Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Tenaska Brownsville Partners, LLC

Permit Number: PSD-TX-1350-GHG

October 2014

This document serves as the Statement of Basis (SOB) 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 will apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On February 15, 2013, Tenaska Brownsville Partners, LLC (Tenaska) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. Tenaska has submitted additional information for inclusion into the application. In connection with the same proposed construction project, Tenaska submitted an application for a PSD permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 22, 2013, subsequently issued by TCEQ on April 29, 2014. Tenaska proposes to construct a natural gas-fired combined-cycle gas turbine (CCGT) electric generating plant, known as the Tenaska Brownsville Generating Station (TBGS), to be located in Brownsville, Cameron County, Texas. The TBGS will consist of one or two combustion turbines (CTs), each shaft-connected to electric generators (CTGs) and exhaust-ducted to supplemental-fired heat recovery steam generator(s) (HRSGs), which will provide steam to power a single steam turbine generator (STG). Each HRSG will use duct burners for supplemental firing to boost the CT exhaust energy when needed for additional steam electric generation. After reviewing the application, EPA Region 6 prepared the following SOB and draft air permit to authorize construction of air emission sources at the TBGS.

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

EPA Region 6 concludes that Tenaska’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 Tenaska, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Tenaska Brownsville Partners, LLC
14302 FNB Parkway
Omaha, NE 68154-5212

Facility Physical Address:
8000 Old Alice Road
Brownsville, TX 78526

Contact:
Larry Carlson
Vice President, Environmental Affairs
Tenaska Inc.
(402) 938-1661

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Melanie Magee
Air Permitting Section (6PD-R)
(214) 665-7161

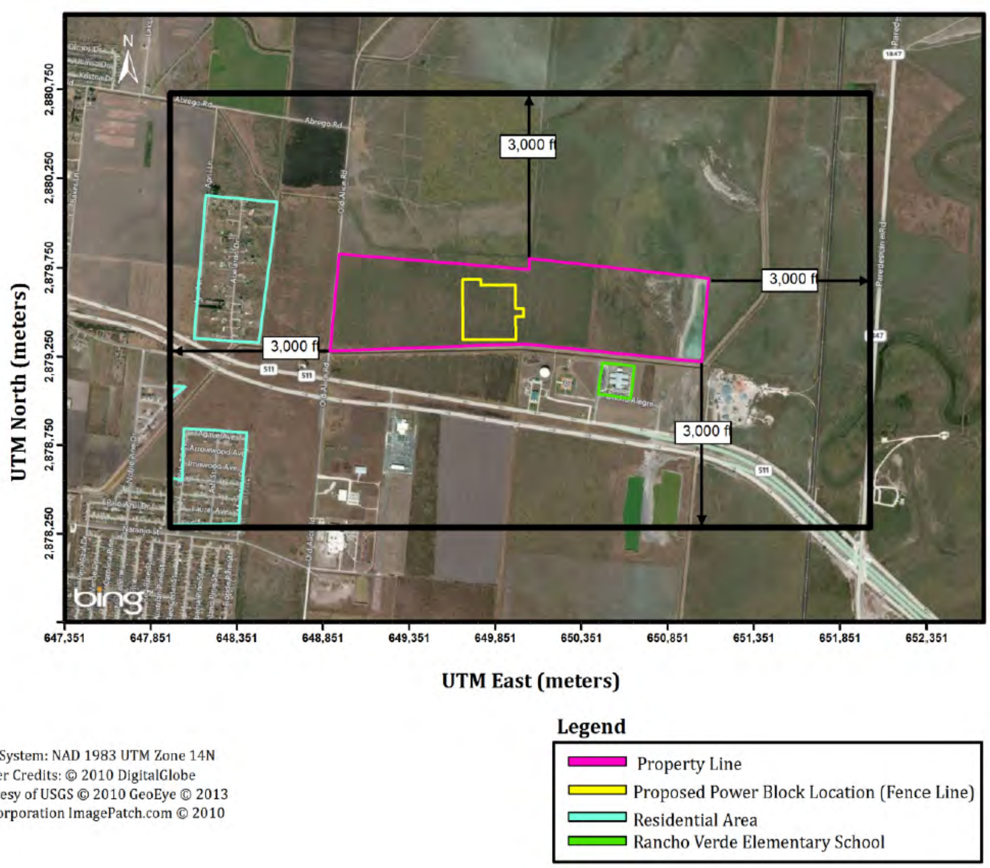
IV. Facility Location

TBGS will be located in Cameron County, Texas, and this area is currently designated “attainment” for all criteria pollutants. The nearest Class 1 area is the Big Bend National Park, which is located over 300 miles from the site. The geographic coordinates for the proposed facility site are as follows:

Latitude: 26º 01′ 36″ North
Longitude: 97º 30′ 13″ West

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

Figure 1. Tenaska Brownsville Generating Station Location



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 GHGs. [*Utility Air Regulatory Group* v. EPA] (No. 12-1146) 134 S.Ct.2427(2014). The Supreme Court said that 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 PSD or Title V permit. The Court also said that EPA could continue to require that PSD permits that are 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 United States Court of Appeals for the D.C. Circuit, EPA is proposing to issue this permit consistent with EPA's understanding of the Supreme Court's decision.

The proposed TBGS is within a major facility category and is subject to a 100 tpy threshold for classification as a PSD major source. The source is a major source because the facility has the potential to emit 2,275 tpy of carbon monoxide (CO), 325 tpy of nitrogen oxide (NOx), 863 tpy of volatile organic compounds (VOC), 134 tpy of particulate matter (PM), 73 tpy of particulate matter with a diameter greater than 10 microns or less (PM_{10}) and 69 tpy of particulate matter with a diameter greater than 2.5 microns or less ($PM_{2.5}$). In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project in a 2x1 configuration is subject to PSD review for the following conventional regulated NSR pollutants: VOC, NOx, CO, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4.[1]

The applicant also estimates for the 2x1 operational configuration that this same project emits or has the potential to emit 3,277,606 tpy CO_2e of GHGs,[2] which well exceeds the 75,000 ton per year CO_2e threshold in EPA regulations. 40 CFR § 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.

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 materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion. [3]

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[1] For the 1x1 operational configuration scenario, the project is subject to PSD review for the following conventional regulated NSR pollutants: VOC, NOx, CO, PM, PM_{10}, and $PM_{2.5}$.

[2] For the 1x1 operational configuration scenario, the project will emit or has the potential to emit 1,650,508 tpy of CO_2e.

[3] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011,

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 issued by TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, would authorize Tenaska to construct a new CCGT electric generating plant (TBGS) in Cameron County, Texas. The TBGS will generate approximately 400 MW, nominal of electrical power for a 1x1 configuration or 800 MW, nominal of electrical power for a 2x1 configuration in the City of Brownsville. The 2x1 operational configuration gross electrical power output is based on two combustion turbines producing a nominal 274 MW at 62°F ambient temperature and one steam turbine to produce an additional nominal 318 MW or about 866 MW total plant gross electric output. Under summertime conditions for the Brownsville, Texas area, the net electric output is approximately 800 MW. TBGS will consist of the following sources of GHG emissions:

- One or two natural gas-fired CTGs equipped with lean pre-mix, low-NO_x combustors;
- One or two natural gas-fired duct burner systems inside the heat recovery steam generator(s) (HRSGs);
- One natural gas-fired auxiliary boiler;
- Natural gas piping and metering;
- One diesel fuel-fired emergency electrical generator engine;
- One diesel fuel-fired fire water pump engine; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

Although the proposed permit authorizes two CTGs (2x1 CCGT), the final design selected by Tenaska may consist of only one CT (1x1 CCGT). The 1x1 configuration gross electrical power output is based on one combustion turbine producing a nominal 274 MW at 62°F ambient temperature and one steam turbine to produce an additional nominal 159 MW, or 433 MW total plant gross electric output. In this smaller configuration, the net summertime electric output for the Brownsville, Texas area about is about 400 MW. The draft permit provides for deleting one CT if the single CT configuration is selected.

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http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

Combustion Turbine Generators

The proposed plant includes up to two Mitsubishi 501GAC natural gas-fired CTGs and two HRSGs. The CTGs burn pipeline quality natural gas to rotate an electrical generator to generate electricity. The main components of a CTG 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. These hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gases then exit the CTG and are ducted to the heat recovery steam generator (HRSG) for steam production.

Heat Recovery Steam Generator (HRSG) with Duct Burners

Each turbine's exhaust heat is recovered in an HRSG to produce steam. The steam produced by the two HRSGs is routed to a single steam turbine. The high pressure steam is expanded across the steam turbine blades, driving a shaft to power the steam turbine generator (STG) to generate electricity. The HRSGs are equipped with duct burners (DBs) for boosting steam production. Like the CTGs, the DBs are fired with pipeline quality natural gas. Each DB has a maximum heat input capacity of 250 million British thermal units per hour (MMBtu/hr). The DBs are located in the HRSGs upstream of the selective catalytic reduction (SCR) system and oxidation catalyst (OC) used for NO_x, CO, and VOC emission control. Each CTG/HRSG has an exhaust stack through which the unit's exhaust gases are emitted to the atmosphere.

The normal DB operation will vary from 0 to 100 percent of the maximum capacity, depending on electricity demand. The CTGs and STG may operate at reduced load to respond to changes in system power requirements and/or stability.

Auxiliary Boiler

The auxiliary boiler provides low pressure steam to several steam cycle components while the STG is in standby and startup modes, helping to minimize the duration and emissions of plant startups. The auxiliary boiler is rated at 90 MMBtu/hr heat input and will use pipeline quality natural gas as fuel. Because it is mostly needed during plant standby and startup, it is limited to 4,380 operational hours per year.

Emergency Equipment

The site will be equipped with two diesel-fired emergency engines, one to provide electricity to the facility in case of power failure, and the other to pump water in the event of a fire. Each emergency engine and fire water pump will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing. The emergency generator engine is rated at 19 MMBtu/hr heat input and 2,681 horsepower (hp) output. The fire water pump engine is rated at 3.8 MMBtu/hr heat input and 575 hp output.

<u>Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)</u>

The generator circuit breakers associated with the proposed units 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 capacity of the circuit breakers associated with the proposed plant is currently estimated to be 366 lbs of SF_6. The proposed circuit breaker at the generator output 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.

VII. General Format of the BACT Analysis

EPA conducted the BACT analyses for this draft permit by following the "top-down" BACT approach recommended in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in a top-down BACT process 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. Emission Units Subject to BACT Analysis

The majority of the GHGs associated with the project are from emissions at combustion sources (i.e., combined cycle combustion turbines, duct burners, auxiliary boiler, and emergency engines). The project will have fugitive emissions from piping components which will account for 25 tpy of CO_2e, or less than 0.001% of the project's total CO_2e emissions. Stationary combustion sources primarily emit CO_2 and small amounts of N_2O and CH_4. The following equipment is included in this proposed GHG PSD permit:

- Combined Cycle Combustion Turbines (EPNs 1 and 2)
- Fire Water Pump (EPN 4)

- Emergency Generator (EPN 5)
- Auxiliary Boiler (EPN 7)
- SF_6 Insulated Equipment (EPN FUG_GHG)

IX. Combined Cycle Combustion Turbines (EPNs 1 and 2)

The two Mitsubishi 501GAC natural gas-fired combustion turbines, their HRSGs, and the steam turbine will be used for power generation. The BACT analysis for these turbines considered two types of GHG emission reduction alternatives: (1) energy efficiency processes, practices, and designs for the turbines and other facility components; and (2) carbon capture and storage (CCS).

As part of the PSD review, Tenaska provided in the GHG permit application a 5-step top-down BACT analysis for the combustion turbines. EPA has reviewed Tenaska's BACT analysis for the combustion turbines, which is part of the record for this permit (including this Statement of Basis), and we provide our own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identify All Available Control Options

(1) **Energy Efficiency Processes, Practices, and Design**

<u>Combustion Turbine:</u>

- *Combustion Turbine Design* – Good turbine design maximizes thermal efficiency. Combustion turbines operate at high temperatures. Heat radiated by the hot turbine components is lost to the surrounding atmosphere. To minimize this heat loss, turbines can be wrapped with insulating blankets so that more of the heat is retained in the hot gases for recovery of useful energy.
- *Periodic Maintenance and Tune-Up* – After several months of continuous operation of the combustion turbine, fouling and degradation contribute to a loss of thermal efficiency. A periodic maintenance program consisting of inspection and cleaning of key equipment components and tuning of the combustion system will minimize performance degradation and recover thermal efficiency to the maximum extent possible. Regularly scheduled combustion inspections involving tuning of the combustors are used to maintain optimal thermal efficiency and performance.
- *Reduction in Heat Loss* – Insulation blankets are applied to the combustion turbine casing to minimize heat loss to the environment. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.
- *Instrumentation and Controls* – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Distributed digital system controls are used to automate processes for optimal operation.

Heat Recovery Steam Generator:

- *Heat Exchanger Design Considerations* – Efficient design of the HRSG improves overall thermal efficiency. This includes the following: finned tube, modular type heat recovery surfaces for efficient, economical heat recovery; use of an economizer, which is a heat exchanger that recovers heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (ISO) for thermal efficiency; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.
- *Insulation* – The use of insulation prevents heat loss. Adding insulation to HRSG surfaces and steam and water lines will minimize heat loss from radiation.
- *Minimizing Fouling of Heat Exchange Surfaces* – Fouling of interior and exterior surfaces of the heat exchanger tubes hinders the transfer of heat from the hot combustion gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by inlet air filtration, maintaining proper feed water chemistry, and periodic maintenance, including cleaning the tube surfaces as needed during scheduled equipment outages.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam loss through venting and leakage reduces the efficiency of the heat exchanger. Restricting the venting outlets is used to maximize steam retention for power generation.

Steam Turbine:

- *Use of Reheat Cycles* – Steam turbine efficiency is dependent on the nature of the steam entering the turbine. Superheating, reheating, as well as, increased maximum cycle pressure are ways to enhance the efficiency of the basic Rankine cycle. TBGS will utilize a three pressure cycle with superheating and reheating to improve steam turbine efficiency.
- *Use of Exhaust Steam Condenser* – Steam turbine efficiency is improved by lowering the exhaust pressure of the steam. Condensing units are utilized to lower the exhaust steam to the saturation point, which reduces the exhaust pressure below atmospheric pressure (creates a vacuum).
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation.
- *Efficient Steam Turbine Generator Design* – The generator for modern steam turbines is cooled allowing for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine.

Other Plant-wide Energy Efficiency Features:

Tenaska has proposed a number of other measures that help improve overall energy efficiency of the plant (and thereby reducing GHG emissions from the emission units), including:

- *Instrumentation and Controls* – Distributed control systems will be used to automate and optimize process operation.
- *Cycle Design Consideration* – All high energy piping and systems will be insulated for safety and to minimize heat loss to the environment. System pressure drops will be minimized to the extent practical to maximize plant performance.
- *Operations and Maintenance* – Plant operations and maintenance will be based on equipment manufacturer's recommendations, Tenaska's extensive operating experience, and good industry practices. Tenaska's collective operations and maintenance program ensures the facility will be operated and maintained at the highest standards, promoting overall plant performance and efficiency. Turbine maintenance consists of prescribed events that are based upon unit operation and facility dispatch to inspect the unit and ensure optimal operating efficiency. Unit efficiency, combustion, emissions and other critical operating parameters will be continually monitored and tuned utilizing good engineering practices. Tenaska will document in their maintenance program an inspection and maintenance schedule that will record the date of the inspection of the unit, at a minimum of once per year. If the results of any inspection are not satisfactory, the deficiencies shall be recorded and the permittee shall promptly take necessary corrective action, recording each action with the date completed.

(2) **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 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)."[4]

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 oxy-fuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable 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, oxy-fuel 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 oxy-fuel combustion are not considered available control options for this proposed gas turbine facility. The third approach, post-combustion capture, is applicable to gas turbines.

[4] 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.

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 (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). 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 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).

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 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). 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.[5]

[5] We note that EPA's recent proposed rule addressing *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* rejected CCS as the best system of emission reduction for nation-wide standard for natural gas combined cycle (NGCC) turbines based on both "insufficient information to determine technical feasibility" and "adverse impact on electricity prices and the structure of the electric power sector." 79 Fed. Reg. at 1485 (Jan. 8, 2014). However, that proposal did not state that CCS was technically infeasible for individual NGCC sources and thus does not conflict with the type of case-by-case PSD BACT analysis (which separates the technical and cost issues) as presented here.

Step 2 – Elimination of Technically Infeasible Alternatives

Tenaska's application examines the technical feasibility of CCS for this project and concludes, "While carbon capture technology may be technologically available on a small-scale, it has not been demonstrated in practice for full-scale combined cycle power plants, such as the proposed Brownsville Generating Station". (Tenaska application at page 32).

EPA's recent proposed rule addressing *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* concluded that CCS was not the best system of emission reduction for a nation-wide standard for natural gas combined cycle (NGCC) turbines based on questions about whether full or partial capture CCS is technically feasible for the NGCC source category. [79 Fed. Reg. at 1485, Jan. 8, 2014]. Considering this, EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this specific NGCC source and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project. In addition, the other control options identified in Step 1 are considered technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Energy efficiency processes, practices, and designs 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 emission reduction from CCS, it has been reported that CCS could enable large reductions (85-90 percent) of CO_2 emissions from fossil fuel combustion.

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

Carbon Capture and Storage

Tenaska developed an initial incremental cost analysis for CCS that provided a total capital cost of $596 million (in addition to the cost of the plant without CCS). By comparison, the estimated total capital cost of the TBGS without CCS is $500 million. Based on these costs, Tenaska maintains that CCS is not economically feasible. While Tenaska provided some information relating to this cost estimate that is provided in the record for this proposed permit (including more detailed cost information that is provided in Appendix B), Tenaska did not provide detailed capital cost information for this facility as a whole. Accordingly, to assess Tenaska's cost claims, EPA has summarized some of the publically available cost information Tenaska provided below and compared Tenaska's overall cost assertions with cost estimates for similar facility types developed by the Agency and by the U.S. Department of Energy (DOE).[6]

Capital costs associated with CCS fall into three primary areas – capture, compression, and transport. Capture and compression costs derive from the installation of needed additional process equipment, including amine units, cryogenic units, dehydration units, and compression facilities. Transport costs are associated with construction of a pipeline to transport the captured CO_2 to a suitable repository or existing pipeline. Tenaska estimated the capital cost of CCS capture and compression equipment for the TBGS using project specific data along with the cost estimates provided by the U.S. Department of Energy's *Updated Costs (June 2011 Basis)* (DOE/NETL-341/082312, August 2012) update to the 2007 document, *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity*. Tenaska's cost estimate for the TBGS is based upon project-specific criteria and was updated to calendar year 2014 dollars. The estimated capital cost for post-combustion CO_2 capture and compression equipment was estimated to be $526 million. For transportation costs, Tenaska identified two possible options for transporting the captured CO_2 – building a pipeline to the nearest existing CO_2 pipeline (258 miles) or to build a separate line to the nearest enhanced oil recovery (EOR) market (106 miles)[7] – and estimated the cost for a 100 mile long 10 inch diameter pipeline at $70 million. Accordingly, Tenaska's total estimated capital cost for CCS at this facility is approximately $596 million.

Examining the proposed TBGS – an 800 MW Natural Gas Combined Cycle (CC) facility located in Cameron County, TX – using the EPA and DOE cost estimates, EPA estimates that the capital costs of the entire facility without CCS would be approximately $500 million.[8] EPA estimates that the capital costs of the entire facility with CCS would be approximately $1 billion.[9] These cost estimates are similar to the estimated CCS costs provided by Tenaska.[10]

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[6] *See* U.S. EPA, Air and Radiation, No. 450R13002, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model* (Nov. 2013) (EPA Report), available at http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v513/Documentation.pdf, and U.S. Department of Energy, U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (April 2013) (DOE Report). *available at http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.*

[7] The closest potential enhanced oil recovery site (an existing oil well in Jim Hogg County API No. 24732057) is approximately 106 miles to the northwest from the proposed Tenaska facility. In addition, Tenaska determined the nearest CO_2 pipeline is in the Hastings Oil Field, operated by Denbury Resources, and is 258 miles from the proposed TBGS.

[8] *See* EPA Report at Table 4-13 (initial capital costs of $1,006/kW) and Table 4-15 (0.954 locality cost adjustment) and DOE Report at Table 1 (initial capital costs of $1,023/kW) and Table 4 (0.92 locality cost adjustment).

[9] *See* DOE Report at Table 1 (initial capital costs of $2,095/kW) and Table 4 (0.90 locality cost adjustment). The EPA Report does not contain similar CCS cost information in Table 4-13.

[10] It is unclear whether the CCS cost estimates provided in the DOE Report include pipeline costs, but EPA estimates that adding separate pipeline construction costs would increase the CCS costs estimates for this facility by 1-5% (based on a CCS costs of approximately $1,535 million). Based on the estimated CO_2 flow rate from the facility, EPA estimates that a 6-inch to 10-inch pipeline would be required to transport the captured CO_2 from TBGS, and that the cost associated to construct a pipeline of this size would be approximately $650,000 to $750,000 per mile. This would result in costs of approximately $16-75 million dollars for a 25 to 100 mile pipeline. EPA's pipeline size estimate is based on distance transported of pure CO_2 gas flowing at 282,340 lb/hr, as obtained from SNC Lavalin on April 12, 2013. Pipeline capital costs are based on equations from DOE NETL analysis as described in CO_2 Transport, Storage & Monitoring Costs Quality Guidelines for Energy Systems

CCS Conclusion

Based on the normalized control cost and comparison of total capital cost of control to project cost, Tenaska maintains that CCS is not economically feasible. EPA has reviewed Tenaska's estimated CCS cost projections, and based upon the potential volume of CO_2 emissions from the project that would be available for capture and current estimates of CCS costs that would be associated with a project such as this, we believe Tenaska's estimated costs to install CCS add-on pollution controls for the facility are credible. Accordingly, we conclude that such costs would render the project economically unfeasible for TBGS and eliminate CCS as BACT for this facility.

Energy Efficiency Processes, Practices, and Design

There are no known adverse economic, energy, or environmental impacts associated with the control technologies identified in Step 1 for energy efficiency process, practices, and design. All these options are proposed for the facility as outlined below.

Combustion Turbine:

- *Combustion Turbine Design* – The Mitsubishi 501GAC turbine model proposed for the TBGS facility is a modern, efficient machine. The trade publication "Gas Turbine World" identifies the introduction year for this model as 2011. The heat rates of the combined cycle plant in 2x1 and 1x1 layout are nearly identical, at 5,735 and 5,726 Btu/kWh (based on fuel LHV), respectively. The corresponding efficiencies are 59.6% and 59.5%, respectively. These numbers are consistent with recent BACT determinations for other PSD GHG permit limits. In addition to the selection of an efficient combustion turbine, Tenaska has proposed features that will improve the efficiency of the plant over a range of operating conditions that will routinely occur. Inlet cooling will improve the combustion turbine efficiency on hot days.

  The HRSGs and plant have been designed to minimize the time the combustion turbines operate at very low loads during startup, where efficiency is lower. The combined cycle plant includes a desuperheater that allows the HRSG steam to be conditioned to meet the requirements for gradual heating of the steam turbine during startup. This design makes it possible to start the turbine up without requiring low load "hold points" below steady state minimum load (i.e., < 50% load) where the combustion turbine is operated while the steam turbine is allowed to slowly warm. Combustion turbine operation at such loads is relatively inefficient, producing higher GHG emissions per MWh of electricity produced than normal combustion turbine operating loads. The unimpeded start design allows the CTs to ramp up to 50% load in as little as 24 minutes, at which load the GHG emissions meet BACT for normal operations. However, control equipment necessary to meet certain

Studies (March 2010) utilizing estimated pipeline length and diameter values. Calculations are included in Appendix B.

conventional pollutant BACT limits will not be at minimum operational temperatures until 60 minutes.

- *Periodic Burner Tuning* – Regularly scheduled combustion inspections involving tuning of the combustors are used to maintain optimal thermal efficiency and performance.
- *Reduction in Heat Loss* – Insulation blankets are applied to the combustion turbine casing to minimize heat loss to the environment. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.
- *Instrumentation and Controls* – Distributed digital system controls are used to automate processes for optimal operation. Higher efficiencies and lower emissions are obtained through automation and easy-to-read digital readouts, which simplify turbine operation.

<u>Heat Recovery Steam Generator:</u>

- *Heat Exchanger Design Considerations* – HRSGs are designed to maximize the contact surface between the turbine exhaust gas and the feed water. The heat transfer occurs within the HRSG, with finned tube heat transfer surfaces. Steam is generated at three pressure levels. Additional heat can be added from duct-burners for incremental steam production, as desired. The expansion of the superheated steam then powers the turbine. After expanding through the high pressure stages, the steam is reheated in the HRSG. The reheated steam is further expanded through the intermediate and low pressure stages of the steam turbine. The HRSG is designed to allow for unrestricted combustion turbine startup to minimize emissions during power plant startups.
- *Insulation* – HRSGs are designed to minimize waste heat from combustion by utilizing that waste heat to generate steam to power a steam turbine. The efficient transfer of this heat from the turbine exhaust gases and the minimization of heat losses to the environment is an integral part of HRSG design. The shell-side housing of the HRSG is well-insulated to prevent unnecessary heat losses to the environment.
- *Minimizing Fouling of Heat Exchange Surfaces* – Fouling occurs when deposition of constituents in the exhaust gases occurs on heat transfer surfaces within the heat exchanger. This fouling “insulates” the heat exchange surfaces from heat transfer between the exhaust gases and the feed water, reducing heat transfer efficiency. Fouling is reduced through filtration of the combustion turbine inlet combustion air and periodic inspection of heat exchange surfaces.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam loss through venting and leakage reduces the efficiency of the heat exchanger. Venting operations are utilized in certain system areas, such as de-aerator vents, to improve operation. Restricting the venting outlets maximizes steam retention for power generation. If a leak is large enough, reduction in power generation efficiency is apparent and will be identified quickly through automatic monitoring and low-pressure alarms. Smaller steam leaks are identified and repaired quickly through the proper implementation of operator Standard Operating Procedures (SOPs) requiring routine checks of the equipment.

<u>Steam Turbine:</u>

- *Use of Reheat Cycles* – The use of a reheat cycle eliminates moisture in the steam exiting the turbine and prevents damage caused by water droplets which would impair turbine efficiency. The reheat cycle does this by extracting steam from the HP turbine before it starts to condense and reheats it in the HRSG. Not only does the reheat cycle prevent efficiency impairing turbine damage caused by water droplet formation, it also increases the overall cycle efficiency by raising the average temperature of heat addition.
- *Use of Exhaust Steam Condenser* – Steam turbine efficiency is improved by lowering the exhaust temperature of the steam. Condensing units are utilized to lower the exhaust steam to the saturation point, which reduces the exhaust pressure. This lowering of the exhaust pressure creates a vacuum, creating a natural draw through the turbine and thus increasing turbine efficiency.
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Materials of construction are also important in blade design, with the newest materials allowing for higher temperatures and large exhaust areas to improve performance. The steam turbines have a multiple steam seal design to obtain the highest efficiency from the steam turbine.
- *Efficient Steam Turbine Generator Design* – The generators for modern steam turbines are cooled, allowing for the highest efficiency of the generator and resulting in an overall high-efficiency steam turbine. The cooling method for the TBGS steam turbine will be either totally enclosed water-to-air cooling or hydrogen cooling.

Other Plant-wide Energy Efficiency Features

Tenaska has proposed a number other measures that help improve overall energy efficiency of the facility (and thereby reducing GHG emissions from the emission units), including:

- *Instrumentation and Controls* – Distributed control systems will be used to automate and optimize process operation. Optimum operating conditions are obtained through automated processes and results in an increase in overall plant efficiency.
- *Cycle Design Considerations* – All high energy piping and systems will be insulated for safety and to minimize heat loss to the environment. System pressure drops will be minimized to the extent practical to maximize plant performance.
- *Operations and Maintenance* – Tenaska's collective operations and maintenance program helps to ensure that the facility will be operated and maintained at the highest standards, promoting overall plant performance and efficiency.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Victoria WLE, Victoria Power Station	255 MW Combined-cycle with Duct Burner	Energy Efficiency Good Design & Combustion Practices	CTG Annual Firing Rate is 1,816 mmBtu/hr, DB Annual Firing Rate is 483 mmBtu/hr; 940 lb CO_2/MWh; MSS events limited to 1,000 hours per year and 108 tons CO2/hr;	2014	PSD-TX-1348-GHG
Pinecrest Energy Center Lufkin, TX	637-735 MW depending on turbine model selected Combined-cycle with Duct Burner	Energy Efficiency Good Design & Combustion Practices	909.2-942.0 lb CO_2/MWh depending on turbine model selected Startup emissions limited to 500 hours per year and 85 tons CO_2/hr.	2014	PSD-TX-1298-GHG
FGE Power, LLC Westbrook, TX	1,620 MW Combined cycle	Energy Efficiency Good Design & Combustion Practices	899 lb CO_2/MWh (gross) Startup Emissions- 48 tons CO_2/hr per turbine and 1,735 lb CH_4/event per turbine Shutdown Emission 192 tons CO_2/hr per turbine and 510 lb CH_4/event per turbine	2014	PSD-TX-1364-GHG
La Paloma Energy Center Harlingen, TX	637 - 735 MW depending on turbine model selected Combined cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input – 7,861-7,679 Btu/kWh depending on turbine model selected 934-909 lb CO_2/MWh depending on turbine model selected	2013	PSD-TX-1288-GHG
Calpine Deer Park Energy Center Deer Park, TX	168 MW/180 MW Combined cycle with Duct Burner	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input – 7,730 But/kWh 920 lb CO_2/MWh BACT at all operational times	2012	PSD-TX-979-GHG
Calpine Channel	168 MW/180 MW	Energy Efficiency	Annual Heat Input – 7,730 Btu/kWh	2012	PSD-TX-955-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Center Pasadena, TX	Combined cycle with Duct Burner	Good Design & Combustion Practices	920 lb CO_2/MWh BACT at all operational times		
Pioneer Valley Energy Center Westfield, MA	431 MW Combined cycle	Energy Efficiency Good Design & Combustion Practices	825 lb CO_2e/MWh_{grid} (initial performance test) 895 lb CO_2e/MWh_{grid} on a 365-day rolling average	2012	052-042-MA15
LCRA Thomas C. Ferguson Plant Horseshoe Bay, TX	195 MW Combined Cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Rate - 7,720 Btu/kWh 920 lb CO_2/MWh BACT at all operational times	2011	PSD-TX-1244-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	195 MW Combined cycle with Duct Burning	Energy Efficiency Good Design & Combustion Practices	Annual Heat Rate - 7,319 Btu/kWh 774 lb CO_2/MWh BACT at all operational times	2011**	SE 09-01
PacifiCorp Energy - Lake Side Power Plant Vineyard, UT	629 MW Combined cycle	Energy Efficiency Good Design & Combustion Practices	950 lb CO_2e/MWh (gross)	2011	DAQE-AN0130310010-11
Calpine Russell City Energy Hayward, CA	600 MW Combined cycle	Energy Efficiency/ Good Design & Combustion Practices	Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487

***The Palmdale facility BACT limit is reduced due to the offset of emissions from the use of a 50 MW Solar-Thermal Plant that was part of the permitted project.*

The following specific BACT practices are proposed for the turbines:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Design

- Highly Efficient Turbine Design
  - Turbine Inlet Air Cooling
  - Periodic Turbine Burner Tuning
  - Reduction in Heat Loss
  - Instrumentation and Controls
- HRSG Energy Efficiency Processes, Practices, and Design
  - Efficient heat exchanger design
  - Insulation of HRSG
  - Minimizing Fouling of Heat Exchange Surfaces
  - Minimizing Vented Steam and Repair of Steam Leaks
- Steam Turbine Energy Efficiency Processes, Practices, and Design
  - Use of Reheat Cycles
  - Use of Exhaust Steam Condenser
  - Efficient Blading Design
  - Efficient Generator Design

BACT Limits and Compliance:

To determine the appropriate heat-input efficiency limit, Tenaska started with the turbines' design base load gross heat rate for combined cycle operation and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. In addition, the base load heat rate was adjusted to account for a projected number of annual operating hours at minimum load, when heat rate is higher than at base load, based upon the anticipated dispatch profile. Actual time spent at minimum or intermediate load will be based upon actual plant dispatch instructions which will be largely out of Tenaska's control. The annual average gross heat rate and associated output-based CO_2 emission rate for a 2x1 and 1x1 configuration combined cycle operation are:

Turbine Model	Heat Rate, Gross[1,2] (Btu/kWh) (HHV)	Output Based Emission Limit, gross (lb CO_2/MWh)[1,2] (HHV)	MSS Emission BACT Limit (tons CO_2/hr)[3]
Mitsubishi 501GAC 2x1 or 1x1 operational configuration	7,500	922	142

[1] Limits are based on a 12-month rolling average

[2] Limits apply with and without duct burner firing

[3] Limit is for each turbine on a 12-month rolling average and is based on 712 hours of MSS on a 12-month rolling total.

The term "gross" above refers to the total amount of electric power produced at the generators. Some of this power is necessarily consumed by operation of the plant and is termed auxiliary load. The gross power output minus the auxiliary power load is electricity exportable to the grid and is termed the net electrical output. The net electrical output is not used here to be consistent with other recent GHG BACT determinations, which base the heat-input efficiency limit on the gross electrical output.

To determine an appropriate heat rate limit for the permit, the following compliance margins are added to the base heat rate:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design Margin - Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. Typically, the market for contracting the engineering and construction of combined cycle power plants has a design margin of 5% for the guaranteed net MW output and net heat rate. This is the condition for which the contractor has a “make right” obligation to continue tuning the facility's performance to achieve this minimum value. Therefore, the contractor must deliver a facility that is capable of generating 95% of the guaranteed MW and must have a heat rate that is no more than 105% of the guaranteed heat rate. Tenaska’s analysis (provided in their December 16, 2013 update to the application) of the appropriate design margin identifies a number of factors that may contribute to differences between the as-designed plant and the as-built plant. Tenaska identifies various factors that can cause these differences, but ultimately, by their nature, such differences cannot be quantified until the plant is built. Based on their experience with construction of other combined cycle power plants and the previous acceptance by EPA of a 3.3% design margin for issued GHG permits for combined cycle plants (e.g. Calpine Russell City, Deer Park, and Channel Energy; FGE Texas, La Paloma),Tenaska accepts a design margin of 3.3% rather than a level of 5%.

Performance Margin on Combustion Turbine and Steam Turbine Generators - The performance margin for equipment degradation relates to the combustion turbine and steam turbine generators. According to Figure 24 of the California Energy Commission publication CEC-200-2010-002, “Cost of Generation Model Users Guide Version 2” (March 2010), the “sawtooth curve” indicates that the degradation will be limited to 2% between inspections and that 75% of that performance will be recovered, resulting in a 20-year degradation of 4.5%. Based on their experience with their operating fleet of combined cycle electric generating facilities, Tenaska estimated the long-term performance degradation of the combustion turbine to result in an increase in heat rate of 2.5% to 3.0% over new and clean performance for the initial major maintenance cycle. Over the same initial maintenance cycle, Tenaska estimates the HRSG performance degradation to be 0.5% to 1.5% of the plant heat rate. For purposes of setting an enforceable heat rate or output-based CO_2 emission limit, the relevant degradation period is over the life of the project and its air permit, not the initial major maintenance cycle. The lifetime degradation is necessarily higher than the initial cycle. Moreover, figures for long-term plant degradation are estimates, not maximum or guaranteed values. Tenaska has proposed the potential degradation to be 6%, which is consistent with performance degradation accepted in previous GHG permit reviews of combined cycle natural gas electric generating facility permits for Calpine's Russell City, Deer Park, and Channel Energy plants, the proposed FGE Texas facility in Mitchell County, and the proposed La Paloma facility in Cameron County, Texas.

Degradation Margin for the Auxiliary Plant Equipment - The degradation margin for the auxiliary plant equipment encompasses the HRSGs. This margin accounts for the scaling and corrosion of the boiler tubes over time as well as minor potential fouling of the heating surface of the tubes. Similar to the HRSGs, scaling and corrosion of the condenser tubes will also degrade the heat transfer characteristics, thus degrading the performance of the steam turbine generator. Because combustion turbine degradation accounts for the majority of the performance loss and as well as the large variation in operating parameters (fuels, temperatures, water treatment, cycling conditions, etc.), little operating data has been gathered and published that illustrate a clear performance degradation characteristic for this auxiliary plant equipment. Tenaska proposes a 3% margin for degradation of balance-of-plant equipment, which is consistent with the issued GHG permits for combined cycle plants for Calpine's Russell City, Deer Park, and Channel Energy plants, the proposed FGE Texas facility in Mitchell County, and the proposed La Paloma facility in Cameron County, Texas.

EPA is proposing the following BACT limits for the TBGS project:

Turbine Model	Heat Rate, Gross[1,2] (Btu/kWh) (HHV)	Output Based Emission Limit, gross (lb CO_2/MWh)[1,2] (HHV)	MSS Emission BACT Limit (tons CO_2/hr)[3]
Mitsubishi 501GAC 2x1 or 1x1 operational configuration	7,500	922	142

1 Limits are based on a 12-month rolling average.

2 Limits apply with and without duct burner firing.

3 Limit is for each turbine on a 12-month rolling basis and is based on 712 hours of MSS on a 12-month rolling total.

The calculation of the gross annual average heat rate and the equivalent lb CO_2/MWh is provided in supplemental information provided by Tenaska on October 10, 2014. The output based emission BACT limit for the 1x1 and 2x1 operational configurations is 922 lb CO_2/MWh and will apply during normal operational conditions, with and without duct burner firing. TBGS shall meet the BACT limit on a 12-month rolling average. Duct burner firing is limited to 5,200 hours per year on a 12-month rolling total basis.

The BACT limit for MSS is 142 tons CO_2/hr for each combustion turbine on a 12-month rolling average basis. For each CCTG, the number of startup and shutdown hours will account for no more than 712 hours of operation per year per turbine on a 12-month rolling total basis. MSS events are estimated as follows:

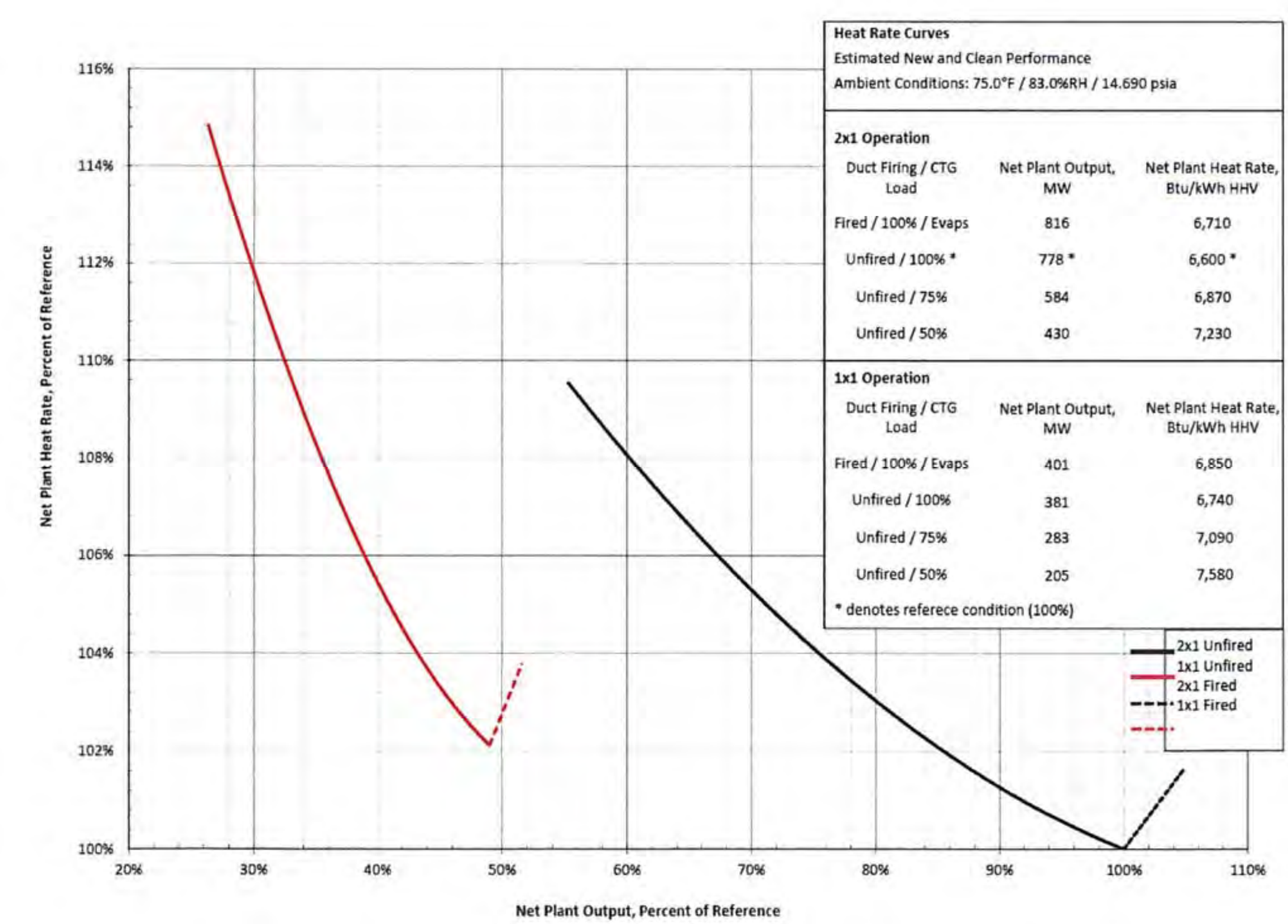
A startup of each CTG is defined as the period that begins when the data acquisition and handling system (DAHS) measures fuel flow to the combustion turbine and ends when both the combustion turbine generator load reaches 50 percent and the SCR has been placed into operation or 60 minutes, whichever comes first. A shutdown of each CTG/HRSG is defined as the period that begins when the combustion turbine generator output drops below 50% load and ends when there is no longer measurable fuel flow to the CTG/HRSG.

TBGS agrees to a BACT limit expressed in lb CO_2/MWh and provides a value of 922 lb CO_2/MWh with or without duct burner firing on a rolling 12-month rolling average. When compared to other BACT limits established for other combined cycle/heat recovery steam generating units, and when taking into account the mode of operation for the Tenaska facility, the proposed limits for TBGS are comparable to the limits established for LCRA, Calpine Deer Park, Calpine Channel Energy Center, Pioneer Valley Energy Center, PacifiCorp Energy Lake Side Power Plant and Victoria WLE. The differences in BACT limits between La Paloma and LCRA are related to the net heat rate for the turbines. The gross heat rate of the turbines proposed by TBGS is lower than those at LCRA. The BACT limit proposed for TBGS is higher than the limit proposed for Pioneer Valley Energy Center (PVEC). PVEC is more likely to operate at base load conditions, whereas TBGS will operate as a load cycling unit. The BACT for TBGS (922 lb CO_2/MWh) is comparable to the limit that is established for both Calpine facilities (920 lb CO_2/MWh).

As demonstrated above, BACT limits for TBGS are comparable to or lower than the emissions of other recently issued GHG 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 available literature (such as the Gas Turbine World Handbook) and confirmed that the CTG's proposed by TBGS 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 Mitsubishi 501GAC CTG located in Cameron County, Texas.

Figure 1. Estimated Performance Curve for a "New and Clean" Mitsubishi 501 GAC



On January 8, 2014, EPA proposed New Source Performance Standard (NSPS) 40 CFR Part 60 Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392) that would control CO_2 emissions from new electric generating units (EGUs).[11] The proposed rule would apply to fossil-fuel fired EGUs that generate electricity for sale and are larger than 25 MW. EPA proposed that new EGUs meet an annual average output-based standard of 1,000 lb CO_2/MWh, on a gross basis. The proposed annual emission rate for the TBGS turbines on a gross electrical output basis is 922 lb CO_2/MWh with or without duct burner firing. The proposed CO_2 emission rates from the TBGS combined cycle turbines are well within the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

[11] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 79 Fed Reg 1430, January 8, 2014. Available at http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

The combined cycle combustion turbine unit will be designed with a number of features to improve the overall efficiency. The additional combustion turbine design features include:

- Inlet evaporative cooling to utilize water to cool the inlet air, thereby increasing the turbine's efficiency;
- Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure more reliable operation of the unit and to maintain optimal efficiency;
- A Distributed Control System will control all aspects of the turbine's operation, including fuel feed and burner operations, to achieve optimal high-efficiency, low-emission performance for full-load and partial-load conditions;
- Insulation blankets are utilized to minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine; and
- Totally enclosed hydrogen cooling will be used to cool the generators resulting in a lower electrical loss and higher unit efficiency.

The HRSG energy efficiency processes, practices, and designs considered include:

- Energy efficient heat exchanger design, including each pressure level incorporating an economizer section(s), evaporator section, and superheater section(s);
- Addition of insulation to the HRSG panels and high-temperature steam and water lines;
- Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes to minimize fouling; and
- Minimization of steam vents and repair of steam leaks.

Within the combined-cycle power plant, several plant-wide, overall energy efficiency processes, practices and designs are included as BACT requirements, because the additional operating conditions/practices help maintain the efficiency of the turbine. The requirements include:

- Cooling Towers. A closed-loop design, which includes a cooling tower to cool the water, will be utilized for the project. Closed-loop designs are either natural circulation or forced circulation. Both natural circulation and forced circulation designs require higher cooling water pump heads; therefore, increasing the pump's power consumption and reducing overall plant efficiency. Additionally, to provide the forced circulation, fans are used for the forced circulation designs, which consume additional auxiliary power and reduce the plant's efficiency.

Tenaska will demonstrate compliance with the lb CO_2/MWh limit established as normal operation BACT by calculating the CO_2 value based on equation G-4 of 40 CFR 75, Appendix G. In this calculation, the CO_2 value is based on the continuously monitored natural gas fuel flow/heat input to the combustion unit(s), and utilizing a site-specific emission factor calculated from measurements of the

Gross Calorific Value and ultimate analysis of the natural gas, in accordance with 40 CFR Part 75, Appendix F. For any period of time that the fuel flow meters are nonfunctional, Tenaska must use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D. The hourly CO_2 emission value is calculated by multiplying the CO_2 emission factor by the hourly heat input, which is adjusted based on monthly analysis of the GCV of the pipeline natural gas. The calculated CO_2 emission value is divided by the summed amount of the combustion turbine's gross output and the apportioned steam turbine's gross output (MW) for the 2x1 configuration. For the 1x1 configuration, the calculated CO_2 emission value is divided by the summed amount of the combustion turbine's gross output and the steam turbine's gross output (MW). Tenaska will monitor and record the gross power output from the generating station to demonstrate on an ongoing basis. To determine the apportioned steam turbine gross output, a plan shall be submitted to demonstrate the apportionment of the gross electric output within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days from the date of initial startup of the combustion turbine. This plan will detail how the apportionment will be determined, and a monitoring strategy to demonstrate the apportionment will be included. The resulting quotient of the calculated CO_2 value and gross electrical output (lb CO_2/MWh) is determined for the calendar month and added to the preceding 11 calendar months to determine the BACT limit on a 12-month rolling average basis. The calculated result is compared to the normal operation BACT limit of 922 lb CO_2/MWh on a 12-month rolling average basis to determine compliance with this limit.

To determine compliance with the MSS BACT limit of 142 tons CO_2/hr on a 12-month rolling average for each combustion turbine, TBGS will calculate the CO_2 value based on equation G-4 of 40 CFR 75, Appendix G. In this calculation, the CO_2 value is based on the continuously monitored natural gas fuel flow/heat input to the combustion unit(s), and utilizing a site-specific emission factor calculated from measurements of the Gross Calorific Value and ultimate analysis of the natural gas, in accordance with 40 CFR Part 75, Appendix F. For any period of time that the fuel flow meters are nonfunctional, TBGS must use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D. The hourly CO_2 emission value is calculated by multiplying the CO_2 emission factor by the hourly heat input, which is adjusted based on monthly analysis of the GCV of the pipeline natural gas. The resulting value is added to the 12-month rolling total and divided by the number of hours that each unit is in startup or shutdown mode during that time. For each combustion turbine, the number of startup and shutdown hours is limited to 712 hours of operation per year. TBGS shall also monitor and record the turbine load and the amount of time that each turbine operates below 50 percent load.

The permittee shall monitor and record the number of hours utilizing duct burning and MSS to demonstrate compliance with the 5,200 hours of duct burning on 12-month rolling total basis and the 712 hours of MSS per turbine on a 12-month rolling total basis.

Tenaska will determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 50 CFR Part 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F § 3.3.6.

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

As an alternative to demonstrating compliance with the CO_2 emission limit using fuel flow, Tenaska may demonstrate compliance by use of a continuous emission monitoring system (CEMS) that measures the CO_2 concentration in the exhaust gases. If the CO_2 CEMS is selected, the measured hourly CO_2 emissions are divided by the hourly energy output and averaged daily. For any period of time that the CO_2 CEMS is nonfunctional, Tenaska shall use the methods and procedures outline in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D.

In addition to monitoring and recording the heat input, Tenaska will monitor and record the gross power output from the generating station to demonstrate on an ongoing basis compliance with the 922 lb CO_2/MWh GHG BACT limit. Monitoring data will be collected, processed, and stored by an automated data acquisition and handling system. To demonstrate compliance with the rolling 12-month average CO_2 BACT limit in lb/MWh, the most recent 12 months of CO_2 emissions in lbs are divided by the gross energy output in MW-hours over the same period. For any period of time that the fuel flow meters or CO_2 CEMS are nonfunctional, Tenaska must use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D.

To determine compliance with the CO_2e annual emission limit, Tenaska shall calculate the emission values for CO_2 based on equation G-4 of 40 CFR Part 75, Appendix G, CH_4 and N_2O based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, fuel usage, and the actual heat input (HHV). To calculate the CO_2e emissions, the 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 shall be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling total basis.

This approach is consistent with the CO_2 reporting requirements of 40 CFR Part 98, Subpart D (Mandatory GHG Reporting Rule for Electricity Generation). The CO_2 monitoring method proposed by Tenaska is consistent with the recently proposed NSPS, Subpart TTTT (40 CFR § 60.5535(c)), which allows for EGUs firing gaseous fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected EGU and using a site-specific F_c factor determined in accordance with 40 CFR Part 75, Appendix F.

An initial stack test demonstration will be required for CO_2 emissions for each CT. Tenaska proposes to demonstrate compliance with the proposed CO_2 emission limits with an initial compliance test at or above 90 percent load and minimum normal operation load (minimum normal load above 50 percent) (corrected to ISO conditions) and subsequent annual testing at 90 percent load or greater only. The conditions of the performance demonstration tests shall be recorded and made available for review upon request. Tenaska will demonstrate compliance with an annual compliance test at or above 90 percent load, corrected to ISO conditions. The duct burners shall be tested at their maximum firing rate within the mechanical limits of the equipment for the atmospheric conditions which exists. An initial and annual stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emissions comprise approximately 0.01% of the total CO_2e emissions from the combustion turbines. If the performance test CO_2 emission total does not exceed the tons per year (TPY) specified in Table 1, no compliance strategy needs to be developed. If the CO_2 emission total exceeds the TPY specified in Table 1, then the facility shall: document the potential to exceed in the test report and explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

To demonstrate compliance with the MSS BACT limitation, Tenaska will record and maintain documentation to support the number of hours each CTG operates in startup and shutdown mode. The number of hours for startup and shutdown shall not exceed 712 hours on a 12-month rolling total basis per turbine. The amount of fuel used during MSS is recorded and used to calculate the amount of CO_2 per hour and compared to the MSS BACT limit of 142 tons CO_2/hr on a 12-month rolling average basis.

IX. Emergency Engines (EPNs 4 and 5)

The TBGS site will be equipped with a 2,681-hp diesel-fired emergency generator to provide electricity to the facility in the case of power failure and a 575-hp diesel-fired water pump engine to provide water in the event of a fire.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* **–** Engine options include engines powered by electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.
- *Good Combustion Practices 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. Each emergency engine will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* **–** The purpose of the engines is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, and natural disasters. Electricity and natural gas may not be available during an emergency and, therefore, cannot be relied on as an energy source for the emergency engines and are eliminated as technically infeasible for this use at this facility. The engines must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as gasoline or diesel. The default CO_2 emission factors for gasoline and diesel are very similar, 70.22 kg/MMBtu and 73.96 kg/MMBtu respectively; however, gasoline has a higher volatility than and cannot be stored for as long as diesel fuel. Due to the need to store the emergency equipment fuel on site and the ability to store diesel for longer periods of time than gasoline, it is technically infeasible to utilize gasoline as a lower-carbon fuel for this use at this facility.

- *Good Combustion Practices and Maintenance* – Technically feasible.
- *Low Annual Capacity Factor* – Technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since both of 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.

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

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

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the diesel-fired emergency generators:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing, and operating within the recommended air-to-fuel ratio, as specified by the manufacturer.
- *Low Annual Capacity Factor* – Each emergency engine will not be operated more than 100 hours per year. Emergency engines will only be operated for maintenance and readiness testing and in actual emergency operation.

Using the BACT practices identified above results in an emission limit of 156 tpy CO_2e for the Emergency Generator (EPN 5) and 31 tpy CO_2e for the Fire Water Pump (EPN 4). Tenaska will demonstrate compliance with the CO_2 emission limit using the default emission factor and default high heating value for diesel fuel from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(3)(iii) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Mass or volume of fuel combusted per year, from company records.
HHV = Default high heat value of the fuel, from Table C-1 of 40 CFR Part 98, Subpart C.
EF = Fuel specific default CO_2 emission factor, from Table C-1 of 40 CFR Part 98, Subpart C.
1×10^{-3} = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

As BACT for the engines is focused on reductions in GHGs through reductions in fuel usage, the reductions in fuel use conferred by the CO_2 emission limits will also lead to a reduction of CH_4 and N_2O, and thus act as a surrogate for limitations on those GHGs.

X. Auxiliary Boiler (EPN 7)

The proposed project will include an auxiliary boiler rated at 90 MMBtu/hr of heat input which will be used to reduce the time required for plant startups.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of Low Carbon Fuels* – 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. Selecting low carbon fuels is a viable method of reducing GHG emissions. Pipeline quality natural gas is the lowest carbon fuel available at TBGS.
- *Use of Good Operating and Maintenance Practices* – Following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of fuel while at the same time preventing introduction of more air than is necessary into the boiler.
- *Energy Efficient Design* – The auxiliary boiler is designed for a thermal efficiency of approximately 80%. The energy efficient design includes insulation to retain heat within the boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed. Therefore, a ranking of the control technologies is not necessary.

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

As all of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary.

Step 5 – Selection of BACT

Tenaska proposes 0.06 Ton CO_2/MMBtu on a 12-month rolling average as the BACT limit for the auxiliary boiler. The BACT practices discussed in Step 1: natural gas as a low carbon fuel; good operation and maintenance practices; and energy efficient design as BACT for the auxiliary boiler are also proposed by Tenaska and are applicable as follows.

- Use of low carbon fuel (pipeline quality natural gas). Pipeline quality natural gas will be the only fuel fired in the proposed auxiliary boiler. It is the lowest carbon fuel available for use at TBGS.
- Good operation and maintenance practices will include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing, and limiting the amount of excess air in the combustion chamber to maximize thermal efficiency.
- Energy efficient design will incorporate insulation to retain heat within the boiler.

Use of these practices corresponds with a permit limit of 23,080 tpy CO_2e for the auxiliary boiler. Compliance will be determined by the hourly heat input and the calculated emissions using Equation C-1 from 40 CFR Part 98, Subpart C, which is based on metered fuel usage and the emission factor for pipeline natural gas. The resulting CO_2 value is converted from metric tons to short tons and is divided by the corresponding measured heat input on a monthly basis. The calculated Ton CO_2/MMBtu is compared to the BACT limit of 0.06 Tons CO_2/MMBtu on a 12-month rolling average. The heat input to the auxiliary boiler shall not exceed 394,200 MMBtu on a 12-month rolling total basis. By limiting the heat input to the auxiliary boiler, the CO_2e emissions are limited to 23,080 tpy. To determine compliance with the CO_2e limit, the calculated CO_2 emissions from Equation C-1 from 40 CFR Part 98, Subpart C and the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 shall be used. Records of the calculations shall be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling total basis.

XI. Natural Gas Fugitive Emissions (EPN FUG_GHG)

The proposed project will include natural gas piping components. These components are potential sources of CH_4 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. The additional CH_4 emissions from process fugitives have been conservatively estimated to be 25 tpy as CO_2e. Fugitive emissions are negligible, and account for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *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%. 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. 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 the use of leakless 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, 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 emissions. 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. Given that GHG fugitives are conservatively estimated to be little more than 21 tons per year CH_4 (0.001 percent of the total project), 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 piping components, EPA proposes to incorporate as-observed AVO as BACT for the piping components in the new combined cycle power plant in natural gas service. The proposed permit contains a condition to implement AVO inspections on a daily basis.

XII. SF_6 Insulated Electrical Equipment (FUG_GHG)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 366 lb of SF_6.

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. The alternatives considered include mixtures of SF_6 and nitrogen, 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.

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of 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.

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.

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. 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.

TBGS will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[12] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD.

Tenaska will implement the following work practices as SF_6 BACT:

- Use of state-of-the-art circuit breakers that are gas-tight and guaranteed to achieve a leak rate of 0.5% by year by weight or less (the current maximum leak rate standard established by the International Electrotechnical Commission);
- An LDAR program (leak detection and repair system) to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and SF_6 gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations

XIII. 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) prepared by the applicant, thoroughly reviewed, and adopted by EPA. Further, EPA designated Tenaska Brownsville Partners, LLC ("Tenaska") and its consultant, Environmental Resources Management ("ERM"), as non-federal representatives for purposes of preparation of the BA and consultation with U.S. Fish and Wildlife Service. The Action Area (AA) for this project includes the 275-acre site of the proposed construction site of the project and all linear facilities associated with the Project. Linear facilities include an 11.05-mile water discharge pipeline, an 11.7-mile transmission interconnect line, a 7.75-mile water reuse pipeline, a 49.62-mile natural gas transmission pipeline, a 250-foot supplemental water supply line, a 250-foot potable water line, and a 800-foot sanitary sewer line. The Action Area primarily is within Cameron County; however, the 49.62 mile natural gas pipeline extends into Hidalgo County. Therefore, federally endangered or threatened species from both Cameron and Hidalgo Counties were included in the BA.

[12] See 40 CFR Part 98 Subpart DD.

The draft BA has identified nineteen (19) species listed as federally endangered or threatened in Cameron and Hidalgo Counties, Texas:

Federally Listed Species for Cameron and Hidago Counties by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Piping Plover	*Charadrius melodus*
Eskimo Curlew	*Numenius borealis*
Northern Aplomado Falcon	*Falco femoralis septentrionalis*
Interior Least Tern	*Sterna antillarum athalassos*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Rio Grande Silvery Minnow	*Hybognathus amarus*
Mammals	
Gulf Coast Jaguarundi	*Herpailurus yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
Jaguar	*Panthera onca*
West Indian Manatee	*Trichechus manatus*
Plant	
South Texas Ambrosia	*Ambrosia cheiranthifolia*
Star Cactus	*Astrophytum asterias*
Walker's Nanioc	*Manihot walkerae*
Texas Ayenia	*Ayenia limitaris*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Atlantic Hawksbill Sea Turtle	*Eretmochelys imbricata*

Based on the information provided in the BA, EPA determines that issuance of the proposed PSD permit allowing Tenaska to construct two natural gas-fired combustion turbines will have no effect on 16 of the 19 species because there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the AA. Those sixteen species include: piping plover, Eskimo curlew, interior least tern, smalltooth sawfish, Rio Grande silvery minnow, jaguar, West Indian manatee, South Texas ambrosia, star cactus, Texas ayenia, Walker's manioc, green sea turtle, Kemp's ridley sea turtle, leatherback sea turtle, loggerhead sea turtle, and Atlantic hawksbill sea turtle.

However, based on the information provided in the BA and by the USFWS, EPA determines that the issuance of the permit may affect, but is not likely to adversely affect, the Northern Aplomado falcon, Gulf Coast jaguarundi and the ocelot. EPA and Tenaska (as EPA's designated non-federal representative) engaged in informal consultation with the USFWS's Southwest Region, Corpus Christi, Texas Ecological Services Field Office and the sub-office in Alamo, Texas. USFWS indicated that they have released Northern Aplomado falcons in Cameron County and that there is potential that the falcon could forage within the action area or perch on transmission lines being constructed for this project. Additionally, USFWS specified that those portions of the AA that contain vegetation, such as along areas surrounding irrigation canals, may provide travel or migration corridors for either the ocelot or jaguarundi. USFWS provided recommendations for additional protections of all of these species, which Tenaska has committed to implement. By letter dated October 1, 2014, EPA requested USFWS's written concurrence with EPA's determination of "may affect, but not likely to adversely affect" for the jaguarundi, ocelot and Northern Aplomado falcon. USFWS provided concurrence and agreed with EPA's determination on October 2, 2014.

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.

XIV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties on or eligible for inclusion in the National Register of Historic Places. As discussed further below, and following consultation with the State Historic Preservation Officer (SHPO), the Advisory Council on Historic Preservation (ACHP), the National Park Service (NPS), and Tenaska (hereinafter "Consulting Parties"), EPA Region 6 has determined that issuance of the permit to Tenaska will adversely affect properties listed or eligible for listing on the National Register, namely the Palo Alto Battlefield NHP and NHL, Cameron County Irrigation District No. 6, Cameron County Drainage District No. 1, Cameron County Irrigation District No. 2, and Port of Brownsville Historic District.

In accordance with 36 CFR § 800.2(a)(3), Tenaska provided through its consultant ERM, a cultural resource report (CRR) submitted on December 19, 2013. This report generally provides EPA with the Section 106 information and analysis including field survey information and research, upon which EPA has relied. However, based on the information in the CRR and additional information provided by the National Parks Service (NPS), EPA does not agree with nor rely on Tenaska and ERM's conclusions of no adverse effect to historic properties. Therefore, EPA adopts only the data presented in the CRR which consists of only in-the-field studies and research conducted by ERM.

EPA defined the area of potential effect (APE) for this project to be comprised of two elements: (1) the 275-acre site of the proposed construction site of the Project, and (2) all linear facilities associated with the Project. The APE for the Project site includes an approximately 14-square mile area around the 275-acre site of the proposed Project that extends up to 3 miles in any one direction. The second portion of the APE is the area extending 0.5 miles in either direction from the center line from each of the following linear facilities. Linear facilities were identified as a 11.05-mile water discharge pipeline, a 11.7-mile transmission interconnect line, a 7.75-mile water reuse pipeline, a 49.62-mile natural gas transmission pipeline, a 250-foot supplemental water supply line, a 250-foot potable water line, and a 800-foot sanitary sewer line.

ERM conducted cultural resources investigations within the APE that included a desktop review on the archaeological background and historical records in the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP) and a field survey. The results of these surveys indicated that there are five historic properties eligible or potentially eligible for listing on the National Register within the APE. Most notably, the Project site is approximately 1.3 miles from the boundary of the Palo Alto Battlefield National Historic Park (NHP), which is listed on the National Register and designated as a National Historic Landmark (NHL).

Consistent with requirements of 36 CFR § 800.5, and in consultation with the Consulting Parties, EPA conducted its own assessment of adverse effects. EPA's analysis is contained in its own report titled: Determination of Adverse Effect for the Tenaska Brownsville Partners LLC EPA GHG Permit Application (EPA Determination). This analysis was provided to the Consulting Parties by letter on October 14, 2014. The construction and operation of the generating station will result in the introduction of visual, atmospheric, and audible elements that will adversely affect the Palo Alto NHP and NHL. Linear facilities associated with the generating station will adversely affect Cameron County Irrigation District No. 6, Cameron County Drainage District No. 1, Cameron County Irrigation District No. 2, and Port of Brownsville Historic District due to the ground disturbing construction activities associated with the installation of these linear facilities.

Due to the designation of Palo Alto Battlefield NHP as a NHL, Section 110(f) of the NHPA requires that EPA, to the maximum extent possible, undertake such planning and actions as may be necessary to minimize harm to this NHL. In accordance with the requirements of Section 110(f), and 36 CFR §§ 800.6 and 800.10, EPA notified the ACHP and the Secretary of the Interior though the NPS, Intermountain Region National Historic Landmark Office of the adverse effect determination and invited both to participate as Consulting Parties. Because of the effects on the Palo Alto Battlefield, EPA also invited the NPS Palo Alto Battlefield Park Superintendent and park staff; Intermountain Region staff from National Historic Landmarks, Natural Resources, and Environmental Quality; Washington D.C. staff from Section 106 Compliance Office and American Battlefield Protection Program to participate in the consultation. The ACHP has chosen to participate as a consulting party pursuant to its authority under Section 800.6(a)(1)(iii). The ACHP notified the EPA Administrator of its intent to participate in consultation by letter dated September 29, 2014. Representative from the NPS also accepted EPA's invitation to be a consulting party by letter received on April 11, 2014.

On January 10, 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.

ACHP regulations at 36 CFR § 800.6, requires that EPA continue consultation with the Consulting Parties to develop and evaluate alternatives or modifications to the undertaking that could avoid, maximize or mitigation adverse effects on historic properties. The National Park Service, who manages the Palo Alto Battlefield, identified and proposed to the Consulting Parties avoidance, minimization and mitigation options to resolve the adverse effects were identified. As of September 11, 2014, the Consulting Parties have agreed in principal upon minimization and mitigation measures that are commensurate with EPA's determination of the effects that the Generating Station and linear facilities will have on listed resources. The parties are currently drafting and negotiating a Memorandum of Agreement (MOA) in accordance with 36 CFR § 800.6(c) to resolve the adverse effects.

Pursuant to 36 CFR § 800.6(a)(4), EPA will provide the public with the opportunity to review all supporting documentation and a final draft MOA and provide comments during a 30-day Public Notice (PN) period that will commence after the PN period on the draft permit. Once the PN review period has ended, EPA and the Consulting Parties will address any comments received. The MOA must be executed by the EPA, SHPO and the ACHP. EPA will invite NPS and Tenaska to be additional signatories. EPA will not issue the permit until all NHPA issues have been resolved and a final MOA is signed by all parties, indicating the conclusion of EPA's Section 106 responsibilities.

XV. 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 GHG. 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.

XVI. Conclusion and Proposed Action

Based on the information supplied by Tenaska, 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 Tenaska 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 A: Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month rolling total for the 2x1 operational configuration, shall not exceed the following:

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
1	1	Combined Cycle CT (Mitsubishi 501 GAC) equipped with duct burning[3]	CO_2	1,570,400	1,627,099	• 922 lb CO_2/MWh (gross) with and without duct burning on a 12-month rolling average. • Startup and Shutdown emissions are limited to 142 tons CO_2/hr on a 12-month rolling average per turbine. • MSS is limited to 712 hrs per year on a 12-month rolling total per turbine. • See Special Conditions III.A.1.
			CH_4	1,782		
			N_2O	40		
2	2	Combined Cycle CT (Mitsubishi 501GAC) equipped with duct burning[3]	CO_2	1,570,400	1,627,099	• 922 lb CO_2/MWh (gross) with and without duct burning on a 12-month rolling average. • Startup and Shutdown emissions are limited to 142 tons CO_2/hr on a 12-month rolling average per turbine • MSS is limited to 712 hrs per year on a 12-month rolling total per turbine. • See Special Conditions III.A.1.
			CH_4	1,782		
			N_2O	40		
4	4	Fire Water Pump	CO_2	31	31	Good Combustion and Operating Practices. Limit to 100 hours of operation per year on a 365-day rolling total basis. See Special Conditions III.C.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
5	5	Emergency Generator	CO_2	155	156	Good Combustion and Operating Practices. Limit to 100 hours of operation per year on a 365-day rolling total basis. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
7	7	Auxiliary Boiler	CO_2	23,060	23,080	• 0.06 Tons CO_2/MMBtu on a 12-month rolling average. • Good Combustion and Operating Practices. • Heat input limited to 394,200 MMBtu on a 12-month rolling total • See Special Conditions III.B.
			CH_4	0.43		
			N_2O	0.04		
FUG_ GHG	FUG_ GHG	Component Leak Fugitive Emissions[5]	CH_4	1.0	25	Implementation of AVO Monitoring. See Special Condition III.D.
		SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[4,5]	No Numerical Limit Established[4,5]	Instrumented monitoring and alarm. See Special condition III.D.
Totals[6]			**CO_2**	**3,164,041**	**3,277,606**	
			CH_4	**3,566**		
			N_2O	**80**		
			SF_6	**0.005**		

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. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
3. The annual emissions limits for each combustion turbine are based on operating at maximum duct burner firing for 5,200 hours per year and operating during startup, shutdown, and maintenance (MSS) for 356 hours per year.
4. All 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. Fugitive process emissions from EPN FUG_GHG are estimated to be 1.0 TPY of CH_4, 0.0 TPY of CO_2, 0.005 TPY of SF_6, and 142 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. Total emissions include the PTE for all listed sources. Totals are given for informational purposes only and do not constitute emission limits.

Annual emissions, in tons per year (TPY) on a 12-month rolling total for the 1x1 operational configuration, shall not exceed the following:

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
1	1	Combined Cycle CT (Mitsubishi 501 GAC) equipped with duct burning[3]	CO_2	1,570,400	1,627,099	• 922 lb CO_2/MWh (gross) with and without duct burning on a 12-month rolling average. • Startup and Shutdown emissions are limited to 142 tons CO_2/hr on 12 12-month rolling average per turbine. • MSS limited to 712 hrs per year on a 12-month rolling total per turbine. • See Special Conditions III.A.1.
			CH_4	1,782		
			N_2O	40		
4	4	Fire Water Pump	CO_2	31	31	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
5	5	Emergency Generator	CO_2	155	156	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
7	7	Auxiliary Boiler	CO_2	23,060	23,080	• 0.06 Tons CO_2/MMBtu on a 12-month rolling average. • Good Combustion and Operating Practices. • Heat input limited to 394,200 MMBtu on a 12-month rolling total • See Special Conditions III.B.
			CH_4	0.43		
			N_2O	0.04		
FUG_GHG	FUG_GHG	Component Leak Fugitive Emissions[5]	CH_4	1.0	25	Implementation of AVO Monitoring. See Special Condition III.D.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
		SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[4,5]	No Numerical Limit Established[4,5]	Instrumented monitoring and alarm. See Special condition III.D.
Totals[6]			**CO_2**	**1,593,642**	**1,650,508**	
			CH_4	**1,784**		
			N_2O	**40**		
			SF_6	**0.005**		

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. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
3. The annual emissions limits for each combustion turbine are based on operating at maximum duct burner firing for 5,200 hours per year and includes MSS emissions.
4. All 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. Fugitive process emissions from EPN FUG_GHG are estimated to be 1.0 TPY of CH_4, 0.0 TPY of CO_2, 0.005 TPY of SF_6, and 142 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. Total emissions include the PTE for all listed sources. Totals are given for informational purposes only and do not constitute emission limits.

Appendix B

Table C-1. Cost Estimation for Transfer of CO_2 via Pipeline to Existing CO_2 Well

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	106	miles
Average Diameter of Pipeline	8	inches
CO_2 emissions from combustion turbines (both CCCTs)	3,140,799	Short tons/yr
CO_2 Capture Efficiency	90%	
Captured CO_2	2,826,719	Short tons/yr

CO_2 Transfer Cost Estimation [1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs			
Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)	$10,576,690.16
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D2 + 2,074 x D + 170,013)	$41,242,164.78
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$12,639,149.60
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$4,424,225.80
Other Capital			
CO_2 Surge Tank	$	$1,150,636	$1,150,636.00
Pipeline Control System	$	$110,632	$110,632.00
Operation & Maintenance (O&M)			
Fixed O&M	$/mile/yr	$8,632	$914,992.00
		Total Pipeline Cost	**$71,058,490.34**

Amortized Cost Calculation

Equipment Life [2]	20	years
Interest rate [3]	7%	
Capital Recovery Factor (CRF) [4]	0.09	
Total Pipeline Installation Cost (TCI)	$70,143,498	$ (Pipeline + Other Capital)
Amortized Installation Cost (TCI *CRF)	$6,621,050	$/yr
Amortized Installation + O&M Cost	$7,536,042	$/yr
CO_2 Transferred	2,826,719	Short tons/yr
Annuitized control cost per ton [5]	**3**	**$/ton-yr**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

[2] Pipeline life is assumed based on engineering judgment.

[3] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.

[4] Capital Recovery Fraction = Interest Rate (%) x (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)

[5] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment.

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Tenaska Brownsville Partners, LLC
Brownsville Generating Station
Table 1. Carbon Capture and Sequestration (CCS) Cost Estimate

Plant Output (2X1)	800	MW
	800,000	kW
Cost of Compression and Storage		
Cost per NGCC Document (June 2011 basis) [1]	*624.00*	*$/kW*
Cost per NGCC Document (2014 basis) [2]	*657.66*	*$/kW*
Total Cost for Compression and Storage	$526,128,000	
Pipeline Transfer Cost [3]	$70,143,498	
Total Capital Cost for CCS	**$596,271,498**	
Total Capital Cost for the Proposed Brownsville Generating Station [4]	**$500,000,000**	$ (Equipment and control costs)
CCS Cost as a Percentage of Project Capital Cost	**119%**	

[1] Capital cost of compression and storage obtained from Exhibit 4-16 Case 14 in the final report of *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases,* dated August 2012.

[2] Capital costs adjusted using the U.S. BLS CPI Inflation Calculator from 2011 ($624/kW) to 2014 dollars ($657.66/kW) (http://www.bls.gov/data/inflation_calculator.htm).

[3] The pipeline transfer cost estimated based on-"Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

[4] Total Capital Cost for the proposed Brownsville Generating Station obtained from Table 30 (Estimated Capital Cost and Fee Verification) submitted with the application.

Magee, Melanie

From: Carlson, Larry <LCarlson@TENASKA.com>
Sent: Wednesday, September 24, 2014 9:46 AM
To: Magee, Melanie
Subject: RE: Tenaska Brownsville CO2 MSS BACT Calculation

I should clarify we obviously didn't use equation G-4 in Part 75 to calculate the other pollutants, but used startup ppm curves from MHI which were converted to 15-sec data, which were then converted to mass using the MHI 15-sec fuel flow values.

From: Carlson, Larry
Sent: Wednesday, September 24, 2014 9:44 AM
To: 'magee.melanie@epa.gov'
Subject: Tenaska Brownsville CO2 MSS BACT Calculation

Melanie-

We calculated the CO2 SUSD BACT limit of 142 tons/hr (representing a shutdown; startup is 138 tons/hr) using fuel flow data from MHI at 15-sec intervals and equation G-4 in Part 75 to calculate emissions for each 15-sec interval, then summing for the entire hour. This is the same methodology used to calculate NOx, CO, VOC, and CH4 startup emissions. Below is the top and bottom of the analysis from a very nasty spreadsheet. FYI, time "00.00" is when the turbine drops below 100% load. Please let me know if you need anything further on this.

Time (min)	Load (%)	Fuel Flow (lbm/hr)	Heat Input HHV (MMBTU/hr)	CO2 (Ton/hr)	ΔCO2 (Ton)
-25.00	100.00	130,038	3,200	200	0.83
-24.75	100.00	130,038	3,200	200	0.83
-24.50	100.00	130,038	3,200	200	0.83
-24.25	100.00	130,038	3,200	200	0.83
-24.00	100.00	130,038	3,200	200	0.83
-23.75	100.00	130,038	3,200	200	0.83
-23.50	100.00	130,038	3,200	200	0.83
-23.25	100.00	130,038	3,200	200	0.83
-23.00	100.00	130,038	3,200	200	0.83
-22.75	100.00	130,038	3,200	200	0.83
-22.50	100.00	130,038	3,200	200	0.83
-22.25	100.00	130,038	3,200	200	0.83
-22.00	100.00	130,038	3,200	200	0.83
-21.75	100.00	130,038	3,200	200	0.83
-21.50	100.00	130,038	3,200	200	0.83
-21.25	100.00	130,038	3,200	200	0.83
-21.00	100.00	130,038	3,200	200	0.83
-20.75	100.00	130,038	3,200	200	0.83
-20.50	100.00	130,038	3,200	200	0.83
-20.25	100.00	130,038	3,200	200	0.83
-20.00	100.00	130,038	3,200	200	0.83
-19.75	100.00	130,038	3,200	200	0.83
-19.50	100.00	130,038	3,200	200	0.83

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32.50	0.00	25,289	622	39	0.16
32.75	0.00	25,289	622	39	0.16
33.00	0.00	25,289	622	39	0.16
33.25	0.00	25,289	622	39	0.16
33.50	0.00	25,289	622	39	0.16
33.75	0.00	25,289	622	39	0.16
34.00	0.00	25,289	622	39	0.16
34.25	0.00	25,289	622	39	0.16
34.50	0.00	25,289	622	39	0.16
34.75	0.00	25,289	622	39	0.16
35.00	0.00	25,289	622	39	
					142.07

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