTT.

If you have any questions or require additional information, please do not hesitate to contact me at (713) 570-4814 or jstavinoha@calpine.com.

Sincerely,

Jan Stavinoha

Jan Stavinoha
EHS Manager- Central Power Region

cc: Patrick Blanchard, Calpine Corporation, Houston
Larry Moon, Zephyr Environmental, Austin

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717 TEXAS AVENUE, SUITE 1000
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April 2, 2012

Dr. Alfred C. Dumaual, PhD
Air Permits Section (6PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Response to Request for Additional Information
Deer Park Energy Center LLC
Deer Park, Harris County, Texas

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The procedure for estimating CO_2 Emissions specified in 40 CFR 75.10(3)(ii) is as follows:

Affected gas-fired and oil-fired units may use the following equation:

$$W_{CO2} = (Fc \times H \times Uf \times MW_{CO2})/2000$$

Where:

W_{CO2} = *CO_2 emitted from combustion, tons/hr*

MW_{CO2} = *molecular weight of CO_2, 44.0 lb/lbmole*

[redacted]

Fc = Carbon Based Fc-Factor, (1040 scf/MMBtu for natural gas <u>or a site-specific Fc factor</u>)

H = Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5)

Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F

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Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))

Gross Calorific Value (GCV): determine the GCV of pipeline natural gas at least once per calendar month (40 CFR 75, Appendix D, §2.3.4.1)

This approach is also consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

Furthermore, the recently proposed NSPS Subpart TTTT –Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units ((40 CFR §60.5535(c)) allows electric generating units firing gaseous fuel and liquid fuel oil to determine CO_2 mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using a site specific Fc factor determined in accordance with 40 CFR 75, Appendix F. Therefore, Deer Park's proposed CO_2 monitoring method is consistent with the proposed NSPS Subpart TTTT.

It is Deer Park's position that the proposed methodology for determining compliance with CO_2 emissions is consistent with the requirements of 40 CFR 75, 40 CFR 98, and the proposed NSPS Subpart TTTT.

If you have any questions or require additional information, please do not hesitate to contact me at (713) 570-4814 or <u>jstavinoha@calpine.com</u>.

Sincerely,

Jan Stavinoha

Jan Stavinoha
EHS Manager- Central Power Region

cc: Patrick Blanchard, Calpine Corporation, Houston
Larry Moon, Zephyr Environmental, Austin

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12 MAY -2 PM 2: 23

April 30, 2012

Dr. Alfred C. Dumaual, PhD
Air Permits Section (6PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Response to Request for Additional Information
Greenhouse Gas (GHG) Permit Application
Deer Park Energy Center, LLC
Deer Park, Harris County, Texas

Dear Dr. Dumaual:

In response to your email dated April 26, 2012, and as a follow-up to our telephone conversation on the same date, Calpine Corporation (Calpine) is providing responses to your questions regarding the GHG permit application for the above referenced facility.

EPA requests brief explanation why Calpine is going through the phased construction to install an FD2 series and then upgrade it to the FD3 series, rather than initially installing the FD3 series turbine. Why is Calpine going through the expense and trouble of installing an FD2 series only to upgrade it within a relatively short period (~18 months) to the FD3 series?

<u>**Response:**</u> The FD3 upgrade involves replacement of a limited number of internal components of the turbine which will be accomplished in the timeframe of a routine outage. The modification includes improvements to the turbine blades and vanes and improved compressor seals that allow the turbine to regain generation capacity that is lost in the summer months due to hot ambient conditions. Calpine plans to install the turbine using the FD2 configuration to ensure that the project is online and available to supply needed power to the ERCOT grid for the summer 2014 peak season. Additional time may be required to install parts required for an FD3 configuration, which would compromise that schedule.

When upgrading from the FD2 series to the FD3 series, is there any benchmarking data to show that there is possibly an increase in efficiency? For example, the ratio of the amount of MWhr generated per ton of GHG produced may be better in the FD3 turbine compared to the FD2 series. Any marked change can be an indicator of improved efficiency due to the FD3 upgrade and would help in the BACT discussion.

<u>**Response:**</u> The FD3 configuration will burn more fuel *and* produce more MW output than the FD2 configuration. Calpine has represented that the efficiency in terms of heat rate (in Btu/kWh) is the same for both configurations. In addition, emission calculations for both scenarios utilize the same GHG factors and calculation methodology. Refer to Tables 3-1 and 3-1A from the original GHG permit application dated September 1, 2011 and the subsequent submittal dated February 3, 2012, respectively.

Therefore, there is no change represented in the number of MW output generated per ton of GHG emitted between the two configurations.

As we had discussed, EPA would like if Calpine can provide more concrete dates for completion of the upgrade of the FD2 turbine to the FD3 turbine, e.g. upgrade to the FD3 turbine is set for May of 2014. There is concern that time period for upgrading to the FD3 series engine could be prolonged if the terms and conditions aren't well established, and hence possibly subject to public comment.

Response: Consistent with 30 TAC 116.120 and 40 CFR 52.21(r), and with Calpine's statement in Calpine's letter to EPA dated February 3, 2012, Calpine proposes to begin construction of the FD3 phase of the project "within 18 months of completion of construction of the initial project." Completion of construction of the initial project will occur the date that commercial operation of the FD2 phase of the project begins, in order to account for any additional work that may take place during the "shakedown period" that immediately follows first fire of the proposed turbine.

Lastly, can you provide a brief explanation of the ambient (case) temperature as it relates to turbine heat input and how that affects the efficiency of the turbine? As you had mentioned in previous communication, it was discussed that the temperature was slightly lower (95F) in the FD3 turbine than the FD2. Does that signify an increase in operating efficiency by having a higher or lower ambient temperature? If so, please explain.

Response: As discussed in Calpine's letter dated February 3, 2012, the maximum short term fuel firing rate for the FD2 configuration (in MMBtu/hr) is the same rate for the FD3 configuration. There is no difference in the ambient temperatures used in the emission cases provided for the vendor for the FD2 and FD3 cases. Table 3-1A, in the attachment to the February 3 letter, should indicate an ambient temperature of 95°F, not 90°F. This is a typographical error, and is not intended to show a different ambient temperature for the FD2 configuration. As stated in our response to the second question, Calpine is not representing a difference in efficiency between the FD2 and FD3 configurations.

If you have any additional questions or require more information, please do not hesitate to contact me at 713-570-4814 or via email at jstavinoha@calpine.com.

Sincerely,
Calpine Corporation

Jan Stavinoha

Jan Stavinoha, P.E.
Environmental Manager, Texas Power Region

cc: Patrick Blanchard, Calpine Corporation, Houston
Larry Moon, Zephyr Environmental, Austin

To: Alfred Dumaual/R6/USEPA/US@EPA,
Cc:
Bcc:
Subject: RE: GHG permit process
From: Jan Stavinoha <Jan.Stavinoha@calpine.com> - Friday 06/22/2012 10:49 AM

AC:

See below for a "typical" analytical for the Channel ref gas. The composition does vary somewhat, but we think this is representative. Note that there is a lot of H2 in the ref gas and the overall carbon content and BTU value are lower than NG. In our application, we assumed a total heat input and based our CO2 emissions on that heat input and the NG factor of ~118 lb CO2/MMBtu. This is conservative because the ref gas, which will make up a small portion of the overall fuel burned, has a lower BTU value and less methane.

Unlike the two existing units, the proposed combined cycle will not use any ref gas in the turbine itself – only the duct burners. I don't have an estimate as to how much ref gas will be burned in the duct burners for the proposed unit. I can check to see if the plant has records of ref gas separate from NG, but the site operations reports show "mixed gas" being burned in the turbines and duct burners, which is a mixture of NG and ref gas. They blend the gases upstream of their fuel meters and monitor the characteristics, such as GCV of the gas blend, but may not have records that isolate the quantity of ref gas burned. However, since it has no effect on our GHG application, you should not need specific data on this.

Let me know if you need anything else.

Thanks,

Jan

Fuel Gas Composition				Pure Component Data			Fuel Gas Component Data			
				(B)					(A) X (C)	(A) X (D)
			(A)	Molecular	(C)	(D)	(A) X (B)		Btu (HHV)	Btu (LHV)
			Mole	Weight	HHV *	LHV *	lb/lb-mol		per scf	per scf
Formula	Name	Mole %	Fraction	(lb/lb-mol)	(Btu/scf)	(Btu/scf)	Fuel Gas	Weight %	Fuel Gas	Fuel Gas
CH4	Methane	42.23	0.31	16.04	1012	911	4.97	36.65	313.72	282.41
C2H6	Ethane	10.41	0.0701	30.07	1773	1622	2.11	15.56	124.29	113.7
C3H8	Propane	2.04	0.0359	44.09	2524	2322	1.58	11.65	90.61	83.36
C4H10	n-Butane	0.28	0.0106	58.12	3271	3018	0.62	4.57	34.67	31.99
i-C4H10	Isobutane	0.18	0.0081	58.12	3261	3009	0.47	3.47	26.41	24.37
n-C5H12	n-Pentane	0.03	0.0037	72.15	4020	3717	0.27	1.99	14.87	13.75
i-C5H12	Isopentane	0.05	0.0032	72.15	4011	3708	0.23	1.7	12.84	11.87
C5H12	Neopentane		0	72.15	3994	3692	0	0	0	0
C6H14	n-Hexane		0.0074	86.17	4768	4415	0.64	4.72	35.28	32.67
C7H16	n-Heptane		0	100.2	5503	5100	0	0	0	0
C2H4	Ethylene	2.07	0.0146	28.05	1604	1503	0.41	3.02	23.42	21.94
C3H6	Propylene	0.97	0.0091	42.08	2340	2188	0.38	2.8	21.29	19.91
C4H8	n-Butene		0.0031	56.1	3084	2885	0.17	1.25	9.56	8.94
i-C4H8	Isobutene		0	56.1	3069	2868	0	0	0	0