Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Draft Permit for the Corpus Christi Liquefaction LLC, LNG Terminal

Permit Number: PSD-TX-1306-GHG

February 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 would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On September 4, 2012, Corpus Christi Liquefaction, LLC (CCL), submitted to the Environmental Protection Agency's (EPA) Region 6 office (Region 6) a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed project, CCL submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on September 4, 2012. CCL proposes to construct and operate a natural gas liquefaction and export plant, and liquefied natural gas import facilities with regasification capabilities (collectively referred to as the "LNG Terminal") to be located in San Patricio and Nueces Counties, Texas. The LNG Terminal will consist of three trains. After reviewing the application, Region 6 has prepared the following SOB and draft GHG PSD permit to authorize construction of air emission sources at the LNG Terminal.

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 air permit requirements based on BACT analyses conducted on the proposed new emission sources, and the compliance terms of the permit.

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

II. Applicant

Corpus Christi Liquefaction, LLC
700 Milam Street, Suite 800
Houston, TX 77002

Physical Address:
2 La Quinta Road
Gregory, TX 78359

Technical Contact:
Andrew Chartrand
Director, Environmental & Regulatory Projects
Cheniere Energy, Inc.
(713) 375-5429

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that made 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:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

IV. Facility Location

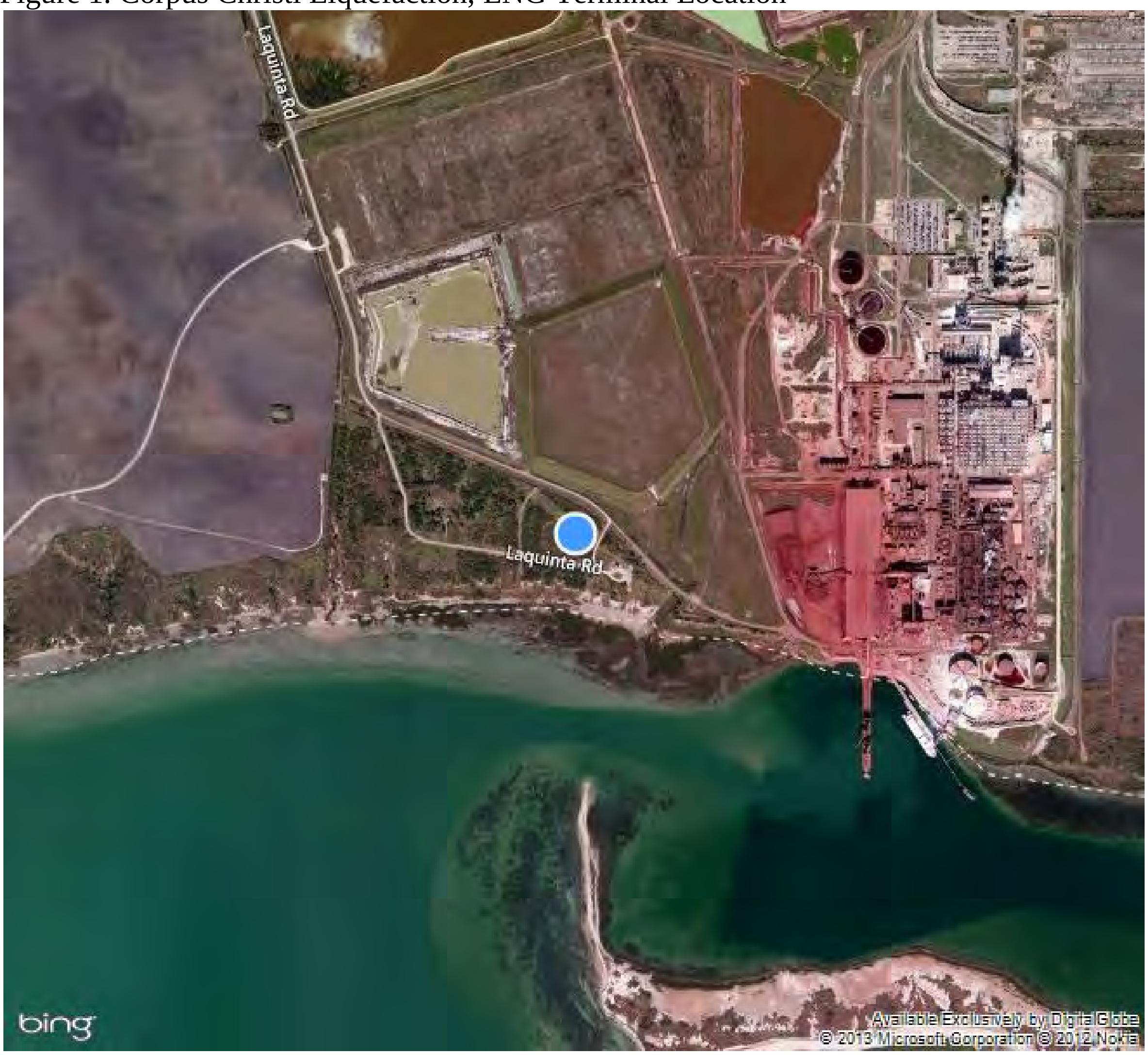
The CCL, LNG Terminal is located in San Patricio and Nueces Counties, Texas, and this area is currently designated “attainment” for all criteria pollutants. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for the facility are as follows:

Liquefaction Facility

Latitude: 27º 52’ 59.7” North
Longitude: -97º 16’ 9” West

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

Figure 1. Corpus Christi Liquefaction, LNG Terminal Location



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

EPA concludes that CCL's application is subject to PSD review for GHGs, because the project will constitute a new stationary source that will emit or have the potential to emit (PTE) 100,000 TPY CO_2e, as described at 40 CFR § 52.21(b)(49)(v)(*a*) and greater than 100/250 TPY on a mass basis (CCL calculates CO_2e emissions of 3,413,185 TPY). As noted above in Section III, Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). *See*, 40 CFR § 52.2305.

CCL represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that CCL is also subject to PSD review for CO, VOC, PM_{10}, $PM_{2.5}$, and NO_2. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and the EPA will issue the GHG portion.[1]

In evaluating this permit application, Region 6 applies the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR 52.21(o) and (p), respectively. Instead, EPA has determined that compliance with the selected BACT 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 will be addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

CCL is proposing to construct and operate a natural gas liquifaction and export plant, and liquefied natural gas (LNG) import facilities with regasification capabilities (collectively referred to as the "CCL Project" or the "LNG Terminal"). The LNG Terminal will be capable of processing an annual average of approximately 2.1 billion standard cubic feet per day (BSCFD) of pipeline quality natural gas in liquefaction mode and 0.4 BSCFD in vaporization mode. LNG will be imported or exported via LNG carriers that will arrive at the Project's marine terminal. The facility will have the capability to liquefy natural gas from the pipeline system for export as LNG or import LNG and re-gasify to send it out into the pipeline system.

The LNG terminal will operate three process trains with each using six gas-fired aeroderivative compressor turbines. There will be two methane, two propane, and two ethylene refrigeration

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

compressor turbines per train. Each of the three trains in the liquefaction process is equipped with an Acid Gas Removal Unit (AGRU). After sulfur removal, the acid gas is controlled by a thermal oxidizer and each train will be equipped with a thermal oxidizer. The LNG Terminal will also have four standby generators, three firewater pumps, one marine flare, and two wet/dry gas flares. Each liquefaction train will also include the following equipment:

- Facilities which remove carbon dioxide (CO_2), hydrogen sulfide (H_2S), and sulfur compounds from the feed gas;
- Facilities to remove water and mercury from the feed gas;
- Facilities to remove heavy hydrocarbons (such as benzene, toluene, ethylbenzene, and xylene (BTEX)) from the feed gas to avoid freezing in the liquefaction unit;
- Six gas turbine driven refrigerant compressors, each with water injection for emission control, and inlet air humidification systems that drive 14 refrigerant compressors;
- Waste heat recovery units for regenerating the gas driers and amine system;
- Induced draft air coolers;
- Miscellaneous storage vessels and tanks;
- Associated fire and gas safety systems;
- Associated control systems and electrical infrastructure;
- Utility connections and distribution systems;
- Soil improvements and paving; and
- Piping, pipe racks, foundation and structures within the LNG train battery limits.

The LNG Terminal will also be equipped with three full containment storage tanks. The tanks will be designed to store a nominal volume of 160,000 m^3 (1,006,400 barrels) of LNG at a temperature of -270 ^oF and a maximum internal pressure of 3.5 pounds per square inch gauge (psig).

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 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. Applicable Emission Units

The majority of the GHG emissions caused by the project are from combustion sources (i.e., combustion turbines, thermal oxidizers, flares, emergency generators and firewater pump engines). The site has some fugitive emissions from piping components which contribute a relatively small amount of GHGs. Fugitive emissions account for 10,825 TPY of CO_2e, or less than 0.3% 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 devices are subject to this GHG PSD permit:

- Combustion Turbines (EPNs: TRB1, TRB2, TRB3, TRB4, TRB5, TRB6, TRB7, TRB8, TRB9, TRB10, TRB11, TRB12, TRB13, TRB14, TRB15, TRB16, TRB17, and TRB18)
- Thermal Oxidizers (EPNs: TO-1, TO-2, and TO-3)
- Flares (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR)
- Emergency Generators (EPNs: GEN1, GEN2, GEN3, and GEN4) and Firewater Pumps (EPNs: FWPUMP1, FWPUMP2, and FWPUMP3)
- Fugitives (EPN: FUG)

IX. Combustion Turbines (EPNs: TRB1, TRB2, TRB3, TRB4, TRB5, TRB6, TRB7, TRB8, TRB9, TRB10, TRB11, TRB12, TRB13, TRB14, TRB15, TRB16, TRB17, and TRB18)

Each process train at the LNG Terminal will have 6 combustion turbines (CT) installed for a total of 18 CTs. Twelve of the proposed combustion turbines (TRB1, TRB2, TRB5, TRB6, TRB7, TRB8, TRB11, TRB12, TRB13, TRB14, TRB17, and TRB18) will be simple cycle; six of the turbines (TRB3, TRB4, TRB9, TRB10, TRB15, and TRB16) will be equipped with a Waste Heat Recovery Unit (WHRU) but still be operated as simple cycle turbines. All of the combustion turbines will fire boil-off gas (BOG) and pipeline quality natural gas. Water injection will be used for NOx control.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that may be applicable to the combustion turbines in the proposed project.
- *Low Carbon Fuel* – 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.
- *Design Energy Efficiency* – Measures that may be included in the design of the turbines to increase combustion efficiency.
- *Operational Energy Efficiency* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the combustion turbine.

- *Post-Combustion Catalytic Oxidation* – Provides rapid conversion of a hydrocarbon into CO_2 and water in the presence of available oxygen.
- *N_2O Catalyst* – Decompose N_2O into nitrogen and oxygen.

Step 2 – Elimination of Technically Infeasible Alternatives

Among the options identified in Step 1, the following are considered technically infeasible for the proposed combustion turbines: carbon capture and storage, post-combustion catalytic oxidation, and N_2O catalysts.

Carbon Capture and Storage (CCS)

Carbon capture and storage is a GHG control process that can be used by "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[2] The CCL turbines will emit a low-purity CO_2 stream (estimated to have a CO_2 concentration of 3.5%).

The three main approaches for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005[3]). 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[4]). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). The third approach, post-combustion capture, is applicable to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011[5]). Many of these methods are either still in development or are not suitable for simple cycle turbines. Of the potentially applicable technologies, post-combustion capture with an amine solvent such as

[2] U.S. EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* March 2011. http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[3]Intergovernmental Panel on Climate Change. (2005). *IPCC Special Report on Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

[4] U.S. Department of Energy. (2011). *DOE/NETL Advanced Carbon Dioxide Capture R&DProgram: Technology Update*. Retrieved from DOE website at http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/

[5] Wang, M., Lawal, A., Stephenson, P., Sidders, J., & Ramshaw, C. (2011). Post-combustion CO2 capture with chemical absorption: A state-of-the-art review. *Chemical Engineering Research and Design*, 89, 1609-1624.

monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011[6]), 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[7]). As such, it 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[8]). 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[9]). As this technology is commercially available and has been demonstrated in practice on a combined-cycle plant, EPA generally considers it to be technically feasible for natural gas combined cycle turbines, but not technically feasible for simple cycle turbines. CCL will be utilizing simple cycle aeroderivative turbines. It should also be noted that, while CCS may be available and demonstrated on combined cycle turbines, there have been no CCS demonstrations on simple cycle combustion turbines.

In 2003, Fluor and BP completed a joint study that examined the prospect of capturing CO_2 from eleven *simple cycle* gas turbines at a BP gas processing plant in Alaska known as the Central Gas Facility (CGF) (Hurst & Walker, 2005[10]; Simmonds et al., 2003[11]). Although the CGF project was not actually implemented, the feasibility study provides valuable information about the design of a capture system for simple-cycle applications, particularly with respect to flue gas

[6] Kvamsdal, H., Chikukwa, A., Hillestad, M., Zakeri, A., & Einbu, A. (2011). A comparison of different parameter correlation models and the validation of an MEA-based absorber model. *Energy Procedia*, 4, 1526-1533.
[7] Reddy, S., Scherffius, J., Freguia, S., & Roberts, C. (2003, May). *Fluor's Econamine FG PlusSM Technology: An Enhanced Amine-Based CO2 Capture Process*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.
[8] Fluor Corporation. (2009). Econamine FG Plus Process. Retrieved from http://www.fluor.com/econamine/Pages/efgprocess.aspx
[9] Reddy, S., Scherffius, J., Freguia, S., & Roberts, C. (2003, May). *Fluor's Econamine FG PlusSM Technology: An Enhanced Amine-Based CO2 Capture Process*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.
[10] Hurst, P., & Walker, G. (2005). Post-combustion Separation and Capture Baseline Studies for the CCP Industrial Scenarios. In Thomas, D.C., & Benson, S.M. (Eds.), *Carbon Dioxide Capture for Storage in Deep Geologic Formations, Volume 1* (pp. 117-131). Oxford: Elsevier Ltd.
[11] Simmonds, M., Hurst, P., Wilkinson, M.B., Reddy, S., & Khambaty, S., (2003, May). *Amine Based CO2 Capture from Gas Turbines*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.

cooling and heat recovery. Absorption of CO_2 by MEA is a reversible exothermic reaction. Before entering the absorber, the turbine exhaust gas must be cooled to around 50 ^oC to improve absorption and minimize solvent loss due to evaporation (Wang, 2011). In the case of the CGF design study, the flue gas would need to be cooled by feeding it first to a heat recovery steam generator (HRSG) for bulk removal of the heat energy and then to a direct contact cooler (DCC). It should be noted that while Hurst & Walker (2005) found that the HRSG could be omitted from the design for another type of source studied (heaters and boilers at a refinery), the DCC alone would be insufficient for the gas turbines at the CGF due to the high exhaust gas temperature (480-500 ^oC). After the MEA is loaded with CO_2 in the absorber, it is sent to a stripper where it is heated to reverse the reaction and liberate the CO_2 for compression. The heat for this regeneration stage comes from high- and intermediate-pressure steam generated in the HRSG. Excess steam from the CGF HRSGs would also be used to export electricity to the local grid. The integral nature of the HRSG to the overall process for the CGF (i.e., the secondary heat production to liberate the CO2 and export electricity) is notable because it would essentially require conversion of the turbines from simple-cycle to combined-cycle operation.

At the CCL facility, combined cycle turbines are not necessary for several reasons. CCL will feature a HRSG on six of its eighteen single-cycle turbines, but the heat generated by the six HRSG will be used exclusively for the production process at the LNG terminal. CCL will not be creating excess heat. Further, unlike the CGF, CCL will not be generating excess steam to produce or export electricity. Finally, single-cycle turbines fit the production needs at the facility: since single-cycle turbines can be powered up quickly, CCL can access heat on a reliable basis, even if the production at the facility is cyclical or intermittent. On the other hand, combined-cycle turbines take additional time to bring on-line (as the heat recovery loop must be heat saturated before any power can be derived), and generally require a stable, continuous, operation to be cost effective. The potential transient loading of the combine-cycle turbines combined with considerable capital costs make combined cycle a non-viable alternative. Since combined-cycle gas turbines are not technically feasible for the proposed Project, CCS is also technically infeasible for the proposed Project.

Post-Combustion Catalytic Oxidation

The turbine exhaust is expected to contain less than 1 ppmv of CH_4. The exhaust gas CH_4 concentration is at the lower end of VOC concentration in streams which would typically be fitted with catalytic oxidation for control. Addition of post-combustion catalytic oxidation on the turbines for control of CH_4 is technically infeasible and will not be considered further in this analysis.

N_2O Catalysts

N_2O catalysts have been used to reduce N_2O emissions from adipic acid and nitric acid plants. The very low N_2O concentrations (<1ppm) present in the exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric industry sector has been effective due to high (1,000 to 2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Low Carbon Fuel,
- Design Energy Efficiency, and
- Operational Energy Efficiency

Low Carbon Fuel

Use of a low-carbon intensity (mass of carbon per MMBtu) fuel selection is a control option that can be considered a lower emitting process. The turbines will be fired with boil-off gas that is approximately 94% methane and 5% nitrogen, and pipeline quality natural gas. These are the cleanest and lowest carbon fuel available for combustion in the turbines.

Design Energy Efficiency

The selection of compressor drivers was limited to gas fired turbines. Two types were considered, heavy duty gas turbines and aeroderivative turbines. Aeroderivative gas turbines achieve significantly higher thermal efficiencies than industrial gas turbines. The higher efficiency of an aeroderivative can result in a 3% or greater increase in overall plant thermal efficiency.

Operational Energy Efficiency

CCL proposes to utilize the following operational efficiencies for the turbines to reduce CO_2 emissions:

- Periodic tune-ups and maintenance for optimal thermal efficiency.
- Oxygen trim control to ensure optimum excess oxygen for efficient combustion.
- Good combustion practices.

Low carbon fuel, design energy efficiency, and operational energy efficiency are all considered effective control methods and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible. In any case, since these control measures are not mutually exclusive, ranking of these measures is of limited significance.

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

Low-Carbon Fuel

The proposed liquefaction project will produce a stream of methane and nitrogen called boil-off gas (BOG) that will need to be removed from the liquefaction process through venting, flaring, or use as fuel in a combustion source. BOG is a combination of gas or vapor that is evolved from the Liquefied Natural Gas (LNG) storage tanks and from LNG vessel loading operations. CCL has estimated that the lowest nitrogen content of the BOG will be about 5%, the balance being 95% methane. Natural gas consists of a high percentage of methane (generally above 85%) and varying amounts of ethane, propane, and inerts (typically nitrogen, carbon dioxide, and helium). These two fuels have very similar properties and composition. Only natural gas and BOG will be fired in the proposed combustion turbines; they have the lowest carbon intensity of any available fuel for the combustion turbines. There are no negative economic, energy, or environmental impacts associated with this control technology.

Design Energy Efficiency

CCL will utilize a high efficiency GE LM2500+ G4 aeroderivative gas turbine which is a suitable design for the operational parameters of the project. The operational parameters include:

- Ambient conditions – Air temperature directly impacts horsepower available and thus LNG production;
- Market conditions – The terminal is bi-directional with the ability to import or export LNG depending on market requirements (LNG trains are shutdown when there is no export market);
- Maintenance requirements – Gas turbines require frequent inspection and maintenance overhaul;
- Inlet gas pressure – Directly impacts LNG production;
- Inlet gas composition – Impacts loading on CO_2 removal units and heavies removal unit.

Each of the ethylene refrigeration turbines (TRB3, TRB4, TRB9, TRB10, TRB15, and TRB16) will be equipped with a waste heat recovery unit (WHRU). Each WHRU will be used to transfer heat to regenerate the amine solution, regenerate the molecular sieves, and provide heat to the reboiler for the Heavies Removal Unit (HRU). By using WHRUs, additional gas-fired heaters are not required in the process to generate process heat. The WHRUs will provide all of the heating required for all 3 LNG trains. The WHRUs enhance efficiency of the trains by reducing overall energy requirements and eliminating emissions by not utilizing gas-fired heaters in the process. There are no negative economic, energy, or environmental impacts associated with this control technology.

Operational Energy Efficiency

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

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance. There are no negative economic, energy, or environmental impacts associated with this control technology.

Step 5 – Selection of BACT

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

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Cheyenne Light, Fuel & Power / Black Hills Power, Inc. Laramie County, WY	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,600 lbs CO_2e/MWhr (gross) 365-day average, rolling daily	2012	PSD-WY-000001-2011.001

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
York Plant Holding, LLC Springettsbury Township, PA	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 11,389 Btu/kWh (HHV) when firing natural gas GHG BACT limit of 1,330 lb CO_2e/MWhr (net) 30-day rolling average	2012	67-05009C*
Pio Pico Energy Center, LLC Otay Mesa, CA	300 MW simple cycle power plant	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,328 lb CO_2e/MWhr (gross) 720 rolling operating-hour average	2012	SD 11-01
Copano Processing, L.P., Houston Central Gas Plant	Compressor Turbine with Waste Heat Recovery	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT is to maintain a minimum thermal efficiency of 40% with WHRU on a 12-month rolling average basis. This equates to 0.84 lb of CO_2e/hp-hr.	2013	PSD-TX-104949-GHG
EFS Shady Hills LLC EPA Region 4	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,377 lb CO_2e/MWhr (gross) when firing natural gas	2014	PSD-EPA-R4013
LADWP Scattergood Generating Station Playa Del Ray, CA	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,271 lb CO_2e/MWhr (net) 12-month rolling average	2013	800075

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Puget Sound Energy, Freedonia Generating Station Bellevue, WA	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,299 lb CO_2e/MWhr (net) for GE 7FA.05 GHG BACT limit of 1,310 lb CO_2e/MWhr (net) for GE 7FA.04 GHG BACT limit of 1,278 lb CO_2e/MWhr (net) for SGT6-5000F4 GHG BACT limit of 1,138 lb CO_2e/MWhr (net) for GE LMS100	2013	PSD-11-05
El Paso Electric Company, Montana Power Station El Paso, TX	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,194 lb CO_2/MWh(gross) output on a 5,000 operational hour rolling basis.	*	PSD-TX-1290-GHG
Freeport LNG Development, Freeport LNG Freeport, TX	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 738 lb CO_2e/MWhr (net) 365-day rolling average	*	PSD-TX-1302-GHG

*Not yet issued.

The CCL turbines selected are aeroderivative, similar to some of the turbines listed above, but unlike most of those turbines listed; CCL will be using the turbines for compression and not for the generation of electricity. The only facility listed above that will utilize turbines for compression purposes is Copano Processing, Houston Central Gas Plant, but the Copano turbines operate as combined cycle units. Copano operates a cryogenic process train at the Houston Central Gas Plant, not a compressor station. Copano will meet a BACT limit of 40% thermal efficiency with Waste Heat Recovery Units (WHRU). The efficiency is equivalent to 0.84 lb CO_2/hp-hr with WHRU. The Copano turbines include waste heat recovery units (WHRU), whereas CCL turbines will have WHRU on only 6 turbines. The WHRUs on the Copano turbines make them more efficient. Copano uses the heat recovered through the WHRU to heat the inlet gas heater, regeneration heater, amine reboiler, and the trim reboiler. CCL has no need for the excess heat or power generated by WHRUs on every turbine since the six turbines with WHRU will produce sufficient heat for their process. The Copano turbines alone (without WHRU) have a rated efficiency of 34.4% at 100% load and an output based limit of 1.32 lb CO_2e/hp-hr, at 70% load the turbines alone have a 25% thermal efficiency. The thermal efficiency of the turbines to be selected by CCL shall have a thermal efficiency between 37.3 to 40%. CCL has proposed an output based limit of 8,041 lb CO_2e/MMscf of outlet LNG, on a 12-month rolling average for each turbine.

The following specific operating practices are proposed for the Combustion Turbines:

- *Low Carbon Fuel* – Use of BOG or natural gas as fuel but natural gas only during startup;
- *Design Energy Efficiency* – Installation of an efficient CT, with waste heat recovery on the ethylene units, suitable for the operational parameters of the project; and
- *Operational Energy Efficiency* – Implementation of good combustion, operating, and maintenance practices.

BACT Compliance:

BACT for each of the combustion turbines is 8,041 lb CO_2e/MMscf of LNG produced. Compliance will be based on a 12-month rolling average. As explained below, this corresponds to an emission limit of 146,754 tpy CO_2e per turbine on a 12-month rolling basis. CCL will maintain records of tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for the turbines.

CCL will monitor and archive periodic data points for operational data gathered from installed instrumentation on the turbines. Data points collected and archived will include the following:

- Inlet air flow, temperature, pressure, and humidity;
- CT Fuel input - volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
- Combustion temperature;
- Exhaust temperature;
- Gross annual LNG output (MMscf);
- CT plant thermal efficiency, %; and
- Gas turbine electrical output, MW.

CCL will demonstrate compliance with the CO_2 limit for each turbine based on metered fuel consumption and using fuel composition and mass balance. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

As an alternative, CCL may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations at 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

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

X. Thermal Oxidizers (EPNs: TO-1, TO-2, and TO-3)

Each of the three trains in the liquefaction process is equipped with an Acid Gas Removal Unit (AGRU). This equipment is designed to remove sulfur from the acid gas in the form of liquid sulfur, which is sent off-site for treatment and/or disposal. After sulfur removal the acid gas is sent to a thermal oxidizer (TO) for control. GHG emissions from the thermal oxidizers result from the combustion of the acid gas from the AGRU. The TO will be designed for a methane destruction and removal efficiency of 99.9%.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that may be applicable to the thermal oxidizers in the proposed project.
- *Design Measures* – Measures that may be included in the design to increase thermal efficiency.
- *Good Combustion and Maintenance Practices* – Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.

Step 2 – Elimination of Technically Infeasible Alternatives

Carbon Capture and Storage

This add-on control technology was already eliminated as BACT as discussed in detail in section IX and therefore it will not be discussed further.

All remaining options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Design measures and good combustion and maintenance practices are both considered effective control methods and have a range of efficiency improvements, which cannot be directly quantified. Therefore, ranking of these measures is not possible. However, since these control measures are not mutually exclusive, ranking of these measures is of limited significance

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

Design Measures

Good thermal oxidizer design can be employed to destroy any CH_4 entrained in the waste gas removed from the amine units. Good thermal oxidizer design includes flow measurement and monitoring/control of waste gas heating values. There are no negative economic, energy, or environmental impacts associated with this control technology.

Good Combustion and Maintenance Practices

Good combustion practices include, proper maintenance and tune-up of the thermal oxidizers at least annually per the manufacturer's specifications. There are no negative economic, energy, or environmental impacts associated with this control technology.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the thermal oxidizers:

- *Design Measures*
- *Good Combustion and Maintenance Practices*

CCL will operate and maintain the thermal oxidizers in accordance with vendor recommended operating procedures and operating and maintenance manuals. To maintain optimal performance, CCL will also:

- Calibrate and perform preventative maintenance checks of the fuel gas flow meters on an annual basis;
- Perform a monthly calibration and check the filters on the oxygen analyzers;
- Perform preventative maintenance checks of oxygen control analyzers on a quarterly basis; and
- Perform tune-up of the oxidizers at least once per year.

Good combustion practices proposed for the thermal oxidizer include, but are not limited to the following:

- Maintaining good air/fuel mixing in the combustion zone;
- Allowing sufficient residence time to achieve a minimum destruction efficiency of 99.9%;
- Maintaining proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Ensuring good burner maintenance and operation;
- Monitoring of and maintaining proper operating temperature in the primary combustion zone. The unit combustion chamber temperature set point will be at or above 1,400 ^{o}F when receiving waste gases; and
- Maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

BACT for the thermal oxidizers will be design measures and good combustion and operating practices. The thermal oxidizer combustion and exhaust temperature, as well as exhaust oxygen content will be monitored to ensure proper operation of the thermal oxidizers. CCL's use of the above practices will result in an emission limit of 196,458 tpy CO_2e for each thermal oxidizer. CCL has proposed to maintain an output based limit of 57.8 ton CO_2/MMscf burned in each thermal oxidizer. This value includes the volumes of the fuel gas and waste gas streams. Compliance monitoring for the thermal oxidizers will be provided by measurement of fuel gas and waste gas volumetric flow rates. Heat input in MMBtu/hr (based on gas quality analyses) will be used to calculate CO_2, CH_4, and N_2O emissions. Compliance shall be determined by the monthly calculation of GHG emissions using equation W-3 consistent with 40 CFR Part 98, Subpart W [98.233(d)(2)].

XI. Flares (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR)

The CCL facility is equipped with one marine flare, and two wet/dry gas flares to control vented GHG and other emissions. The wet/dry flares are approximately 500 feet tall. The methane destruction efficiency of the flares is 99%. Trains 1 and 2 will vent to one wet/dry flare and trains 2 and 3 will vent to a second separate wet/dry flare. Maintenance and startup/shutdown (MSS) emissions will be routed to the wet/dry flares for control. The marine flare will be used to combust ship loading/unloading emissions and when a ship arrives inerted with CO_2, the ship vapor will be purged to the marine flare for control. These streams contain VOCs that when combusted by the flare produce CO_2 emissions. The flares' pilots are fueled by boil-off gas (BOG) and pipeline quality natural gas.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Flare Gas Recovery* – A flare gas recovery system can be used to recover flared gas to the fuel gas system or recycled to process.
- *Good Flare Design* – Proper flare design can assure high reliability and destruction efficiencies.
- *Use of Clean Fuel for Pilots* – Use of low carbon fuel.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except flare gas recovery.

The flare will largely handle intermittent MSS emissions occurring during sip loading/unloading. These emissions are rare and generally of short duration. Given these conditions flare gas recovery of high volumes and short durations is infeasible to implement.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Use of low carbon fuel and good flare design with appropriate instrumentation and control are the only remaining options. They provide effective control and have a range of efficiency improvements, which cannot be directly quantified. Therefore, ranking of these measures is not possible. However, since these control measures are not mutually exclusive, ranking of these measures is of limited significance.

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

Use of Clean Fuel for Pilots

Natural gas and BOG will be used in the pilots. There are no negative economic, energy, or environmental impacts associated with this control technology.

Good Flare Design

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value. There are no negative economic, energy, or environmental impacts associated with this control technology.

Step 5 – Selection of BACT

CCL proposes to use both identified control options to minimize GHG emissions from flaring of MSS and loading/unloading emissions from the proposed facilities. The following specific BACT practices are proposed for the flares:

- *Use of Clean Fuel for Pilots* – The flares will only combust pipeline quality natural gas and BOG in the pilots. This is the lowest carbon fuel available at the facility.
- *Good Flare Design* – Flares will be designed to meet the requirements of 40 CFR 60.18. Flow rate and gas composition analyzers shall be used to continuously monitor the combined waste gas stream sent to the flare from the proposed and other existing facilities to determine the quantity of natural gas required to maintain a minimum heating value of 300Btu/scf.

CCL will limit the volume of MSS emissions to 341,667 lb/hr for each flare. The above control options will result in an annual emission limit of 28,610 tpy CO_2e for the marine flare, and 71,303 tpy CO_2e for each of the wet/dry flares. Compliance monitoring for the flares will be provided by measurement of fuel gas and waste gas volumetric flow rates. Heat input in MMBtu/hr (based on gas quality analyses) will be used to calculate CO_2, CH_4, and N_2O emissions in accordance with § 98.253. On a monthly basis, operator records will be used to verify the measured flow rates and calculations.

CCL will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1, and the site specific analysis for MSS and loading/unloading vapors. The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.98 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XII. Emergency Generators (EPNs: GEN1, GEN2, GEN3, and GEN4) and Firewater Pump Generators (EPNs: FWPUMP1, FWPUMP2, and FWPUMP3)

The proposed Project will use a total of four emergency generators, each 2,200 hp, to serve as a reliable power source for lighting and other emergency equipment in the event of power failure. The engines will be diesel-fuel fired units and used only for emergency purposes, except for periodic readiness and maintenance testing. In addition, three 422 hp firewater pump engines will be used for the proposed project, expressly for the facility firewater system. The firewater pumps will also use diesel fuel. Each emergency generator engine will be limited to no more than 27 hours of operation per year for the purpose of maintenance, testing, and inspection. The firewater pump engines will be limited to no more than 52 hours per year for routine testing, maintenance, and inspection purposes.

Step 1 – Identification of Potential Control Technologies for GHGs

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

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except fuel selection. The only technically feasible fuel for the emergency generator engines and firewater pumps is diesel fuel. While natural gas-fueled generator engines and firewater pumps may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the emergency generator engines/firewater pumps since they will be used in the event of facility-wide power outage or in case of fire, when natural gas supplies may be interrupted.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The selection of fuel efficient engines and good combustion, operating, and maintenance practices are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking. In any case, since these measures are not mutually exclusive, ranking of these measures is of limited significance.

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

Efficient Engine Design

CCL will install new emergency generators and firewater pumps; the equipment is designed to optimal combustion efficiency. The emergency generator engines will meet Tier 2 emission standards for non-road engines as specified at 40 CFR § 89.112(a), and the firewater pump engines will meet the Tier 3 requirements. There are no negative economic, energy, or environmental impacts associated with this control technology.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating and maintenance practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. These practices also consider proper maintenance and tune-up of the emergency generators and firewater pumps at least annually per the manufacturer's specifications. There are no negative economic, energy, or environmental impacts associated with this control technology.

Step 5 – Selection of BACT

CCL proposes to use both identified control options to minimize GHG emissions from emergency generators and firewater pumps from the proposed facilities. The following specific BACT practices are proposed for the emergency generators and firewater pumps:

- *Selection of Fuel Efficient Engine* - CCL will purchase emergency generators and firewater pump internal combustion engines (ICEs) certified by the manufacturer to meet the applicable emission standards (40 CFR Part 60, Subpart IIII), and will monitor diesel fuel usage on a monthly basis.
- *Good Combustion, Operating, and Maintenance Practices* - CCL will implement good combustion, operating, and maintenance practices for the emergency generators and firewater pumps.

BACT Limits and Compliance

Using the practices identified above results in an emission limit of 35 tpy CO_2e for each emergency generator engine and 13 tpy CO_2e for each firewater pump engine for non-emergency operations. BACT for the emergency generator engines will be to limit their operation to no more than 27 hours per year for maintenance, testing, and inspection for each engine. The firewater pump engines will be limited to no more than 52 hours per year for routine testing, maintenance, and inspection for each engine. Compliance will be based on run-time hour meter readings on a 12-month rolling basis.

To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 as published on November 29, 2013 (78 FR 71904). Records of the calculations will be required to be kept to demonstrate compliance with the emission limits on a 12-month, rolling total. Additionally, CCL shall maintain records of fuel usage, hours of operation, and maintenance/tune-ups performed on the engines.

XIII. BOG Compressor Venting – MSS (EPN:BOG)

The BOG compressors will be overhauled approximately every two years. Purge gas and startup emissions from the compressors will be vented to the atmosphere. These emissions are approximately 0.75 TPY of CH_4 or about 19 TPY of CO_2e. The only control option is to follow good operational practices. Operating the BOG compressor following the manufacturer's recommendations and performing the required maintenance will ensure the unit is operating properly and will ensure the BOG compressors will not need more frequent overhauls. A numerical BACT limit was not determined to be technically feasible for MSS emissions released to the atmosphere because work practices are difficult to numerically quantify for purposes of emission limits. CCL will maintain records of MSS activities to include the date, time, and duration.

XIV. Process Fugitives (EPN: FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. CCL is utilizing leakless components (welded flanges) to the maximum extent possible in the facility. The additional methane emissions from process fugitives have been conservatively estimated to be 10,825 tpy as CO_2e. Fugitive emissions of methane are negligible, and account for less than 0.3% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- Installing leakless technology components to eliminate fugitive emissions;
- Implementing various instrument leak detection and repair (LDAR) programs in accordance with applicable state and federal air regulations;
- Implementing a monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for compounds; and

- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless/Sealless Technology – Leakless valves and sealless pumps are effective at minimizing or eliminating leaks, but their use may be limited by materials of construction considerations and process operating conditions. Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown. Installing leakless and sealless equipment components is generally reserved for individual, chronic leaking components and specialized services. Leakless technology components are not considered technically feasible on a facility-wide basis for CCL.

Instrument LDAR Programs – LDAR programs have traditionally been developed for control of VOC emissions. Instrumented monitoring is considered technically feasible for components in CH_4 service.

Remote Sensing – Remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbon.

AVO Monitoring – Leaking components can be identified through AVO methods. AVO programs are common and in place industry and are considered technically feasible.

High quality components - A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrumented monitoring can identify leaking CH_4, making identification of components requiring repair possible. This is the second most effective of the controls.

Remote sensing using an infrared imaging has proven effective for identification of leaks. Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[12]

[12] 73 FR 78199-78219, December 22, 2008.

As-observed AVO methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to 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

Instrumented monitoring implemented through the 28LAER[13] LDAR program, with control effectiveness of 97%, is considered top BACT. Although AVO program is not as effective, it can be used to monitor for leaks in between instrumented checks.

Step 5 – Selection of BACT

CCL will implement the TCEQ 28LAER LDAR program, TCEQ 28M[14] LDAR program, and supplemented with an AVO program. The 28LAER LDAR program will be implemented on the fugitive streams that contain greater than 10% VOC. For fugitive streams in methane service, a modified form of the TCEQ 28M LDAR program will be implemented for fugitive emissions of methane. For the remaining streams, an AVO program will be implemented. CCL will utilize high quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed.

Because GHG emissions associated with leaks are difficult to quantify, the proposed permit contains no numerical BACT limitation for fugitives from equipment leaks. CCL will be required to implement an LDAR program that is compliant with TCEQ 28LAER and 28M LDAR programs. The leak thresholds, and repair requirements, and record keeping requirements will be consistent with the TCEQ air permit requirements for VOC emissions.

XV. Compliance with Endangered Species Act (ESA), Magnuson-Stevens Fishery Conservation and Management Act, and National Historic Preservation Act (NHPA)

Before EPA may issue CCL's GHG PSD permit, EPA must comply with Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) the Magnuson-Stevens Fishery Conservation

[13] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28laer.pdf
[14] The boilerplate special conditions for the TCEQ 28M LDAR program can be found at http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28m.pdf

and Management Act (Magnuson-Stevens Act) and Section 106 of the National Historic Preservation Act (NHPA). Under the Energy Policy Act of 2005, FERC is designated as the lead agency for LNG projects. As such, FERC is responsible for complying with these regulations and in addition the National Environmental Policy Act.

CCL is currently pursuing approval and authorization from several federal regulatory agencies including the Federal Energy Regulatory Commission (FERC), U.S. Army Corp of Engineers (USACE), and EPA. As such, FERC is responsible for complying with these regulations and in addition the National Environmental Policy Act. EPA intends to rely on the findings, consultations, and concurrences with NOAA's National Marine Fisheries Office, Protected Resources Division and the US Fish and Wildlife Service for Section 7 of the ESA; NOAA's National Marine Fisheries, Habitat Conservation Division for Magnuson-Stevens Act; and the Texas State Historic Preservation Officer for NHPA.

EPA may not issue its permits until it receives confirmation from FERC and/or these agencies that consultations under these laws are complete.

XVI. 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.

XVII. Conclusion and Proposed Action

Based on the information supplied by CCL, 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 CCL a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month rolling total, rolled monthly, shall not exceed the following:

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
TRB1 TRB2 TRB3 TRB4 TRB5 TRB6 TRB7 TRB8 TRB9 TRB10 TRB11 TRB12 TRB13 TRB14 TRB15 TRB16 TRB17 TRB18	TRB1 TRB2 TRB3 TRB4 TRB5 TRB6 TRB7 TRB8 TRB9 TRB10 TRB11 TRB12 TRB13 TRB14 TRB15 TRB16 TRB17 TRB18	Combustion Turbines	CO_2	146,601[4]	146,754[4]	8,041 lb CO_2e/MMscf of LNG produced for each turbine. See Special Conditions III.A.1.i.
			CH_4	2.8[4]		
			N_2O	0.28[4]		
TO-1	TO-1	Thermal Oxidizer 1	CO_2	196,438	196,458	57.8 tons CO_2/MMscf combusted. Good Combustion and Operating Practices. See Special Conditions III.A.2.
			CH_4	0.55		
			N_2O	0.02		
TO-2	TO-2	Thermal Oxidizer 2	CO_2	196,438	196,458	57.8 tons CO_2/MMscf combusted. Good Combustion and Operating Practices. See Special Conditions III.A.2.
			CH_4	0.55		
			N_2O	0.02		
TO-3	TO-3	Thermal Oxidizer 3	CO_2	196,438	196,458	57.8 tons CO_2/MMscf combusted. Good Combustion and Operating Practices. See Special Conditions III.A.2.
			CH_4	0.55		
			N_2O	0.02		
WTDYFLR1	WTDYFLR1	Wet/Dry Gas Flare 1	CO_2	66,670	71,303	Total gas flow rate limited to 340,734 lb/hr. Good Combustion Practices. See Special Condition III.A.3.
			CH_4	184		
			N_2O	0.11		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
WTDYFLR2	WTDYFLR2	Wet/Dry Gas Flare 2	CO_2	66,670	71,303	Total gas flow rate limited to 340,734 lb/hr. Good Combustion Practices. See Special Condition III.A.3.
			CH_4	184		
			N_2O	0.11		
MRNFLR	MRNFLR	Marine Flare	CO_2	25,932	28,610	Good Combustion Practices. See Special Condition III.A.3.
			CH_4	107		
			N_2O	0.01		
GEN1	GEN1	Emergency Generator 1	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
GEN2	GEN2	Emergency Generator 2	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
GEN3	GEN3	Emergency Generator 3	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
GEN4	GEN4	Emergency Generator 4	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
FWPUMP1	FWPUMP1	Fire Water Pump 1	CO_2	13	13	Limit operation to no more than 52 hours on a 12-month rolling basis. See Special Condition III.A.4.c.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
FWPUMP2	FWPUMP2	Fire Water Pump 2	CO_2	13	13	Limit operation to no more than 52 hours on a 12-month rolling basis. See Special Condition III.A.4.c.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
FWPUMP3	FWPUMP3	Fire Water Pump 3	CO_2	13	13	Limit operation to no more than 52 hours on a 12-month rolling basis. See Special Condition III.A.4.c.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
BOG	BOG	BOG Compressor Venting (MSS)	CH_4	No Emission Limit Established[6]	No Emission Limit Established[6]	Good Operating Practices. See Special Condition III.A.5.
FUG	FUG	Fugitive Process Emissions	CO_2	No Emission Limit Established[7]	No Emission Limit Established[7]	Implementation of LDAR and AVO monitoring program. See Special Condition III.A.6.
			CH_4	No Emission Limit Established[7]		
Totals[8]			**CO_2**	**3,387,583**	**CO_2e 3,413,185**	
			CH_4	**960.8**		
			N_2O	**5.3**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total, to be updated the last day of the following month.
2. 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.
3. Global Warming Potentials (GWP): $CH_4 = 25$, $N_2O = 298$
4. The values shown are for each turbine. The emissions for all 18 turbines combined are 2,638,818 TPY CO_2, 50 tpy CH_4, 5 tpy N_2O, and 2,641,580 tpy CO_2e.
5. Values are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
6. BOG compressor Venting from MSS activities released to the atmosphere are estimated to be 0.75 TPY of CH_4 and 19 TPY of CO_2e.
7. Fugitive process emissions from EPN FUG are estimated to be 433 TPY of CH_4, 0.22 TPY CO_2, and 10,825 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4.