Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Freeport LNG Development, L.P., Freeport LNG Liquefaction Project

Permit Number: PSD-TX-1302-GHG

December 2013

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 December 21, 2011, Freeport LNG Development, L.P. (Freeport LNG) Freeport LNG Liquefaction Project submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. Additional permit application information was submitted by Freeport LNG to EPA by letters dated July 18, 2012, July 20, 2012, September 17, 2012, March 14, 2013, April 5, 2013, and April 23, 2013. In connection with the same proposed project, Freeport submitted Nonattainment New Source Review (NNSR), PSD, and minor NSR permit applications for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 20, 2011. The Freeport LNG Liquefaction Project proposes to construct a natural gas liquefaction plant adjacent to Freeport LNG's existing Liquefied Natural Gas Terminal facility on Quintana Island and a natural gas pretreatment facility to be located approximately 3.5 miles from Freeport LNG's existing Quintana Island terminal, in Brazoria County, Texas. These facilities, while acknowledged to be interdependent and therefore, considered to be one source by the EPA, are being permitted separately by TCEQ. The liquefaction plant will consist of three propane pre-cooled mixed refrigerant trains. The pretreatment facility will purify pipeline quality natural gas to be sent to the liquefaction plant for the production of liquefied natural gas (LNG). After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Freeport LNG Liquefaction Project.

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 Freeport LNG'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 Freeport LNG, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Freeport LNG Development, L.P.
333 Clay Street, Suite 5050
Houston, TX 77002

Pretreatment Facility Physical Address:
CR690, approximately 0.25 miles north of the intersection of CR690 and CR891
Freeport, TX 77541

Liquefaction Plant Physical Address:
1500 Lamar Street
Quintana, TX 77541

Technical Contact:
Mr. Ruben I. Velasquez, P.E.
Senior Engineer – Air Quality
Atkins North America, Inc.
(512) 342-3395

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. 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

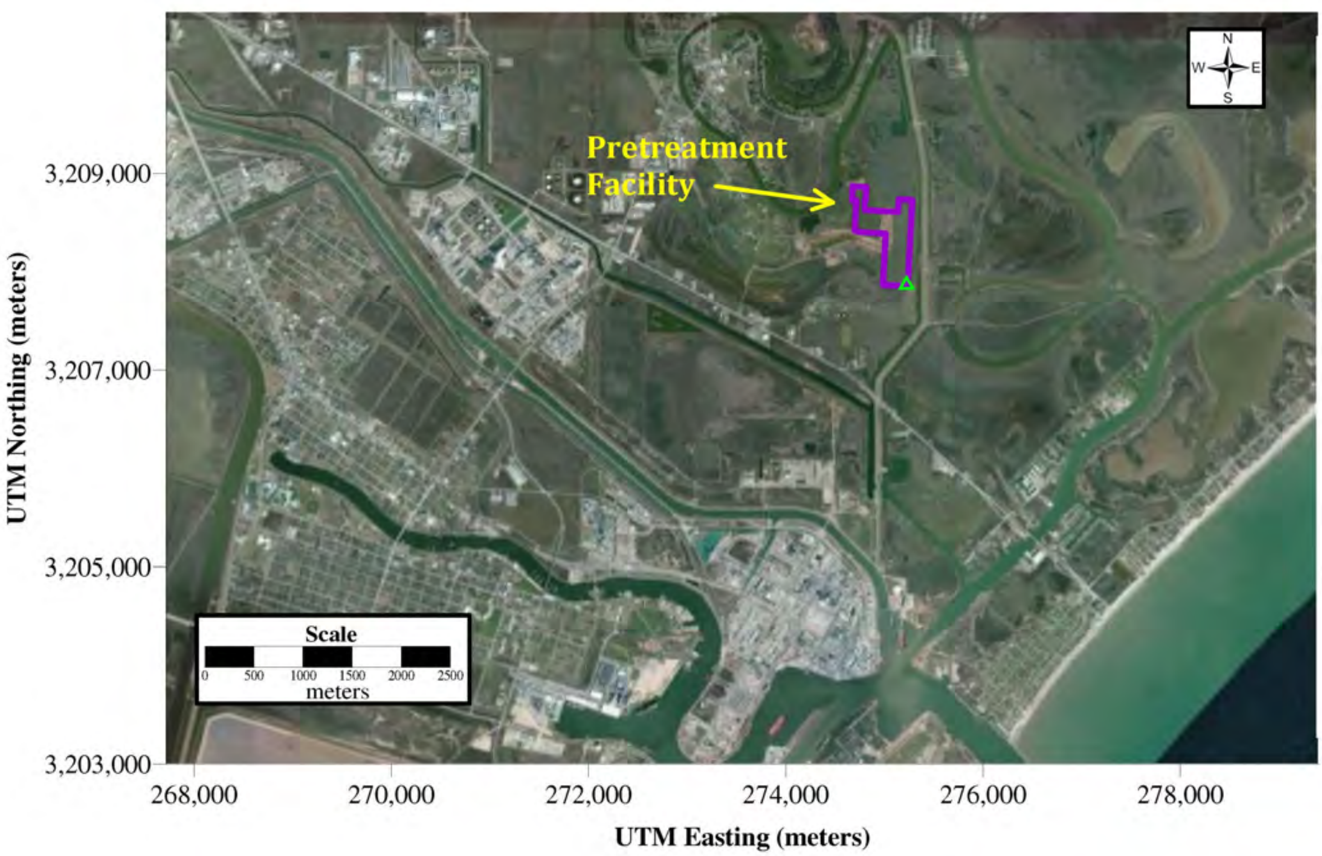
The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

IV. Facility Location

The Freeport LNG, Liquefaction Project is located in Brazoria County, Texas. The area is currently designated nonattainment for ozone and attainment/unclassified for all other pollutants. The geographic coordinates for the facilities are as follows:

Pretreatment Facility		Liquefaction Plant	
Latitude:	28º 58’ 45” North	Latitude:	28º 55’ 42” North
Longitude:	-95º 18’ 25” West	Longitude:	-95º 19’ 00” West

Below, Figure 1 illustrates the pretreatment facility location for this draft permit.
Figure 1. Freeport LNG, Pretreatment Facility Location



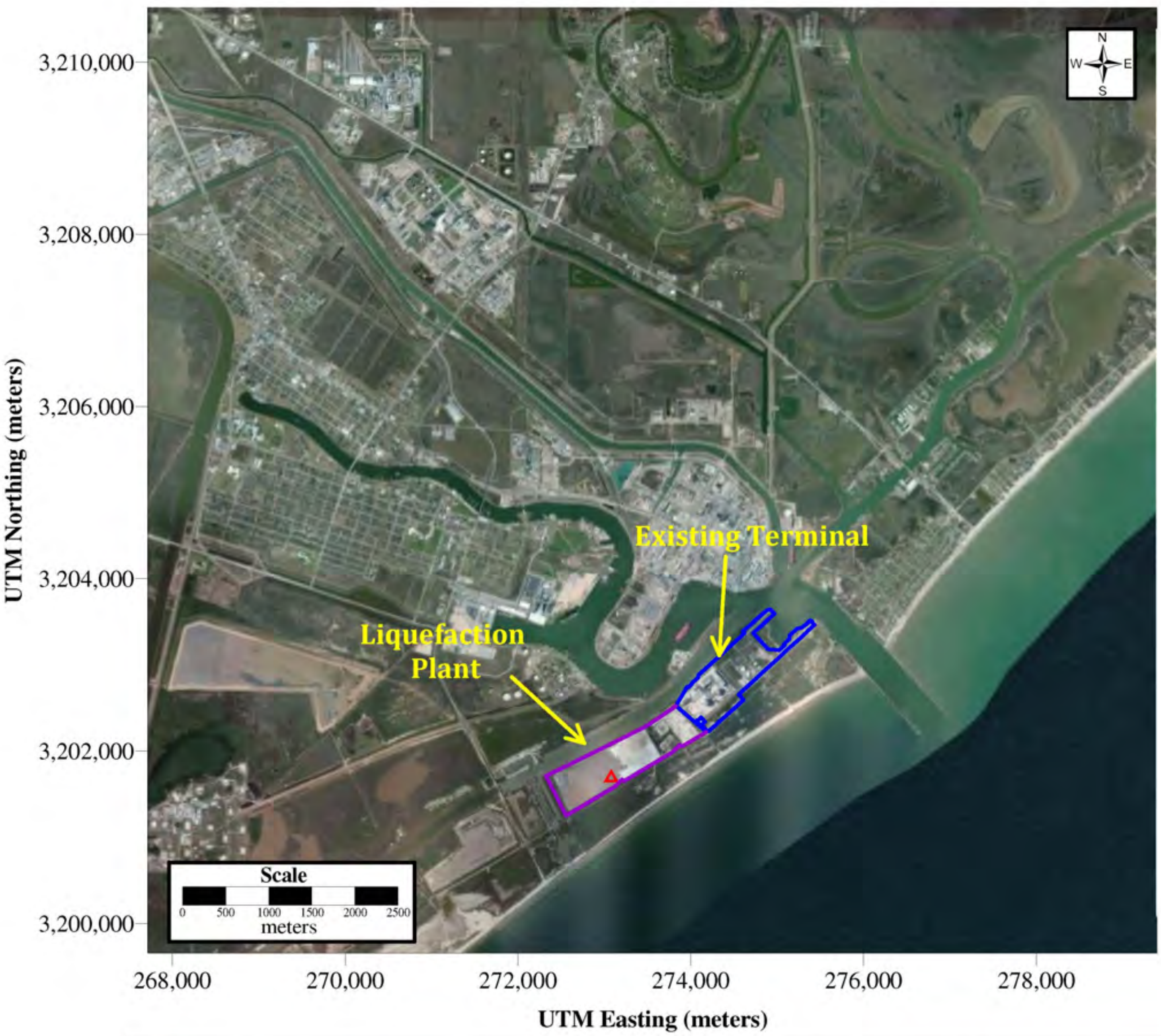
△ Benchmark coordinates: 275,226 m E, 3,207,869 m N (UTM NAD83, Zone 15)
3,149,000 E, 13,558,600 N (Texas South Central, NAD83, U.S. Survey Feet)

UTM coordinates in Zone 15, NAD83 datum.

Source: 15R 267,719m E 3,200,221m N. Bing Aerial. Accessed: January 22, 2013.

Below, Figure 2 illustrates the Liquefaction Plant location for this draft permit.

Figure 2. Freeport LNG, Liquefaction Plant Location



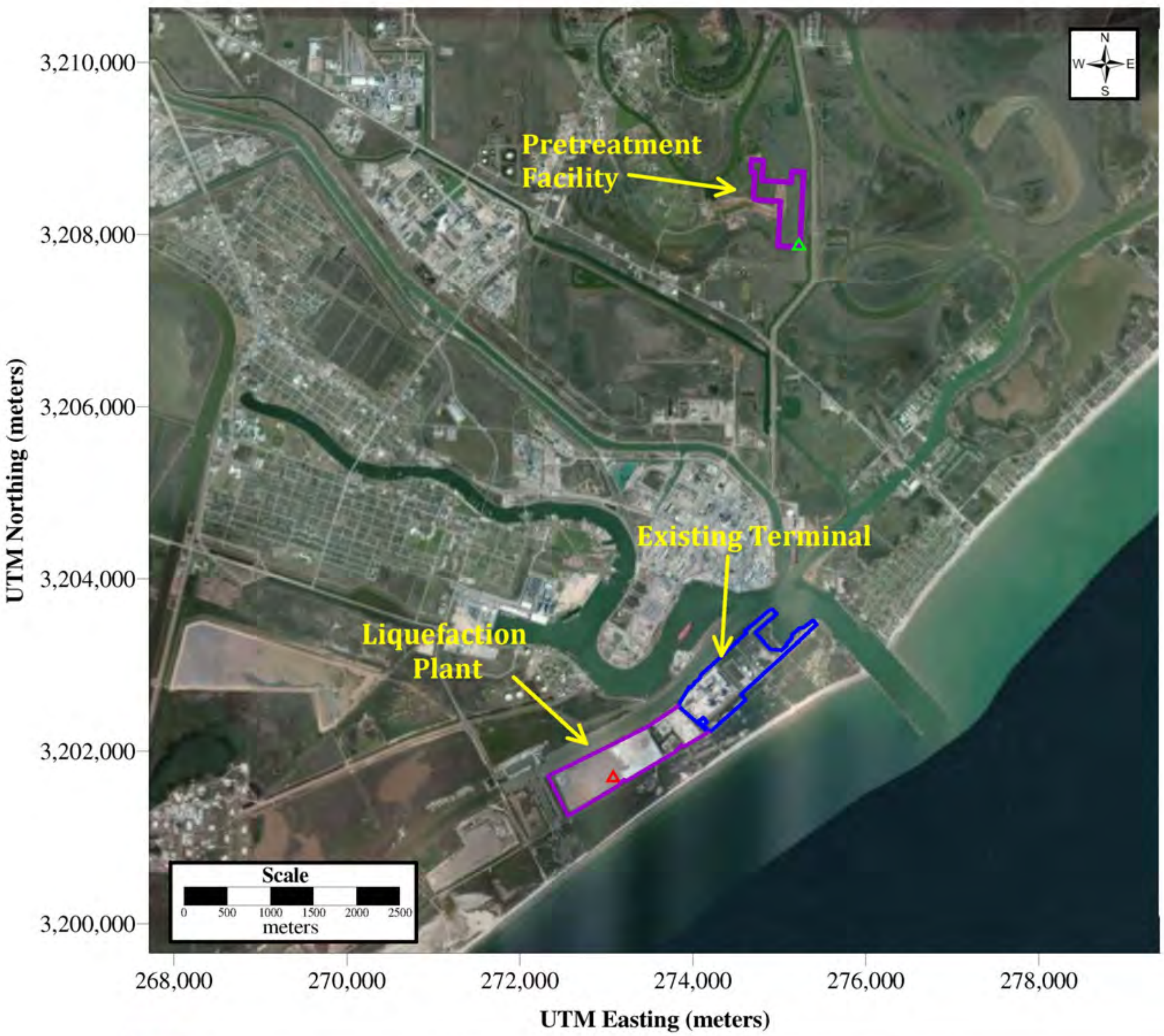
△ Benchmark coordinates: 273,078 m E, 3,201,689 m N (UTM NAD83, Zone 15)
3,143,000 E, 13,538,000 N (Texas South Central, NAD83, U.S. Survey Feet)

UTM coordinates in Zone 15, NAD83 datum.

Source: 15R 267,719m E 3,200,221m N. Bing Aerial. Accessed: January 22, 2013.

Below, Figure 3 illustrates the Pretreatment Facility and the Liquefaction Plant locations for this draft permit.

Figure 3. Freeport LNG, Pretreatment Facility and Liquefaction Plant Locations



△ Benchmark coordinates: 275,226 m E, 3,207,869 m N (UTM NAD83, Zone 15)
3,149,000 E, 13,558,600 N (Texas South Central, NAD83, U.S. Survey Feet)

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3,143,000 E, 13,538,000 N (Texas South Central, NAD83, U.S. Survey Feet)

UTM coordinates in Zone 15, NAD83 datum.

Source: 15R 267,719m E 3,200,221m N. Bing Aerial. Accessed: January 22, 2013.

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

EPA concludes Freeport LNG's application is subject to PSD review for the pollutant GHGs because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(v). Under the project, increased CO_2e emissions are calculated to exceed the applicability threshold of 75,000 tpy at an existing stationary source having the potential to emit 100,000 tpy CO_2e.[1] EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

The applicant represents that the source emits regulated NSR pollutants other than GHGs below the major source thresholds and that PSD review applies to the modification solely because the source emits GHGs above the thresholds described above. The applicant acknowledges that under 40 CFR 52.21 and EPA guidance, PSD review is additionally required for all accompanying increases of regulated NSR pollutants other than GHGs that are increased or emitted at rates equaling or exceeding applicable significant emission rates. Accordingly, the applicant has applied for a preconstruction authorization from TCEQ and requested that the TCEQ apply applicable non-GHG PSD criteria for review and authorization of the projected significant increases of NOx, PM_{10}, and $PM_{2.5}$.[2] By a letter dated February 13, 2013, TCEQ has explained to EPA Region 6 the basis for TCEQ's view that it has the legal authority to issue permits meeting PSD requirements for regulated NSR pollutants other than GHGs for sources that are major sources based solely on the level of GHG emissions. Based on these representations by TCEQ, EPA has communicated that it has no objection to TCEQ's proposal to address regulated NSR pollutants other than GHGs in PSD permits issued in conformity with state law and TCEQ's EPA approved PSD rules.[3] Under the circumstances of this project, EPA will therefore issue a PSD permit covering GHG emissions, while the state will issue a PSD permit covering emissions of all other regulated NSR pollutants increased or emitted in amounts equaling or exceeding the significant emissions rates.

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither 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 has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again,

[1] Freeport LNG calculates CO_2e emissions of 3,149,201 tpy. GHG emissions will also well exceed the mass-based major source threshold of 100/250 TPY.

[2] The applicant has also sought TCEQ issuance of a nonattainment NSR permit for NOx (as an ozone precursor), because the project will constitute a "major source" of a nonattainment pollutant.

[3] Letter from EPA Region 6 Deputy Regional Administrator Samuel Coleman to TCEQ Executive Director Zak Covar (April 4, 2013).

however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ. Thus, TCEQ's PSD permit that will address regulated NSR pollutants other than GHGs should address the additional impacts analysis and Class I area requirements for other pollutants, as appropriate.

VI. Project Description

Freeport LNG is proposing to add liquefaction infrastructure to its existing Quintana Island Terminal to provide export capacity of a nominal 13.2 million tons per annum (mtpa) of LNG, which equates to processing a nominal 2.2 billion standard cubic feet per day (BSCFD) of pipeline quality natural gas. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide (CO_2), sulfur compounds, water, mercury, and heavy hydrocarbons. The pretreated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG's existing 42-inch natural gas pipeline. At the Liquefaction Plant, the pretreated natural gas will be liquefied and then stored in LNG storage tanks. The LNG will be loaded and exported from the terminal by ships arriving via marine transit through the Port Freeport channel.

The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route. The Pretreatment Facility will be comprised of three natural gas pre-treatment systems, five heating medium heaters, three thermal oxidizers, a Natural Gas Liquids removal unit, an emergency ground flare system, a combustion turbine/heat recovery system, five diesel fuel-fired emergency electrical generators, one diesel fuel-fired emergency air compressor, one diesel fuel-fired firewater pump system, and additional electrical compression units and connecting laterals for natural gas supply to the Liquefaction Plant. Each natural gas pretreatment system for Trains 1, 2, and 3 will also include the following:

- Amine sweetening system to remove CO_2 and sulfur compounds;
- Molecular sieve dehydration system to remove water;
- Mercury removal unit (in-line unit);
- Natural gas liquids or heavies removal unit;
- Additional electrical compression units and connecting laterals for natural gas supply to the Liquefaction Plant; and
- Miscellaneous storage vessels.

The Pretreatment Facility includes a heating medium system that is integrated with power production. The heating medium is circulated from the combustion turbine waste heat exchangers to heaters in the amine units, molecular sieve dehydration system, and heavies removal unit. Treated gas from the Pretreatment Facility will be sent via pipeline to the proposed Liquefaction Plant at the Quintana Island Terminal Location.

The main components of the Liquefaction Plant will be three liquefaction trains (Train 1, Train 2, and Train 3), each capable of producing a nominal 4.4 mtpa of LNG. All three trains and their supporting facilities will be located to the southwest of the existing liquefaction storage and vaporization facilities. In addition to the three liquefaction trains, peripheral aboveground infrastructure will include the following:

- Refrigerant and utility storage units;
- Pipe racks and pipes;
- Sumps and associated LNG troughs;
- An emergency ground flare;
- A control room;
- A maintenance building;
- Six emergency electrical generators;
- An emergency air compressor;
- An emergency firewater unit including two firewater pump engines;
- An electrical substation; and
- Plant roads.

VII. General Format of the BACT Analysis

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

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

VIII. Overall Project Energy Efficiency Considerations

Freeport LNG utilized overall energy efficiency as a basic design criterion in the selection of technologies and processing alternatives for the Liquefaction Project. Two design decisions made by Freeport LNG promote overall energy efficiency for the Liquefaction Project, selection of electric motors as its primary drivers, and modularization of the liquefaction trains and natural gas pretreatment units.

Electric Motors

Freeport LNG has determined that electric motor primary drivers are the most energy efficient of the available primary driver alternatives for the Liquefaction Project. Electric motors, in comparison to other drivers, produce no GHG emissions, do not have their energy efficiency affected by weather or add-on control technologies, have more efficient turndown characteristics for variable output operations, can be sized to allow for a more efficient design, and have no waste heat which is readily usable with the design of the Liquefaction Plant. Selecting electric motors as the primary drivers for the large compressors and pumps in the Liquefaction Project avoids these inefficiencies. Also, once operational, the Liquefaction Project will be operated at varying rates due to, among other things, changes in customer demands and variations in the inlet natural gas supply.

When coupled with variable speed drives (which will be used for the Liquefaction Project), electric motors remain efficient within a larger operating envelope than other primary driver alternatives. Electric motors are supplied in a greater number of standard sizes which allow Freeport LNG to pick a motor size that is optimal to the desired design output of the liquefaction train.

Modularization

Freeport LNG designed the Liquefaction Project with multiple liquefaction trains, each with an accompanying natural gas pretreatment unit. This promotes energy efficiency notwithstanding the varying throughputs that the facility may encounter. With modularization, each of the three liquefaction trains will be operated in tandem with one of three natural gas pretreatment trains. Rather than build one or two large liquefaction trains or pretreatment units with flexible turndown capabilities, Freeport LNG decided to build three liquefaction trains and corresponding pretreatment units, with each pretreatment unit having the capacity to treat the natural gas for one liquefaction train. Significant energy efficiencies are gained from this design because as the overall liquefaction rates change (either due to varying economic conditions, customer demands, maintenance outages, etc), Freeport LNG can optimize the operation of the three trains and pretreatment units (including shutting down a train and pretreatment unit) in order to maintain the throughput of each train and pretreatment unit at the most energy efficient rates possible. As the throughput of a liquefaction train or pretreatment unit is reduced, the turndown characteristics of the equipment in those facilities cause energy efficiency to be reduced. By having multiple trains and pretreatment units, Freeport LNG can avoid much of these inefficiencies, thereby allowing, the amine systems and associated heaters and thermal oxidizers in the pretreatment units to remain operating under optimal conditions.

IX. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., combustion turbine, heaters, thermal oxidizers, and flare). The project has some fugitive emissions from piping components which contribute an insignificant amount of GHGs. Fugitive emissions account for 1,306 TPY of CO_2e, or less than 0.08% 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 at both the Pretreatment Facility and Liquefaction Facility is subject to this GHG PSD permit:

Pretreatment Facility Equipment

FIN	EPN	Description
CT	CT	Natural Gas-Fired General Electric 7EA Combustion Turbine (Combustion Unit). The unit has a nominal base-load gross electric power output of approximately 87 MW vented to a heat exchanger for waste heat recovery. The combustion turbine is equipped with selective catalytic reduction (SCR) exhausting through a single flue gas stack.
65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	5 Heating Medium Heaters (Combustion Unit). Each unit has a maximum design heat input rate of 130 MMBtu/hr (HHV), and is fired with natural gas, boil off-gas (BOG), or a natural gas/BOG blend. Emissions are combined into an emissions cap (HTRCAP).
AU1/TO1 AU2/TO2 AU3/TO3	TO1 TO2 TO3	3 Regenerative Thermal Oxidizers (Combustion Units).
PTFFLARE	PTFFLARE	1 Emergency Ground Flare (Combustion Units).
PTFFWP	PTFFWP	1 Fire Water Pump (Combustion Units). 660 horsepower (hp) Diesel Fuel-Fired Fire Water Pump limited to 100 hours of operation per year for non-emergency activities for each unit.
PTFEG-1 PTFEG-2 PTFEG-3 PTFEG-4 PTFEG-5	PTFEG-1 PTFEG-2 PTFEG-3 PTFEG-4 PTFEG-5	5 Emergency Generators (Combustion Units). 755 horsepower (hp) Diesel Fuel-Fired Emergency Generators limited to 50 hours of operation per year for non-emergency activities for each unit.
PTFEAC-1	PTFEAC-1	1 Emergency Air Compressor Engine (Combustion Unit). 300 horsepower (hp) Diesel Fuel-Fired Engine limited to 50 hours of operation per year for non-emergency activities.
FUG-PTSF6	FUG-PTSF6	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) with 978 pound SF_6 capacity.
FUG-TREAT	FUG-TREAT	Process Fugitives.

Liquefaction Plant Equipment

FIN	EPN	Description
LIQFLARE	LIQFLARE	1 Emergency Ground Flare (Combustion Unit).
LIQFWP-1 LIQFWP-2	LIQFWP-1 LIQFWP-2	2 Fire Water Pumps (Combustion Units). 660 horsepower (hp) Diesel Fuel-Fired Fire Water Pumps limited to 100 hours of operation per year for non-emergency activities for each unit.
LIQEG-1 LIQEG-2 LIQEG-3 LIQEG-4 LIQEG-5	LIQEG-1 LIQEG-2 LIQEG-3 LIQEG-4 LIQEG-5	5 Emergency Generators (Combustion Units). 755 horsepower (hp) Diesel Fuel-Fired Emergency Generators limited to 50 hours of operation per year for non-emergency activities for each unit.
LIQEG-6	LIQEG-6	1 Emergency Generator (Combustion Unit). 400 horsepower (hp) Diesel Fuel-Fired Emergency Generator limited to 50 hours of operation per year for non-emergency activities.
LIQEAC-1	LIQEAC-1	1 Emergency Air Compressor Engine (Combustion Unit). 300 horsepower (hp) Diesel Fuel-Fired Engine limited to 50 hours of operation per year for non-emergency activities for each unit.
FUG-LIQSF6	FUG-LIQSF6	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) with 5,683 pounds SF_6 capacity.
FUG-LIQ	FUG-LIQ	Process Fugitives.

X. Combustion Turbine (EPN: CT) - Pretreatment Facility

The combustion turbine proposed by Freeport LNG for the Pretreatment Facility is being installed in a combined heat and power (CHP) configuration. The Pretreatment Facility will utilize a high efficiency GE Frame 7EA turbine consisting of a natural gas-fired combustion turbine exhausting to a heat exchanger for waste heat recovery. It will be equipped with a dry low-NO_x burner (DLNB), Selective Catalytic Reduction (SCR) system, and Oxidation Catalyst (Ox-Cat). The DNLB and SCR are used to reduce NO_x emissions while Ox-Cat is used to reduce CO and VOC emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Efficient Combustion Turbine Design* – The Pretreatment Facility will utilize a high efficiency GE Frame 7EA turbine consisting of a natural gas-fired combustion turbine exhausting to a heat exchanger for waste heat recovery. The combustion turbine proposed by Freeport LNG for the Pretreatment Facility is being installed in a combined heat and power (CHP) configuration.
- *Fuel Selection* – 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.

- *Good Combustion, Operating, and Maintenance Practices* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the combustion turbine.
- *Use of an Air Intake Chiller* – Chilling the incoming air increases the thermal and power efficiency of the CT.
- *Use of an Oxidation Catalyst* – Oxidation catalysts are widely used as a control technology for CO and VOC emissions and could also provide a collateral reduction in CH_4 emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[4]

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)."[5] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is 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, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for the proposed LNG facility; the third approach, post-combustion capture, is applicable to combustion turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many

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[4] Based on the information provided by Freeport LNG and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source.

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

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). 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.

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.[6]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CCS (up to 90% control),
- Efficient Turbine Design,
- Fuel Selection,

[6] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

- Good Combustion, Operating, and Maintenance Practices,
- Use of an Air Intake Chiller.
- Use of an Oxidation Catalyst

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. Efficient turbine design, fuel selection, and good combustion, operation, and maintenance practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible.

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

Carbon Capture and Storage

Freeport LNG developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option based on economic costs, and environmental impact. Freeport LNG identified two options, capture and geological sequestration of CO_2 (without any post-processing) and capture and transfer of CO_2 (with post processing) for enhanced oil recovery (EOR).

Freeport LNG provided a cost analysis for capture and geological sequestration of CO_2 from the combustion turbine (without any post-processing). The total capital cost of geological sequestration (without pretreatment) is projected to be approximately $444 million. The annual operating and maintenance costs were estimated to be approximately $65 million. Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, is estimated to be nearly $131 million.

Freeport LNG also provided a cost analysis for the capture and transfer of the CO_2 from the combustion turbine, with post-processing. The CO_2 stream from the combustion turbine would contain sulfur compounds, particulate matter, other products of combustion, and water which would require removal. The CO_2 stream would also have to be compressed to be transferred at the high pressure required for the EOR transmission pipeline. The cost for treatment, compression, and delivery for EOR is estimated to be approximately $466 million. The annual operating and maintenance expenses are estimated to be approximately $54 million. Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, is estimated to be nearly $124 million. In addition, Freeport provided a cost analysis for the use of Carbon Capture and Sequestration (CCS) to remove CO_2 from the proposed Amine Treatment Units. The addition of CCS to capture CO_2 from the Amine

Treatment Units would result in an added cost to the project in the range of $46 to $115 million depending on whether the CO_2 captured is sequestered or used for enhanced oil recovery.

EPA Region 6 reviewed Freeport LNG's CCS cost estimates and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project. The cost of CCS would potentially increase the cost of the natural gas pretreatment portion of the project by as much as 50% to 60%, and thus, CCS has been eliminated as BACT for this project.

In addition, Freeport LNG has provided information[7] detailing that the installation of a CCS system would result in an energy penalty of about 62-63% of the produced energy from the combustion turbine. Since the facility thermal energy need is approximately equal to recoverable exhaust energy of the proposed combustion turbine, a larger combustion turbine would be required to meet the additional energy requirements for CCS.

Economic infeasibility notwithstanding, CCS can have a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of CCS would increase emissions of GHGs, NOx, CO, VOC, PM_{10}, and SO_2. Assuming approximately 30 to 45% more fuel would be required to produce this additional electrical output, it is estimated that an additional 3.5 billion cubic feet of natural gas per year would be burned that would produce an additional 209,000 tons of CO_2 per year just to support the electrical energy requirements for CCS. The proposed plant is located in the Houston-Galveston-Brazoria (HGB) area of ozone non-attainment, and the generation of additional NOx and VOC emissions from the additional carbon capture control equipment that would be needed to capture CO_2 could exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, energy efficient technologies are preferred over add-on controls such as CCS that would cause an increase in emissions of NOx and VOCs to the HGB non-attainment area.

Efficient Combustion Turbine Design

The Pretreatment Facility will include one General Electric (GE) Frame 7EA natural gas-fired combustion turbine (CT) exhausting to a heat exchanger for waste heat recovery. The combustion turbine proposed by Freeport LNG for the Pretreatment Facility is being installed in a combined heat and power (CHP) configuration. Since combustion turbine exhaust energy is being recovered and harnessed for use along with electrical energy from the generator, more of the fuel burned in a CHP application is recovered as useful energy than in a simple-cycle combustion turbine application. Waste heat will be recovered from the combustion turbine using a heat recovery system. The use of the waste gas heat recovery system will allow for heat

[7] Response to EPA request for additional information dated July 20, 2012. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/freeport_lng_response07202012.pdf

transfer to the amine, molecular sieve dehydration units, and heavies removal unit in lieu of fully firing natural gas fuel in all process heaters serving these units, thus reducing GHG emissions. In addition, the transfer of most of the combustion turbine exhaust energy to the heating medium system increases the overall cycle efficiency of the combustion turbine in the combined heat and power configuration.

Fuel Selection

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 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. Freeport has estimated that the lowest nitrogen content of the BOG will be about 6 mole %, the balance being 94% methane. The peak, or maximum, BOG nitrogen content could be as high as 20 mole % with the balance, 80% 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, BOG, or BOG supplemented with natural gas will be fired in the proposed combustion turbine. Natural gas has the lowest carbon intensity of any available fuel for the combustion turbine.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are a control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine; thus, maximizing fuel efficiency and minimizing incomplete combustion. Furthermore, the turbine's operation is automated to ensure optimal fuel combustion and efficient operation leaving virtually no operator ability to further tune these aspects of operation. Good combustion practices also include proper maintenance and tune-up of the combustion turbine system per the manufacturer's specifications or as warranted by monitoring of operational parameters.

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.

Use of Air Intake Chiller

An intake air chiller system will maintain the incoming combustion turbine air at a maximum of about 60 ^{o}F. The use of the proposed chiller system may not be needed during cooler ambient temperatures. Chilling the incoming air in this way increases the thermal efficiency of the combustion turbine, thus reducing GHG emissions.

Use of an Oxidation Catalyst

The proposed combustion turbine will be equipped with an oxidation catalyst used to reduce carbon monoxide and volatile organic compound (VOC) emissions. While the use of the oxidation catalyst is designed to reduce VOC emissions, it is also anticipated to have a collateral effect in minimizing residual methane emissions from the combustion process. However, in estimating methane emissions from the combustion turbine exhaust, no credit was claimed for reduction of CH_4 through use of the oxidation catalyst.

Step 5 – Selection of BACT

To date, other GHG BACT limits for simple cycle turbines 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
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*

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
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
EFS Sandy 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	*	
LADWP Scattergood Generating Station Playa del Rey, 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	Facility ID 800075
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
Air Liquide Large Industries U.S., Bayou Cogeneration Plant Pasadena, TX	Simple Cycle Combustion Turbines in a Combined Heat & Power Configuration	Energy Efficiency/ Good Design & Combustion Practices	7,720 $Btu_{(HHV)}/kWh_{gross}$ equivalent based on a 365-day rolling average.	2013	PSD-TX-612-GHG

*Not yet issued.

The Pretreatment Facility combustion turbine is being installed in a combined heat and power (CHP) configuration. The turbines listed in the table above are mostly either aero derivative or F-class frame machines operating in a simple cycle combustion turbine configuration. There is only one CHP configuration in the table above, Air Liquide Bayou Cogeneration Plant. Since combustion turbine exhaust energy is being recovered and harnessed for use along with electrical energy from the generator, more of the fuel burned in a CHP application and the subsequent thermal energy generated is recovered as useful energy than in a simple cycle combustion turbine application. In order to have a more direct comparison with the BACT examples above, the useful thermal energy recovered from the combustion turbine exhaust must be added to the combustion turbine net electrical output to determine the total useful energy recovered from burned fuel in order to calculate the lb CO_2/MWh in a meaningful way. This is the same methodology that requires the electrical output of a steam turbine be added to the electrical output of the combustion turbine in order to arrive at the total useful energy recovered in a combined-cycle combustion turbine application. In the case of CHP at the PTF, the useful thermal energy recovered from the combustion turbine exhaust converted to the same unit of measure, kW, as the combustion turbine electrical output is analogous to the steam turbine electrical output. Freeport LNG has proposed an output based limit of 738 lb CO_2/Mwh (based on gross CT energy output and equivalent energy produced). The combustion turbine will maintain an average heat rate not to exceed 5,210 Btu/kWh on a 12-month rolling average basis. The basis for calculation of the Btu/kWh for the CHP at the Pretreatment Facility is shown in Table 2 of the Appendix. The BACT limit proposed by Freeport is lower than those listed in the table above. The output based limit for Air Liquide, is approximately 1,380 lb CO_2/MWh(gross). The Freeport heat rate limit is also lower than that established for Air Liquide. On the basis of total useful energy recovered in exchange for fuel consumed, the BACT for the CHP combustion turbine proposed at the Pretreatment Facility is essentially 35% lower than the "best" simple-cycle BACT example (LMS100 for Puget Sound Energy) provided in the table above.

To establish an enforceable BACT limit that can be achieved over the life of the facility, the output-based CO_2 limit must account for short-term degradation in performance as the unit is broken in; anticipated degradation of the combustion turbine over time between regular maintenance cycles; and potential degradation of other elements of the system over time. Performance degradation during the first 24,000 hours of operation is estimated to be about 2% to 6% from the performance test measurements when corrected to guaranteed conditions. A 6% margin was incorporated into the determination of the adjusted net heat rate to account for performance degradation.

In addition to recoverable and non-recoverable degradation of the CT, degradation of the CT's waste heat recovery system as well as other elements of the Pretreatment Facility that depend on the waste heat recovery system (e.g., amine regeneration units) that can potentially cause the overall plant heat rate to rise were also considered by the applicant. Therefore, a 5% margin was incorporated into the determination of the adjusted net heat limit rate. These additional margins were added to the base net heat rate to arrive at the adjusted heat rate for the CT of 5,210 Btu/kWh.

The following specific BACT practices are proposed for the Combustion Turbine:

- *Efficient Combustion Turbine Design* – Installation of an efficient CT with waste heat recovery suitable for the operational parameters of the project;
- *Fuel Selection* – Use of natural gas, BOG or BOG supplemented with natural gas as fuel;
- *Good Combustion, Operating, and Maintenance Practices* – Implementation of good combustion, operating, and maintenance practices; and
- *Use of an Air Intake Chiller* – Installation of an intake air chiller.
- *Use of an Oxidation Catalyst* – Installation of an oxidation catalyst; however, no reduction credit will be taken.

BACT Compliance:

BACT for the combustion turbine (CT) is 738 lb CO_2/MWh (based on gross CT energy output and equivalent energy produced). Compliance will be based on a 365-day rolling basis. In addition, Freeport LNG will limit the combustion turbine to an average heat rate of 5,210 Btu/kWh (LHV, adjusted gross CT energy heat rate with compliance margin) on a 12-month rolling average basis. Freeport LNG will maintain records of tune-ups, burner maintenance, O_2 analyzer calibrations and maintenance for the CT. In addition, records of fuel flow, combustion temperature, stack exhaust temperature, and a number of other internal operating parameters that affect turbine operation and safety will be monitored.

Combustion turbine fuel efficiency is based in the physics of the compressor and expander design and condition rather than control of the air-fuel ratio in the charge. Fuel input to the combustion turbine is controlled primarily by monitoring and controlling the rotating speed and the combustion temperature and applying that data to a control algorithm inside the unit control system. Parameters that will be measured are fuel flow, combustion temperature, exhaust temperature, and a number of other internal parameters, such as rpm and vibration levels that affect turbine operations and safety, but not emissions. Fuel flow is a volumetric measurement that can be converted into mass (lb/hr) or energy flow (MMBtu/hr) in the control system based on fuel temperature and heating value. Combustion turbine mass flow exhausting from the unit is difficult to measure with any degree of accuracy and is usually calculated within the combustion turbine unit control system based on measurements of rpm and temperature applied to a proprietary algorithm specific to the turbine. The calculated mass flow is available as an output from the unit control system.

The combustion turbine and chiller control system, as well as the plant control system, will monitor and archive periodic data points for operational data gathered from installed instrumentation. 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 hourly energy output (Mwh);
- CT plant thermal efficiency, %;
- Gas turbine electrical output, MW;
- Chilled water supply and return temperatures; and
- Energy input to the chillers.

Freeport LNG will demonstrate compliance with the CO_2 mass emissions limit for the CT based on metered fuel consumption and using the Tier III methodology and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2 and/or 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, Freeport LNG 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 Equation C-8 and the emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations 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 the combustion turbine exhaust. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the CT and are considered a *de minimis* level in comparison to the CO_2 emissions.

XI. Heating Medium Heaters (EPNs: 65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E) - Pretreatment Facility

GHG emissions from the proposed process heaters (Heating Medium Heaters) will result from the combustion of natural gas, BOG, or a natural gas/BOG mixture. The heaters will be fitted with ultra low-NO_x burners and flue gas recirculation. Potential annual emission rates are based on maximum operation of 8,760 hours per year for three heaters and 336 hours per year for two heaters. This basis assumed each heater would operate at 100% of its rated capacity on a continuous basis. During actual operation, it is anticipated the heaters will be operated at less than maximum, and thus, a limit on the total hours of operation would not be appropriate. The heaters would be able to operate more hours at less than maximum operation and still stay below the overall heater emissions cap.

As part of the PSD review, Freeport LNG provides in the GHG permit application a 5-step top-down BACT analysis for the heaters. EPA has reviewed Freeport LNG's BACT analysis for the heaters, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Fuel Selection* – 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.

- *Good Combustion, Operating, and Maintenance Practices* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel combustion efficiency of the heaters.
- *Waste Heat Recovery from Combustion Turbine* – The use of waste heat recovery in the combustion turbine will provide the heat energy requirements for the amine units in lieu of fully firing all process heaters.
- *Efficient Heater Design* – Efficient heater design improves mixing of fuel and creates more efficient heat transfer.
- *Limiting Hours of Operation* – Limiting the hours of operation inherently reduces GHG emissions.

Carbon Capture and Storage

This add-on control technology was already discussed in detail in Section X. Based on the economic infeasibility and environmental detriment issues discussed in Section X, CCS will not be considered further since it was eliminated for BACT in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. CCS will not be considered further based on its elimination for BACT in Section X. CCS is also not technically feasible, according to Freeport LNG, due to the intermittent stream and limited hours of operation.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Fuel Selection,
- Good Combustion, Operating, and Maintenance Practices,
- Use of Waste Heat Recovery from Combustion Turbine,
- Efficient Heater Design
- Limiting Hours of Operation

Efficient heater design, fuel selection, and good combustion, operation, and maintenance practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible.

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

Fuel Selection

The proposed process heaters will be fired with natural gas fuel, boil off gas (BOG), or a natural gas/BOG blend. Natural gas has the lowest carbon intensity of any available fuel for the process heaters. BOG has nearly the same composition as natural gas.

Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a control option that improves the fuel efficiency of the process heaters. Good combustion practices include proper maintenance and tune-up of the process heaters annually or per the manufacturer's specifications.

Use of Waste Heat Recovery from Combustion Turbine

The natural gas-fired combustion turbine (EPN-CT) will exhaust to a heat exchanger for waste heat recovery. The use of waste heat recovery in the combustion turbine will provide the heat energy requirements for the amine units in lieu of fully firing all process heaters and will therefore reduce the GHG emissions from fuel combustion in the heaters.

Efficient Heater Design

Efficient heater design improves mixing of fuel and creates more efficient heat transfer. Since Freeport LNG is proposing to install new heaters, it is anticipated that these heaters will be designed to optimize combustion efficiency. New heaters can be designed with efficient burners, more efficient heat transfer efficiency to the hot oil and regeneration streams, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency.

Limiting Hours of Operation

Limiting the hours of operations inherently reduces GHG emissions. The proposed project anticipates that three heaters will operate at all times and that the remaining 2 heaters will only operate when the combustion turbine is down for maintenance, approximately 336 hours per year for each heater on a rolling 12-month basis. This basis assumed each heater would operate at 100% of its rated capacity on a continuous basis. During actual operation, it is anticipated the heaters will be operated at less than maximum capacity and therefore, the heaters would be able to operate more hours and still stay below the overall heater emissions cap. Thus, a limit on the total hours of operation would not be appropriate.

Step 5 – Selection of BACT

To date, other GHG BACT limits for heaters are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT 1,102.5 lbs CO_2/MMSCF natural gas output for each plant. 1 plant contains: hot oil heater (48.5 MMBtu/hr); Trim Heater (17.4 MMBtu/hr); Molecular Sieve Regeneration Heater (9.7 MMBtu/hr); and TEG Dehydrator Unit Regeneration Gas Heater (3 MMBtu/hr).	2012	PSD-TX-1264-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	Combined cycle combustion turbine and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Heater heat input limit of 40MMBtu/hr and 1,000 hours operation on 12-month rolling average	2011	SE 09-01
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Enterprise Products Operating LLC, Eagleford Fractionation and DIB Units Mont Belvieu, TX	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters (140 MMBtu/hr) BACT 85% thermal efficiency. Regenerant heaters (28.5 MMBtu/hr) BACT is good operating and maintenance practices.	2012	PSD-TX-1286-GHG
Energy Transfer Partners, Lone Star NGL Mont Belvieu, TX	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters (270 MBtu/hr) BACT limit 2,759 lb CO_2/bbl of NGL processed Regenerator Heaters (46 MMBtu/hr) BACT Limit 470 lbs CO_2/bbl of NGL processed.	2012	PSD-TX-93813-GHG
PL Propylene LLC Houston, TX	Propane Dehydrogenation Facility	Energy Efficiency/ Good Design & Combustion Practices	Regeneration Air Heater/Duct Burner (200 MMBtu/hr) and Charge Gas Heater (373 MMBtu/hr) BACT limit of 117 lb CO_2/MMBtu on a 365-day rolling average for each heater.	2013	PSD-TX-18999-GHG

The following specific BACT practices are proposed for the heaters:

- *Fuel Selection* – Natural gas, BOG or a natural gas/BOG blend will be the only fuels fired in the proposed heaters. These are the lowest carbon fuels available for use at the complex;
- *Good Combustion, Operating, and Maintenance Practices* – Implementation of good combustion, operating, and maintenance practices;
- *Use of Waste Heat Recovery from Combustion Turbine* – The use of waste heat recovery in the combustion turbine will provide the heat energy requirements for the amine units in

lieu of fully firing all process heaters and will therefore reduce the GHG emissions from fuel combustion in the heaters;

- *Efficient Heater Design* – Heaters will be designed to be energy efficient, maintaining a thermal efficiency of 80% on a lower heating value (LHV) basis; and
- *Limiting Hours of Operation* – It is anticipated that only three heaters are required to meet system energy demands when the combustion turbine is operating. The remaining 2 heaters (all five heaters may be utilized) will only be needed when the combustion turbine is not operating.

All heaters will be designed to incorporate efficiency features, including insulation, to minimize heat loss and heat transfer components that maximize heat recovery while minimizing fuel use. Freeport LNG will operate and maintain the heating medium heaters in accordance with the vendor-recommended operating procedures and operating and maintenance manuals. To maintain optimal performance, Freeport LNG will:

- Calibrate and perform preventative maintenance checks of the fuel gas flow meters on an annual basis;
- Perform preventative maintenance checks of oxygen control analyzers on a quarterly basis; and
- Perform tune-ups of the heaters on an annual basis.

Freeport LNG will maintain a file of all records, data, measurements, reports, and documents related to the operation of the proposed heaters, including, but not limited to, the following:

- Records or reports pertaining to significant maintenance performed; and
- Records relating to performance tests and monitoring of combustion equipment.

BACT Compliance:

BACT for the heaters has been determined to be a CO_2e emission limit of 117 lb CO_2e/MMBtu for each heater based on actual hours of operation and Btus produced, and excludes non-operational time. This BACT limit is based on a 12-month rolling average. Compliance with this BACT limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with 40 CFR part 98 Subpart C.

The heaters will comply with an emissions compliance cap of 80,046 tpy of CO_2e on a 12-month rolling average. This cap was calculated based on 3 heaters operating at 8,760 hours per year at the maximum heat input capacity (130 MMBtu/hr), and the remaining 2 heaters operating for 336 hours per year; i.e., this is based on all heaters operating during periods when the combustion turbine is shut down for planned maintenance. For purposes of estimating GHG emissions from the heating medium heaters, it was assumed the combustion turbine would be down for 2 weeks per year (14 days) for maintenance and each heater would operate at 100% of its rated capacity on a continuous basis. During actual operation, it is anticipated the heaters will be operated at less than maximum capacity, and therefore, the heaters would be able to operate more hours and still stay below the overall heater emissions cap.

The process heaters will be continuously monitored for exhaust temperature, fuel temperature, ambient temperature, and excess oxygen. Thermal efficiency will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G. A minimum thermal efficiency of 80% (LHV) shall be met on a 12-month rolling average basis.

Freeport LNG will demonstrate compliance with the CO_2 cap for the heaters based on metered fuel consumption and using the Tier III methodology and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1.and/or 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, Freeport LNG 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). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations will be maintained to demonstrate compliance with the emission limits.

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

XII. Amine Units/Regenerative Thermal Oxidizers (EPNs: TO1, TO2, and TO3) - Pretreatment Facility

Amine units at the Pretreatment Facility will be used to remove CO_2 and other compounds in the feed in order to meet downstream liquefaction system requirements. Stripped emissions (waste gases) from the amine units will be routed to three regenerative thermal oxidizers (RTO). GHG emissions from the RTOs result from the combustion of natural gas, BOG, or a natural gas/BOG blend in the RTO combustion burner as well as from the process waste gas removed from the amine units. The RTO will be designed for a VOC destruction and removal efficiency of 99% or an outlet concentration of 10 ppmv VOC as propane corrected to 3% O_2, whichever limit is most stringent. The BACT analysis includes emissions from the combustion in these sources.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* **–** CCS is an available add-on control technology that is applicable for all of the sites' affected combustion units.
- *Fuel Selection* **–** Natural gas, BOG or a natural gas/BOG blend will be the only fuels fired in the proposed RTOs. These are the lowest carbon fuels available for use at the complex.
- *Proper Thermal Oxidizer Design and Operation* - Use of good thermal oxidizer design can be employed to destroy VOCs and CH_4 entrained in the waste gas removed from the amine units.
- *Good Combustion Practices, Operating 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

All options identified in Step 1 are considered technically feasible.

Carbon Capture and Storage

This add-on control technology was already eliminated as BACT as discussed in detail in section X. Freeport LNG provided a separate cost analysis for CCS for these emission units. Step 4 of the BACT analysis in section X contains the information provided.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CCS (up to 90% control)
- Proper Thermal Oxidizer Design (1-15%)
- Good Combustion, Operating, and Maintenance Practices (1-10%)
- Fuel Selection

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. Good thermal oxidizer design and operation results in approximately 1-15% and 1-10% reduction in GHG emissions, respectively.[8] Low carbon fuel selection and the implementation of good combustion, operating, and maintenance practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

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

Carbon Capture and Storage

Freeport LNG developed a cost analysis for CCS that provided the basis for eliminating the technology in Section X, Step 4 of the BACT process as a viable control option based on economic costs and environmental impacts. Freeport LNG identified two options; capture and geological sequestration of CO_2 (without any post-processing) and capture and transfer of CO_2 (with post processing) for enhanced oil recovery (EOR).

Freeport LNG provided a cost analysis for capture and geological sequestration of CO_2 from the amine treatment units (without any post-processing). The estimated cost of an injection well is estimated to be approximately $4 million. The cost of electric driven compression facilities to force the CO_2 into the aquifer is estimated to be approximately $39 million. The total capital cost of geological sequestration (without pretreatment) is projected to be approximately $46 million. The annual operating and maintenance costs were estimated to be approximately $9 million.

[8] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry,* U.S. EPA, October 2012, Section 3. Available at http://www.epa.gov/nsr/ghgdocs/refineries.pdf

Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, is estimated to be nearly $13 million.

Freeport LNG also provided a cost analysis for the capture and transfer of the CO_2 from the amine treatment units, with post-processing. The cost for treatment, compressions, and delivery for EOR is estimated to be approximately $115 million. The annual operating and maintenance expenses are estimated to be approximately $9.6 million. Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, is estimated to be nearly $20 million.

EPA Region 6 reviewed Freeport LNG's CCS cost estimates and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project. The additional cost of CCS would be at least 50% of the cost of the pretreatment facility, and thus CCS has been eliminated as BACT for this project.

<u>Proper Thermal Oxidizer Design</u>

Good thermal oxidizer design can be employed to destroy VOCs and CH_4 entrained in the waste gas removed from the amine units. Good thermal oxidizer design includes flow measurement and monitoring of waste gas heating values.

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

Good combustion practices include proper maintenance and tune-up of the thermal oxidizers at least annually per the manufacturer's specifications

<u>Fuel Selection</u>

The fuel fired in the RTO combustion burners will be limited to natural gas, BOG, or a natural gas/BOG blend. BOG and natural gas have the lowest carbon intensity of any available fuel for the thermal oxidizers.

Step 5 – Selection of BACT

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

- *Proper Thermal Oxidizer Design*
- *Good Combustion Practices, Operating and Maintenance Practices*
- *Fuel Selection - BOG and natural gas*

Freeport LNG will operate and maintain the RTOs in accordance with vendor recommended operating procedures and operating and maintenance manuals and will maintain these recommended operating and maintenance manuals on-site along with a schedule of maintenance activities. To maintain optimal performance, Freeport LNG will also:

- Calibrate and perform preventative maintenance checks of the fuel gas flow meters on an annual basis;
- Perform preventative maintenance checks of oxygen control analyzers on an annual basis; and
- Perform tune-ups of the oxidizers at a minimum of annually or per the manufacturer's specifications.

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

- Good air/fuel mixing in the combustion zone;
- Allowing sufficient residence time to achieve a VOC conversion efficiency of 99% or an outlet concentration of 10 ppmv VOC as propane corrected to 3% O_2, whichever limit is most stringent;
- Maintenance of proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- Monitoring and maintenance of proper operating temperature in the primary combustion zone. The unit combustion chamber temperature set point will be at or above 1,525 ^{o}F when receiving waste gas from the amine units; and
- Maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

BACT for the regenerative thermal oxidizers will be good combustion and operating practices. Using the above practices will result in an emission limit of 301,339 tpy CO_2e for each thermal oxidizer. The annual emission limit includes MSS 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)].

XIII. Flares (EPN: PTFFLARE (Pretreatment Facility) and EPN: LIQFLARE (Liquefaction Plant))

The flares at the Liquefaction and Pretreatment plants will be used to control releases to the atmosphere during emergency events or planned maintenance, startup, and shutdown (MSS) activities. These streams contain VOCs that when combusted by the flare produce CO_2

emissions. The Pretreatment plant will utilize an emergency ground flare system to serve the three gas processing trains. The proposed ground flare will consist of a warm flare system (68Z-70) and a cold flare system (68Z-71). Both the warm and cold flare systems will use multipoint ground flares that will be located in a common enclosed radiation fence. The ground flare will have a destruction and removal efficiency (DRE) of 99% for methane. The flare at the Liquefaction plant is a non-assisted emergency ground flare with a DRE of 99% for methane. The Liquefaction Plant flare pilots will be fueled by pretreated natural gas. The Pretreatment Facility Flare will be fueled by natural gas, BOG or a natural gas/BOG blend.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Sequestration*– CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Flare Gas Recovery* – A flare gas recovery compressor system can be used to recover flared gas to the fuel gas system.
- *Good Flare Design* – Proper flare design can assure high reliability and destruction efficiencies.
- *Flaring Minimization* – Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practices.

Step 2 – Elimination of Technically Infeasible Alternatives

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

With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not a viable control option. Also, CCS is not technically feasible for intermittent sources such as the flares.

The proposed flares are not process flares, but are intermittent use emergency flares that will also be used to control emissions from MSS events. Therefore, no continuous stream (other than pilot gas) is being combusted, and flare gas recovery is infeasible to implement.

For a process flare used for the control of continuous vent gas streams, flaring may be reduced by the installation of a commercially available flare gas recovery system comprised of, for example; vapor recovery compressors, flow controls, piping systems, and collection and storage systems. The recovered gas may then be utilized by introducing it into the fuel system or recycling back into the process, as appropriate.

In the gas processing industry, flare gas recovery is considered most feasible in situations where:

- the gas that is vented or flared does so on a continuous basis;
- the volumetric rate of the gas that is vented or flared is generally small, or alternatively, a small percentage of the overall throughput of the facility in question; and
- the potential for air ingress into the recovered gas is not a significant process or safety concern.

For the Liquefaction Project, flaring will be limited to upsets or emergency situations and during startup and shutdown events that are anticipated to be of short duration. In addition, the emergency ground flare systems proposed by Freeport LNG are designed for significant instantaneous release rates with varying induced back-pressure in the flare collection system. The rates of flared gas, although of short duration, could potentially reach millions of pounds per hour, which is a significant percentage of the facility gas-processing throughput. Any recovered gas of this magnitude would be much greater than the total facility fuel demand. Additionally, potential oxygen contamination of the gas from air ingress would be extremely undesirable as recycling gas could potentially have severe consequences in the amine treating systems (corrosion), molecular sieve dehydration systems (inability to obtain water dew-point specifications), and even the LNG product (off-spec due to high levels of oxygen).

Due to infrequent MSS activities and the reasons stated above, the use of a flare gas recovery system is technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization and good flare design are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking.

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

<u>Good Flare Design</u>

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 of waste gas heating values.

Flare Minimization

Minimize the duration and quantity of MSS flaring to the extent possible through good engineering design of the process and good operating practices will minimize GHG emissions from flare venting. Flaring will be limited to emergency situations and during maintenance, startup, and shutdown events of limited duration and vent rates.

Step 5 – Selection of BACT

Freeport LNG proposes to use both identified control options to minimize GHG emissions from flaring of process vents from the proposed facilities. The following specific BACT practices are proposed for the flares:

- *Flaring Minimization* – The proposed process facilities will be designed to minimize the volume of the vent stream generated during MSS activities.
- *Good Flare Design* – Flow rate and gas composition analyzers shall be used to continuously monitor the combined waste gas stream sent to the flare from the proposed facilities to determine the quantity of natural gas required to maintain a minimum heating value of 300 Btu/scf.

BACT for the Pretreatment Facility Flare (PTFFLARE) will be to limit vent gas releases to the flare to no more than 3 MMscf/yr during planned startup and shutdown events on a 12-month rolling total.

BACT for the Liquefaction Flare (LIQFLARE) will be to limit vent gas releases to the flare to no more than 167 MMscf/yr during planned startup and shutdown events on a 12-month rolling total.

Compliance with these throughput limits will be demonstrated by monitoring flare vent gas flow rate and performing calculations consistent with 40 CFR Part 98 Subpart W § 98.233. These calculations will be performed on a monthly basis to ensure that the 12-month rolling vent rate to the flares and the CO_2e emission limits are not exceeded.

XIV. Emergency Generators (EPNs: PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, and PTFEG-5 (Pretreatment Facility) and EPNs: LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4, LIQEG-5, and LIQEG-6 (Liquefaction Plant)), Emergency Air Compressor Engines (EPN: PTFEAC-1 (Pretreatment) and LIQEAC-1 (Liquefaction)), and Firewater Pumps (EPN: PTFFWP (Pretreatment Facility) and EPNs: LIQFWP-1 and LIQFWP-2 (Liquefaction Plant))

The proposed Liquefaction Project will use a total of ten 755-hp emergency generators (five units at the Pretreatment Facility and five units at the Liquefaction Plant) and one 400-hp emergency generator (located at the Liquefaction Plant) 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 for emergency purposes only except for weekly readiness and maintenance testing. The Pretreatment Facility and Liquefaction Plant will each have one diesel fuel-fired emergency air compressor engine rated at 300-hp. In addition, three 660-hp diesel fuel-fired firewater pumps will be used for the proposed project, one at the Pretreatment Facility and two at the Liquefaction Plant, for the facilities firewater systems. Each emergency generator engines and emergency compressor engine will be limited to no more than 50 hours of operation per year for the purpose of maintenance, testing, and inspection. The firewater pump engines will be limited to no more than 100 hours per year for routine testing, maintenance, and inspection purposes only.

Step 1 – Identification of Potential Control Technologies for GHGs

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

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except CCS and fuel selection. CCS is not considered technically feasible for intermittent sources such as the emergency and firewater pump engines. In addition, CCS will not be considered further based on the evaluation in Section X.

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.

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

Freeport LNG will install new emergency generators, emergency compressors, and firewater pumps. It is anticipated that this equipment will be designed to optimal combustion efficiency.

Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the emergency generators and firewater pumps at least annually or per the manufacturer's specifications.

Step 5 – Selection of BACT

Freeport LNG 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* - Freeport LNG will purchase emergency generators and firewater pump internal combustion engines (ICEs) certified by the manufacturer to meet applicable emission standards at the time of installation and the applicable requirements of 40 CFR Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." Freeport LNG will also monitor hours of operation for each engine on a monthly basis.
- *Good Combustion, Operating, and Maintenance Practices* - Freeport LNG will implement good combustion, operating, and maintenance practices for the emergency generators and firewater pumps.

BACT for the emergency generator engines and emergency compressor engines will be to limit operation to no more than 50 hours of operation per year for the purpose of maintenance, testing, and inspection. The firewater pump engines will be limited to no more than 100 hours per year for routine testing, maintenance, and inspection purposes only. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

XV. Process Fugitives (EPN: FUG-TREAT (Pretreatment Facility) and EPN: FUG-LIQ (Liquefaction Plant))

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 1,306 tpy as CO_2e. Fugitive emissions of methane 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

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

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 place in industry and are considered technically feasible.

High quality components - A key element in the 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

Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless technology components in place. In addition, the sealing mechanism, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. This is the most effective of the controls.

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.[9]

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

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, it is reasonable to state that these technologies are impracticable for control of GHG emissions. Any further consideration of available leakless technologies for GHG controls is unwarranted.

Instrumented monitoring implemented through the 28MID[10] LDAR program, with control effectiveness of 97%, is considered top BACT. In addition, Freeport will utilize an AVO program to monitor for leaks in-between instrumented checks.

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[9] 73 FR 78199-78219, December 22, 2008.
[10] The boilerplate special conditions for the TCEQ 28MID LDAR program can be found at http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28mid.pdf

Step 5 – Selection of BACT

Freeport LNG will implement the TCEQ 28MID LDAR program, supplemented with an AVO program. Freeport LNG will utilize high quality components and materials of construction, including gasketing, which are compatible with the service in which they are employed.

XVI. Circuit Breakers SF_6 Emissions (FUG-PTSF6 (Pretreatment Facility) and FUG-LIQSF6 (Liquefaction Plant))

Sulfur hexafluoride (SF_6) gas is used in the circuit breakers associated with electricity generation equipment. Potential sources of SF_6 emissions include equipment leaks from SF_6 containing equipment, release from gas cylinders used for equipment maintenance and repair operations, and SF_6 handling operations. The Pretreatment Facility will have 6 circuit breakers each containing 163 lbs of SF_6, and the Liquefaction Plant will have 13 circuit breakers each with 163 lb SF_6, and 27 circuit breakers each with 132 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

- Use of new and state-of-the-art circuit breakers that are gas-tight and require less amount of SF_6;
- Evaluating alternate substances to SF_6 (e.g., oil or air blast circuit breakers);
- Implementing an LDAR program 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.

Step 2 – Elimination of Technically Infeasible Alternatives

Of the control technologies identified, only substitution of SF_6 with other non-GHG substances is determined as technically infeasible. All other control technologies are technically feasible. Freeport LNG proposed to implement these methods to reduce and control SF_6 emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since Freeport LNG proposed to implement the feasible control options identified, ranking these control options 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

No adverse energy, environmental, or economic impacts are associated with the technically feasible control options.

Step 5 – Selection of BACT

Freeport LNG proposes 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;
- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible. The LDAR program proposed by Freeport LNG would be based on detection of fugitive leaks using an infrared camera and thus, quantification of SF_6 concentrations at a leaking component is not 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.

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

Before EPA may issue Freeport LNG'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 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.

Freeport LNG 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. 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. 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.

XVIII. 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.

XIX. Conclusion and Proposed Action

Based on the information supplied by Freeport LNG, 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 Freeport LNG 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 average, 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]		
CT	CT	Combustion Turbine/Waste Heat Recovery (Pretreatment Facility)	CO_2	561,118	561,669	738 lb CO_2/MWh (based on gross CT energy output and equivalent energy produced) on a 365-day rolling average. See Special Condition III.C.1.
			CH_4	10.6		
			N_2O	1.06		
65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	Heating Medium Heaters[4] (Pretreatment Facility)	CO_2	79,968	80,046	117 lb CO_2e/MMBtu (HHV) for each heater Minimum Thermal Efficiency of 80% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	1.5		
			N_2O	0.15		
AU1/TO1	TO1	Amine Unit / Regenerative Thermal Oxidizer 1 (Pretreatment Facility)	CO_2	301,338	301,339	Good Combustion and Operating Practices. See Special Condition III.F.
			CH_4	0.05		
			N_2O	No Emission Limit Established[5]		
AU2/TO2	TO2	Amine Unit / Regenerative Thermal Oxidizer 2 (Pretreatment Facility)	CO_2	301,338	301,339	Good Combustion and Operating Practices. See Special Condition III.F.
			CH_4	0.05		
			N_2O	No Emission Limit Established[5]		
AU3/TO3	TO3	Amine Unit / Regenerative Thermal Oxidizer 3 (Pretreatment Facility)	CO_2	301,338	301,339	Good Combustion and Operating Practices. See Special Condition III.F.
			CH_4	0.05		
			N_2O	No Emission Limit Established[5]		
PTFFLARE	PTFFLARE	Emergency Ground Flare (Pretreatment Facility)	CO_2	2,208	2,212	Vent gas releases to flare limited to no more than 3 MMscf/yr on a 12-month rolling total. See Special Condition III.G.3.
			CH_4	0.06		
			N_2O	0.01		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
PTFFWP	PTFFWP	Fire Water Pump (Pretreatment Facility)	CO_2	38	38	Limit operation to no more than 100 hours on a 12-month rolling total. See Special Condition III.H.2.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-1	PTFEG-1	Emergency Generator 1 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-2	PTFEG-2	Emergency Generator 2 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-3	PTFEG-3	Emergency Generator 2 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-4	PTFEG-4	Emergency Generator 2 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-5	PTFEG-5	Emergency Generator 5 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			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]		
PTFEAC-1	PTFEAC-1	Emergency Air Compressor Engine (Pretreatment Facility)	CO_2	9	9	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQFWP-1	LIQFWP-1	Fire Water Pump (Liquefaction Plant)	CO_2	38	38	Limit operation to no more than 100 hours on a 12-month rolling total. See Special Condition III.H.2.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQFWP-2	LIQFWP-2	Fire Water Pump (Liquefaction Plant)	CO_2	38	38	Limit operation to no more than 100 hours on a 12-month rolling total. See Special Condition III.H.2.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-1	LIQEG-1	Emergency Generator 1 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-2	LIQEG-2	Emergency Generator 2 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-3	LIQEG-3	Emergency Generator 3 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			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]		
LIQEG-4	LIQEG-4	Emergency Generator 4 - Liquefaction (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-5	LIQEG-5	Emergency Generator 5 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-6	LIQEG-6	Emergency Generator 6 - Liquefaction (Liquefaction Plant)	CO_2	11	11	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEAC-1	LIQEAC-1	Emergency Air Compressor Engine (Liquefaction Facility)	CO_2	9	9	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQFLARE	LIQFLARE	Emergency Ground Flare (Liquefaction Plant)	CO_2	11,512	11,523	Vent gas releases to flare limited to no more than 167 MMscf/yr on a 12-month rolling total. See Special Condition III.G.4.
			CH_4	0.22		
			N_2O	0.02		
FUG-PTFSF6 FUG-LIQSF6	FUG-PTFSF6 FUG-LIQSF6	Circuit Breakers (Liquefaction Plant)	SF_6	No Emission Limit Established[6]	No Emission Limit Established[6]	Implementation of LDAR program using infrared camera. See Special Condition III.I.5.
FUG-TREAT and FUG-LIQ	FUG-TREAT and FUG-LIQ	Fugitive Process Emissions (Pretreatment and Liquefaction)	CH_4	No Emission Limit Established[7]	No Emission Limit Established[7]	Implementation of LDAR and AVO monitoring program. See Special Condition III.I.1. and 2.
Totals[8]			**CO_2**	**1,559,209**	**CO_2e 1,561,445**	
			CH_4	**74.5**		
			N_2O	**1.2**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month, rolling total.
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 = 21, N_2O = 310, SF6=23,900
4. The 5 heaters have an emissions cap.
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. SF_6 fugitive emissions from EPN FUG-PTFSF6 are estimated to be 0.002 TPY of SF_6 and 47.8 TPY of CO_2e. SF_6 fugitive emissions from EPN FUG-LIQSF6 are estimated to be 0.01 TPY of SF_6 and 239 TPY of CO_2e. The emission limit for EPNs FUG-PTSF6 and FUG-LIQSF6 will be a design/work practice standard as specified in the permit.
7. Fugitive process emissions from EPNs FUG-TREAT and FUG-LIQ are estimated to be 62 TPY of $CH_{4,}$ and 1,306 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. Total emissions are for information only and do not constitute an emission limit.

Table 2

Calculation of Output-Based BACT CO_2 limit Pretreatment Facility -Combustion Turbine Freeport LNG Development, L.P.

Manufacturer	General Electric	
Combustion Turbine	Frame 7EA	
CT Cycle Operating Mode	CHP	
CT Inlet Dry Bulb, F	60	
Gross CT Power Out. kW	87,470	
CT Fuel Input MMBtulhr LHV	906.2	Note: CT Performance from Manufacturer's Data
Process Thermal Energy Required, MMBtu/hr	406	
Process Thermal Energy from CT Exhaust, MMBtu/hr	406	
Process Thermal Energy from CT Exhaust. kW	118,873	
Fired Heater Fuel Input. MMBtu/hr LHV		
CT Plant Auxiliary Loads, kW (estimated)	(3.061)	-3.5 % percent of gross output
Net CT Plant Electrical Output, kW	84.409	
Total Useful Energy Produced. MMBtu/hr	694	Note Includes net electrical and process thermal output
CT Plant Thermal Efficiency	76.6%	
Gross CT Energy Output kW equivalent net electric and useful thermal converted to Kw	203.281	
Gross CT Energy Heat Rate. Btu/kWh	4,458	CT Fuel Input / Gross CT Energy Output
Design Margin	0.05	Allowance for equipment underperformance and measurement uncertainty
Performance Margin	0.06	Allowance for loss of plant efficiency due to normal and expected gas turbine performance degradation between overhauls.
Degradation Margin	0.05	Allowance for degradation of other elements of the Pretreatment Facility that could cause overall combustion turbine heat rate to rise
Adjusted Gross CT Energy HeatRate with Compliance Margin. Btu/kWh	5,210	Gross CT Energy Heat Rate • (1 + 0.05) • (1 + 0 06) • (1 + 0.05)
CO_2 tons/hr	64.17	Estimated based on Mandatory Greenhouse Gas Reporting Rule. 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas
CO_2 lb/hr	128,340	
CO_2 lb/MMBtu	141.62	CO_2 lb/hr / CT Fuel Input (LHV)
Proposed Output-based CO_2 Limit. lb CO_2/MWhr equivalent useful energy produced	738	Based on Gross CT Energy Output, MW