Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Tenaska Roan's Prairie Partners, LLC, Tenaska Roan's Prairie Generating Station

Permit Number: PSD TX 1378-GHG

May 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 July 22, 2013, Tenaska Roan's Prairie Partners, LLC (TRPP) submitted to EPA Region 6 a Greenhouse Gas (GHG) emissions Prevention of Significant Deterioration (PSD) permit application for the Roan's Prairie Generating Station. TRPP submitted additional information to EPA on January 14, 2014, January 21, 2014 and March 5, 2014 and a final revised GHG PSD permit application on April 24, 2014 including all previous revisions. In connection with the same proposed major stationary source, TRPP submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on October 24, 2013.

TRPP proposes to construct a peak power generating facility near Shiro located in Grimes County, Texas. The proposed project will provide up to approximately 694 nominal gross megawatts (MW) of power to supplement the Electric Reliability Council of Texas (ERCOT) power grid during periods of peak power demand. TRPP is requesting approval to construct three simple cycle turbines in one of the following power generation configuration options (output ratings are nominal at 69 °F ambient dry bulb):

1. Three Siemens SGT6-5000F(5ee), each rated at 231 MW,
2. Three GE 7FA.05, each rated at 212 MW, or
3. Three GE 7FA.04, each rated at 176 MW.

EPA Region 6 is proposing to allow TRPP to select one of the power generation configuration options with the turbines identified above after final permit issuance. EPA Region 6 has included all three options with proposed Best Available Control Technology (BACT) in the permit. Only one option may be chosen and built. The project also includes the installation of associated equipment, two diesel-powered emergency engines, and seven circuit breakers. For the purposes of this proposed permitting action, GHG emissions are permitted from three turbines, two diesel-powered emergency engines, fugitive emissions from seven circuit breakers and piping components, and maintenance, startup and shut down emissions. The remaining units are not considered to be potential GHG emission sources.

EPA has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Roan's Prairie Generating Station. This SOB documents the information and analysis EPA used to support its decision drafting the air permit and 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 TRPP'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 requested by EPA and provided by TRPP, and EPA's own technical analysis. With the exception of information that TRPP claims to be confidential business information, EPA is making this information available as part of the public record.

II. Applicant

Tenaska Roan's Prairie Partners, LLC
Tenaska Roan's Prairie Generating Station
14302 FNB Parkway
Omaha, NE 68154

Facility Physical Address:
Shiro, TX 77873

Contact:
Mr. Larry Carlson
Director, Air Programs
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Omaha, NE 68154
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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 retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated new source review (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:
Quang Nguyen
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-7161

IV. Facility Location

The proposed project is located in Grimes County, Texas near Shiro. Grimes County is currently designated attainment for all criteria pollutants. The proposed plant site is to be located approximately 25 miles east of College Station, Texas, on highway TX-30E.

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

Latitude: 30° 35’ 16”
Longitude: 95° 55’ 42”

Figure 1 illustrates the proposed facility location on the USGS map.

V. Applicability of Prevention of Significant Deterioration Regulations

EPA Region 6 concludes that TRPP’s application is subject to PSD review for the pollutant GHGs because the facility will constitute a new stationary source that will emit or have the potential to emit greater than 100,000 tpy carbon dioxide equivalent (CO_2e), as described in 40 CFR § 52.21(b)(49)(v)(*a*). TRPP calculates total potential CO_2e emissions of 1,279,629 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. TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

The EPA Region 6 applies the policies and practices reflected in the EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with the guidance, EPA has neither required the applicant to model or conduct ambient monitoring for GHGs, nor has EPA required any assessment of impacts of GHGs in the context of the additional impacts analysis or PSD 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.

VI. Project Description

Roan's Prairie Generating Station is designed as a natural gas-fueled power generating facility to serve the peaking segment of the ERCOT wholesale power market. This market segment is characterized by increases in daytime demand during the summer months, and relatively infrequent, high-demand peak periods that occur when demand is extraordinarily high and supply decreases substantially due to plants going off-line. The high penetration of renewable (wind generation) in ERCOT also increases volatility and intermittency. Natural gas-fueled peaking units, which are capable of quickly providing supplemental power to the grid, are ideal for providing generation and load balancing against unanticipated or uncontrollable changes in load generation.

A peaking plant composed of multiple turbines can offer multiple "tranches" of power by operating the units independently. Roan's Prairie Generating Station will be able to operate one, two or all three turbines to meet a broad range of energy demand and can generate energy across a wide range of output from approximately 94 MW up to the full capacity (nominally 507–694 MW).

TRPP proposes to construct a new peaking power plant generally located near Shiro in Grimes County, Texas. To meet the anticipated need for peak power demand, TRPP proposes to construct three new turbines of one of the following high efficiency natural gas-fired simple cycle combustion turbine generator (CTG) options (output ratings are nominal at 69 °F ambient dry bulb):

1. Three Siemens SGT6-5000F(5ee), each rated at 231MW;
2. Three GE 7FA.05, each rated at 212 MW, or;
3. Three GE 7FA.04, each rated at 176 MW.

[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/ghgissudualpermitting.pdf.

Figure 1: Tenaska Roan's Prairie Generating Station Site Location

TRPP requested an enforceable limit on the annual capacity factor for each turbine of 33 percent, equivalent to approximately 2,920 hours per year of operation at full load. TRPP also proposes to install one diesel-powered fire water pump engine, one diesel-powered emergency generator, seven circuit breakers and other auxiliary equipment. GHG emissions will result from the following emission units:

- Three Simple-Cycle Combustion Turbines (EPNs: TURB1, TURB2 and TURB3);
- One Diesel-Powered Engine for Fire Water Pump (EPN: FWPUMP);
- One Diesel-Powered Emergency Generator (EPN: EMGEN);
- Fugitive Emissions from Seven SF_6 Circuit Breakers (EPN: CBFUG); and
- Fugitive Emissions from Piping Components (EPN: FUG).

Figure 2 presents a process flow diagram at the proposed plant. The power block will have the potential to generate up to approximately 694 nominal gross MW of power to supplement the ERCOT power grid during peak power demand. Each combustion turbine will utilize low NOx burners to minimize NOx emissions.

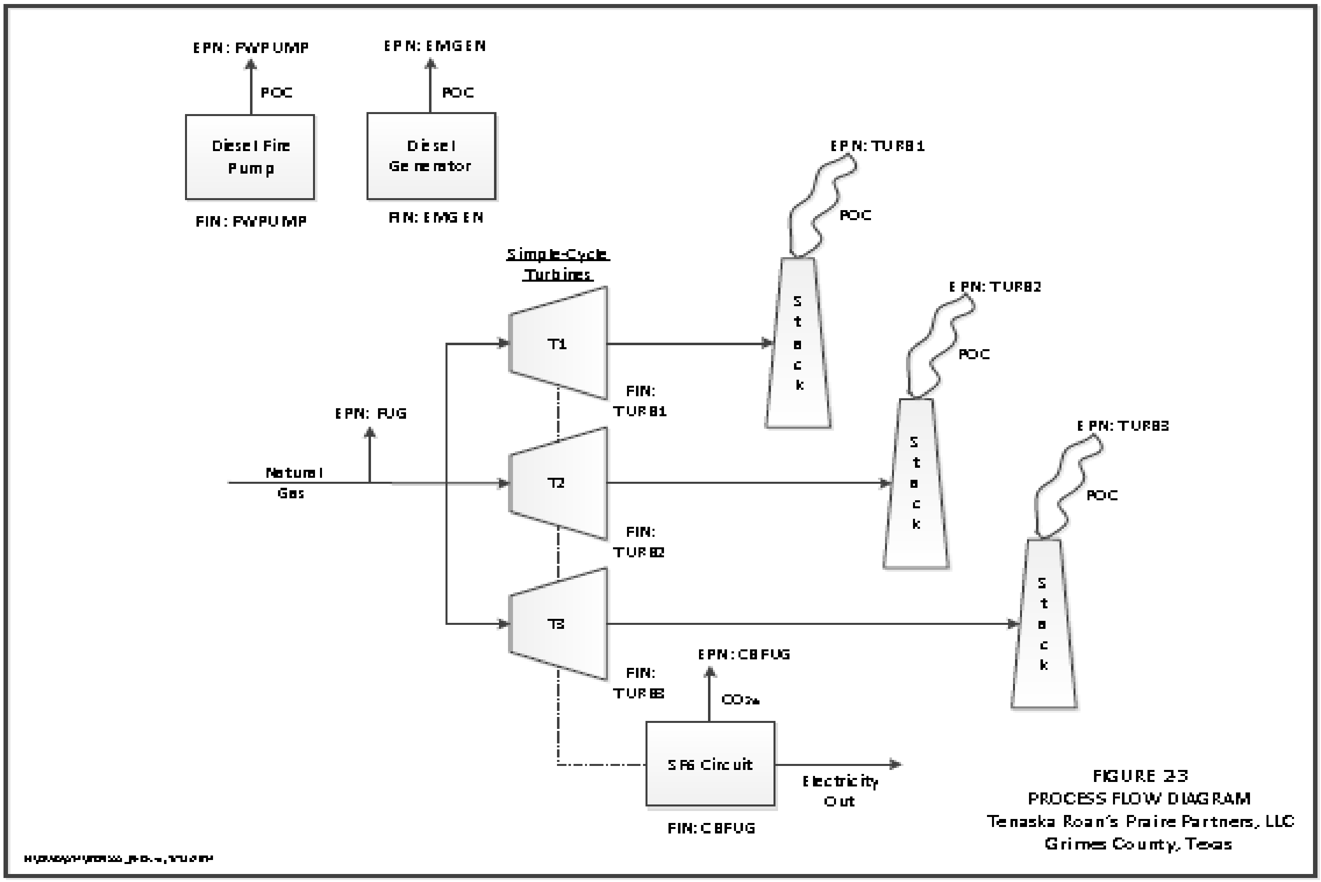

Figure 2: Process Flow Diagram at the Tenaska Roan's Prairie Generating Station

1. Natural Gas-fired Simple Cycle Combustion Turbine Generator(s) (CTGs)

TRPP is proposing to construct three identical natural gas-fired simple cycle CTGs to meet a demand for peak power. Each generator will use CTG technology and will burn pipeline natural gas to rotate an electrical generator to produce electricity. The main components of a generator using CTG technology consist of a compressor, combustor, 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 where the gases expand across the turbine blades, driving a shaft to power an electric generator. Table 1 shows potential emissions of each of the three different combustion turbine models being considered for the project.

Table 1. Estimated Potential Emissions From Individual Turbine(s) Under Consideration by TRPP, Excluding Start-up/Shutdown							
Pollutant	**Fuel**	**SGT6-5000F(5ee)** Max. Heat Input: 2,441 MMBtu/hr per Turbine Operating Time: 2,920 hours/year		**GE 7FA.05** Max. Heat Input: 2,378 MMBtu/hr per Turbine Operating Time: 2,920 hours/year		**GE 7FA.04** Max. Heat Input: 2,198 MMBtu/hr per Turbine Operating Time: 2,920 hours/year	
		(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
CO_2	NG	291,749.39	425,954.12	284,119.31	414,814.19	262,705.55	383,550.1
CH_4	NG	5.38	7.86	5.24	7.65	4.85	7.07
N_2O	NG	0.54	0.79	0.52	0.77	0.48	0.71
CO_2e	NG	292,044.27	426,384.63	284,406.47	415,233.44	262,971.06	383,937.75

1.1 Start-up and Shutdown (SU/SD) Emissions

The duration of SU/SD for a combustion turbine in a simple cycle mode is relatively short and involves bringing the turbine rotors up to speed, lighting the turbine burners, synchronizing the electric generator to the grid, and ramping the generator output load until the minimum steady state load is reached. Since emissions of some pollutants from combustion turbines can be significantly higher during SU/SD than during normal operation due to relatively inefficient combustion, they can represent a substantial portion of the proposed project's total potential to emit (PTE) and need to be accounted for in the permit. During start-up, the turbines cannot initially operate in lean pre-mix mode, which results in higher emissions of some pollutants. A similar transition from lean air/fuel pre-mix combustion to standard combustion occurs during shutdown, but the time involved is considerably shorter. To account for these potential increases in emissions, the annual emission estimates for all pollutants include potential emissions from SU/SD events. For emission calculation purposes, TRPP assumed 365 startups and 365 shutdowns per year.

2. Diesel-Powered Emergency Engines

TRPP will equip the proposed plant with two diesel-powered emergency engines. The first emergency engine (2,937 hp) will drive a generator to supply electrical power for control systems in the event of power outage. The second diesel-powered emergency engine (575 hp) will be used to power a firewater pump in the event of a fire. Each of the emergency engines will be limited to 100 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing.

Tables 2 and 3 show the potential emissions of the fire water pump engine and the emergency generator engine, respectively. These estimates are based on 100 hours of testing/maintenance and emission factors from EPA's GHG Mandatory Reporting Rule at 40 CFR 98 Subpart C.

Table 2. Estimated Potential Emissions from the Firewater Pump Engine		
Pollutant	**Emissions from FWP Engine (lb/hr)**	**Emissions from FWP Engine (tpy)**
CO_2	654.79	32.74
CH_4	0.03	1.33E-03
N_2O	0.01	2.66E-04
CO_2e	657.04	32.85

Table 3. Estimated Potential Emissions from the Emergency Generator		
Pollutant	**Emissions from Emergency Generator (lb/hr)**	**Emissions from Emergency Generator (tpy)**
CO_2	3,125.45	156.27
CH_4	0.13	0.01
N_2O	0.03	1.27E-03
CO_2e	3,136.18	156.81

3. Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The seven circuit breakers associated with the proposed units and associated equipment will be insulated with SF_6. The SF_6 gas is a colorless, odorless, non-flammable, and non-toxic synthetic gas and 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 SF_6 gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. The SF_6 gas is only used in the 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 3500 lb SF_6. The proposed seven circuit breakers will have a low density alarm and a low density 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. Table 4 shows annual potential CO_2e emissions from the proposed circuit breakers.

Table 4. Estimated Potential Fugitive Emissions from the SF_6 Circuit Breakers Emissions									
Description of SF_6 containing equipment	**Number of Pieces of Equipment**	**Weight of SF_6 per piece of Equipment (lb)**	**Weight of SF_6 per Equipment Type (lb)**	**IEC Standard for Equipment Leakage (% per year) [1]**	**Fugitive SF_6 (lb/hr)**	**Fugitive SF_6 (tpy)**	**Global Warning Potential [2]**	**Fugitive CO2e (lb/hr)**	**Fugitive CO2e (tpy)**
Circuit Breakers	7	500	3500	0.5	0.00200	0.00875	22,800	45.55	199.50
TOTAL			3500	0.5	0.00200	0.00875	22,800	45.55	199.50

[1] IEC, International Electrotechnical Commission Standard 62271-1, 2004, assume 100% loss of content upon leakage.
[2] Based on the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 as published on November 29, 2013 (78 FR 71904)

4. Fugitive Emissions from Piping Components

Fugitive GHG emissions result from leaks of natural gas from piping components and from losses that occur during maintenance activities. Fugitive emissions from piping components 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, an estimate was done to assume that all piping components are in a rich methane stream. Table 5 shows annual potential CO_2e emissions from piping components.

Table 5. Estimated Potential Fugitive Emissions from Piping Components				
Component and Service	**Number of Components**	**Control Efficiency (%) [1]**	**Total Emissions**	
			(lb/hr)	**(tpy)**
Valves				
Gas/Vapor	936	97	0.25	1.09
Light Liquid	0	97	0	0
Heavy Liquid	0	97	0	0
Pumps				
Light Liquid	0	93	0	0
Heavy Liquid	0	93	0	0
Flanges/Connectors				
Gas/Vapor	2,628	97	0.23	1.00
Light Liquid	0	97	0	0
Heavy Liquid	0	97	0	0
Compressors				
Gas/Vapor	6	95	0.15	0.66
Pressure Relief Valves				
Gas/Vapor	18	97	0.12	0.54
Open Ended Lines				

All Liquid	0	97	0	0
Total Emissions			0.75	3.30
CO_2 Emissions			0.04[2]	0.18
CH_4 Emissions			0.75[2]	3.30
CO_2e Emissions			18.87[3]	82.66

[1] Control Efficiency for AVO Program from October 2000 Draft TCEQ Technical Guidance Package for Equipment Leak Fugitives.
[2] Total Emissions * Content of Natural Gas (wt%)
(Where: CO_2 content of natural gas = 5.49 wt% and CH_4 content of natural gas = 100 wt%)
[3] Based on the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 as published on November 29, 2013 (78 FR 71904)

VII. General Format of the BACT Analysis

The EPA conducted the BACT analyses for this draft permit in accordance with the 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.

A. <u>Natural Gas-Fired Simple Cycle Combustion Turbines BACT Analysis (EPNs: TURB1, TURB2 and TURB3)</u>

1. 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 that 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 an add-on pollution control option for "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)."[2]

CCS contains three major components: carbon capture, transport and storage. With respect to carbon capture, CCS systems use 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 suitable primarily to 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 requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed gas turbine facility because the technologies do not appear to currently have the potential for practical application to this type of facility. The third approach, post-combustion capture, is an available option for 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 absorption, 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 the 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 on at least part of the exhaust gas stream (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

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).

[2] U.S. EPA, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011. Available at: http://www.epa.gov/nsr/ghgdocs/ghgpermttingguidance.pdf.

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 (Bellingham Energy Center), currently owned by NEXTera Energy Resources of which Florida Power and Light is a subsidiary. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). The CO_2 capture operation was discontinued in 2005 due to a change in operations from a baseload unit to a peak load shaving unit, which created technical impediments to continuing to operate the system.

In applications where CO_2 has been captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres or higher for ease of transport (usually by pipeline). The CO_2 may then be transported to an appropriate location for underground injection if a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, is available or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.

- *Combined cycle CTGs* – As stated in the "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011), 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.[3] The applicant's project is conceived as a peaking power provider with a limited annual capacity factor and is designed to provide power quickly when dispatched 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 at variable levels and quickly cease operation when those additional power needs are satisfied. Simple cycle turbines also provide the flexibility to operate at partial load and respond to dispatch requirements in smaller increments than would be consistent with the operations of a larger integrated combined cycle system.

  Combined cycle units generally have higher efficiencies than simple cycle units; however, combined cycle units are well suited as baseload power generating units. EPA has not concluded, at this time, that combined cycle units can provide the rapid response and shutdown required of a peaking power source with limited hours of operation producing reasonably priced power to sell in a deregulated market. The start-up sequence for a

[3] 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.

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 duration of 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 typically longer than that of a similarly sized simple cycle plant.[4]

Fast-start technology is capable of enabling startup of a combined cycle combustion 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 combustion turbine with fast-start technology may take as long as 90 minutes. To keep the HRSG and the steam 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.

TRPP's proposed project is a peaking power provider operating no more than 2,920 hours per year and providing power quickly when dispatched on a cost effective basis. TRPP's business purpose requires the ability to accommodate flexible and on-demand operations from approximately 94 MW up to 694 MW,[5] including the operational flexibility to frequently start up and shut down to respond immediately to variable electricity grid demand as dispatched by ERCOT. TRPP also noted the high capital cost for a combined cycle combustion turbine configuration would require a much higher capacity factor than would be consistent with a peaking project business purpose. Therefore, based on the defined business purpose of the proposed project and for the reasons discussed herein, the use of combined cycle units for this specific project would result in a redefinition of the source and is excluded from Step 1 of this BACT analysis.[6]

- *Efficient Generating Technology* – A key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Older, 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 and the use of higher quality

[4] U.S. Environmental Protect Agency, Region 9. Fact Sheet and Ambient Air Quality Impact Report for the Proposed Prevention of Significant Deterioration Permit, Pio Pico Energy Center.

[5] Power output rate varies depending upon the ambient temperature and selected turbine configuration option, which can at various capacities meet a very broad range of energy demand.

[6] Even if combined cycle technology were not excluded as a redefinition of the source for this project, the case-by-case analysis of TRPP's peaking power generation project also demonstrates that combined cycle units with fast-start technology may be infeasible under the standard BACT analysis. Therefore, while maintaining that combined cycle technology is a redefinition of the source, we have also included TRPP's economic feasibility analysis under Step 4 of the BACT analysis.

metallurgy. Use of modern, efficient simple cycle turbines is an available control option.

EPA evaluated the turbine models proposed for this project using available resources such as Gas Turbine World (2012) and in conjunction with the stated purpose of this project, and all of three proposed simple cycle turbine models are considered to be modern and efficient turbines.

The applicant also considered reciprocating engines in its BACT analysis. The applicant notes that, due to relatively small generation capacities, reciprocating engines are used to generate small amounts of electricity for isolated sources or to provide back-up power in case of an emergency. The largest commercial model of reciprocating engine is capable of generating approximately 18 MW of gross power. More than three dozen reciprocating engines would be required to provide the 694 nominal gross MW of output provided by the three simple cycle turbines considered by the applicant; therefore, requiring reciprocating engines would result in redefinition of the source and is excluded from Step 1 of the this BACT analysis.

- *Fuel Selection* – In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (e.g., coal, natural gas or 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. As noted below, TRPP evaluated the use of, in ascending order of expected GHG emissions, natural gas, propane gas, distillate oil, and biomass liquids as fuel for the CTGs.

- *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. 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 an Electric Fuel Pre-heater* – Preheating the fuel increases the thermal and power efficiency of the combustion turbine.

- *Inlet Air Cooling* – Chilling the incoming air increases the thermal and power efficiency of the CTG under certain ambient conditions. An evaporative cooling system will be used to cool the incoming combustion turbine air (to approximately 64-79^{o}F, depending upon ambient temperature) in order to increase the combustion air mass flow. Chilling the incoming air in this way increases the thermal efficiency and power gain of the combustion turbine, 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 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.

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, de-mineralized water is not necessary, and in many cases only filtration is required as pretreatment of the water.

2. Step 2 – Elimination of Technically Infeasible Alternatives

- *Carbon Capture and Storage:* As discussed in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by U.S. EPA and U.S. Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have not been demonstrated nor utilized commercially for simple cycle electric generating units operating as peaking power providers with multiple starts and stops to respond to electricity demand dispatch requirements. Peaking units frequently cycle their operation, and it is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of a carbon capture system. Further, operation of a carbon capture system in a “start/stop” mode as an add-on control technology does not presently appear to have the potential for practical applications to gas-fired CTGs, thus adding carbon capture to a cycling operation may limit operational flexibility. EPA is not aware of any pilot scale carbon capture project that has successfully operated in a cycling mode. TRPP's proposed project is to be operated solely in a frequent cycling mode, thus carbon capture is not applicable. Further, EPA is not aware of any carbon capture system that is commercially available at this time for a simple cycle combustion turbine peaking unit. Therefore, carbon capture is eliminated as not technically feasible at this facility and will not be evaluated in the remainder of this BACT analysis.[7]

- *Efficient Generating Technology:* The applicant documented the factors it considered in selecting particular turbine models and configurations for this facility, in light of operational variables such as project size, project purpose, fuel use, technical feasibility, and ambient conditions. The turbine models under consideration by the applicant are all considered efficient, modern simple cycle turbines.

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

3. Step 3 – Ranking of Controls

- Efficient Generating Technology
- Fuel Selection
- Good Combustion, Operating, and Maintenance Practices
- Use of Electric Fuel Pre-heater and Air Evaporative Cooling

Selection of highly efficient simple cycle combustion turbines is considered the most effective control technology in this analysis. Fuel selection; good combustion, operation, and maintenance practices; fuel pre-heating; and the use of evaporative cooling technology are all considered effective and have a range of efficiency improvements which cannot be directly quantified, and therefore, ranking them is not possible. In assessing CO_2 emissions for potential fuel types for combustion turbines, natural gas combustion results in lower GHG emissions (116-120 lbs CO_2e/MMBtu) than propane gas (135 lbs CO_2e/MMBtu), distillate oil (163 lbs CO_2e/MMBtu), and biomass liquids (143–179 lbs CO_2e/MMBtu).

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

1) *Efficient Generating Technology:* The applicant assessed various types and models of modern, efficient simple cycle turbines. Although combined cycle units, including those with

[7] Since CCS is eliminated in Step 2 of the BACT analysis, EPA does not need to include a cost analysis in Step 4 of the BACT analysis. TRPP did, however, submit a cost analysis for CCS as part of the application, and that analysis is included in the administrative record.

fast-start technology, and reciprocating engines were eliminated from this analysis as a redefinition of the source, the applicant included two models of fast-start combined cycle units and reciprocating engines in its economic analysis. While the applicant's operational hour limit is approximately 33% of its annual capacity, the applicant notes that the ERCOT average dispatch rates for peaking units for 2011–2013 equates to an approximately 5.5% capacity factor. Therefore, it is appropriate to consider economic costs across a wide range of capacity factors in determining economic feasibility. Based upon its economic analysis finding the cost of CO_2 avoided ranges from $245 per ton (at 33% annual capacity factor) to $2,430 per ton (at 5.5% annual capacity factor) for aero-derivative units, the applicant has selected frame-type simple cycle turbines for this project.

The GE 7FA.05, GE 7FA.04, and Siemens SGT6-5000F (5ee) natural gas fired combustion turbines are modern, efficient turbines that are economically feasible for TRPP's project and no energy or environmental impacts warrant elimination of these frame-type simple cycle turbines.

2) *Low Carbon Fuels:* As discussed in Step 3, natural gas produces the lowest GHG emissions and is the top ranked option. EPA concludes that natural gas is the appropriate fuel for this source and no economic, energy or environmental impacts warrant elimination of this control option.

3) *Good Combustion, Operating, and Maintenance Practices:* EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

4) *Use of and Electric Fuel Preheater and Evaporative Cooling:* After considering 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 as BACT. Refrigeration units have a very high parasitic load and are very costly to install, and inlet foggers require demineralized water, which also requires additional energy consumption. Evaporative coolers represent the most energy efficient means of cooling inlet air to a simple cycle combustion turbine, and EPA concludes that no economic, energy, or environmental impacts warrant elimination of these control options.

5. Step 5 – Selection of BACT

From this analysis, EPA has concluded that the GHG BACT for Roan's Prairie Generating Station is the use of a modern natural gas-fired, thermally efficient simple cycle combustion turbine combined with a fuel pre-heater, air evaporative cooling and good combustion and maintenance practices to maintain optimum efficiency. EPA believes that the applicant's proposal to use the GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F(5ee) turbines is consistent with the BACT requirement for the specific goal of this project. With this BACT determination, EPA is proposing a GHG BACT limit for each turbine model being considered for the project as shown in Table 6. Each proposed BACT limit is based on a 2,920 rolling operational hour basis. The GHG rolling operational hour average BACT limit for CTGs is determined by the calculation of the total summed CO_2 mass emissions of the unit over 2,920 rolling operational hours. The total summed CO_2 mass emissions is divided by the total summed gross electrical output generated by the unit over the same corresponding operational time period. The resulting quotient of this mathematical operation is compared to the CO_2 BACT limit. Until the 2,920 operational hour basis has been established, the applicant 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.

Table 6. GHG BACT Summary for TRPP's Natural Gas Fired Combustion Turbines

Pollutant	Limit SGT6-5000F(5ee)	Limit GE7FA.05	Limit GE7FA.04	BACT Control Technology	Averaging Time/Compliance Method
Proposed BACT for CO_2 (lb CO_2/MWhgross)	**1334**	**1310**	**1321**	High-efficiency simple cycle gas turbine technology, Primary Use of Natural Gas	2920 operational hour rolling basis per turbine/Fuel monitoring/Initial stack test for CO_2/CO_2 CEMS (only if elected) and recordkeeping
CO_2e (tpy)	**1,279,154**	**1,245,701**	**1,151,814**		

Each combustion turbine is limited to 2,920 hours of operation per year, including 365 startup and 365 shutdown events on a 12-month rolling basis. TRPP will be responsible for demonstrating compliance with the permitted limits and should evaluate its actual emissions and verify actual compliance from recorded operational data. To account for the startup and shutdowns, each turbine is limited by fuel use associated with the 2,920 hours of operation per year. Limiting the fuel use achieves the same objective as limiting the number of hours of operation of each turbine to 2,920 hours. The fuel use limits for each combustion turbine that corresponds to the 2,920 hours of operation on a 12-month rolling basis is 6,129,560 MMBtu (HHV) for the GE 7FA.05 combustion turbine, 5,156,210 MMBtu (HHV) for the 7GE FA.04 combustion turbine, or 6,785,520 MMBtu (HHV) for the SGT6-5000F(5ee) combustion turbine.

The proposed BACT limits for the GE 7FA.05, GE 7FA.04, or Siemens SGT6-5000F(5ee) natural gas-fired combustion turbines are comparable to or lower than emissions of other similar peak power facilities with a GHG BACT limit, as summarized in Table 7.

Table 7. GHG BACT Limit of Peak Power Facilities					
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	GE7FA.05 Option: 1,299 lb CO_2e/MWhr (net) 311,382 tpy CO_2e GE7FA.04 Option: 1,310 lb CO_2e/MWhr (net) 274,496 tpy CO_2e SGT5000F4 Option: 1,278 lb CO_2e/MWhr (net) 301,819 tpy CO_2e GELMS100 Option: 1,138 lb CO_2e/MWhr (net) 327,577 tpy CO_2e	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	GE7FA.05: 1,377 lb CO_2e/MWhr (gross) when firing natural gas	2014	PSD-EPA-R4013

The proposed BACT limits are comparable to recently permitted 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 determined that all three of the CTGs proposed by TRPP are, in general, considered highly efficient, modern CTG models.

Variations in elevation and ambient temperature will affect a combustion turbine's operational performance and are important considerations 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. The Appendices to TRPP's application provide the anticipated combustion turbine performance data across various load percentages and at the various ambient conditions for the proposed turbines.

To allow for variations in manufacturing tolerances and test uncertainties, equipment manufacturers frequently rely on design margins to accommodate the small variation in turbine performance. A design margin of 2 percent was included within the calculations for the combustion turbine, which is comparable to other recently permitted projects. The performance margin used in this analysis (6 percent) is also comparable to other recently permitted projects.

a. **BACT During Startup and Shutdown:**

BACT applies during all periods of turbine operation, including startup and shutdown. Startup and shutdown emissions are limited 4,425 tons CO_2/yr for the GE 7FA.05 combustion turbine, 3,905 tons CO_2/yr for the GE 7FA.04 combustion turbine or 3,267 tons CO_2/yr for the SGT6-5000F(5ee) combustion turbine, and each start up and shut down event is limited to 12.12 tons CO_2 per event for the GE 7FA.05 combustion turbine, 10.69 tons CO_2 per event for the GE FA.04 combustion turbine or 8.95 tons CO_2 per event for the SGT6-5000F(5ee) combustion turbine . The number of startups and shutdowns is included in the number of operational hours per year (2,920 service hours per year per turbine) and is limited to 365 startups and 365 shutdowns per year on a 12-month rolling basis. A startup of the turbine is defined as the period that begins when fuel flow is initiated in the combustion turbine as indicated by flame detection and ends when the normal low-NOx combustion mode is achieved. A shutdown is defined as the period that begins when the combustion turbine, following an instruction to shut down, drops out of the normal operating low-NOx combustion mode and ends when a flame is no longer detected in the combustion turbine combustor. BACT for startup/shutdown is the work practice standard to utilize good pollution control practices, safe operating practices and protection of the facility. The startup /shutdown activities shall be minimized by limiting the duration of operation in startup/shutdown mode as follows:

- A combined duration of a startup and shutdown is limited to no more than 25 minutes (for the Siemens turbine) and 40 minutes (for the GE turbines) per event.
- No more than 365 startup events and 365 shutdown events per turbine on a 12-month rolling basis.
- The maximum heat input during startup shall be limited to 1,774 MMBtu/hr for the GE 7FA.05 combustion turbine, 1,603 MMBtu/hr for the GE 7FA.04 combustion turbine or 1,857 MMBtu/hr for the SGT6-5000F(5ee) combustion turbine.

b. **BACT Compliance**:

Proposed BACT for this project is the use of new natural gas-fired thermally efficient simple cycle combustion turbines combined with good combustion and maintenance practices to maintain optimum efficiency, and an output based limit for each combustion turbine as shown in Table 6. Compliance will be based on a 2,920 operational hour rolling basis, calculated daily for each turbine. TRPP will maintain records of tune-ups, burner tip maintenance, and maintenance for each combustion turbine. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for each combustion turbine. For each combustion turbine, 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 (MWhr).

TRPP will demonstrate compliance with the CO_2 limit for each combustion turbine by using a non-resettable elapsed time fuel flow meter to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR § 75.10(a)(3)(ii) and the procedures listed in 40 CFR Part 75, Appendix G. TRPP may choose to use the results of the fuel sampling 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 TRPP 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 GHG rolling operational hour average BACT limit for the combustion turbine generator is determined by the calculation of the total summed CO_2 mass emission rate of the unit over 2,920 rolling operational hours. The total summed CO_2 mass emission rate is divided by the total summed gross electrical output generated by the unit over the same corresponding operational time period. The resulting quotient of this mathematical operation is compared to the BACT limit shown in Table 6. Until the 2,920 operational hour basis has been established, TRPP 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.

If TRPP chooses to determine a site-specific Fc factor, the analysis and GCV in equation F-7b of 40 CFR Part 75, Appendix F shall be used. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F, § 3.3.6.

The equation for estimating CO_2 emissions as specified in 40 CFR Part 75, Appendix G, Procedure 2.3 is as follows:

$$W_{CO_2} = (Fc \times H \times Uf \times MW_{CO_2})/2000$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/hour
MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole
Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor
H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR Part 75, Appendix F § 5
Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

TRPP is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR Part 75, Appendix D, which include:

- The fuel flow meter shall meet an accuracy of 2.0% and is required to be tested once each QA operating quarter pursuant to 40 CFR Part 75, Appendix D, § 2.1.5 and § 2.1.6(a).
- TRPP shall determine the GCV of pipeline natural gas at least once per calendar month pursuant to 40 CFR Part 75, Appendix D, § 2.3.4.1.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors either represented in the permit application or provided in 40 CFR Part 98, Subpart C, 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 and; therefore, 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 2,920 operational hour average, calculated daily.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the CTG and are considered a *de minimis* level in comparison to the CO_2 emissions.

B. <u>Diesel-Powered Emergency Engines BACT Analysis (EPNs: FWPUMP and EMGEN)</u>

Roan's Prairie Generating Station will be equipped with two diesel-powered emergency engines. The first emergency engine will have a rating of 2937-hp and will drive a generator to supply electrical power for control systems in the event of power outage. The second diesel-powered emergency engine, which is nominally rated 575-hp, will be used to power a fire water pump in the event of a fire.

1. Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options includes engines powered by electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.
- *Good Combustion Practices, Operation and Maintenance* – Good combustion practices include appropriate maintenance of equipment, such as periodic readiness testing, and operating within the recommended air to fuel ratio recommended by the manufacturer.
- *Low Annual Capacity Factor* – Limiting the hours of operation reduces the emissions produced. The emergency engines will be limited to 100 hours of non-emergency operation per engine per year for purposes of maintenance, inspection and readiness testing.

2. **Step 2 – Elimination of Technically Infeasible Alternatives**

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

Low Carbon Fuels – The purpose of the engines is to provide a source of water during a fire emergency and to supply electrical power for control systems in the event of power outage. Natural gas- and propane-fueled engines are not considered technically feasible fuels for the emergency engines since they will be used in the event of a fire or facility-wide power outage, when natural gas or propane supplies may be interrupted. Gasoline fuel has a much higher volatility than diesel, thus it is less safe for use in an emergency situation. Therefore, the only technically feasible fuel for the emergency engines is diesel fuel.

3. **Step 3 – Ranking of Remaining Technologies Based on Effectiveness**

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, a ranking of the control technologies is not necessary.

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

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engine, an evaluation of the most effective controls is not necessary.

5. **Step 5 – Selection of BACT**

The following specific BACT practices are proposed for the diesel-powered emergency engines:

- *Good Combustion Practices, Operation and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The emergency engines will not be operated more than 100 hours of non-emergency operation per engine per year. They will only be operated for maintenance, inspection and readiness testing. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

C. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPN: CBFUG)

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 seven breakers of 500 lb SF_6 each.

1. Step 1 – Identification of Potential Control Technologies for GHGs

Circuit Breaker Design Efficiency - In comparison to older SF_6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 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 SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

Alternative Dielectric Material – Because SF_6 has a high GWP, one alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 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 SF_6*.[8] The alternatives considered include mixtures of SF_6 and nitrogen, gases and mixtures and potential gases for which little experimental data are available

2. Step 2 – Elimination of Technically Infeasible Alternatives

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

Alternative Dielectric Material - According to the report NIST Technical Note 1425, among the alternatives examined in the report, SF_6 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 SF_6 insulated equipment. The report concluded that "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture." The mixture of SF_6 and nitrogen is noted to need further development and may only be applicable in limited installations. This alternative has not been demonstrated in practice for this project's design installation. The second alternative of various gases and mixtures has not been demonstrated in practice, and needs additional systematic study before this alternative could be considered technically feasible. The third alternative of potential gases has not been demonstrated in practice, and there is little experimental data available. Additional studies are needed before this alternative would be considered feasible. 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." Therefore, because the alternative dielectric material options have not been

[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

demonstrated in practice for this project's proposed design application and are not commercially available, this alternative is considered technically infeasible.

3. Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of efficient circuit breaker design (including state-of-the-art SF_6 technology with leak detection to limit fugitive emissions) is the highest ranked control technology that is feasible for this application.

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

Since the only remaining control option is circuit breaker design efficiency, and since that option is selected as BACT, a Step 4 evaluation of the most effective controls is not necessary.

5. Step 5 – Selection of BACT

Circuit breaker design efficiency is selected as BACT. Specifically, state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection are the BACT control technology option selected. 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 density alarm and a low density 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 TRPP through annual monitoring 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.

D. <u>Fugitive Emissions from Piping Components BACT Analysis (EPN: FUG)</u>

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.

1. Step 1 – Identification of Potential Control Technologies

[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.

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

2. Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

3. Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless/sealless 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%. TCEQ's 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.

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

The use of leakless/sealless components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, but the incremental GHG emissions controlled by implementation of the TCEQ 28 LAER LDAR program or a comparable remote sensing program is considered a *de minimis* level in comparison to the total project's proposed CO_2e emissions. 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

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

between the considered control alternatives. Accordingly, given the costs of implementing 28LAER 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.

5. Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas components, EPA 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.

VIII. 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 has reviewed and adopted a Biological Assessment (BA), dated February 25, 2014, prepared by Environmental Resources Management (ERM) on behalf of Tenaska and EPA. The draft BA identified six (6) species listed as federally endangered or threatened in Grimes County, Texas:

Federally Listed Species for Jefferson County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Interior least tern	*Sterna antillarum athalassos*
Red-cockaded woodpecker	*Picoides borealis*
Whooping crane	*Grus americana*
Mammals	
Louisiana black bear Red wolf	*Ursus americanus luterolus* *Canis rufus*
Plants	
Navasota ladies'-tresses	*Spiranthes parksii*

EPA has determined that issuance of the proposed permit to Tenaska for a new electric generating station which includes three gas turbines and associated equipment will have no effect on the six (6) 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.

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. To make this determination, EPA reviewed and adopted a cultural resource report prepared by Environmental Resources Management (ERM), a contractor to Tenaska. For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be the 195-acre tract containing the construction footprint of the project plus approximately 0.6 miles of associated water pipeline corridor.

Based on the result of the desktop review, two cultural resource surveys have previously been done and two historic sites were identified within a one-mile radius of the APE; however, both sites are outside of the APE. Based on the results of the field survey and previous surveys, an additional historical site was identified within the APE which will be avoided by a permanent fence line that Tenaska will construct. All three sites are potentially eligible for listing on the National Register of Historic Places (NRHP).

Based upon the information provided in the cultural resources report, while there are cultural materials of historic age identified within the 1-mile radius of the APE and the historic site within the APE will be avoided via permanent fence line, EPA Region 6 determines that the potential for other intact archaeological resources eligible for listing on the NRHP is low within the construction footprint of the project itself. Therefore, issuance of the permit to Tenaska will not affect properties on or potentially eligible for listing on the National Register.

On February 20, 2014, EPA sent letters to 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 will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. 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 Cultural Resource Report is posted on EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

X. 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 EPA has 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 [EPA's *PSD and Title V Permitting Guidance for GHGS* (March 2011) at 48]. Thus, EPA concludes it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, EPA has determined an environmental justice analysis is not necessary for the permitting record.

XI. Conclusion and Proposed Action

Based on the information supplied by TRPP, 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 TRPP 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

Annual Facility Emission Limits

Table 1. Annual Emission Limit – Siemens –SGT6-5000F(5ee) CT
Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY		
TURB1 TURB2 TURB3	TURB1 TURB2 TURB3	Natural Gas Fired Simple Cycle Turbine	CO_2	1,277,862[3]	1,279,154[3]	BACT limit of 1,334 lb CO_2/MW-hr (gross) on a 2,920 hour rolling basis, rolling daily, each turbine. Not to exceed 2,920 hours of operation on a 12-month rolling basis per turbine. See permit condition III.A.2 and 4.
			CH_4	23.57[3]		
			N_2O	2.36[3]		
TURB1 TURB2 TURB3	TURB1 TURB2 TURB3	Natural Gas Fired Simple Cycle Turbine – Startup and Shut down	CO_2	9801[3]	9,803[3]	Each event limited to 8.95 tons CO_2 per turbine. Limit of 365 events per turbine on a 12-month rolling total. Maximum heat input during startup limited to 1,857 MMBtu/hr per turbine See Special Condition III.A.4.b. through e.
			CH_4	0.06[3]		
			N_2O	No Numerical Limit Established[3,4]		
FWPUMP	FWPUMP	Diesel-powered Engine for Firewater Pump	CO_2	33	33	- 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]		
EMGEN	EMGEN	Diesel-powered Emergency Generator	CO_2	156	156	-Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. - See permit condition III.C.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
CBFUG	CBFUG	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Maintenance and Implementation of AVO Program. See permit condition III.D.

Table 1. Annual Emission Limit – Siemens –SGT6-5000F(5ee) CT Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following						
FIN	**EPN**	**Description**	**GHG Mass Basis**		**TPY CO_2e[1,2]**	**BACT Requirements**
				TPY		
FUG	FUG	Component Fugitive Leak Emissions	CO_2	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO Program. See permit condition III.E.
			CH_4	No Numerical Limit Established[6]		
Totals[7]			CO_2	1,287,852.55	**CO_2e 1,289,432**	
			CH_4	26.99		
			N_2O	2.36		
			SF_6	0.01		

1. The TPY emission limits specified in this table are 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 CO2e TPY limit are for the three natural gas fired simple cycle turbines combined.
4. These values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. SF_6 fugitive emissions from EPN CBFUG are estimated to be less than 0.01 TPY of SF_6 and 200 TPY of CO_2e. In lieu of an emission limit, the emissions will be limited by using state of the art SF_6 circuit breakers with leak detection.
6. Fugitive Leak Emissions from EPN FUG are estimated to be 0.18 TPY CO_2, 3.3 TPY CH_4, and 82.65 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

Table 2. Annual Emission Limit – GE 7FA.04 CT Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following						
FIN	**EPN**	**Description**	**GHG Mass Basis**		**TPY CO_2e[1,2]**	**BACT Requirements**
				TPY		
TURB1 TURB2 TURB3	TURB1 TURB2 TURB3	Natural Gas Fired-Simple Cycle Turbine, each	CO_2	1,150,650[3]	1,151,813[3]	BACT limit of 1,321 lb CO_2/MW-hr (gross) on a 2,920 hour rolling basis, rolling daily, each turbine. Not to exceed 2,920 hours of operation on a 12-month rolling basis per turbine. See permit condition III.A.2 and 4
			CH_4	21.22[3]		
			N_2O	2.12[3]		
TURB1 TURB2 TURB3	TURB1 TURB2 TURB3	Natural Gas Fired Simple Cycle Turbine – Startup and Shut down	CO_2	11,715[3]	11,717[3]	Each event limited to 10.69 tons CO_2 per turbine. Limit of 365 events per turbine on a 12-month rolling total. Maximum heat input during startup limited to 1,603 MMBtu/hr per turbine.See Special Condition III.A.4.b. through e.
			CH_4	0.07[3]		
			N_2O	No Numerical Limit Established[3, 4]		
FWPU MP	FWPU MP	Diesel-powered Engine for Firewater Pump	CO_2	33	33	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]		
EMGE N	EMGE N	Diesel-powered Emergency Generator	CO_2	156	156	Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis Use of Good Combustion Practices. See permit condition III.C.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
CBFUG	CBFU G	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Maintenance and implementation of AVO Program. See permit condition III.D.
FUG	FUG	Components Fugitive Leak Emissions	CO_2	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO Program. See permit condition III.E.
			CH_4	No Numerical Limit Established[6]		
Totals[7]			CO_2	1,162,554	**1,164,005**	
			CH_4	24.64		
			N_2O	2.12		

Table 2. Annual Emission Limit – GE 7FA.04 CT Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following						
FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY		
			SF_6	0.01		

1. The TPY emission limits specified in this table are 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 are for the three natural gas fired simple cycle turbines combined.
4. These values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. SF_6 fugitive emissions from EPN CBFUG are estimated to be less than 0.01 TPY of SF_6 and 200 TPY of CO_2e. In lieu of an emission limit, the emissions will be limited by using state of the art SF_6 circuit breakers with leak detection.
6. Fugitive Leak Emissions from EPN FUG are estimated to be 0.18 TPY CO_2, 3.3 TPY CH_4, and 82.65 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

Table 3. Annual Emission Limit – GE 7FA.05 CT Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following						
FIN	**EPN**	**Description**	**GHG Mass Basis**		**TPY CO_2e[1,2]**	**BACT Requirements**
				TPY[1]		
TURB1 TURB2 TURB3	TURB1 TURB2 TURB3	Natural Gas Fired-Simple Cycle Turbine, each	CO_2	1,244,442[3]	1,245,700[3]	BACT limit of 1,310 lb CO_2/MW-hr (gross) on a 2,920 hour rolling basis, rolling daily, each turbine. Not to exceed 2,920 hours of operation on a 12-month rolling basis per turbine. See permit condition III.A.2 and 4.
			CH_4	22.95[3]		
			N_2O	2.30[3]		
TURB1 TURB2 TURB3	TURB1 TURB2 TURB3	Natural Gas Fired Simple Cycle Turbine – Startup and Shut down	CO_2	13,275[3]	13,277[3]	Each event limited to 12.12 tons CO per turbine. Limit of 365 events per turbine on a 12-month rolling total. Maximum heat input during startup limited to 1,774 MMBtu/hr per turbine. See Special Condition III.A.4.b. through e.
			CH_4	0.07[3]		
			N_2O	No Numerical Limit Established[3, 4]		
FWPU MP	FWPU MP	Diesel-powered Engine for Firewater Pump	CO_2	33	33	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]		
EMGE N	EMGE N	Diesel-powered Emergency Generator	CO_2	156	156	Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis Use of Good Combustion Practices. See permit condition III.C.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
CBFUG	CBFU G	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Maintenance and implementation of AVO Program. See permit condition III.D.
FUG	FUG	Components Fugitive Leak Emissions	CO_2	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO Program. See permit condition III.E.
			CH_4	No Numerical Limit Established[6]		
Totals[7]			CO_2	1,257,907	**CO_2e 1,259,452**	
			CH_4	26.37		

Table 3. Annual Emission Limit – GE 7FA.05 CT Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following						
FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
			N_2O	2.3		
			SF_6	0.01		

1. The TPY emission limits specified in this table are 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 are for the three natural gas fired simple cycle turbines combined.
4. These values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. SF_6 fugitive emissions from EPN CBFUG are estimated to be less than 0.01 TPY of SF_6 and 200TPY of CO_2e. In lieu of an emission limit, the emissions will be limited by using state of the art SF_6 circuit breakers with leak detection.
6. Fugitive Leak Emissions from EPN FUG are estimated to be 0.18 TPY CO_2, 3.3 TPY CH_4, and 82.65 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.