February 18, 2010

Patrick Blanchard,
Designated Representative
Calpine Corporation
717 Texas Avenue
Suite 1000
Houston, TX 77002

Re: Petition to Use Alternative Substitute Data to Calculate SO_2 Emissions Prior to Initial Certification, for Units G102, G103, and G104 at the Clear Lake Cogeneration, L.P. Plant (Facility ID (ORISPL) 10741), and for Units GT-A, GT-B, and GT-C at the Texas City Cogeneration, L.P. Plant (Facility ID (ORISPL) 52088)

Dear Mr. Blanchard:

The United States Environmental Protection Agency (EPA) has reviewed the November 19, 2008 petition submitted by Calpine Corporation (Calpine) under 40 CFR 75.66, in which Calpine requested to use alternative missing data substitution to account for sulfur dioxide (SO_2) emissions from Units G102, G103, and G104 at the Clear Lake Cogeneration, L.P. Plant (Clear Lake); and Units GT-A, GT-B, and GT-C at the Texas City Cogeneration, L.P. Plant (Texas City) prior to initial certification. EPA approves the petition in part, with conditions, as discussed below.

Section I – The Clear Lake Plant

Background

Calpine owns and operates three gas-fired combined cycle units, i.e., Units G102, G103, and G104, at its Clear Lake Plant in Harris County, Texas. These three units, each consisting of a Siemens Westinghouse 501D5 combustion turbine and a heat recovery steam generator (HRSG), commenced commercial operation in January 1985. Steam produced in the heat recovery steam generators is used to generate additional electric power and to supply process steam to an adjacent chemical complex. The Clear Lake facility is fueled primarily by pipeline natural gas, supplemented with a hydrogen fuel supplied by the chemical complex. Pipeline natural gas and hydrogen fuels are sometimes co-fired. Clear Lake is capable of generating approximately 387 MW of electricity, with each unit serving a generator with a nameplate capacity exceeding 25 MW.

According to Calpine, the Clear Lake units were cogeneration units that met the requirements for an Acid Rain Program (ARP) exemption under 40 CFR 72.6(b)(5) until certain qualifying power purchase commitments expired on August 31, 2004. However, Calpine believes that it cannot adequately demonstrate that the ARP exemption remained in effect until August 31, 2004. Therefore, Calpine believes that the most prudent course of action is to treat Clear Lake as if the ARP exemption expired on September 30, 1998, which is the latest date for which Calpine believes it can demonstrate that the qualifying power purchase commitments support the exemption. In view of this, Calpine maintains that, pursuant to 40 CFR 75.4(c), it was required to continuously monitor and report SO_2, nitrogen oxides (NO_x), and carbon dioxide (CO_2) emissions, and heat input for these units (in accordance with 40 CFR Part 75) starting no later than December 29, 1998 (i.e., 90 days[1] after the date when Calpine believes the units became subject to the ARP). Furthermore, Calpine believes that, pursuant to §72.9(c)(3)(iv), it was required to hold SO_2 allowances equal to the units' emissions beginning on January 1, 2000. Calpine did not meet these requirements.

Calpine has since installed and certified the required Part 75 monitoring systems and has made the following submittals to EPA for the Clear Lake units: (a) certificates of representation; (b) ARP permit applications; (c) monitor certification applications; and (d) electronic data reports. According to Calpine, the units have been in full compliance with Part 75 monitoring and reporting requirements since January 1, 2008.

Calpine has elected to use the methodology in Appendix D of Part 75 to quantify SO_2 mass emissions and unit heat input for the Clear Lake units, instead of certifying continuous emission monitoring systems (CEMS) for these parameters. Appendix D, which applies only to gas- and oil-fired units, requires continuous monitoring of the fuel flow rate and periodic sampling of the fuel sulfur content, gross calorific value (GCV), and, in some instances, fuel density.

In the November 19, 2008 petition, Calpine requests to use the following alternative missing data substitution method to estimate the SO_2 emissions from Units G102, G103, and G104 in the time period from January 1, 2000 through December 31, 2007. For each calendar year:

- The hourly heat input to each unit was calculated by the plant's data acquisition and handling system (DAHS) using measured fuel flow rates (scf/hr) and the gross calorific values (GCV) of the fuels;

    - The flow rates of both natural gas and hydrogen fuel were measured using in-line orifice meters;

    - From January 1, 2000 through August, 2007, a default GCV of 1040 Btu/scf, for natural gas was used in the calculations; after that, actual measured GCVs began to be used. According to Calpine, the default GCV of 1040 Btu/scf is appropriate because it is the GCV value for natural gas specified in EPA publication AP-42.[2] Calpine used 324 Btu/scf as the GCV of the hydrogen

[1] Before June 2002, §75.4(c) allowed 90 days to certify the required monitoring systems. In June 2002, §75.4(c) was revised to allow 90 unit operating days or 180 calendar days (whichever occurs first) to complete monitor certification.

[2] The actual value in AP-42 is 1050 Btu/scf . See U.S. Environmental Protection Agency, AP-42, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources (5th ed. 1995).

fuel, which is the maximum value specified in the contract with the fuel supplier;

- The hourly heat input values from natural gas and hydrogen fuel combustion were summed over the entire year to obtain a single, non fuel-specific, annual heat input value for each unit;

- The annual SO_2 emissions for each unit were calculated using Equation D-5 in section 3.3.2 of, Appendix D of Part 75. The annual unit heat input was multiplied by the default SO_2 emission rate for pipeline natural gas[3] (i.e., 0.0006 lb/mmBtu, according to Appendix D, Table D-5);

- To ensure that the SO_2 emissions estimates would be conservative, the 0.0006 lb/mmBtu default SO_2 emission rate was applied to all unit operation during the year, including hours when hydrogen fuel (which contains no sulfur) was combusted.

  The results of these calculations are presented in Table 1, below.

Table 1: Estimated SO_2 Emissions from Clear Lake Units G102, G103, and G104, 2000 through 2007 (from the November 19, 2008 Petition)

Year	Unit G102 SO_2 Emissions (tons)	Unit G103 SO_2 Emissions (tons)	Unit G104 SO_2 Emissions (tons)	Total SO_2 Emissions (rounded tons)
2000	2.90	2.89	3.06	9
2001	2.51	2.69	2.74	8
2002	2.97	2.77	2.13	8
2003	2.40	1.44	1.97	6
2004	1.64	0.90	1.85	4
2005	0.81	1.50	1.06	3
2006	0.36	0.29	0.17	1
2007	0.45	0.56	0.52	2
			Total Tons of SO_2 =	**41**

Note: Applying to each year the rounding procedures set forth in the definition of “ton or tonnage” in 40 CFR 72.2, the Clear Lake units emitted a total of 42 tons of SO_2 from January 1, 2000 through December 31, 2007, not 41 as stated in Calpine’s November 19, 2008 petition and listed in this table.

[3] Calpine provided the documentation required by Section 2.3.1.4 of Appendix D to demonstrate that the fuel met the definition of “pipeline natural gas” in 40 CFR 72.2.

Section II – The Texas City Plant

Background

Calpine owns and operates three combined-cycle units, i.e., Units GT-A, GT-B, and GT-C, at its Texas City Plant in Galveston County, Texas. Each of these units consists of a 99.7 MW combustion turbine and a heat recovery steam generator (HRSG) equipped with auxiliary firing (i.e., a duct burner). Units GT-A, GT-B, and GT-C commenced commercial operation in May 1987. Steam produced in the HRSGs is used to generate additional electric power and to supply process steam to adjacent industrial complexes. The combustion turbines burn pipeline natural gas (PNG). Refinery gas from the adjacent petroleum refinery is combusted in the duct burners. PNG and refinery gas are sometimes co-fired, but only in the duct burners. The Texas City Plant is capable of generating approximately 450 MW of electricity, with each unit serving a generator with a nameplate capacity exceeding 25 MW.

According to Calpine, the Texas City units were cogeneration units that met the requirements for an Acid Rain Program exemption under 40 CFR 72.6(b)(5) until certain qualifying power purchase commitments expired on September 30, 2002. Calpine maintains that, at that point, Texas City Units GT-A, GT-B, and GT-C became Phase II ARP affected units, pursuant to 40 CFR 72.6(a)(3)(v). Therefore, Calpine believes that pursuant to 40 CFR 75.4(c), it was required to continuously monitor and report SO_2, NO_x, and CO_2 emissions, and heat input for these units (in accordance with 40 CFR Part 75) starting no later than 90 unit operating days or 180 calendar days (whichever occurred first) after the date that the units first operated after the date Calpine believes the units became subject to the requirements of the ARP. Calpine determined that the monitoring and reporting deadline was December 30, 2002 for Units GT-A and GT-B and January 5, 2003 for Unit GT-C. Further, Calpine believes that pursuant to 40 CFR 72.9(c)(3)(iv), it was required to hold SO_2 allowances equal to its emissions, beginning on December 30, 2002 for Units GT-A and GT-B and January 5, 2003 for Unit GT-C. However, Calpine did not meet these requirements.

Calpine has since installed and certified the required Part 75 monitoring systems and has made the following submittals to EPA for the Texas City units: (a) certificates of representation; (b) ARP permit applications; (c) monitor certification applications; and (d) electronic data reports (EDRs). Calpine has elected to use the Appendix D methodology to quantify SO_2 mass emissions and heat input for Units GT-A, GT-B, and GT-C. According to Calpine, the units have been in full compliance with Part 75 monitoring and reporting requirements since January 1, 2008.

In the November 19, 2008 petition, Calpine requests to use the following alternative missing data substitution method to estimate the SO_2 emissions from Units GT-A, GT-B, and GT-C in the time period from October 1, 2002[4] through December 31, 2007. For each calendar year:

[4] Note that Calpine assumed it is accountable for SO_2 emissions beginning on October 1, 2002, the date Calpine believes Units GT-A, GT-B, and GT-C became subject to the ARP. However, according to 40 CFR 72.9(c)(3)(iv), a newly affected unit is not required to hold allowances equal to its SO_2 emissions until the expiration of the monitoring and reporting deadline under §75.4(c) , which according to Calpine, was December 30, 2002 for Units GT-A and GT-B and January 5, 2003 for Unit GT-C.

- The hourly heat input to each unit from each type of fuel was calculated by the plant's data acquisition and handling system (DAHS), using fuel flow rates (scf/hr) measured with in-line orifice meters, and gross calorific values (GCV) measured with an on-line gas chromatograph;

- The fuel-specific hourly heat input values for each unit were then summed to obtain fuel-specific annual heat input values; and

- The annual SO_2 emissions for each unit were calculated separately for PNG and refinery gas, using Equation D-5 in section 3.3.2 of Appendix D of Part 75. The annual heat input from PNG combustion was multiplied by the default SO_2 emission rate for pipeline natural gas[5] (i.e., 0.0006 lb/mmBtu). For refinery gas combustion, the annual heat input was multiplied by a default SO_2 emission rate of 0.0011 lb/mmBtu, determined from fuel sampling data.[6]

  The results of these calculations are presented in Table 2, below.

Table 2: Estimated SO_2 Emissions from Texas City Units GT-A, GT-B, and GT-C, 2002 through 2007 (from November 19, 2008 Petition)

Year	Unit GT-A SO_2 Emissions (tons)	Unit GT-B SO_2 Emissions (tons)	Unit GT-C SO_2 Emissions (tons)	Total SO_2 Emissions (rounded tons)
2002[7]	0.63	0.61	0.65	2
2003	2.60	2.58	2.58	8
2004	2.37	2.88	2.93	8
2005	2.23	1.75	3.33	7
2006	0.80	1.20	1.66	4
2007	1.80	1.72	0.75	4
			Total Tons of SO_2 =	**33**

Note: Applying to each year the rounding procedures set forth in the definition of "ton or tonnage" in 40 CFR section 72.2, the Texas City units emitted a total of 36 tons of SO_2, not 33 as stated in Calpine's November 19, 2008 petition and listed in this table.

Section III – EPA's Determination

EPA approves Calpine's petition to use an alternative substitute data methodology to calculate SO_2 emissions from Clear Lake Units G102, G103, and G104 for the period January 1, 2000 through December 31, 2007 and Texas City Units GT-A, GT-B, and GT-C for the

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[5] Calpine provided the documentation required by section 2.3.1.4 of Appendix D to demonstrate that the fuel met the definition of "pipeline natural gas" in 40 CFR 72.2.

[6] Calpine provided the documentation required by section 2.3.6 of Appendix D to show that the refinery gas has low sulfur variability and qualifies to use a default SO_2 emission rate.

[7] This is based on the October 1 - December 31 period used by Calpine.

periods December 30, 2002 through December 31, 2007 (Units GT-A and GT-B) and January 5, 2003 through December 31, 2007 (Unit GT-C). However, for the reasons given below, the approved annual and cumulative SO_2 emissions for these units are the ones shown in Tables 3 and 4 below, rather than the ones shown in Tables 1 and 2.

In making this determination, EPA assumes -- solely for purposes of this response to Calpine's November 19, 2008 petition -- that Calpine is correct that the Clear Lake units were exempt from the ARP until August 31, 2004 and that the Texas City units were exempt from the ARP until September 30, 2002. However, Calpine did not provide, and EPA has not reviewed, the power purchase agreements on which Calpine bases its claims for exemption of these units. EPA has also not considered whether the units meet any of the other requirements for an exemption. EPA's determination here about the use of alternative substitute data does not address, or imply, any determination about the applicability of the ARP (or any other EPA-approved or administered program to which an exemption based on these power purchase agreements applies, such as the Clean Air Interstate Rule (CAIR) trading programs) to any of these units before the expiration of these power purchase agreements.

<u>Clear Lake Plant</u>

In order to determine whether Calpine's proposed calculation methodology for substitute data is sufficiently conservative to provide a strong incentive for compliance with Part 75 monitoring and reporting requirements and to ensure protection of the environment, EPA estimated the SO_2 emissions from Units G102, G103 and G104 using two different methods for the time period in question:

- First, EPA calculated the emissions using the standard missing data routines in section 2.4 of Appendix D of Part 75. The maximum potential fuel flow rate (as defined in section 2.4.2.1 of Appendix D) and the maximum potential SO_2 emission rate of 0.002 lb/mmBtu for pipeline natural gas (from Table D-6 in Appendix D) were used for each operating hour. For the hours in which the units burned hydrogen gas (which contains no sulfur), it was assumed that pipeline natural gas was burned. This resulted in a total of 168 tons of SO_2 for the 8 years of substitute data.

- Second, EPA calculated substitute data using the default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas (instead of 0.002 lb/mmBtu) and the maximum potential fuel flow rates. The monitoring plan identified the maximum potential fuel flow rates to be 12,800 scf/hr for natural gas and 7,600 scf/hr for hydrogen gas. This resulted in a total of 50 tons of SO_2 for the 8 years of substitute data.

From these calculations, using standard substitute data would grossly overstate Clear Lake's probable SO_2 emissions (which were estimated using actual heat inputs and GCV measurements and the pipeline natural gas emission rate of 0.0006 lb/mmBtu) by approximately 300%. The second calculation method, however, provides a reasonable, yet conservative estimate of the SO_2 emissions. This method is acceptable because Calpine provided the data required by section 2.3.1.4 of Appendix D showing that the natural gas combusted in Units G102, G103, and G104 meets the definition of "pipeline natural gas" in 40 CFR 72.2 and therefore qualifies for the 0.0006 lb/mmBtu SO_2 emission rate.

EPA rejects Calpine's proposed calculation methodology. Calpine's proposed method uses actual non-quality assured data and, to some extent, default factors and so does not provide conservative estimates of fuel flow rate. Calpine's approach is therefore inconsistent with the purposes of Part 75 missing data substitution, which are to provide a strong incentive for maximizing monitoring system availability and to ensure that emissions are not underreported. EPA maintains that, in light of these purposes, maximum potential fuel flow rate should be used instead in the calculations, given the absence of quality-assured flow rate data (see 40 CFR part 75, Appendix D, section 2.4.2.2.1).

In view of these considerations, EPA approves the values shown in Table 3 below for Clear Lake's annual and cumulative SO_2 emissions for calendar years 2000 through 2007.

Table 3: Accepted SO_2 Mass Emissions (2000 through 2007) for Clear Lake Units G102, G103, and G104

Year	SO_2 Emissions (tons)			
	Unit G102	Unit G103	Unit G104	Total
2000[8]	4	4	4	12
2001	3	3	3	9
2002	4	4	3	11
2003	3	2	2	7
2004	2	1	2	5
2005	1	2	2	5
2006	1	0	0	1
2007	0	0	0	0
Total	18	16	16	**50**

Texas City Plant

EPA used the same calculation methods described above for Clear Lake to estimate the SO_2 emissions from Texas City Units GT-A, GT-B, and GT-C for the time period in question. The first method (i.e., using both the maximum potential fuel flow rate and the maximum potential SO_2 emission rate) resulted in 128 tons of SO_2 for the 5 year period. The maximum potential fuel flow rate was identified in the monitoring plan to be 17,000 scf/hr for natural gas and 4,000 scf/hr for the refinery gas. The second method, using the default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas, 0.4185 gr/100 scf, the highest calculated refinery gas sulfur content from three annual samples (2004, 2005, and 2007), and the maximum potential fuel flow rate, resulted in 42 tons of SO_2 emissions for the time period. Calpine provided the operating hours in which the unit burned refinery gas. In order to be conservative in the calculations and not underestimate emissions, EPA assumed that, for any hour in which the unit burned both pipeline natural gas and refinery gas, both fuels were burned at maximum fuel flow for the entire hour.

[8] This assumes, solely for purposes of this response, that the appropriate period begins January 1, 2000.

For this facility also, EPA concluded that:

- Using standard substitute data would grossly overstate Texas City's probable SO_2 emissions (which were estimated using actual heat inputs and GCV measurements and the pipeline natural gas emission rate of 0.0006 lb/mmBtu) by approximately 256%;

- Fuel sampling data provided by Calpine show that the natural gas combusted in the units qualifies to use the 0.0006 lb/mmBtu emission rate. Therefore, the Agency's second calculation method provides reasonable, yet conservative emissions estimates; and

- Calpine's proposed calculation method is inconsistent with the purposes of missing data substitution and thus unacceptable because Calpine used actual, non-quality-assured data rather than maximum potential fuel flow rates.

In view of these considerations, EPA approves the values shown in Table 4, below, for Texas City's annual and cumulative SO_2 emissions for calendar years 2002 through 2007.

Table 4: Accepted SO_2 Mass Emissions (2002 through 2007) for Texas City Units GT-A, GT-B, and GT-C

Year	**SO_2 Emissions (tons)**			
	Unit GT-A	**Unit GT-B**	**Unit GT-C**	**Total**
2002[9]	0	0	0	0
2003[10]	4	4	4	12
2004	3	3	4	10
2005	2	1	2	5
2006	2	3	3	8
2007	2	3	2	7
Total	13	14	15	**42**

As a condition of this approval, Calpine shall address the SO_2 allowance accounting issues for Clear Lake, Units G102, G103, and G104, and Texas City, Units GT-A, GT-B, and GT-C with Mr. Kenon Smith, who may be reached at (202) 343-9164, or by e-mail at smith.kenon@epa.gov

EPA's determination relies on the accuracy and completeness of the information provided by Calpine in the November 19, 2008 petition and in subsequent clarifying e-

[9] This assumes, solely for purposes of this response, that the appropriate period for Units GT-A and GT-B begins December 30, 2002.
[10] This assumes, solely for purposes of this response, that the appropriate period for Units GT-C begins January 5, 2003.

mails,[11] and is appealable under Part 78. If you have any questions regarding this determination, please contact Travis Johnson at (202) 343-9018 or at Johnson.Travis@epa.gov. Thank you for your continued cooperation.

Sincerely,

/s/
Sam Napolitano, Director
Clean Air Markets Division

cc: John Smith, Texas CEQ
Joyce Johnson, EPA Region VI
Travis Johnson, CAMD
Kevin Tran, CAMD
Kenon Smith, CAMD
John Schakenbach, CAMD

[11] Emails dated 07/18/2008, 08/07/2008, 08/29/2008, 12/01/2008, 02/10/2009, 02/19/2009, 02/20/2009, 03/25/2009, 04/07/2009, 04/08/2009, 04/15/2009, 04/17/2009, 04/21/2009, 04/23/2009, 04/24/2009, 04/27/2009, 04/29/2009, 05/05/2009, 05/06/2009, 05/07/2009, 05/08/2009, 08/18/2009, 08/20/2009, 08/31/2009, 09/10/2009, 09/11/2009, 09/23/2009, 09/28/2009, 09/29/2009, 10/30/2009, and 11/18/2009.