Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Guadalupe Power Partners, Guadalupe Generating Station

Permit Number: PSD-TX-1310-GHG

October 2014

This document serves as the statement of basis for the above-referenced draft permit, as 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 November 12, 2012, Guadalupe Power Partners LP (GPP), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions increases from the existing major stationary source, Guadalupe Generating Station (GGS). In connection with the same proposed project, GPP submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on September 21, 2012. In February 2014, Calpine Corporation (Calpine) completed the acquisition of the GGS from GPP. Calpine has requested EPA to continue to review the proposed project and has provided supplemental information and a revised application on September 10, 2014 and September 29, 2014 to reflect the company ownership change and project revisions.

GPP proposes to add two (2) new gas-fired simple-cycle combustion turbines of 227 MW (nominal) electric generating capacity each to the 1,000 MW (nominal) existing major stationary source, Guadalupe Generating Station (GGS), located in Marion, Texas. The proposed project will provide peaking capacity at an existing natural gas fired combined cycle electric generating station. The two new natural gas-fired simple-cycle turbines are proposed to provide a fast ramp up for additional peaking capacity during peak electricity demand periods. In addition, the project also includes the installation of a firewater pump engine, circuit breakers and associated fugitive emissions. After reviewing the application and supplemental information provided by Calpine, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the GGS.

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 requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that GPP'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 GPP, 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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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
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IV. Facility Location

GGS is located in Guadalupe County, Texas. Guadalupe County is currently designated attainment for all criteria pollutants. The GGS plant site expansion is to be located on an undeveloped tract of land due north of the existing GGS operating area, south of County Road (CR) 374, Weil Road, and east of CR 359 approximate 3.65 miles (6 km) North of Marion, Texas.

The geographic coordinates for this facility are planned to be as follows:

Latitude: 29° 37’ 32” N
Longitude: 98° 8’ 42” W

The following figures illustrate GGS facility location and the proposed site layout for this draft permit.

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

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court

issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (No. 12-1146). The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a Prevention of Significant Deterioration (PSD) or title V permit. However, the Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

The source is a major source because the facility has the potential to emit 238 tpy of carbon monoxide (CO) and 189 tpy of nitrogen oxides (NOx). In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project is subject to PSD review for increases in the following conventional regulated NSR pollutants: CO and NOx.

The applicant also estimates that this same project will result in a GHG emissions increase and a net GHG emissions increase of, 611,655.16 tpy CO_2e and greater than zero tons per year on a mass basis, which well exceeds the GHG thresholds in EPA regulations. 40 C.F.R § 52.21 (49)(iv); see also, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March, 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes 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 regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

GPP proposes to construct a peaking power addition to the existing power station, GGS, generally located north of Marion, Texas. The existing power station consists of four natural gas-fired combined-cycle combustion turbine generator units capable of producing a nominal 1,000 MW of electricity. To meet market demand for peak power in ERCOT, GPP proposes to construct two (2) identical natural

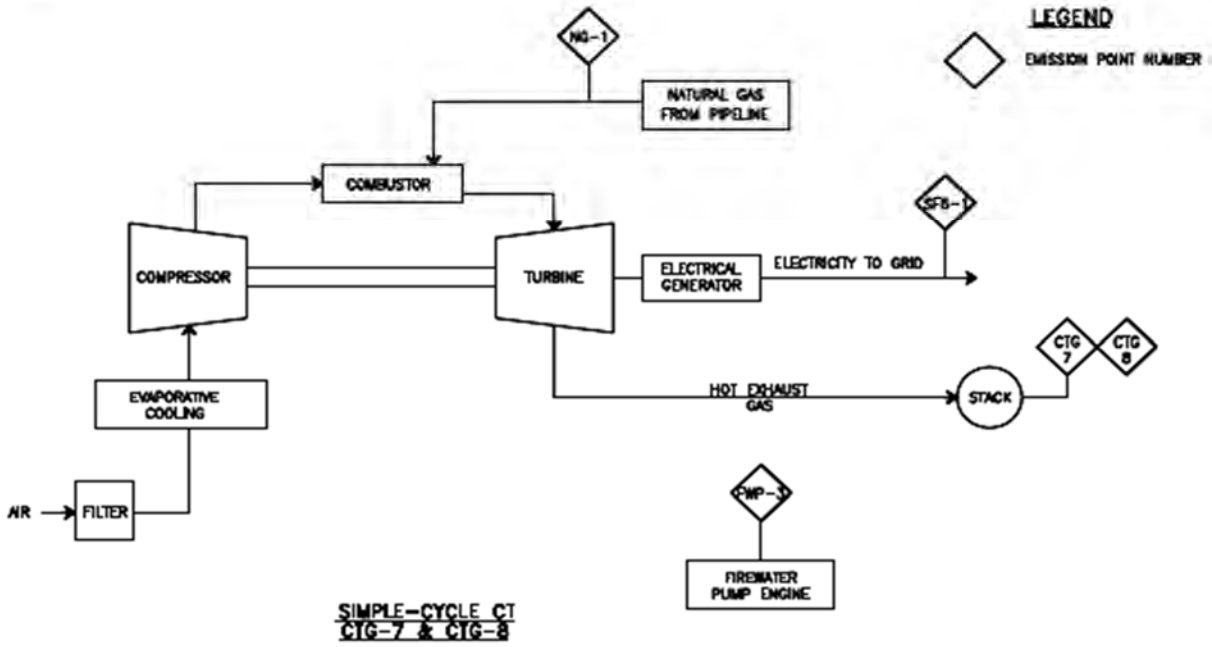
[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

gas-fired simple-cycle combustion turbines with associated ancillary equipment. The two new natural gas-fired simple cycle combustion turbine generators (CTG) will be General Electric 7FA.05 (GE 7FA.05), each with a maximum base-load electric power output of 227 megawatts (MW, nominal). The applicant also proposes to install one fire water pump and other auxiliary equipment. Greenhouse gas (GHG) emissions will result from the following emission units:

- Two new 227 MW (nominal net) Natural Gas-Fired Simple-Cycle Combustion Turbines, GE 7FA.05 (EPNs: CTG-7 and CTG-8);
- One ultra-low-sulfur diesel-fired (ULSD) Fire Water Pump Engine, not to exceed 300 hp (EPN: FWP-3);
- Fugitive Emissions from SF_6 Circuit Breakers (EPN: SF6-1); and,
- Fugitive Emissions from Piping Components (EPN: NG-1)

Process Description and Process Flow

The following presents a process flow diagram for the two simple-cycle combustion turbines at GGS, The power block will have the potential to generate a nominal 454 MW of electricity.



Peak Load Operation Using Two Natural Gas-Fired Simple Cycle CTGs

In February 2014, Calpine acquired GPP including the Guadalupe Generation Station. Calpine is an independent power producer and provides electricity to wholesale customers in ERCOT. Calpine's operations in the ERCOT market include 14 facilities utilizing similar turbine technologies to that proposed for this project. An independent power generator is differentiated from a municipality or

cooperative as it has no prescribed service area or captive customer base. As such, its turbine based facilities are designed to meet a broad range of potential customer needs over the life cycle of the projects.

As a member of the Electric Reliability Council of Texas (ERCOT), GPP is responsible for meeting the requirements and standards for reliable and adequate bulk power transmission by the National Electric Reliability Corporation (NERC) and ERCOT. NERC is the entity certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. In an agreement between NERC and ERCOT, the ERCOT provides the coordination and promotion of electric system reliability for a region that covers a majority of Texas. In 1999, the Texas Legislature restructured the Texas electric market by unbundling the investor-owned utilities and created a retail customer choice for service areas. ERCOT has the following responsibilities: system reliability, open access to transmission, retail switching process for customer choice and wholesale market settlement for electricity production and delivery. As a member of ERCOT, GPP has agreed to provide reliable operation of a portion of the bulk electric system for the Texas service area. In addition, GPP has mandatory and enforceable stands from NERC to ensure the reliable operation of the bulk electric system.

GPP is proposing to add two identical natural gas-fired simple-cycle CTGs to meet a demand for peak power to customers in ERCOT. The applicant documented the design and efficiency considerations for its selection of a turbine model by providing a comparative analysis of several simple-cycle CTG models. While the BACT requirement does not necessarily dictate the selection of any particular turbine model, particularly when each model is reflective of the efficiency upgrades attained in the last several years, an applicant's study or discussion of multiple models can be helpful in delineating the design and feasibility considerations that are crucial for meeting the project's business purpose. The CTG models considered will burn pipeline natural gas to rotate an electrical generator to produce electricity. The main components of a CTG consist of a compressor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine section where the gases expand across turbine blades, driving a shaft to power an electric generator. To increase the density of air prior to entering the compressor, and allow for a higher mass flow of combustion air, the GE 7FA.05 proposed by GPP will be equipped with evaporative cooling on the intake air of the compressors. Use of inlet air cooling increases the gas turbine output and can provide an improvement in the efficiency of the turbines under certain ambient conditions. The evaporative coolers in and of themselves are not a source or control device of GHG emissions.

In 2012, renewable energy resources (other than hydroelectric) accounted for approximately 5 percent of the electricity generated by electric utilities.[2] Because the use of solar and wind power are not typically utilized to provide peaking power to the grid due to interruptible service, renewable resources were not addressed in the BACT analysis because these interruptible sources are not suited for the primary purpose serving as peaking power project.

<u>Fire Water Pump</u>

[2] U.S. Department of Energy, Energy Information Administration, *Frequently Asked Questions*. See http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3, September 30, 2010 .

The site will be equipped with one nominally rated 300-hp diesel-fired fire water pump engine to provide water in the event of a fire. The fire water pump engine will operate on low-sulfur (0.0015%) fuel and will be limited to 100 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing. The fire water pump engine will meet Tier 3 standards for off-road diesel engines under 40 CFR Part 89.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The circuit breakers associated with the proposed units and associated equipment will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The total capacity of the circuit breakers associated with the proposed plant is currently estimated not to exceed 1,380 lb SF_6. The proposed circuit breakers will have a low pressure alarm and a low pressure lockout. The alarm will alert personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" of SF_6 gas.

Fugitive Emissions from Piping Components

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Because a majority of the GHG fugitives comes from methane and the GWP is higher for methane, a conservative estimate was done to assume that all piping components are in a rich methane stream. The CO_2e from fugitive emissions, account for less than 0.007% of the project's total CO_2e emissions.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

VIII. Natural Gas Fired Simple Cycle Combustion Turbines BACT Analysis (EPNs: CTG-7 and CTG-8)

Step 1 – Identify all available control technologies

The first step in the top-down BACT process is to identify all "available" control options. In general, if a control option has been demonstrated in practice on a range of exhaust gases with similar physical and chemical characteristics and does not have a significant negative impact on process operations, product quality, or the control of other emissions; it may be considered as potentially feasible for application to another process

- *Carbon Capture and Storage (CCS)* – CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is generally applied to "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production and iron and steel manufacturing)."[3]

  CCS contains three major components: carbon capture, transport, and storage. With respect to carbon capture, CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is used primarily in gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion have no practical application for this proposed gas turbine facility. The third approach, post-combustion capture, is applicable to gas turbines.

  With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical adsorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in the BACT analysis.

  Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to

[3]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR), if available. There is a large body of ongoing research and field studies focused on developing a better understanding of the science and technologies for CO_2 storage.

- *Generating technologies such as combined-cycle gas turbines* – As stated in the *PSD and Title V Permitting Guidance for Greenhouse Gases*, combined-cycle CTGs should be listed as an option for proposed natural gas-fired projects. However, the guidance also recognizes that this option may be evaluated under the redefining-the-source framework and excluded from Step 1 on a case-by-case basis if it can be shown that application of this control technology would disrupt the applicant's basic or fundamental business purpose for the proposed facility.[4] The applicant's project is conceived as a peaking power provider operating the two combustion turbine units no more than 5,000 hours combined on a 12-month rolling total basis (including MSS), and is designed to provide power quickly when dispatched by the grid operator, to respond to varying needs of the electric grid and to expeditiously shut down when no longer needed. Simple-cycle turbines, such as the CTGs selected by the applicant, are well suited for peaking power supply due to their ability to rapidly respond to immediate needs for additional power generation and quickly cease operation when these additional power needs are satisfied.

  Combined-cycle turbines generally have higher efficiencies than simple-cycle turbines; however, while combined-cycle units are well suited to operate as baseload-power electric generating units, EPA has not concluded at this time that combined-cycle turbines can provide the rapid response and shutdown required of a peaking power source with limited hours of operation, while continuing to produce reasonable priced power to sell in a deregulated market. The start-up sequence for a combined-cycle plant includes three phases: 1) purging of the heat recovery steam generator (HRSG); 2) gas turbine speed-up, synchronization, and loading; and 3) steam turbine speed-up, synchronization, and loading. The third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted because the HRSG and steam turbine contain parts that can be damaged by thermal stress and require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined-cycle plant is longer than that of a similarly sized simple-cycle plant.[5] Fast-start technology is capable of enabling startup of a combined-cycle turbine within 30 minutes; however, this technology requires that the unit be maintained in a state allowing warm or hot startup. Cold startup of a combined-cycle turbine seals and auxiliary equipment at a sufficiently high temperature to allow for quick startup of the combustion turbine, the facility would have to continuously operate an auxiliary boiler. An additional concern with the use of a combined-cycle configuration is the thermal mechanical fatigue due to the large numbers of startups and shutdowns.

  GPP states that the operation of a combined-cycle plant in a manner consistent with a simple-cycle plant, is not economically feasible on an extended basis and could not reasonably accommodate the quick and immediate electrical demands required for a peaker plant. GPP application is based on a business plan where it believes market indicators point towards a need

[4] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases, at 29-30, March 2011, http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.
[5] U.S. Environmental Protection Agency, Region 9. Fact Sheet and Ambient Air Quality Impact Report for the Proposed Prevention of Significant Deterioration Permit, Pio Pico Energy Center.

for peaking power in ERCOT. Therefore, based on the defined business purpose of the proposed project and for the reasons discussed herein, EPA has determined that the use of combined-cycle turbines would result in a redefinition of the source for this specific project and therefore are excluded from Step 1 of this BACT analysis.

- *Combustion Turbine (CTG) Design Efficiency* – A key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Older, more inefficient turbines consume more fuel to generate the same amount of electricity as newer, more efficient turbines. This is due to equipment wear and tear, improved design in newer models, as well as the use of higher quality metallurgy. EPA evaluated the turbines proposed for this project using available resources such as the Gas Turbine World (2012) handbook and concludes that the proposed model, the GE 7FA.05, is a modern and efficient combustion turbine.

- *Fuel Selection* – In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (coal, natural gas, petroleum liquids). Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. In assessing CO_2 emissions for the three potential fuel types, natural gas combustion results in lower GHG emissions (119 lbs CO_2e/mmBtu) than distillate oil (163 lb CO_2e/mmBtu) or coal (243 lbs CO_2e/mmBtu).

- *Good Combustion, Operating, and Maintenance Practices* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine, thus maximizing fuel efficiency and minimizing incomplete combustion. Furthermore, the turbine's operation is automated to ensure optimal fuel combustion and efficient operation, leaving virtually no operator ability to further tune these aspects of operation. Good combustion practices also include proper maintenance and verification that the combustion turbine system is operating within the manufacturer's specifications at least twice annually and tuning to meet such.

- Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

- *Use of Evaporative Cooling* – Chilling the incoming air increases the thermal and power efficiency of the CTG. An evaporative cooling system will be used to cool the incoming combustion turbine air (to approximately 60°F) in order to increase the combustion air mass flow. Chilling the incoming air increases the output of the combustion turbine and can result in an increase in thermal efficiency, thus reducing GHG emissions.

  There are three commercial systems for cooling the inlet air to a combustion turbine:

  a. **Foggers** – Atomized, demineralized water is sprayed into the inlet air of the combustion turbine. The cooling effect is created by the evaporation of the water droplets. This process has been used in many installed combustion turbines, and has proven to be very

efficient especially in very dry desert like areas. However, turbine suppliers are discouraging power plant operators from using these systems due to many reported incidents of droplet impingement damage to the air compressor section of the gas turbine. General Electric does not recommend inlet fogging for their combustion turbines due to erosion concerns for the first stage of compressor blades. Furthermore, air foggers require the installation of costly demineralized water treatment systems.

b. **Refrigeration Units** – Coils carrying a cooled aqueous solution of glycol are placed in the inlet structure of a gas turbine to cool the incoming air. These systems have become more popular in humid regions of the world where the effect of evaporative cooling is very limited. However, the refrigeration systems are very costly to install and have a substantial parasitic load with their operation.

c. **Evaporative Coolers** – A film of water is distributed downward through a plastic media. The inlet air of the gas turbine passes through the media and the water is evaporated causing a drop in the air temperature. This effect is similar to the foggers as described above. The difference between the systems is that in the case of evaporative coolers, demineralized is not necessary, and in many cases only filtration is required as pretreatment of the water. However, since the technology relies on evaporation to achieve cooling, benefits of operations diminish as ambient humidity increases. The system is also limited during decreases in ambient condition temperatures. This is due to the potential for formation of ice from the introduction of moisture and evaporative cooling which can form ice below 59 °F. Weighing in the capital cost of the evaporation systems, the cost of water treatment, and the cooling efficiency of the systems, the use of evaporative coolers is the technology of choice for this project.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Carbon Capture and Storage* - In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere, while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). Post-combustion capture using MEA is also the only process known to have previously demonstrated in practice on at least part of the exhaust gas stream of a combustion turbine (Reddy, Scherffius, Freguia, & Roberts, 2003).This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant previously owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003).

  As identified by the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and US Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have not been demonstrated in practice on a simple-cycle electric generating unit that operates as a peaking power provider. Peaking units frequently cycle their operation, with multiple starts and stops, to respond to electricity demand dispatch requirements. Because a CCS system is unable to operate in cycling

mode, we conclude that carbon capture is not applicable to the proposed peaking power project. Therefore, because CCS has not been demonstrated in practice for simple-cycle peaking units and cannot be applied to systems that involve frequent cycling of operations, CCS is not technically feasible at this facility.

Because CCS has been eliminated in Step 2 of the BACT analysis, EPA need not include a cost analysis in its evaluation of this option and is not addressing a cost analysis in Step 4 of the BACT analysis. However, GPP submitted a cost analysis for CCS as supplemental information, and that analysis has been included in the administrative record.[6]

- *Combustion Turbine Design Efficiency* – GPP documented its considerations in selecting particular turbine models for this facility, while weighing in operational variables such as project size, project purpose, fuel use, technical feasibility, and ambient conditions. The turbine model selected, the GE 7FA.05, is considered an efficient, modern simple-cycle turbine. Operation of the proposed turbine model has been demonstrated in practice, thus making this a technically feasible option.

  Aside from CCS, the remaining control options identified in Step 1 are considered technically feasible and are being proposed for Step 3 analysis.

Step 3 – Ranking of Controls

- Efficient Turbine Design,
- Fuel Selection,
- Good Combustion, Operating, and Maintenance Practices,
- Use of Evaporative Cooling

Efficient turbine design is considered the most effective control technology in this analysis. Fuel selection; good combustion, operating, and maintenance practices; and the use of evaporative cooling are considered effective and have a range of efficiency improvements which cannot be directly quantified. Therefore, ranking of those control technologies based on effectiveness is not possible.

Step 4 – Economic, Energy and Environmental Impacts

<u>Efficient Combustion Turbine Design</u>

The applicant assessed various turbines operating in a simple-cycle configuration. The GE 7FA.05 will meet the technical requirements of the proposed project and is considered a modern and efficient combustion turbine design.

[6] Correspondence from W. Karl to D. Garcia, June 12, 2013.

Fuel Selection

The combustion of a fossil fuel to generate electricity can be either: 1) in a steam generating unit (also referred to simply as a "boiler") to feed a steam turbine that spins an electric generator; or 2) in a combustion turbine or a reciprocating internal combustion engine that directly drives the generator.[7]

EPA concludes that natural gas is the appropriate fuel for this source because it is the lowest source of CO_2e from combustion and best fits the project's purpose and design considerations.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are a control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine, thus maximizing fuel efficiency and minimizing incomplete combustion. Furthermore, the turbine's operation is automated to ensure optimal fuel combustion and efficient operation. Good combustion practices also include proper maintenance and verification that the combustion turbine system is operating within manufacturer's specifications at least twice annually and tuning to meet such.

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Use of Evaporative Cooling

Weighing in the capital cost of the evaporation systems, the cost of water treatment, the cooling efficiency of the systems, and the energy consumed by the technologies, EPA is eliminating foggers and refrigeration units. Evaporative coolers represent the most energy efficient means of cooling inlet air to a simple-cycle combustion turbine because refrigeration units have a very high parasitic load and inlet fogging requires demineralized water, which also requires additional energy consumption. Therefore, EPA concludes that foggers and refrigeration units are eliminated as BACT. For evaporative coolers, EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Step 5 – Selection of BACT

To date, other similar peak power facilities with a GHG BACT limit are summarized in the table below. The bold emphasis is added for comparison purposes:

[7] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units". EPA, OAR. October 2010.

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Puget Sound Energy Fredonia Generating Station Mt. Vernon, Washington	Peak Power, Simple cycle combustion turbine, to provide an additional 181-207 MW	Energy Efficiency/ Good Design & Combustion Practices	**GE 7FA.05 Option: 1,299 lb CO_2e/MWhr (net)** GE 7FA.04 Option: 1,310 lb CO_2e/MWhr (net) SGT5000F4 Option: 1,278 lb CO_2e/MWhr (net) GE LMS100 Option: 1,138 lb CO_2e/MWhr (net)	2013	PSD-11-05
EFS Shady Hills LLC EPA Region 4	Simple cycle combustion turbine, to provide an additional 436 MW	Energy Efficiency/ Good Design & Combustion Practices	**GE 7FA.05: 1,377 lb CO_2e/MWhr (gross) when firing natural gas**	2014	PSD-EPA-R4013
Indeck Wharton Energy Center	Peak Power, Simple cycle combustion turbines (3 CTG units). Provides 650 MW.	Energy Efficiency/ Good Design & Combustion Practices	**GE 7FA.05 Option: 1,276 lb CO_2e/MWhr (gross)** SGT-5000F(5) Option: 1,337 lb CO_2/MWhr (gross)	2014	PSD-TX-1374-GHG
Golden Spread Electric Cooperative, Inc., Antelope Elk Energy Center	Peak Power, Simple cycle combustion turbine, to provide an additional 202 MW(gross)	Energy Efficiency/ Good Design & Combustion Practices	**GE 7FA.05: 1,304 lb CO_2/MWhr (gross)**	2014	PSD-TX-1358-GHG
Invenergy	Peak Power, Simple cycle combustion turbine (2 CTG units). Provides 330 MW (nominal net)	Energy Efficiency/ Good Design & Combustion Practices	GE 7FA.03: 1,393 lb CO_2/MWhr (gross) and 21 tons CO_2e per turbine MSS event.	2014	PSD-TX-1366-GHG
Tenaska Roan's Prairie Partners, LLC	Peak Power Simple Cycle combustion turbine (3 CTG units). Provides 507 to 694 MWe.	Energy Efficiency/ Good Design & Combustion Practices	GE 7FA.04 Option: 1,321 lb CO_2/MWhr (gross) and 10.69 tons CO_2 per turbine MSS event. **GE 7FA.05 Option:**	2014	PSD-TX-1378-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
			1,310 lb CO_2/MWhr (gross) and 12.12 tons CO_2 per turbine MSS event. SGT6-5000(5ee) Option: 1,334 lb CO_2/MWhr (gross) and 8.95 tons CO_2 per turbine MSS event.		

From this analysis, EPA has concluded that the GHG BACT for GGS is the use of modern natural gas fired, thermally efficient, simple-cycle combustion turbines combined with evaporative cooling and good combustion and maintenance practices to maintain optimum efficiency. The use of evaporative cooling will be limited to ensure safe operation of the equipment and prudent consumption of available water resources. The evaporative coolers are specifically limited due to the potential for formation of ice from the introduction of moisture and evaporative cooling which can form ice below 59 °F. The GE 7FA.05 turbine is consistent with the BACT requirement and the specific goal of this project. EPA is proposing an emission limit of 1,293.3 lb CO_2/MWhr gross output for each combustion turbine on a 12-month rolling average basis. Both combustion turbines shall not exceed 5,000 hours of operation combined on a 12-month rolling total basis.

The MSS BACT limit for each combustion turbine is limited to 20.8 tons CO_2 per hour on a 12-month rolling average basis. Both combustion turbines are limited to 300 hours combined for startup and 300 hours combined per year of shutdown on a 12-month rolling basis.

To determine the BACT limit (lb CO_2/MWh), the CO_2 data calculated each day over a month is averaged and divided by the hourly measured amount of electricity that is produced during the corresponding month. The quotient is added to the preceding 12-month rolling basis. Until the 12-month rolling basis has been established, the company should utilize the performance testing data to establish a plan whereby the company may operate the emission unit in a manner that will not exceed the permitted limits.

The company is responsible for demonstrating compliance with the permitted emission limits and should evaluate its actual emissions and verify actual compliance from recorded operational data. The operating scenario provided by the applicant (5,000 hours at 100% load per year) was used to calculate the worst-case emission rates from the proposed project.

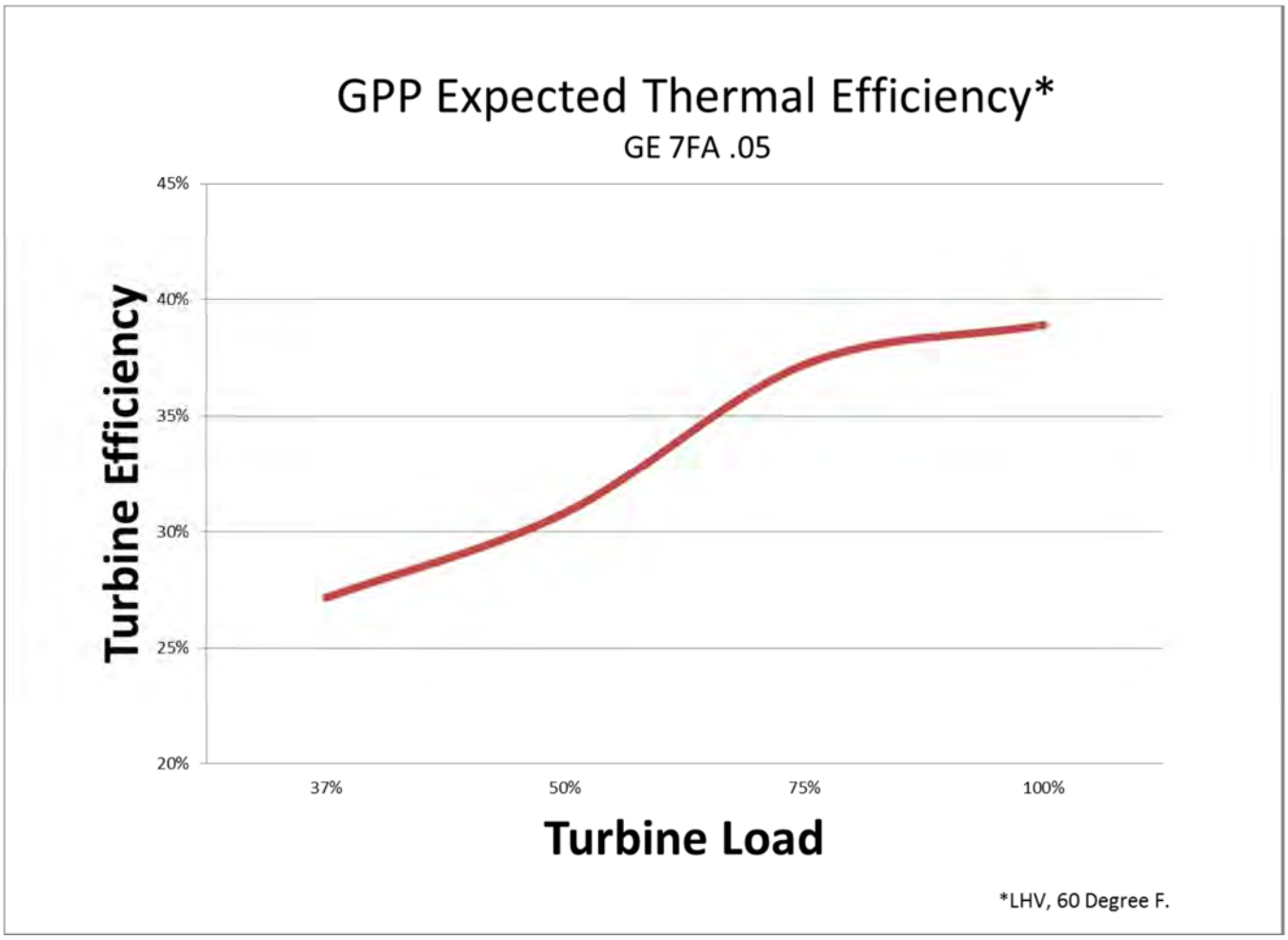
To account for the additional hours of operation associated with MSS events, each turbine is limited by fuel use associated with the 5,000 hours of operation per year. Limiting the fuel use achieves the same objective as limiting the number of hours of operation of the combustion turbines to 5,000 hours combined. The combined fuel use limit for the combustion turbines that corresponds to the 5,000 hours of operation on a 12-month rolling total basis is 10,279,456 MMBtu (HHV). The permittee shall monitor and record the amount of fuel used on a 12-month rolling total basis and compare the measured result with the fuel use limit to determine compliance.

The proposed BACT limit of 1,293.3 lb CO_2/MWhr (gross) is comparable to or lower than the emissions of other recently issued GHG BACT limits for peak power facilities with a GHG BACT limit. When comparing the net-based BACT limit for the Puget Sound Energy Fredonia Generation Station ("PSE Fredonia"), the proposed GGS BACT limit, if converted to a net basis is calculated to be 1,305 lb CO_2/MWhr for the GE 7FA.05 and is comparable to PSE Fredonia.

As demonstrated above, BACT limits for GGS are comparable to or lower than recently issued BACT limits at similar facilities; however, it is important to note that surface level comparison does not account for factors such as operational hours and load, elevation, and ambient conditions, which directly impact turbine efficiency. While EPA considered these BACT limits from previously permitted actions, EPA also examined the available literature (such as the Gas Turbine World Handbook) and confirmed that the CTG's proposed by GPP are, in general, considered highly efficient, modern CTG models.

Variations in elevation and ambient temperature will affect a combustion turbine's operation performance and is an important consideration in the comparison of various combustion turbines in different locations. In a discussion about CTG efficiency, it is important to note that the calculated gross CTG power and efficiency are as "measured" across the electric generator terminals at ISO (International Organization for Standardization) site conditions without allowances for inlet filter and duct losses, exhaust stack and silencer losses, gearbox efficiency, or any auxiliary mechanical and electrical systems' parasitic power consumption. ISO design ratings are typically set at 59°F and sea level. To assess site-specific CTG performance, correction factors should be applied. Figure 1 includes an efficiency curve to estimate the anticipated actual operational scenario for a GE 7FA.05 simple cycle CTG located in Guadalupe County, Texas. The efficiency has been corrected to represent the output at the site-specific elevation of approximately 646 ft and the various ambient temperatures.

Figure 1. Estimate Performance Curve for the GE 7FA.05 CTG located in Guadalupe County, Texas



Supplemental information provided for the proposed project, shows that a 3.3% margin is included in the BACT limit to account for the potential difference between the design CTG heat rate and the actual tested CTG heat rate. A 6% margin is also included to account for CTG efficiency losses due to degradation prior to a CTG overhaul. Therefore, the total allowance used in the calculation of the BACT limit is 9.3%. The performance margin used in this analysis, 9.3%, is a 0.8% higher than other recently permitted projects, Indeck Wharton Energy Center used 8.5%, Invenergy used 5% and Tenaska Roans Prairie used 6%. However, because the proposed BACT limit is consistent with recent permitting actions, the additional 0.8% compliance margin is accepted for this analysis.

BACT During Startup and Shutdown

The two CTGs combined annual emission limit of 611,514.32 CO_2e tpy on a 12-month rolling total is a combined emission limit and is limited to 5,000 operational hours combined on a 12-month rolling basis. The CTG combined annual emission limit includes CO_2e emissions from startup and shutdown. For startup and shutdown, the BACT limit for each CTG is 20.8 Ton CO_2/hr on a 12-month rolling

average basis. The two CTGs have a combined MSS limit of 300 hours startup and 300 hours shutdown on a 12-month rolling total basis. A startup of each turbine is defined as the period that begins when there is measureable fuel flow to the turbine and ends when the turbine load reaches 60%. A shutdown of each turbine is defined as the time period that begins when the combustion turbine drops out of the normal operating low-NOx combustion mode (which equated to approximately 60% combustion turbine load) following an instruction to shut down and ends when flame is no longer detected in the combustion turbine combustors. A shutdown event will also end if the combustion turbine is instructed to return to a load greater than 60% and resumes normal operation. In addition to the MSS BACT limit of 20.8 Ton CO_2/hr, we are including a BACT requirement for startup/shutdown that includes the work practice standard to utilize good pollution control practices, safe operating practices and protection of the facility.

BACT Compliance

The proposed BACT for the CTGs is the use of modern, natural gas-fired thermally efficient, simple-cycle combustion turbines combined with evaporative cooling and good combustion and maintenance practices to maintain proper efficiency for each combustion turbine, with an output-based limit of 1,293.3 lb CO_2/MWh (gross). Compliance will be based on a 12-month rolling average basis, calculated daily for each turbine. The two CTGs are limited to 5,000 combined hours of operation on a 12-month rolling basis that includes MSS events. During MSS events, the MSS BACT limit is 20.8 tons CO_2/hr and the two CTGs are limited to 300 startup hours combined and 300 shutdown hours combined on a 12-month rolling total basis. GPP will maintain records of tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for each combustion turbine. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for each CTG. For each CTG, the parameters that will be measured are natural gas flow rate using an operational non-resettable elapsed flow meter, total amount of fuel combusted on an hourly basis, fuel gross calorific value (GCV) on a high heat value (HHV), carbon content, combustion temperature, exhaust temperature, and gross hourly energy output (MWh).

GPP will demonstrate compliance with CO_2 limit for each CTG by using non-resettable elapsed fuel flow meters to separately monitor the quantity of fuel combusted in each of the CTGs and performing periodic scheduled fuel sampling pursuant to 40 CFR 75.10(3)(ii) and the procedures listed in 40 CFR 75, Appendix G. Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculate CO_2 mass emissions. The proposed permit also includes an alternative compliance demonstration method in which GPP may install calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. The permittee shall calculate each day a combustion turbine operates the CO_2 emissions from the daily operational period divided by the gross electrical output over the same period for comparison to the limit for each combustion turbine. The resulting quotient (lb CO_2/MWh, gross) is added to the 12 month rolling average and the calculations shall be completed on a daily basis to determine compliance with the lb CO_2/MWh BACT limit.

The permittee shall also monitoring and record the number of combined operational hours, including combined MSS hours, to demonstrate compliance with the 5,000 operational hour combined limit on a 12-month rolling total basis.

A site-specific Fc factor using the analysis and GCV in equation F-7b of 40 CFR 75, Appendix F shall be used for analysis. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, § 3.3.6.

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

$$W_{CO_2} = \frac{\left(Fc\ x\ H\ x\ U_f\ x\ MW_{CO_2}\right)}{2000}$$

Where:

W_{CO_2}	=	CO_2 emitted from combustion, tons/hour
MW_{CO_2}	=	molecular weight of CO_2, 44.0 lbs/mole
F_c	=	Carbon-based Fc-Factor, 1,040 scf/MMBtu for natural gas or site-specific Fc factor
H	=	Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, § 5
U_f	=	1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

GPP is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR 75, Appendix D, which include: Fuel flow meter and Gross Calorific Value (GCV)

The combined annual quantity of fuel used in the CTGs shall not exceed 10,279,456 MMBtu (HHV) in any 12 month rolling period. The permittee shall calculate each month a combustion turbine operates, the quantity of fuel used by each turbine over the previous 12-month basis by multiplying the gross calorific value of the fuel combusted by the volume of fuel metered for comparison to the annual fuel limit for each combustion turbine.

The emission limits associated with CH_4 and N_2O 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 project and additional analysis is not required for CH_4 and N_2O. 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 are required to be kept to demonstrate compliance with the emission limits on a 12 month rolling basis calculated daily. The demonstration of compliance with the lb CO_2/MWhr BACT emission limit excludes periods of startup and shutdown. The permittee shall also demonstrate compliance with the startup and shutdown work practice standard by maintaining a copy of the vendor recommendations and maintaining documentation on-site to show that the CTGs do not exceed the 300 hours combined of startup and 300 hours combined of shutdown.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. Following the initial stack test demonstration, emission testing for the combustion turbines shall be performed every five years, plus or minus six months, from the previous performance test to verify continued performance at the permitted emission limits. A stack test demonstration for CH_4 and N_2O

emissions are not required because the CH_4 and N_2O emissions are less than 0.01% of the total CO_2e emissions from the CTGs and are considered not significant level in comparison to the CO_2 emissions.

IX. Fire Water Pump BACT Analysis (EPN: FWP-3)

GGS will be equipped with one nominally rated 300-hp diesel-fired pump engine to provide water in the event of a fire. The fire water pump will operate a maximum of 100 hours of non-emergency operation on a 12-month rolling basis for testing and maintenance. The fire water pump engine emissions represent 0.002% of the total facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies

- Selection of a Fuel Efficient Engine;
- Fuel Selection; and
- Good Combustion Practices, Operating and Maintenance Practices.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except fuel selection.

The only technically feasible fuel for the fire water pump engine is diesel fuel. While natural gas-fueled engines may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the fire water pump engine because it will be used in the event of facility-side power outage, when natural gas supplies may be interrupted.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The selection of fuel efficient engines and good combustion, operating and maintenance practices are potentially equally effective but their case-by-case effectiveness cannot be quantified to allow ranking.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Efficient Engine Design</u>

GPP will install a new fire water pump engine. It is anticipated that this equipment will be designed for optimal combustion efficiency. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

<u>Good Combustion, Operating and Maintenance Practices</u>

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the fire water pump engine at least annually or per the manufacturer's specifications. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Step 5 – Selection of BACT

GPP proposes to use both remaining identified control options to minimize GHG emissions from the fire water pump engine. The following specific BACT practices are proposed for the emergency diesel generator:

- *Selection of Fuel Efficient Engine* – GPP will purchase a fire water pump internal combustion engine (ICE) certified by the manufacturer to meet applicable emission standards at the time of installation and the applicable requirements of 40 CFR Part 60 Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."
- *Good Combustion, Operating and Maintenance Practices* – GPP will implement good combustion, operating and maintenance practices for the fire water pump engine.

BACT for the fire water pump engine will be to limit operation to no more than 100 hours of non-emergency operation per year for the purpose of maintenance, testing and inspection. GPP will also monitor hours of operation for the purpose of maintenance, testing and inspection for each engine on a monthly basis. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

IX. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPN: SF6-1)

The circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant expansion is currently estimated to be two (2) breakers of 690 lb SF_6 each.

Step 1 – Identification of Potential Control Technologies for GHGs

- Circuit Breaker Design Efficiency – In comparison to older SF6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

- Alternative Dielectric Material – Because SF6 has a high GWP, one alternative considered in this analysis is to substitute another non-GHG substance for SF6 as the dielectric material in the breakers. Potential alternatives to SF6 were addressed in the National Institute of Standards and Technology (NIST) Technical note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*.[8] The alternatives considered include mixtures of SF6 and nitrogen, various gases and mixtures, and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

- Circuit Breaker Design Efficiency – Considered technically feasible and is carried forward for Step 3 analysis.

[8] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*. NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

- Alternative Dielectric Material – According to the report NIST Technical Note 1425, among the alternatives examined in the report, SF6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil-insulated equipment used prior to the development of SF6-insultated equipment. The mixture of SF6 and nitrogen is noted to need further development and may only be applicable in limited installations. The report cites a second alternative of various gases and mixtures that needs additional systematic study before the alternative could be considered technically feasible. The report also cites a third alternative of the use of potential gases that have not been demonstrated in practice, and there is little experimental data available to examine applicability. Therefore, based on the information contained in this report, "it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Consequently, because the alternative dielectric material options have not been demonstrated in practice for this project's circuit breakers and there is insufficient data to determine whether they are commercially available or applicable to the circuit breakers, this alternative is considered technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of efficient circuit breaker design (including state-of-the-art SF6 technology with leak detection to limit fugitive emissions) is the highest ranked control technology that is feasible for this application.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Because the only remaining technically feasible alternative from Step 1 is the circuit breaker design efficiency, an evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.06 and C37.010 standard for high voltage circuit breakers.[9] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by GPP through the annual monitoring of emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[10] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

X. Fugitive Emissions from Piping Components BACT Analysis (EPN: NG-1)

[9] ANSI Standard C37.06, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current Basis* and ANSI Standard C37.010, *Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.*
[10] See 40 CFR Part 98 Subpart DD.

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Because a majority of the GHG fugitives comes from methane and the GWP is higher for methane, a conservative estimate was done to assume that all piping components are in a rich methane stream.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument Leak Detection and Repair (LDAR) Programs*
- *Remote Sensing*
- *Auditory/Visual/ Olfactory (AVO) Monitoring*
- *Use of High Quality Components and Materials*

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless technologies are effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g. relief valves).

Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. Texas' LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[11]

AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is not preferred for identifying large leaks of odorless gases such as methane. However, since pipeline natural gas is odorized with very small quantities of mercaptan, AVO observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, AVO observations of potential fugitive leaks are likewise moderately effective.

The use of high quality components is also effective relative to the use of lower quality components.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28 LAER LDAR program or a comparable remote sensing program is considered an insignificant level in comparison to the total project's proposed CO_2e

[11] 73 FR 78199-78219, December 22, 2008.

emissions. Accordingly, given the costs of implementing 28 LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service. Given that GHG fugitives are conservatively estimated to be little more than 2 tons per year CH_4, there is, in any case, a negligible difference in emissions between the considered control alternatives.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas components, GPP proposes to incorporate as-observed AVO as BACT for the natural gas piping components. The proposed permit contains a condition to implement AVO inspections on a daily basis.

XI. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA), dated December 13, 2013, prepared by the applicant, Guadalupe Power Partners, LP ("GPP"), and its consultant, Environmental Consulting & Technology, Inc., thoroughly reviewed and adopted by EPA.

A draft BA has identified thirteen (13) species listed as federally endangered or threatened in Comal and Guadalupe Counties, Texas:

Federally Listed Species for Comal and Guadalupe Counties by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Black-capped vireo	*Verio atricapilla*
Golden-cheeked warbler	*Setophaga chrysoparia*
Interior least tern	*Sterna antillarum athalassos*
Whooping Crane	*Grus americana*
Fish	
Fountain darter	*Etheostoma fonticola*
Crustacean	
Peck's cave amphipod	*Stygobromus pecki*
Mammals	
Black Bear	*Ursus americanus*
Jaguarundi	*Herpailurus yaguarondi*
Red Wolf	*Canis rufus*

Insects	
Comal Springs riffle beetle	*Comaldessus stygius*
Comal Springs dryopid beetle	*Stygoparnus comalensis*
Amphibians	
San Marcos salamander	*Eurycea nana*
Texas blind salamander	*Typhlomolge rathbuni*

EPA has determined that issuance of the proposed permit for the construction of two new natural gas-fired simple cycle combustion turbines located at GPP's existing electric generating station in Marion, Texas will have no effect on any of the thirteen listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. 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. To make this determination, EPA relied on a cultural resource report prepared by Horizon Environmental Services, Inc. ("Horizon") on behalf of ECT and GPP dated January 2013, thoroughly reviewed and adopted by EPA.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be a 6.9-acre construction footprint at GPP's existing facility. Horizon performed a desktop review of the archeological background and historical records within a one-mile radius of the proposed site boundary. Based on the desktop review, no cemeteries, historic properties or districts were identified within the one-mile review radius. Three prior cultural resources surveys have been conducted within the one-mile radius, one of which covered the current project's proposed APE in its entirety, including a field survey with shovel testing. The Texas Historical Commission concurred with the findings of "no adverse effects" from this report on March 24, 1999.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to GPP will not affect properties potentially eligible for listing on the National Register.

On September 18, 2013, EPA sent letters to twenty-six (26) Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA submitted a copy of the final draft of the cultural report to the State Historic Preservation Officer (SHPO) for consultation and requested concurrence with its determination on September 5, 2014. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIV. Conclusion and Proposed Action

Based on the information supplied by GPP, our review of the analyses contained in 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 GPP a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comment. 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 Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
CTG-7 CTG-8	CTG-7 CTG-8	Pipeline Quality Natural Gas Fired-Simple Cycle Turbine, combined	CO_2	610,893.38	611,514.32	- BACT limit of 1,293.3 lb CO_2/MW-hr (gross) for each turbine on a 12-month rolling average basis. -MSS BACT limit of 20.8 tons CO_2/hr for each turbine on a 12-month rolling average basis. -Both turbines combined shall not exceed 5,000 hours of operation (including MSS) on a 12-month rolling total basis. -Both turbines are limited to 300 hours combined of startup and 300 hours combined of shutdown on a 12-month rolling total basis. -See permit condition III.A.1 and 3.
			CH_4	11.34		
			N_2O	1.14		
FWP-3	FWP-3	Fire water Pump Engine	CO_2	15.6	15.71	- Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.B.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
SF6-1	SF6-1	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Work Practices. See permit condition III.C.
NG-1	NG-1	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO Program. See permit condition III.D.
Totals[5]			CO_2	610,909.60	**611,655.16**	
			CH_4	13.43		
			N_2O	1.14		
			SF_6	0.00345		

1. The TPY emission limits specified in this table are combined emission limits not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.

2. Global Warming Potentials (GWP): CO_2=1, CH_4 = 25, N_2O = 298, SF_6=22,800
3. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the natural gas fired simple cycle turbines applies to each turbine and is not a combined limit.
4. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding (0.00063 tpy CH_4 and 0.00013 tpy N_2O). The emission limit will be a design/work practice standard as specified in the permit.
5. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.
6. Fugitive Leak Emissions from SF6-1 and NG-1 are estimated to be 0.00345 TPY SF_6 and 78.7 TPY CO_2e from SF6-1 and 2.03 TPY CH_4 and 50.9 TPY CO_2e from NG-1. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.