Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Lower Colorado River Authority, Thomas C. Ferguson Plant

Permit Number: PSD-TX-1244-GHG

September 2011

This document serves as the statement of basis required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On March 15, 2011, the Lower Colorado River Authority (LCRA)-Thomas C. Ferguson Plant, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed project, LCRA submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on October 29, 2010. The project at the Thomas C. Ferguson Plant proposes to replace an existing 37 year-old 440 megawatt electric generating boiler with a new highly efficient natural gas-fired combined cycle power plant with a generating capacity of approximately 590 megawatts. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the LCRA, Thomas C. Ferguson plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that LCRA's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information EPA requested and provided by LCRA, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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Austin, TX 78767-0220

Physical Address:
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Horseshoe Bay, TX 78657

Contact: Kenneth W. Taylor, Power Production Manager

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Melanie Magee
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(214) 665-7161

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

IV. Facility Location

The LCRA, Thomas C. Ferguson plant is located in Llano County, Texas, and this area is currently considered to be in attainment for all NAAQS. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude:	30° 26' 48" North
Longitude:	98°22'15" West

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. LCRA, Thomas C. Ferguson Power Plant Location

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes LCRA's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(iv). Under the project, increased GHG emissions will have a mass basis over zero tpy and CO_2e emissions are calculated to meet and well exceed the applicability threshold of 75,000 tpy. (LCRA calculates CO_2e emissions of 1,821,242 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305

As the permitting authority for regulated NSR pollutants other than GHGs, TCEQ has determined the modification is subject to PSD review for non-GHG pollutants. Specifically, the TCEQ final permit decision (having a notice issuance date of September 1, 2011), explains the proposed facility will:

"emit the following air contaminants in a significant amount: organic compounds, carbon monoxide, sulfuric acid, and particulate matter, including particulate matter with diameters of 10 microns or less and 2.5 microns or less."

Accordingly, under the circumstances of this project, the State will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow LCRA to replace an existing 37 year-old 440 megawatt steam boiler with two new 195 MW natural gas-fired General Electric (model 7FA) combined cycle combustion turbines with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to a dedicated Heat Recovery Steam Generator (HRSG) to produce steam. The steam produced from the two HRSGs is then routed to the new shared 200 MW steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.

VII. Applicable Emission Units

Natural Gas-Fired Combined-Cycle Combustion Turbines

The existing steam electric generating unit, including the boiler and turbine/generator set, is proposed to be replaced with a new combined-cycle power plant that would be more efficient, more reliable and have improved environmental controls. The existing steam electric generating unit includes an older 440 MW natural gas-fired utility boiler (emission unit: EPN Stack 1) that will be permanently shutdown and dismantled. LCRA seeks to take a creditable NO_x reduction from the permanent shutdown of the boiler. To do so, LCRA shall notify EPA by letter of the dismantling activities within 15 days of the permanent shutdown.

The new power plant will have a generating capacity of approximately 590 MW. This generating capacity is divided into two emission units of identical 195 MW natural gas-fired combined cycle combustion turbines (General Electric 7FA) and one 200 MW steam turbine.

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[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

The new power plant is limited to natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf).

As part of the PSD review, LCRA provides in the GHG permit application a 5-step top-down BACT analysis for the two combustion turbine emission units. In this analysis, LCRA identifies the use of combined cycle power generation technology, the use of carbon capture and storage (CCS) and, as a supplement to the permit application, the General Electric Rapid Response System and solar thermal generating equipment. EPA has reviewed LCRA's BACT analysis for the natural gas-fired combined-cycle combustion turbines, finds it sufficient, and adopts it in setting forth this proposed permit, as summarized below. A search of the RACT/BACT/LAER Clearing house was completed and no entries were found for natural gas-fired combustion turbine generators that address BACT for GHG emissions. However, LCRA did identify a GHG BACT analysis that was completed for the Russell City Energy Center project located in Hayward, California. The Russell City Energy Center project included two Siemens-Westinghouse 501FD3 combustion turbines and a GHG BACT permit condition was established which set the heat rate limit to 7,730 Btu/kWh. The proposed LCRA GHG PSD permit, if finalized, requires a combustion turbine annual net heat rate limit of 7,720 Btu/kWh (HHV).

In EPA's BACT review an additional facility, Palmdale Hybrid Power Project (SE-09-01), was identified. The Palmdale project is located in the City of Palmdale, California and consists of two General Electric 7FA natural gas-fired CTGs rated at 154 MW each, one steam turbine generator rated at 267 MW and 251 acres of parabolic solar-thermal collectors with associated heat-transfer equipment. EPA requested LCRA to provide a supplemental analysis comparing the use of the General Electric Rapid Response System and the inclusion of solar equipment into their design process[1]. In LCRA's response, the General Electric Rapid Response System is noted to be similar to the LCRA combustion turbine design. The LCRA combustion turbine design includes similar types of controls integration and equipment for reducing start times such as the steam turbine bypass system and terminal temperature attemperators[2]. However, LCRA notes that the solar thermal generating equipment should not be considered for these emission units. The solar thermal generating equipment would require an additional auxiliary boiler and a heat transfer fluid heater for the solar steam unit. Therefore, the CO_2 emission from these sources could exceed the GHG reductions resulting from the anticipated reduction in startup time.

Within the permit application BACT analysis, LCRA discusses the infeasibility of utilizing the CCS technology and an additional cost analysis[3] is provided to support this determination. EPA has reviewed LCRA's CCS technical and cost analysis and concurs with the assessment. In LCRA's CCS technology analysis, amine adsorption technology is noted to have been applied for CO_2 capture to processes in the petroleum refining and natural gas processing industries and exhausts from gas-fired industrial boilers. However, LCRA reports that based upon an initial

[2] Email from Mr. Joseph Bentley, LCRA, to Melanie Magee, EPA Region 6. August 4, 2011 (re: Alternative Technologies)

[3] Email from Mr. Joseph Bentley, LCRA, to Ms. Melanie Magee, EPA Region 6. April 22, 2011 (re: CCS and CCS Cost Estimation email attachment). email and attachment

assessment with a vendor, Mitsubishi, and literature review[4], the CO_2 capture and compression technology for power plant gas turbine exhausts is not yet commercially available.

As noted in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical challenges to implementation. EPA, which participated in the Interagency Task Force, supports the Task Force's recommendations concerning ongoing investment in demonstrations of the CCS technologies based on the report's conclusion that: "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment." [4] EPA Region 6 has completed a research and literature review and have found that nothing has changed dramatically in the industry since the August 2010 report and there is no specific evidence that larger capture systems are available for LCRA.

EPA Region 6 reviewed LCRA's CCS cost estimate and believes the overall cost estimation is financially prohibitive due to the overall cost of GHG control strategies. Not only would LCRA need to install carbon capture controls, but they would also need to build a new pipeline to transport the CO_2 approximately 85 miles to the closest site with recognized potential for geological storage of CO_2. Further, the closest known site with actual demonstrated capacity for geological storage would be the Scurry Area Canyon Reef Operators (SACROC) site in Scurry County, Texas at about 210 miles away. The bulk of the cost for CCS is attributable to the post-combustion capture and compression system. LCRA has provided a cost estimation that indicates that the overall cost for the entire CCS system could add as much as $232,341,530 annual costs to the project using the maximum cost estimate to install and operate the CCS system. LCRA estimated cost to construct the Thomas C. Ferguson power plant will range from $520 - $550 million without the CCS technology. Adding the cost of a CCS system to the Ferguson plant could increase the cost of the project by almost 42% if the technology could be properly scaled and made commercially available to LCRA. In addition, adding CCS would result in some energy penalty simply because the CCS process will use energy produced by the plant resulting in a loss of efficiency which may in turn potentially increases the natural gas fuel use of the plant to overcome these efficiency losses. The *Report of the Interagency Task Force on Carbon Capture and Storage*[4] has estimated that an energy penalty of as much as 15% would result from inclusion of CO_2 capture (Reference 4, page A-14). EPA has eliminated CCS from its

[4] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html

BACT analysis based upon our research and analysis that a commercially available CCS system to proper scale could not be provided to LCRA in the near term; in addition, even if technically feasible, the option has been eliminated based on economic impacts due to the additional projected capital costs of adding CCS as the control technology.

From the BACT analysis for greenhouse gas emissions, it is determined that the most efficient method to generate electricity from a natural gas fuel source is the use of a combined-cycle design. The major components incorporated into a combined-cycle unit are a combustion turbine, a heat recovery generator (HRSG) and a steam turbine. Specific energy efficiency processes, practices and designs are included in the permit application for each component of the combined cycle unit.

The combined cycle combustion turbine unit selected is a high-efficiency F-Class machine and is designed with a number of features to improve the overall efficiency of the machine. The additional combustion turbine design features include:

1. Inlet evaporative cooling to utilize water to cool the inlet air and thereby increasing the turbine's efficiency;
2. Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure a more reliable operation of the unit and maintain optimal efficiency;
3. Insulation blankets are utilized to minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine; and
4. Hydrogen will be used to cool the generators resulting in a lower electrical loss and higher unit efficiency.

The Heat Recovery Steam Generator (HRSG) energy efficiency processes, practices and designs considered include:

1. Energy efficient heat exchanger design. In this design, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s);
2. Addition of insulation to the HRSG panels, high-temperature steam and water lines and to the bottom portion of the stack;
3. Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes (performed at least every 18 months) is performed to minimize fouling; and
4. Minimization of steam vents and repair of steam leaks.

As a part of the TCEQ permitting action, the existing steam turbine (emission unit: FIN STG-1) is replaced with a new, high-efficiency, reheat, condensing unit (emission unit: ST1LOV-VNT). No greenhouse gas emissions are associated with this piece of equipment; however, the following energy efficiency processes, practices and designs are included in the GHG permit application.

1. Reheat cycles are used to minimize the moisture content of the exhaust stream;
2. Use of a condenser to lower the exhaust steam conditions;
3. Efficient blading design and multiple steam seal designs; and
4. Steam turbine cooling by totally enclosed water to air-cooled or hydrogen-cooled.

Within the combined-cycle power plant, several plant-wide energy efficiency processes, practices and designs are included as BACT requirements. The requirements include:

1. Fuel gas preheating. For the F-class combustion turbine based combined-cycle, the fuel gas is heated, during winter environmental conditions, with high temperature water from the HRSG;
2. Cooling water source. A once-through system using water from Lake LBJ is used for this project;
3. Drain operation. Operation drains are controlled to minimize the loss of energy from the cycle but closing the drains as soon as the appropriate steam conditions are achieved;
4. Multiple combustion turbine/HRSG trains. Multiple combustion turbine/HRSH trains help with part-load operation. A higher overall plant part-load efficiency is achieved by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation;
5. Boiler feed pump fluid drives. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives are used to minimize the power consumption at part-load conditions;
6. Lighting. High-efficiency lighting, including Light Emitting Diode (LED) type lighting, is used to minimize auxiliary power consumption; and
7. Steam turbine bypass. A steam turbine bypass system is used to direct the steam being generated in the HRSH to the condenser during startup and trip conditions.

The proposed GHG PSD permit, if finalized, requires a GHG BACT limit of 0.459 tons CO_2/MWhr (net) on a 365-day rolling average. The GHG BACT limit is calculated from emission factors and the annual average heat rate (HHV), 7,720 Btu/kWh, and includes a 5 percent degradation factor and seasonal variation. From the calculations, with the emission units running at 100 percent gross load and a heat rate of 7720 Btu/kWh, the facility base load efficiency is calculated to be approximately 50 percent. However, it is anticipated that the facility will operate at a range of loading scenarios and a 50 percent gross load may be more characteristic of normal operations. LCRA has submitted an analysis of the facility's heat input rate for 50 percent, 75 percent and 100 percent gross load scenarios. At 50 percent gross load, the facility efficiency is calculated to be approximately 44 percent. The permit application indicates 50 percent efficiency and for this efficiency the gross load is 100 percent. The calculation method proposed by LCRA to calculate the BACT limit contains only one variable, the amount of heat going to the CTG averaged on a 12-month basis assuming 50 percent gross load (includes seasonal variation averages). With LCRA's proposed BACT calculation method, relying only on the quantity and quality of fuel being consumed does not demonstrate the operation of a unit in an efficient manner. In order to more accurately measure efficiency, EPA is requiring LCRA to measure the actual heat input in MMBtu per hour and measure the pounds of CO_2 on an hourly basis with a CO_2 emissions monitor. This analysis can be completed utilizing the updated F_c factor, 40 CFR Part 75, Appendices F and G, and a conversion methodology similar to the equations provided for SO_2 and NO_x in the *Air Calculations and Conversions Guide*[5]. As an alternative, LCRA may install, calibrate and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. To demonstrate compliance with the CO_2 BACT limit of 0.459 tons of CO_2 per MWh (net), the measured hourly CO_2 emissions are divided by the net hourly energy output and averaged daily.

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[5] See Air Calculations and Conversions Guide available at:
http://www.tecenv.com/awma_iowa/Air%20Calculations%20&%20Conversions%20Guide.pdf

An initial stack test is required to establish the actual quantities of CO_2 emissions from emission points U1-STK and U2-STK. Each emission point is required to be tested at or above 90% of maximum load operations, below 90% of maximum load operations but above 60% and below 60% but above 45% load operations. The testing scenarios are representative of the various gross loading scenarios that LCRA has provided in their emissions calculations (50%, 75% and 100%). An initial stack test is not required for CH_4 and N_20 because the CH_4 and N_2O emissions are approximately 0.09% of the total CO_2e emissions from the CTGs and are considered a de minimis level in comparison to the CO_2 emissions.

LCRA may choose to calculate or measure the hourly stack gas volumetric flow rate needed to calculate the CO_2 stack emission rate. The calculation method for the hourly stack gas volumetric flow rate is based on the monthly fuel analysis and updated F_c factor in 40 CFR Part 75, Appendices F and G. The applicant may also choose to install and operate a volumetric gas flow monitor and associated data acquisition and handling system in accordance with the CO_2 CEMS provided in 40 CFR § 75.10(a)(3) and (a)(5).

The calculated hourly CO_2 concentration result for emission points U1-STK and U2-STK are required to be compared to the measured hourly CO_2 concentration from the CO_2 emission monitor. If the mean difference between the calculated and measured CO_2 concentration result is greater than 10%, LCRA shall review the emission units and monitoring instrumentation operational performance. This comparison is generally similar to the Relative Accuracy Test Audit (RATA) trial run standards provided in 40 CFR Part 75(E)(2). From this review, any corrective measures taken are to be identified, recorded, including the reason for the CO_2 emissions difference and corrective measures completed within 48 hours of the corrective measures being taken. If LCRA chooses to install and operate a CO_2 CEMS equipped with a volumetric stack gas monitoring system, then the CO_2 concentration calculation and mean difference comparison is no longer a requirement and the applicant shall rely on the data from the CO_2 CEMS for compliance purposes.

The emission limits associated with CH_4 and N_20 are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the CTGs and; therefore, additional analysis is not required for CH_4 and N_20. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day rolling average.

An initial stack test demonstration will be required for CO_2 emissions from emission units U1-STK and U2-STK. An initial stack test demonstration for CH_4 and N_20 emissions are not required because the CH_4 and N_2O emission are approximately 0.09% of the total CO_2e emissions from the CTGs and are considered a de minimis level in comparison to the CO_2 emissions.

Startup and shutdown emissions are authorized and provided in a separate operating scenario[6]. The startup and shutdown emission limits are quantified in Table 2 of the draft permit and the table is entitled "Startup and Shutdown Emissions." In this table, short term (hourly) limits are provided and the startup and shutdown annual emissions are not expected to exceed the normal operations annual emissions. During periods of startup and shutdown, the permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and the duration of each startup and shutdown event. All emissions during startup and shutdown are minimized by limiting the duration of operation. Emission limits during startup and shutdown are provided in Table 2 of the draft permit. To demonstrate compliance with the startup and shutdown emissions, LCRA shall record the time, date, fuel heat input and duration of each startup and shutdown event. The duration of operation during startup and shutdown are defined as follows:

1. A startup of each CTG (EPNs: U1-STK and U2-STK) is defined as the period that begins when there is measureable fuel flow to the CTG and ends when the CTG load reaches 50 percent. A startup for each CTG is limited to six hours.
2. A shutdown of each CTG (EPNs: U1-STK and U2-STK) is defined as the period that begins when the CTG load falls below 50 percent and ends when there is no longer measureable fuel flow to the CTG. A shutdown for each CTG is limited to 2 hours.

Under draft terms, records of all emission limit calculations and startup and shutdown events shall be kept on-site for a period of 5-years. After review of the submitted materials, EPA agrees with and adopts LCRA's BACT analysis for the natural gas-fired combined-cycle combustion turbines.

Auxiliary Combustion Equipment

The proposed GHG PSD permit, if finalized, includes the installation of a new, high efficiency, 617-hp fire pump engine (emission unit: FWP1-STK) and 1,340-hp emergency generator (EMGEN1-STK) that will replace older existing units. A review of the RACT BACT LAER Database (RBLC) and other sources shows that the BACT control decisions for these types of engines include good engine design and proper operating practices. A numerical BACT limit is infeasible due to their relatively low annual emission and the emergency nature of the equipment. EPA has reviewed LCRA's BACT analysis and concurs and adopts LCRA's BACT for emergency engines. The BACT for emergency engines is determined to be the use of engines with a low annual capacity factor and performance of routine maintenance. For these emission units, the units are limited to fire diesel fuel containing no more than 0.5 percent sulfur by weight and the hours of operation are limited to 100 hours of non-emergency operation per year for each unit. The emergency engines shall also meet the requirements as specified in 40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. An operational non-resettable elapsed time meter is required to be installed and maintained to demonstrate compliance with the operational limitation. Records are also required from the fuel supplier to certify compliance with the fuel sulfur content limit. After reviewing the submitted materials, EPA concurs with the applicant and proposes BACT for the combustion equipment to be burning only diesel fuel containing no more than 0.5 percent sulfur

[6] Email from Mr. Joseph Bentley, LCRA, to Ms. Melanie Magee and Ms. Bonnie Braganza, EPA Region 6. July 11, 2011 (re: CO_2 Emissions during startup)

by weight, and the hours of operation limited to 100 hours of non-emergency operation per year for each unit.

Fugitive Emission Sources

EPA has reviewed and concurs with LCRA's Fugitive Emission Sources BACT analysis. Based on LCRA's top-down BACT analysis for fugitive emissions, LCRA concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is the appropriate BACT control technology option. The proposed GHG PSD permit, if finalized, includes 2 new 24 lb, 6 new 58 lb and 4 existing 58 lb SF_6 insulated circuit breakers. Sources of fugitive methane (CH_4) emissions include the 520 gas/vapor valves, 1460 gas/vapor flanges and 3 gas/vapor compressors. LCRA will monitor the SF_6 emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use. The annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD. The annual CH_4 emissions will be calculated according to the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems. EPA concurs with and adopts LCRA's best work practice standards for control of SF_6 and CH_4 emissions and the state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection for fugitive SF_6 emissions as BACT.

VIII. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA), and implementing regulations at 50 CFR Part 402, EPA must insure this permit action is not likely to jeopardize the continued existence of any federally listed threatened and/or endangered species or result in the destruction or adverse modification of designated critical habitat. After careful review of a biological assessment submitted by the applicant, EPA Region 6 concludes this permit action will have no effect on listed species or critical habitat because none occur in the project action area.

IX. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. After considering a report submitted by the applicant, EPA Region 6 determines no such properties will be affected by its permit action because none are present in the action area. Before that report was submitted to EPA, the Texas Historical Commission provided LCRA written concurrence on the report and its conclusion that no such properties are present. EPA is providing a copy of this Statement of Basis and the applicant's report to the Advisory Council on Historic Preservation and Indian tribes with potential cultural interests in the action area for review and comment. The Council, tribes, and the public are welcome to bring particular concerns or information to our attention.

X. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA maintains an ongoing commitment to ensure environmental justice for all people, regardless of race, color, national origin, or income. Ensuring environmental justice means not only protecting human health and the environment for everyone, but also ensuring that all people are treated fairly and are given the opportunity to participate meaningfully in the development, implementation, and enforcement of environmental laws, regulations, and policies.

EPA has conducted a preliminary demographic analysis based on the project location, which suggested that environmental justice concerns are unlikely to be raised in connection with the permitting decision. This analysis has been added to the supporting file for this permit and may be revised as necessary before any final decision on the application. Commenters are welcome to bring particular environmental justice concerns or information to our attention during the public comment period. All such comments that are received during the draft permit public comment period will be evaluated prior to the final permit decision.

XI. Conclusion and Proposed Action

Based on the information supplied by LCRA, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue LCRA a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

Appendix

Table 1. Annual Facility Emission Limits

Short term emissions, in pounds per hour (lb/hr) on a 30-day basis, annual emissions, in tons per year (TPY) on a 365-day rolling average basis shall not exceed the following:

ID No.	Description	GHG Mass Basis			CO_2e		
			lb/hr[1]	TPY[2,3]		lb/hr[1]	TPY CO_2e[2,3]
U1-STK	Unit 1 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO_2		908,957.6	CO_2		908,957.6
		CH_4		16.8	CH_4		353.3
		N_20		1.7	N_20		521.6
U2-STK	Unit 2 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO_2		908,957.6	CO_2		908,957.6
		CH_4		16.8	CH_4		353.3
		N_20		1.7	N_20		521.6
NG-FUG	Fugitive Natural Gas emissions from piping components	CH_4[4]		16.2			327.2
EMGEN1-STK	1,340-hp Diesel Fired Emergency Generator	CO_2[5,6]	15,263.2[1]	763.2		15,314.0[1]	765.7
FWP1-STK	617-hp Diesel Fired Fire Water Pump	CO_2[5,6]	7,027.8[1]	351.4		7,052.0[1]	352.6
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6		0.006			131.0
Totals		**CO_2**		**1,819,029.8**	**CO_2e**		**1,821,241.5**
		CH_4		**49.8**			
		N_20		**3.4**			
		SF_6		**0.006**			

1. Compliance with the short term emission limits (pounds per hour) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emission (CO_2) is not presented in the table.
5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions (CH_4 and N_2O) are not presented in the table.
6. Hours of operation for emission units EMGEN1-STK and FWP1-STK shall not exceed 100 hours of non-emergency only operation per year.

Table 2. Startup and Shutdown Emissions

ID No.	Description	Pollutant	Startup and Shutdown GHG Mass Basis[1]	Startup and Shutdown CO_{2e}
			lb/hr	lb/hr
U1-STK	Unit 1 of 2 Natural Gas Fired Combustion Turbine	CO_2	153,392.10	153,392.10
		CH_4	2.84	353.30
		N_2O	0.28	521.60
U2-STK	Unit 2 of 2 Natural Gas Fired Combustion Turbine	CO_2	153,392.10	153,392.10
		CH_4	2.84	353.30
		N_2O	0.28	521.60

[1] Startup and Shutdown lb/hr emissions are an estimate and are enforceable through compliance with the applicable special condition(s) such as Special Condition II.B.4.e and other permit application representations, such as fuel gas preheating and boiler feed pump fluid drives.

Received Email Correspondence

Thomas C. Ferguson Power Plant - Carbon Capture and Sequestration (CCS) Costs

From: Joe Bentley
to: Melanie Magee
04/22/2011 12:40 PM
Show Details

Melanie,

As I mentioned in my email to you on April 14, we have been examining the cost estimates for carbon capture, transport, and sequestration for our proposed natural gas combined cycle (NGCC) project. While there are currently no instances where CCS is deployed commercially on a NGCC plant, we have relied on the 2010 Report of the Interagency Task Force on Carbon Capture and Storage (attached) to provide us with rough cost estimates. With respect to a NGCC plant, the study concludes that "[f]or post-combustion CO2 capture on a similarly sized [550 MWe] new NGCC plant, the capital costs would increase by $340 million or 80 percent." It is important to note that this capital cost does not include the cost of the pipeline and storage, nor does it account for the significant energy penalty, which is likely to be well over 15 percent of energy generated by the project. I have also attached an Excel spreadsheet, which further breaks down the range of these costs as they might apply to a project similar in scope to the Ferguson project.
We also plan to provide a Biological Assessment of the project to your office by mid May.

Please contact me if you have any questions or need additional information.

Thanks.

Joe Bentley
512-473-3272

CCS Cost Estimation Email Attachment

Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of CO_2 Emissions from the Proposed Combined Cycle Electric Generating Units at Thomas C. Ferguson Power Plant, Llano County, Texas

Carbon Capture and Storage (CCS) Component System	Factors for Approximate Costs for CCS Systems	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored)[1]	CO_2 Transport System (km CO_2 transported)[5]	Range of Approximate Annual Costs for CCS Systems ($)
Post-Combustion CO_2 Capture and Compression System				
Minimum Cost	$44.11 / ton of CO_2 avoided[2]	1,854,461		$81,800,274
Maximum Cost	$103.42 / ton of CO_2 avoided[3]	1,854,461		$191,786,604
Average Cost	$73.76 / ton of CO_2 avoided[4]	1,854,461		$136,793,439
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km[3]	1,854,461	137	$2,302,718
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km[3]	1,854,461	137	$6,908,154
Average Cost	$1.81 / ton of CO_2 transported per 100 km[4]	1,854,461	137	$4,605,436
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored[3,6]	1,854,461		$942,110
Maximum Cost	$18.14 / ton of CO_2 stored[3,6]	1,854,461		$33,646,773
Average Cost	$9.33 / ton of CO_2 stored[4]	1,854,461		$17,294,441
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$45.86 / ton of CO_2 removed	1,854,461		$85,045,101
Maximum Cost	$125.29 / ton of CO_2 removed	1,854,461		$232,341,530
Average Cost	$85.57 / ton of CO_2 removed[4]	1,854,461		$158,693,316

[1] Assumes that a capture system would be able to capture 90% of the total CO_2 emissions generated by the power plant's gas turbines.

[2] This cost factor is the minimum found for implementation/operation of CO_2 capture systems within the cost-related information reviewed for CCS technology. The factor is from the on the "Properties" spreadsheet of the *Greenhouse Gas Mitigation Strategies Database* (Apr. 2010) (http://ghg.ie.unc.edu:8080/GHGMDB/#data), which was obtained through the EPA GHG web site (http://www.epa.gov/nsr/ghgpermitting.html). The factor is based on the increased cost of electricity (COE; in $/MW-h) resulting from implementation and operation at a CO_2 capture system on a natural gas-fired combined cycle power plant. The factor accounts for annualized capital costs, fixed operating costs, variable operating costs, and fuel costs.

[3] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage*, pp.33, 34, 37, and 44 (Aug. 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO_2 avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs over its lifetime: initial

[4] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each CCS component system and for all systems combined.

[5] The length of the pipeline was assumed to be the distance to the closest potential geologic storage site, as identified by Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, in *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at http://www.beg.utexas.edu/environqlty/co2seq/pubs_presentations/Hovorka-%20for%20posting%20new%206-8/New%20Developments%20%96%20Solved%20and%20Unsolved%20Questions_TCEQ%202008.ppt

[6] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage*, p. 44)

=>

Per DOE: "Avoided emissions are those emissions that are not produced (are avoided) by using non-emitting technologies or by capturing and sequestering emissions from an emitting source. For the fossil energy industry, avoided emission measures reduction in CO2 and other greenhouse gas emissions but also takes into account the reduced capacity of power plants caused by the addition of a CO2 capture and sequestration system. Avoided emissions are calculated from a baseline that describes what the emissions would have been without carbon capture and sequestration. For capture and sequestration purposes, calculating avoided emissions takes into consideration 1) the reduction in power plant efficiency resulting from the extra energy load of the CO2 CCS system, and 2) the fact that not all exhaust CO2 can be captured with current technology. Assessing carbon capture and sequestration systems on an avoided emissions basis is the best way to show results that can be compared to nuclear, renewables, and other GHG reduction options."
(http://www.netl.doe.gov/technologies/carbon_seq/FAQs/greenhouse-gas.html)

From: Joe Bentley
To: Melanie Magee/R6/USEPA/US@EPA
Cc: Bonnie Braganza/R6/USEPA/US@EPA; Jeffrey Robinson/R6/USEPA/US@EPA
Subject: RE: Alternative Technologies
Date: 08/04/2011 09:30 AM

Melanie,

In response to your question, yes, LCRA has considered these technologies and incorporated some of them into the plant design. The GE Rapid Response System is a GE proprietary design offered when GE supplies the steam turbine, the combustion turbines, the heat recovery steam generators, and associated piping and valving. It is a system of integrating the controls for this equipment to reduce start times. Our EPC contractor is supplying the main components of the combined cycle plant. In the EPC bid responses for the Ferguson Power Plant, the steam turbine and the heat recovery steam generator are not being supplied by GE. However, the plant does include similar types of controls integration and equipment for reducing the start times (e.g., steam turbine bypass systems and terminal temperature attemperators to decouple the steam turbine from the combustion turbine startup which allows the combustion turbine to ramp to emissions compliance load sooner and to shorten the overall startup duration).

Regarding the solar component of the City of Palmdale, our design did not consider the integration of solar thermal generating equipment. Such equipment may indeed incrementally enhance the overall thermal efficiency; however, we do not view the integration of a separate "generation" technology as a "control" technology to be evaluated in a BACT analysis. We believe that this position is consistent with EPA's GHG guidance document. In addition, the employment and viability of solar technologies is a function of local or regional meteorological conditions. So, what might be viable in Palmdale, California (which appears to be fairly isolated and in what looks to be desert terrain) does not necessarily translate to other regions. We also noted the heat rate performance metric and associated CO_2 emission rate in the Palmdale application does not include the solar input. Our other comments relate to the Palmdale GHG emission rate of 0.370 MT CO_2 /MWH, which is obviously in metric tons, whereas our rate of 0.459 tons CO_2/MWH is in short tons. The Palmdale emission rate in short tons would be 0.408 tons/CO_2/MWH. Although we're unable to see in their application what assumptions were made regarding operating conditions, it is apparent that they expect to operate at optimum conditions more frequently than we do. We did not see that the Palmdale emission rate factored in any degradation of efficiency over time.

We also noted that the Palmdale facility included an auxiliary boiler and a heat transfer fluid heater for the solar steam unit. As you know, we did not propose to include these two CO_2 emission sources in the Ferguson design. The CO_2 emissions from these sources could exceed the GHG reductions resulting from a reduction in startup time. We could not determine from their application what (if any) the GHG emission reductions were going to be as a result of the Rapid Response System, only that startup time will be reduced by greater than 50 percent during cold starts with smaller reductions in startup times for warm and hot starts. The Palmdale PSD permit application also classifies a cold start as having an average duration of 48 hours without fuel being supplied to the turbine. The Ferguson technical specifications noted that a cold start was classified as a period of greater than 72 hours without fuel firing. This makes us wonder if their claim of at least a 50 percent reduction in startup duration would apply if the startup classifications were the same.

Thank you for the opportunity to provide our response. Please let me know if you have questions or need additional information concerning our GHG permit application. Joe Bentley

From: Melanie Magee [mailto:Magee.Melanie@epamail.epa.gov]
Sent: Monday, August 01, 2011 8:00 AM **To:** Joe Bentley **Cc:** Bonnie Braganza; Jeffrey Robinson **Subject:** Alternative Technologies

Joe,

I have received a copy of a GHG PSD permitting action from Region 9 and this permit is anticipated to go to public notice for the draft permit by the second week in August. In this application, the applicant, Palmdale, has noted the use of the GE Power Systems Rapid Start Process (RSP) as BACT. Also, this facility has added 50 MW solar thermal generation to produce up to 10% of the facility's total generation. Has LCRA considered these technologies?

Thanks, Melanie

Melanie Magee Air Permits Section (6PD-R)
U.S. Environmental Protection Agency 1445 Ross Avenue Dallas, TX 75202
(214) 665-7161

From: Joe Bentley
To: Melanie Magee/R6/USEPA/US@EPA
Subject: Proposed Ferguson Annual Heat Rate Spreadsheet
Date: 06/10/2011 02:17 PM

Attachments: GT_Annual_Heat_Rates.xls

Melanie,

As we discussed yesterday, LCRA received heat rates for the proposed combined cycle project from three contractors bidding for the Engineering, Procurement, and Construction (EPC) Contract. The heat rates provided in the attached table are a function of both ambient temperatures, provided in three increments (97F, 59F, and 30F), and operation at 100%, 75% and 50% loads.

Given that the operational characteristics of the units will be a function of the Texas nodal market, it is difficult to predict or forecast how the facility will be run throughout the year. However, being an intermediate unit (as opposed to a base load or peaker) we can be certain that the unit will be called on to run throughout its operational range and will be expected to respond rapidly to changes in load demands and startup and shutdown as required. Although the minimum output presented on the table is 50%, the operation of the turbines will not be limited to 50% of maximum loads. Accordingly, to ensure all operation ranges and variabilities are accounted for, LCRA based the proposed replacement facility's heat rate on the EPC specified heat rates assuming 50% output.

Also, assumptions were made concerning the ambient temperature conditions. Obviously it is difficult to predict future weather conditions; nevertheless, LCRA believes that for the Central Texas location of the facility it is reasonable and conservative to assume that three months out of the year will be at the high range (97F), two months at the cold range (30F) and the remaining seven months at the more moderate temperature (59F). These assumptions were used to weight the heat rates (at 50% load).

Lastly, it was assumed that the heat rates will degrade somewhat over time. Based on information provided by vendors, LCRA has assumed a 5% degradation (i.e., increase) in heat rate. Accordingly, the temperature weighted heat rates from all three EPC bidders have been multiplied by 1.05. In that the final bid has yet to be awarded, LCRA has assumed these resulting heat rates to be appropriate for the establishment of BACT for greenhouse gas emissions. As shown in the attached table, the proposed heat rate is 7,720 Btu/kWh.

Please let me know if you need anything else. We appreciate your help with this project.

Joe Bentley 512-
473-3272

THOMAS C. FERGUSON COMBINED CYCLE HEAT RATES

From Bidder's Submittal			97F			59F			30F		
GT Gross Load (%)			100%	75%	50%	100%	75%	50%	100%	75%	50%
EPC Bidder 1											
Facility Net Heat Rate, HHV	Btu/kWh		6,697	7,039	7,407	6,605	6,859	7,245	6,635	6,866	7,317
EPC Bidder 2											
Facility net heat rate, HHV	Btu/kWh		6,643	6,907	7,527	6,557	6,734	7,278	6,603	6,745	7,351
EPC Bidder 3											
Facility net heat rate, HHV	Btu/kWh		6,639	6,956	7,300	6,575	6,785	7,163	6,613	6,801	7,250

Assume

Months at 97F	3
Months at 59F	7
Months at 30F	2

Annual average at 50% output — **Degradation** 1.05

	Heat Rates	
EPC Bidder 1	7,297	7,662
EPC Bidder 2	7,352	7,720
EPC Bidder 3	7,212	7,573

From: Joe Bentley
To: Bonnie Braganza/R6/USEPA/US@EPA; Melanie Magee/R6/USEPA/US@EPA
Subject: GE Load vs. Efficiency Curve
Date: 07/21/2011 01:30 PM

Attachments: Book3.xlsx

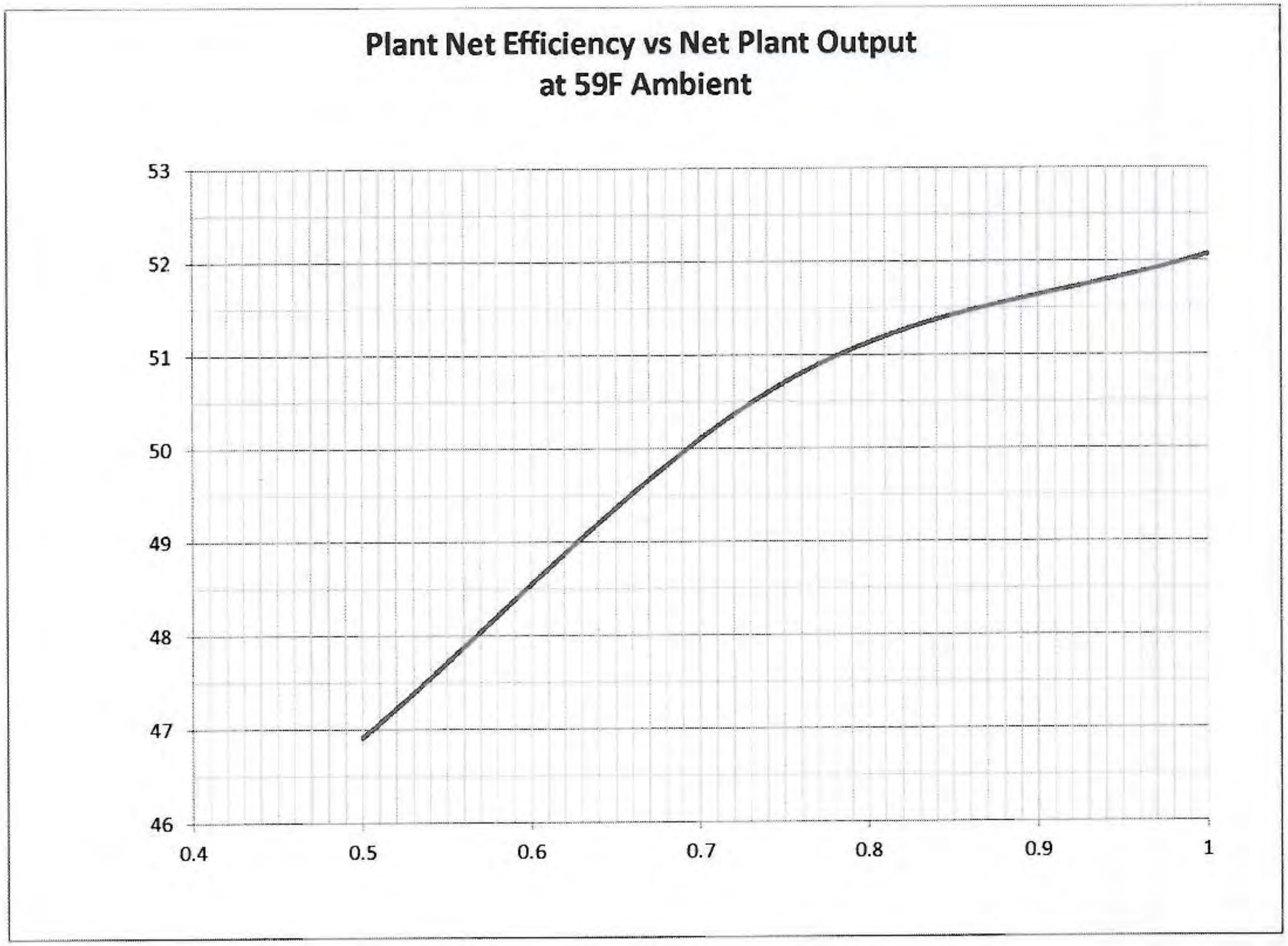
Bonnie,

Attached is a representative facility load vs. efficiency curve for the new Ferguson Power Plant.

Yesterday, you also asked about a facility maintenance agreement. We do intend to have a long-term service agreement (probably with GE). The terms and conditions will be finalized once all the permits and construction contracts are in place.

Please let me know if you have any questions or need additional information. Thanks.

Joe Bentley 512-
473-3272


Plant Net Efficiency vs Net Plant Output
at 59F Ambient
53
52
51
50
49
48
47
46
0.4
0.5
0.6
0.7
0.8
0.9
1

Melanie and Bonnie,

The attached includes our preliminary calculations of the startup CO2 emissions for each turbine. The EPC contractor is checking on some numbers and may not be able to get the final version until tomorrow. I wanted to at least get you something before the end of the day. Please let me know if you have any questions.

As for our meeting on the 20th, we were thinking 10:30 would work for us. Let me know if this date/time is OK with you.

Thanks again.

Joe

AMBIENT CONDITIONS										
Air Temperature (Dry Bulb)	°F	97	97	97	59	59	59	30	30	30
Relative Humidity	%	30	30	30	60	60	60	62	62	62
Elevation	ft	850	850	850	850	850	850	850	850	850
CTG Gross Load	%	100	75	Guaranteed Minimum Output (59)	100	75	Guaranteed Minimum Output (56)	100	75	Guaranteed Minimum Output (53)
OPERATING DATA										
CTG in Operation	#	2	2	1	2	2	1	2	2	1
Evap. Cooler Water Mass Flow (per CTG Train)	lb/h	19,200	0	0	6,000	0	0	0	0	0
Fuel LHV	Btu/lb	20,358	20,358	20,358	20,358	20,358	20,358	20,358	20,358	20,358
Fuel Mass Flow (per CTG Train)	lb/h	74,752	57,511	50,079	79,507	63,051	53,542	82,911	66,392	54,391

Per CTG

Fuel LHV	Btu/lb	20,358		LHV
Fuel mass flow	lb/hr		54,391	
BTU Consumed, LHV	mmBtu/hr	1,107		LHV
Conversion to HHV	mmBtu/hr	1,229		HHV
Degradation	5%	**1,291**		mmBTU/hr

Using Equation G-4 in 40 CFR Part 75, Appendix G

WCO2, tons/hr	F_c * H * U_f * MW CO2 / 2,000
WCO2, tons/hr	76.7
WCO2, lbs/hr During MSS =	153,392.1