10/11/2011

Mr. James Shetler
Designated Representative
Sacramento Municipal Utility District Financing Authority
Cosumnes Power Plant
P.O. Box 15830
Sacramento, CA 95852-1830

Re: Monitoring of Emissions when Digester Gas and Natural Gas are Co-fired at the Cosumnes Power Plant (Facility ID (ORISPL) 55970)

Dear Mr. Shetler:

The United States Environmental Protection Agency (EPA) has reviewed the March 28, 2011 petition and the July 21, 2011 amendment to that petition, submitted under 40 CFR 75.66 by the Sacramento Municipal Utility District Financing Authority (SFA), in which SFA requested approval of alternatives to certain monitoring provisions of 40 CFR Part 75, to account for the nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) emissions produced when natural gas and digester gas are co-fired in Units 2 and 3 at the Cosumnes Power Plant. EPA approves the petition, with conditions, as discussed below.

Background

SFA owns and operates the Cosumnes Power Plant (CPP), located in Herald, California. Units 2 and 3 at CPP are natural gas-fired 170 megawatt gas turbines, which, according to SFA, are subject to the Acid Rain Program (ARP). Therefore, CPP is required to continuously monitor and report SO_2 , NO_x, and CO_2 emissions and heat input for Units 2 and 3 according to 40 CFR Part 75.

The Sacramento Municipal Utility District (SMUD) supplies pipeline natural gas to CPP and is planning to blend digester gas into the natural gas pipeline that feeds CPP. The digester gas is produced by the Sacramento Regional Wastewater Treatment Plant (SRWTP) and is currently combusted at either the Carson Cogeneration Facility (Carson) or SRWTP (in boilers and/or flares).

Digester gas from SRWTP will be injected into SMUD's 26-mile gas transmission pipeline that connects the Carson facility to CPP. Prior to injection into the pipeline, the digester gas will be dried, and its total sulfur content will be reduced to a maximum of 1.0 grains per 100 standard cubic feet (gr/100 scf). The primary reason for pre-treating the digester gas is to meet gas pipeline design and safety criteria. If at any time CPP cannot receive digester gas into the pipeline, the gas will be burned at Carson and/or at SRWTP.

According to SFA, the heating value of digester gas is approximately 618 British thermal units per standard cubic foot (Btu/scf). The maximum amount of digester gas produced at SRWTP will be about 2,500 standard cubic feet per minute (scfm) or 150,000 standard cubic feet per hour (scfh). Therefore, the maximum heat input to Units 2 and 3 from digester gas combustion will be around 100 million Btu per hour (mmBtu/hr), which is less than 3 percent of the units' combined heat input capacity of 3,730 mmBtu/hr.

When digester gas is blended with pipeline natural gas, the resultant fuel mixture cannot be classified as "pipeline natural gas", but rather, for the purposes of Part 75, must be reclassified as an "other" gaseous fuel. The emissions monitoring requirements in Part 75 for "other" gaseous fuels are much more rigorous than those for pipeline natural gas. SFA submitted a petition to EPA on March 28, 2011, requesting to use alternatives to some of these requirements for "other" gaseous fuel, with regard to combustion of the blended gas stream at CPP Units 2 and 3.

SFA's March 28, 2011 Petition

2. *Site-Specific F Factors for NO_x and CO_2 Emissions Calculations*

For Units 2 and 3, CPP monitors and reports hourly NO_x emission rates (in pounds per million Btu (lb/mmBtu)), using continuous emission monitoring systems (CEMS). Equation F-5 in section 3.1 of Appendix F to Part 75 is used to calculate the NO_x emission rates. To determine hourly CO_2 mass emissions (tons per hour), CPP uses Equation G-4 in Appendix G to Part 75. Equations F-5 and G-4 both include an "F factor" term. Equation F-5 requires a dry-basis F factor ("F_d")[1], which is the volume of dry flue gas produced per million Btu of heat input from the combustion of a particular type of fuel. Equation G-4 requires a carbon-based F factor ("F_c"), which is the volume of CO_2 produced per million Btu of heat input from combustion of a particular fuel.

Table 1 in section 3.3.5 of Appendix F to Part 75, lists default F_d and F_c factors for various fuel types. Natural gas is included on the list, but digester gas is not. Section 3.3.6.3 of Appendix F states that when an affected unit combusts a combination of a fuel (or fuels) listed in Table 1 with fuel(s) not listed in the Table, the F_d or F_c factor used for the combined fuel stream is subject to the Administrator's approval, through the petition process under §75.66.

In the March 28, 2011 petition, SFA has proposed the following approach for determining appropriate F factors for the individual fuels and for the combined gas stream at CPP:

- First, the provisions of Appendix F, section 3.3.6 would be used to calculate site-specific F_d and F_c values for natural gas and digester gas. Section 3.3.6 allows the owner or operator to use the results of fuel sampling and analysis to calculate F_d and F_c, using

[1] Note that F_d is a commonly-used symbol for a dry basis F factor. Part 75 uses the symbol "F" without the "d" subscript.

Equations F-7a and F-7b, respectively. Although Part 75 restricts the use of these equations to fuels listed in Table 1 of Appendix F, SFA believes that the equations can be applied equally well to fuels such as digester gas, which are not listed in the Table, and has proposed to implement the provisions of section 3.3.6 at CPP in the following manner:

- ✓ Develop average F_d and F_c factors for both pipeline natural gas and digester gas, based on a minimum of 9 samples of each fuel;
- ✓ Determine the percentage of hydrogen, carbon, sulfur, nitrogen, and oxygen in each fuel by ultimate analysis, in accordance with section 3.3.6.1 of Appendix F;
- ✓ Determine the gross calorific value (GCV) of each fuel would be determined in accordance with section 3.3.6.2 of Appendix F;
- ✓ Calculate the F_d and F_c factor for each fuel at standard conditions of 20 ºC (68 ºF) and 29.92 inches of mercury, using Equations F-7a and F-7b;
- ✓ Re-determine the F_d and F_c factors for each fuel at least annually;
- ✓ Use the F_d and F_c values from the most recent determinations in the emissions calculations, unless they are lower than the F_d and F_c values currently in use; and
- ✓ Keep records of all fuel-specific F_d and Fc determinations, active for at least 3 years.

- Second, Equation F-8 in section 3.3.6.4 of Appendix F to Part 75 would be used to calculate monthly prorated F_d and F_c factors for the combined gas stream, based on the F_d and F_c values for the individual fuels (obtained from Equations F-7a and F-7b) and the fraction of the monthly heat input derived from each fuel. The prorated F_d and F_c factors would be used in the NO_x and CO_2 emissions calculations. Although Part 75 restricts the use of Equation F-8 to mixtures of fuels listed in Table 1 of Appendix F, SFA believes that the equation can be used for combined gas streams that consist of fuel(s) listed in Table 1 and fuel(s) not listed in the Table, provided that a reliable estimate of the fractional heat input contribution of each fuel is available. In view of this, SFA has proposed to implement the provisions of section 3.3.6.4 for the combined gas stream at CPP in the following manner:

- ✓ Determine the monthly heat input to Units 2 and 3 from digester gas combustion using hourly digester gas flow rates measured with a certified Appendix D fuel flow meter, together with measurements of the GCV of the digester gas, made using methods specified in section 2.2.4.3 of Appendix D;

- ✓ Determine the total monthly heat input to Units 2 and 3 from combustion of the combined gas stream using hourly flow rates measured with certified Appendix D fuel flow meters, together with measurements of the GCV of the combined gas stream, made using methods specified in section 2.2.4.3 of Appendix D;

- ✓ Calculate the monthly heat input to Units 2 and 3 from pipeline natural gas combustion by subtracting the monthly heat input provided by digester gas combustion from the monthly heat input provided by combustion of the combined gas stream;

- ✓ Calculate the fractional heat input contribution from digester gas (X_{DG}), as the ratio of the monthly heat input provided by digester gas to the monthly heat input provided by the combustion of the combined gas stream;

- ✓ Determine the fractional heat input contribution from pipeline natural gas (X_{PNG}) by subtraction, i.e., ($1-X_{DG}$);

- ✓ Use Equation F-8 to calculate prorated monthly F_d and F_c values for the combined gas stream, using the F_d and F_c for the individual fuels and the values of X_{DG} and X_{PNG}; and

- ✓ Apply the calculated, prorated monthly F_d and F_c values to the next calendar month, except for the first month of digester gas combustion at CPP, where an estimate of the values for X_{DG} and X_{PNG} based on the previous year's fuel usage at CPP and the previous year's digester gas production at SRWTP should be used.[2]

[2] The reason for this is that prorated F_d and F_c factors must be programmed into the data acquisition and handling system (DAHS) at the beginning of each month, in order to generate hourly NO_x and CO_2 emission rates. These prorated F factors must be based on the values of X_{DG} and X_{PNG} for the previous month. However, for the first month in which SFA uses the proposed methodology, there will have been no digester gas combustion at CPP in the previous month. Therefore, for the first month of digester gas combustion at CPP, SFA has proposed to estimate the values of X_{DG} and X_{PNG} as described above.

According to SFA, the proposed calculation methodology for site-specific individual and prorated F_d and F_c factors is consistent with current ARP calculation procedures for fuels listed in Table 1 of Appendix F, suggesting that the use of this proposed alternative would not adversely impact the quality of the emissions data reported for CPP Units 2 and 3.

2. *SO_2 Emissions from Combustion of the Combined Gas Stream*

Historically, CPP has followed the procedures in Appendix D of Part 75 to account for the SO_2 emissions from Units 2 and 3. For gas-fired units, Appendix D requires the use of certified fuel flow meters to continuously measure hourly fuel flow rates. Periodic fuel sampling and analysis are also required to determine the fuel sulfur content, gross calorific value (GCV), and, in some cases, density.

For pipeline natural gas, section 2.3.1.4(e) of Appendix D requires annual sampling of the fuel for total sulfur and section 2.3.4.1 of Appendix D requires monthly GCV sampling. However, for "other" gaseous fuels, such as the combined gas stream at CPP, section 2.3.3.1.1 of Appendix D requires hourly sampling of the total sulfur content using an on-line gas chromatograph (GC), unless 720 hours of total sulfur data are available to demonstrate that the fuel has a low sulfur variability and qualifies for less frequent (daily or annual) sampling (see Section 2.3.6 of Appendix D). Further, Section 2.3.4.3.3 of Appendix D requires daily measurement of the GCV for "other" gaseous fuels, unless 720 hours of GCV data are available to demonstrate that the fuel has a low GCV variability, in which case monthly GCV sampling may be performed (see Section 2.3.5 of Appendix D).

SFA does not have the requisite historical data to demonstrate the sulfur or GCV variability of the combined gas stream at CPP. In view of this, SFA proposed an alternative to the rigorous sulfur and GCV sampling requirements of Appendix D to account for the SO_2 emissions from combustion of the combined gas stream. SFA proposed to:

- Use Equation D-4 of Appendix D to estimate the hourly SO_2 mass emission rate (lb/hr), from combustion of the digester gas, based on data from an ultrasonic fuel flow meter and a continuous hydrogen sulfide (H_2S) monitor.

    - ✓ SFA included the accuracy specifications of the flow meter and H_2S monitor as attachments to the March 28, 2011 petition. According to SFA, the flow meter conforms to AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters* (1998) and is accurate to within ± l% of full scale. The specification sheet for the H_2S analyzer indicates that it is accurate to within ± 0.5 ppm for a range of 0 to 20 ppm H_2S.
    - ✓ SFA would multiply the H_2S readings by 1.15, to convert them to total sulfur. A 1.15 adjustment factor was previously approved by EPA in 1999 for use at the

Carson facility, based on fuel analyses showing that more than 85% of the total sulfur in the SRWTP digester gas comes from H_2S.

- Use Equation D-5 of Appendix D to estimate the hourly SO_2 mass emission rate (lb/hr), from combustion of pipeline natural gas (PNG).

    - ✓ The hourly heat input rate for PNG in Equation D-5 would be obtained by subtracting the measured heat input rate of the digester gas from the heat input rate of the combined gas stream that is fed to Units 2 and 3.
    - ✓ Data from certified Appendix D fuel flow meters and an on-line gas chromatograph that meets Appendix D requirements would be used to quantify the heat input rate of the combined gas stream.
    - ✓ The default SO_2 emission rate of 0.0006 lb/mmBtu for PNG would be used in the calculations.

- Sum the hourly SO_2 mass emission rates from PNG and digester gas combustion.

- Rearrange Equation D-4 of Appendix D to determine the hourly sulfur content of the combined gas stream.

    - ✓ The total SO_2 mass emission rate for the combined gas stream and the sum of the measured flow rates of combined gas to Units 2 and 3 would be used in this calculation.

- Calculate and report hourly SO_2 mass emissions for each unit.

    - ✓ Use Equation D-4 of Appendix D.
    - ✓ Substitute the measured flow rate of the combined gas stream to the unit and the calculated hourly sulfur content of the combined gas stream into Equation D-4.

According to SDFA, because the proposed alternative method for calculating SO_2 emissions from CPP Units 2 and 3 is based on calculation procedures in Appendix D, no adverse impact on the quality of the SO_2 emissions data reported to EPA is expected.

The July 21, 2011 Amendment to the March 28, 2011 Petition

In June, 2011, EPA contacted SFA to discuss the March 28, 2011 petition. Among other things, EPA and SFA sought ways to simplify the proposed SO_2 emissions calculation methodology for Units 2 and 3. One suggested approach would be for SFA to take multiple samples of the digester gas and analyze them for total sulfur. If the results of the fuel analyses could demonstrate that the digester gas has a total sulfur content equivalent to that of PNG, i.e., 0.5 gr/100 scf or less, then SFA could use the PNG default SO_2 emission rate (0.0006 lb/mmBtu) to calculate SO_2 mass emissions from Units 2 and 3 for all unit operating hours, including hours when PNG and digester gas are co-fired.

On July 21, 2011, SFA submitted an amendment to the March 28, 2011 petition, proposing to take 9 samples of the digester gas and analyze them for total sulfur, using methods in Appendix D of Part 75. If the results of the analyses demonstrate that the sulfur content of the digester gas is 0.5 gr/100 scf or less, SFA would:

- Use the PNG default SO_2 emission rate of 0.0006 lb/mmBtu to calculate SO_2 emissions from CPP Units 2 and 3, for all unit operating hours; and
- Sample the digester gas annually (i.e., at the same frequency as PNG), to confirm that the sulfur content of the gas remains at or below 0.5 gr/100 scf.

However, if SFA is unable to demonstrate that the sulfur content of the digester gas is equivalent to that of PNG, SFA would implement the SO_2 emissions calculation methodology described in the March 28, 2011 petition.

<u>EPA's Determination</u>

EPA has reviewed SFA's March 28, 2011 petition, as amended on July 21, 2011, and approves the petition, with conditions, as follows:

1. EPA approves SFA's proposed methodology for determining site-specific F-factors for the Units 2 and 3 at the Cosumnes Power Plant. The individual F_d and F_c factors for pipeline natural gas and digester gas and the prorated F-factor for the combined gas stream must be re-determined annually. The value from the most recent determination must be used in the NO_x and CO_2 emissions calculations, unless it is lower than the value currently in use. CPP must keep records of all site-specific F_d and F_c determinations, for at least 3 years.

2. EPA approves SFA's proposal to calculate the SO_2 mass emissions from Units 2 and 3 using a default SO_2 emission factor of 0.0006 lb/mmBtu for all operating hours, provided that a minimum of 9 samples of the digester gas are analyzed, using methods specified in Appendix D of Part 75, and the results of the analyses demonstrate that the sulfur content of the digester gas is 0.5 gr/100 scf or less.

- If SFA is able to successfully demonstrate this, annual sampling of the digester gas for total sulfur is required, using methods specified in Appendix D of Part 75, to confirm that the sulfur content remains at or below 0.5 gr/100 scf.

- If SFA is unable to successfully demonstrate this, or if the results of required annual sampling show that the sulfur content of the digester gas is greater than 0.5 gr/100 scf, SFA must implement the SO_2 emissions calculation methodology proposed in the March 28, 2011 petition for CPP Units 2 and 3, which is hereby approved.

EPA's determination relies on the accuracy and completeness of SFA's March 28, 2011 petition and the July 21, 2011 amendment and is appealable under Part 78. If you have any questions regarding this correspondence, please contact Carlos R. Martinez at (202) 343-9747 or by e-mail at martinez.carlos@epa.gov. Thank you for your continued cooperation.

Sincerely,

/s/
Sam Napolitano, Director
Clean Air Markets Division

cc: Steve Frey, EPA Region IX
Sandy Simko, Texas Commission on Environmental Quality
Carlos R. Martínez, CAMD
Edgar Mercado, CAMD
Craig Hillock, CAMD