From:	Velasco, Robert A.
To:	McWade, Tammy
Cc:	Burrows, Byron T.
Subject:	RE: Tampa Electric Company, Big Bend Station, Project No. 0570039-065-AC, Units 1 - 4 Natural Gas Igniter Project
Date:	Thursday, June 06, 2013 12:54:48 PM
Attachments:	Big Bend Ignitor PSD Applicability Calculations.pdf

Tammy:

Please see responses to your email, dated June 3, 2013.

1. **Comment:** In the application Tampa Electric Company (TEC) is requesting to retain the existing provisions to burn fuel oil. However, Units 1 – 4 will no longer have the capability of firing fuel oil. Therefore, a new air construction application requesting a modification to these units will need to be submitted if equipment will be installed in the future for these units to fire fuel oil.

   Response: Agree, no comment.

2. Comment 2. TEC is requesting a natural gas heat input limit when co-firing coal and natural gas and a combined natural gas heat input limit while firing only natural gas during low-load. Please confirm.

   Response: Correct. Having two limits will ensure that emission increases will be below the PSD major modification thresholds for either natural gas igniter operating scenario.

3. Comment 3: The application currently shows the emissions of VOC will be 41.8 tons/year, which are exceeding the PSD significant emission rate of 40 tons/year. Is TEC requesting an emissions limit to avoid PSD? If not, please provide the proper application and PSD analysis. Please clarify.

   Response: The analysis of PSD applicability was conducted for two natural gas igniter operating scenarios; (a) co-firing with coal and (b) low-load firing. The projected change in actual emission rates was conducted for each scenario assuming total annual heat input rates for each Big Bend boiler equal to their 2011/2012 average actual heat input rates. Accordingly, the two natural gas igniter operating scenarios were evaluated as separate alternative cases with <u>each</u> alternative using the total projected annual heat input rates. The proposed separate natural gas heat input caps will ensure that the change in emissions for either alternative scenario will not exceed the PSD major modification thresholds.

   However, Tampa Electric requests the flexibility to use either natural gas igniter operating scenario or any combination of the two. To ensure that both natural gas igniter operating scenarios combined will not exceed the PSD major modification thresholds, a third alternative operating scenario comprised of both co-firing and low-load firing was developed again based on total 2011/2012 average actual heat input rates. To remain below the PSD major modification thresholds for this third alternative, the natural gas heat input caps for co-firing were reduced slightly. The revised requested natural gas heat input caps during coal and natural gas co-firing are summarized as follows:

Unit ID	Natural Gas Heat Input Cap (MMBtu/yr)
1	5,140,056
2	4,402,030
3	5,154,534
4	5,672,397

Revised PSD applicability calculation tables are attached.

4. Comment: The application shows emissions of NOx will be 39.0 tons/year. When co-firing natural gas and coal the natural gas emission factor used to calculate NOx are the same as the emission factor used to calculate coal. Please provide historical data/SCR vendor guarantee/calculations to show and support the proposed emission factor used in calculating NOx emission when co-firing coal and natural gas.

   Response: When co-firing natural gas and coal, the SCR controls will be in use. During co-firing, the SCR controls will be operated such that the historical 2011/2012 NOx emission rates will be maintained through adjustment of ammonia injection rates as needed. For Big Bend Units 1-3, the AP-42 uncontrolled NOx emission factor for coal is 31 lb/ton of coal which equates to 1.31 lb/MMBtu based on a coal heat content of 23.6 MMBtu/ton. For Big Bend Unit 4, the AP-42 uncontrolled NOx emission factor for coal is 10 lb/ton of coal which equates to 0.42 lb/MMBtu. The AP-42 uncontrolled NOx emission factor for natural gas is 0.137 lb/MMBtu. Since combustion of natural gas will generate lower NOx emissions compared to coal, Tampa Electric expects that lower rates of ammonia injection will be needed during natural gas co-firing.

5. Comment 5: Please clarify Tables 2 and 3 calculations. See response below. Is the projected actual emissions for co-firing coal and natural gas given in Table 2.D. and for firing only natural gas during low-load given in Table 3.D.? Yes Table 3.D. includes emissions produced from co-firing coal and natural gas during low-load. Please clarify. See response below AP-42 Table 1.4-1 emission factor for large wall fired boiler (> 100 MMBtu/hour) controlled by flue gas recirculation shows an emission factor of 100 lb/10^6 scf for NOx. Please clarify.

   Response: Units 1-4 are each equipped with low-NOx burners and SCR controls. For estimating NOx emissions during natural gas low-load firing when the SCR controls will not be in use, an AP-42 emission factor of 140 lb/MM scf (which equates to 0.137 lb/MMBtu) for large wall-fired boilers controlled with low-NOx burners was used. The project actual increase in NOx emissions during low-load natural gas firing will be lower if the lower 100 lb/MM scf NOx emission factor is used. Please provide the following calculations:

   Please see response to Item 3 above. Revised PSD applicability calculation tables are attached. The revised tables include the historical actual emission rates in units of lb/MMBtu (Table 1A) and emission rates for the third alternative scenario (Table 4) discussed in Item 3 above.

a) Emissions produced from co-firing coal and natural gas;

Please see Tables 2 and 4.

b) Emissions produced from firing natural gas alone during startup, shutdown, malfunction, flame stabilization and/or low load;

Please see Tables 3 and 4.

c) Please provide these calculations separately and then as a total for you projected actual emission less the baseline emissions to show an actual increase in emissions for the proposed project;

Please see Tables 2, 3, and 4.

d) To provide reasonable assurance that GHG emissions will not increase due to the proposed project, please provide the projected actual emissions for GHG emissions as part of the PSD analysis; and

Modifications at major PSD sources that result in an increase in 75,000 tons per year of greenhouse gases (GHG) as carbon dioxide equivalents (CO_2e) are subject to PSD review. The 40 CFR Part 98 (i.e., the EPA Mandatory GHG Reporting Rule) CO_2 emission factors for bituminous coal and natural gas are 205.9 and 116.9 lb CO_2 per MMBtu, respectively; i.e., coal has 1.8 times the amount of CO_2 emissions on a lb/MMBtu basis compared to natural gas. Since increased use of natural gas and lower coal use will not change the future utilization of Units 1-4, projected actual annual heat input rates for Units 1-4 were assumed to be equal to the actual 2011/2012 average heat input rates for each unit. Since actual annual heat input rates will not change, the substitution of natural gas for coal on a heat input basis will result in a <u>decrease</u> in actual GHG emissions. Please let me know if the Department needs an estimate of the decrease in actual GHG emissions due to the igniter project.

e) To demonstrate that the proposed project will not result in an increase in the emission rates (in lbs/hour) of NOx, SO_2 and PM for NSPS Subpart Db of 40 CFR 60, please provide a comparison in emissions from firing fuel oil versus natural gas.

An assessment of NSPS Subpart Da applicability for Big Bend Units 1-3 was provided in the submitted regulatory applicability analysis. For changes at existing electric utility steam generating units, the test for NSPS applicability is contained in 40 CFR §60.14(h); i.e., "No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change." Maximum hourly NOx emission rates for the 2008-2012 five year period were included in the submitted regulatory applicability analysis – these rates are well above the maximum hourly NOx emission rate that will occur during low-load natural gas firing when the SCR controls will not be in use. Due to the negligible

sulfur and ash contents of natural gas, maximum hourly emissions of PM and SO_2 during natural gas co-firing or low-load firing will be lower than the maximum rates that occurred during the 2008-2012 five year period when firing 100 percent coal.

Best Regards,

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From: McWade, Tammy [mailto:Tammy.McWade@dep.state.fl.us]
Sent: Monday, June 03, 2013 12:37 PM
To: Velasco, Robert A.
Cc: Burrows, Byron T.
Subject: Tampa Electric Company, Big Bend Station, Project No. 0570039-065-AC, Units 1 - 4 Natural Gas Igniter Project

Hi Rob,

As per our conversation, I need the following information and/or clarifications to complete the application for the above described project:

1. In the application Tampa Electric Company (TEC) is requesting to retain the existing provisions to burn fuel oil. However, Units 1 – 4 will no longer have the capability of firing fuel oil. Therefore, a new air construction application requesting a modification to these units will need to be submitted if equipment will be installed in the future for these units to fire fuel oil.
2. TEC is requesting a natural gas heat input limit when co-firing coal and natural gas and a combined natural gas heat input limit while firing only natural gas during low-load. Please confirm.
3. The application currently shows the emissions of VOC will be 41.8 tons/year, which are exceeding the PSD significant emission rate of 40 tons/year. Is TEC requesting an emissions limit to avoid PSD? If not, please provide the proper application and PSD analysis. Please clarify.
4. The application shows emissions of NOx will be 39.0 tons/year. When co-firing natural gas and coal the natural gas emission factor used to calculate NOx are the same as the emission factor used to calculate coal. Please provide historical data/SCR vendor guarantee/calculations to show and support the proposed emission factor used in

calculating NOx emission when co-firing coal and natural gas.

5. Please clarify Tables 2 and 3 calculations. Is the projected actual emissions for co-firing coal and natural gas given in Table 2.D. and for firing only natural gas during low-load given in Table 3.D.? Table 3.D. includes emissions produced from co-firing coal and natural gas during low-load. Please clarify. AP-42 Table 1.4-1 emission factor for large wall fired boiler (> 100 MMBtu/hour) controlled by flue gas recirculation shows an emission factor of 100 lb/10^6 scf for NOx. Please clarify. Please provide the following calculations:

   a) Emissions produced from co-firing coal and natural gas;

   b) Emissions produced from firing natural gas alone during startup, shutdown, malfunction, flame stabilization and/or low load;

   c) Please provide these calculations separately and then as a total for you projected actual emission less the baseline emissions to show an actual increase in emissions for the proposed project;

   d) To provide reasonable assurance that GHG emissions will not increase due to the proposed project, please provide the projected actual emissions for GHG emissions as part of the PSD analysis; and

   e) To demonstrate that the proposed project will not result in an increase in the emission rates (in lbs/hour) of NOx, SO_2 and PM for NSPS Subpart Db of 40 CFR 60, please provide a comparison in emissions from firing fuel oil versus natural gas.

Please respond to the additional information requested to complete the application process by 6/10/2013. This will allow time to review the information provided. Otherwise, due to our time clock, a request for additional information will need to be issued.

If you have any questions please give me a call or email.

Thank you,

Tammy T. McWade
Engineer Specialist III
Florida Department of Environmental Protection
Division of Air Resource Management (DARM)
Office of Permitting and Compliance (OPC)
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Please take a few minutes to share your comments on the service you received from the department by clicking on this link DEP Customer Survey.

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