ATKINS

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December 16, 2011

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. Environmental Protection Agency
Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Re: Application for Prevention of Significant Deterioration (PSD) for Greenhouse Gas Emissions
Proposed Liquefaction Project – Liquefaction Plant and Pretreatment Facility
Freeport LNG Development, L.P., Brazoria County, Texas

Dear Mr. Robinson,

On behalf of Freeport LNG Development, L.P., I am here-by submitting the attached application for a PSD permit for GHG emissions to authorize the construction of a proposed Liquefaction Project consisting of 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 six miles inland from the Quintana Island Terminal, both in Brazoria County, Texas.

Air emissions from the Liquefaction Project are subject to the jurisdiction of both the U.S. Environmental Protection Agency (EPA) and the Texas Commission on Environmental Quality (TCEQ). GHG emissions from the Liquefaction Project will trigger the requirements for a GHG PSD permit and are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its Federal Implementation Plan for the regulation of GHGs. All non-GHG emissions that are PSD significant are subject to the jurisdiction of the TCEQ, and the TCEQ will issue the PSD and NSR Permits for the non-GHG emissions including the Nonattainment New Source Review of the project. Accordingly, Freeport LNG is submitting applications to both agencies to obtain the requisite authorizations to construct.

The Pretreatment Facility will be constructed as a support facility to the Liquefaction Plant; the two facilities belong to the same industrial grouping; and the two facilities are under common control. Because of these considerations and the interdependency of the two plants, the EPA has indicated a preference to permit these two sites as a single source for the GHG PSD permit. Accordingly, Freeport LNG is submitting a single permit application to authorize emissions of GHGs from the Liquefaction Project as a whole. A copy of this GHG PSD application will be submitted to the TCEQ.

Freeport LNG is requesting your most expeditious review of this application so as to begin construction on the project in January 2013. As such, Freeport LNG will be contacting your staff soon after submittal of this application to arrange a meeting to review the application contents and discuss any questions your staff may have.

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Thank you for your consideration. Should you have any questions regarding this application, please contact Mr. Mark Mallett, P.E., Freeport LNG Development, L.P. at (713) 333-4271 or me at (512) 342-3395 or by email: Ruben.Velasquez@atkinsglobal.com.

Sincerely,

Ruben I. Velasquez

Ruben I. Velasquez, P.E.
Senior Engineer – Air Quality
Atkins North America, Inc.

STATE OF TEXAS
RUBEN I. VELASQUEZ
69126
REGISTERED
PROFESSIONAL ENGINEER

Ruben I. Velasquez
12-19-2011

ATKINS
TBPE REG. #F-474

Enclosures

cc: Mr. Mike Wilson, Director, Air Permits Division, TCEQ
Mr. Mark Mallett, P.E., Vice-President, Freeport LNG Development, L.P.

GREENHOUSE GAS PSD APPLICATION

FREEPORT LNG DEVELOPMENT, L.P.

GREENHOUSE GAS EMISSIONS

PREPARED BY:

TRINITY CONSULTANTS
7000 North Mo-Pac Expressway
Suite 200
Austin, Texas 78713
(512) 514-6600

December 2011

Project 114404.0017

STATE OF TEXAS
RUBEN I. VELASQUEZ
69126
REGISTERED
PROFESSIONAL ENGINEER

12-19-2011

ATKINS
TBPE REG. #F-474

Trinity Consultants

1. Executive Summary

Freeport LNG Development, L.P. (Freeport LNG) owns and operates a Liquefied Natural Gas (LNG) import terminal located on Quintana Island near Freeport, Texas (referred to as the "Quintana Island Terminal"). The terminal was designed and constructed to receive LNG by tankers from around the world. The imported LNG is intended to be stored at the terminal, vaporized, and discharged to the Texas natural gas pipeline system for delivery to the end-users.

The existing Quintana Island Terminal is permitted for a LNG design storage capacity of 320,000 cubic meters (m^3), equivalent to about 6.9 billion cubic feet of LNG, and a natural gas send-out rate of up to 1.5 billion standard cubic feet per day (BSCFD) of natural gas. The authorized facilities include two LNG ship berths, three LNG storage tanks, associated vaporization facilities, and a 42-inch diameter natural gas send-out pipeline that is 9.6-miles long. These facilities are permitted by the Texas Commission on Environmental Quality (TCEQ) under Air Quality Permit No. 55464.

Air Quality Permit No. 55464 also authorizes Freeport LNG to export foreign-sourced LNG. These exporting activities involve offloading LNG from incoming ships, storing LNG in the terminal's on-shore storage tanks, and returning the LNG to other ships for international delivery when market conditions are favorable.

In addition, Freeport LNG's Permit 55464 authorized the construction and operation of a boil-off gas (BOG) liquefaction system and an LNG truck delivery system in the terminal facilities. The BOG liquefaction system gives Freeport LNG additional operational and commercial flexibility and reliability in handling BOG generated by thermal leakage from the terminal's storage tanks and associated equipment and piping. In the absence of sufficient LNG imports, these systems will provide alternative sources of LNG to maintain safe and continual cryogenic terminal operation.

Freeport LNG is proposing to construct a natural gas Liquefaction Plant adjacent to the terminal facility on Quintana Island. The Liquefaction Plant will consist of three propane pre-cooled mixed refrigerant trains, each capable of producing a nominal 4.4 million tonnes (metric tons) per annum (mtpa) of LNG, which equates to a total liquefaction capacity of approximately 1.98 BSCFD of natural gas. Due to operational constraints, when the Liquefaction Plant is operational, Freeport LNG will not operate the vaporization or BOG facilities authorized under Air Quality Permit No. 55464.

In support of the proposed Liquefaction Plant, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipe-line quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 6 miles inland from the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route.

Collectively, the proposed development of the Liquefaction Plant and the Pretreatment Facility is hereinafter referred to as the "Liquefaction Project". The term "Liquefaction Project" will be used to describe the project as a whole.

The Liquefaction Project will allow Freeport LNG to convert domestically produced natural gas to LNG for storage and export, and will enable Freeport LNG to respond favorably and proactively to short-term and longer-term fluctuations in domestic and global gas markets. With the recent development of major gas reserves in the shale regions of the United States, natural gas supply is projected to far outstrip domestic demand, and the conversion of excess gas for LNG export provides the opportunity to increase local and regional commerce without compromising the nation's energy resources or stability.

The proposed Liquefaction Project will be a source of Greenhouse Gas (GHG) emissions and is subject to the U.S. Environmental Protection Agency's (EPA) GHG Prevention of Significant Deterioration (PSD) permitting rules, commonly referred to as the "GHG Tailoring Rule," published June 3, 2010. EPA is implementing the GHG Tailoring Rule in two steps. Step 1 commenced January 2, 2011 and ended June 30, 2011. Step 2 commenced July 1, 2011 and ends June 30, 2013. During Step 2, PSD permit requirements cover new projects and modifications to existing facilities solely on the basis of their GHG emissions and even if they do not exceed PSD permitting thresholds for any other pollutant. After July 1, 2011, new sources having the potential to emit more than 100,000 tons/year of GHGs and modifications to existing major sources increasing GHG emissions more than 75,000 tons per year on a carbon dioxide equivalent (CO_2e) basis are subject to GHG review.

GHG emissions for each applicable emission unit in the Liquefaction Project were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel). The combined potential to emit of GHGs from the Liquefaction Plant and the Pretreatment Facility will be greater than 100,000 tpy on a CO_2e basis primarily due to separation of carbon dioxide from the raw natural gas feed stream and the combustion of fuel at the Pretreatment Facility. A summary of the GHG emissions from the proposed Liquefaction Project, calculated on a CO2e basis by use of the Global Warming Potentials set forth in Table A-1 to Subpart A of 40 CFR Part 98, is shown in Table 1-1 below.

Table 1-1. Freeport LNG - Proposed Liquefaction Project GHG Emissions

	Annual Emissions (tpy)				
Source	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CO_2e**
Proposed Emissions for Pretreatment	1,567,308	33.52	1.27	0.002	1,568,464
Proposed Emissions for Liquefaction	11,719	9.86	0.02	0.015	12,273
Total Project Emissions	**1,579,026**	**43.38**	**1.29**	**0.017**	**1,580,737**

The Liquefaction Project consists of two new sources - the Pretreatment Facility and the Liquefaction Plant. The Pretreatment Facility will be located about 6 miles to the north of the Liquefaction Plant. Because of the interdependence of the Liquefaction Plant and the Pretreatment Facility, the two plants will be considered a single project for PSD permitting purposes. Accordingly, a single application for permitting of GHG emissions under the PSD Tailoring Rule is being submitted to the EPA for the proposed Liquefaction Project. Two separate but parallel-in-time applications for TCEQ New Source Review and PSD permits are being filed with the TCEQ to authorize emissions increases of non-GHG emissions from the proposed Liquefaction Plant and Pretreatment Facility.

This document constitutes Freeport LNG's application for a GHG PSD Permit from the EPA to authorize the proposed Liquefaction Project. This application is being submitted to EPA under authority EPA has asserted in Texas through its Federal Implementation Plan (FIP) for the regulation of greenhouse gases.

All required supporting documentation for the permit application is provided in the following sections. The TCEQ Form PI-1 is included in Section 2 of this application. An area map indicating the site location and a plot plan identifying the location of various emission units at the site are included in Sections 3 and 4 of the report, respectively. A project description and process flow diagram are presented in Sections 5 and 6, respectively. Emission calculations can be found in Section 7 of this application.

Detailed federal regulatory requirements including the New Source Review Analysis relating to the Liquefaction Facility are provided in Section 8. Discussions of Best Available Control Technology (BACT) are provided in Sections 9 and 10, respectively.

2. TCEQ FORMS

FORM PI-1

TCEQ

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Freeport LNG Development, L.P.		
Texas Secretary of State Charter/Registration Number (*if applicable*): 0800125153		
B. Company Official Contact Name: Mr. Mark W. Mallett, P.E.		
Title: Vice President - Operations and Engineering		
Mailing Address: 333 Clay Street, Suite 5050		
City: Houston	State: TX	ZIP Code: 77002-4173
Telephone No.: (713) 980-2888	Fax No.: (713) 980-2903	E-mail Address: mmallett@freeportlng.com
C. Technical Contact Name: Mr. Ruben I. Velasquez, P.E.		
Title: Senior Engineer – Air Quality		
Company Name: Atkins North America, Inc.		
Mailing Address: 6504 Bridge Point Parkway, Suite 200		
City: Austin	State: TX	ZIP Code: 78730
Telephone No.: (512) 342-3395	Fax No.: (512) 327-2453	E-mail Address: Ruben.Velasquez@atkinsglobal.com
D. Site Name: Freeport LNG Liquefaction Project		
E. Area Name/Type of Facility: Freeport LNG Liquefaction Project		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Liquefied Natural Gas		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS): 211112		
G. Projected Start of Construction Date: January 2013		
Projected Start of Operation Date: January 2015		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: On CR 792 0.8 miles northeast of the intersection of FM 523 and CR 792 in Brazoria County, TX		
City/Town:	County: Brazoria	ZIP Code: TX
Latitude (nearest second): 29° 00' 36"	Longitude (nearest second): 95° 18' 47"	

TCEQ

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility):	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☒ YES ☐ NO
K. Customer Reference Number (CN): CN601720345	
L. Regulated Entity Number (RN): To be Assigned	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 163 (for entire project)	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Joan Huffman	District No.: 17
Representative: Dennis Bonnen	District No.: 25
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☒ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:____________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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III. Type of Permit Action Requested (continued)		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: None at this time.		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): None – Initial Application		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☒ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐		

III. Type of Permit Action Requested (continued)		
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐	
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐	
IV. Public Notice Applicability		
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers of an affected state?	☐ YES ☒ NO
If *Yes*, list the affected state(s).		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3. NO	
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F.	List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*)*:	
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO_2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NO_x):		
Particulate Matter (PM):		
PM 10 microns or less (PM_{10}):		
PM 2.5 microns or less ($PM_{2.5}$):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above: CO_2e : 1,580,737 tpy		

***Total emissions increases for the Liquefaction Project including Liquefaction Plant and Pretreatment Facilities.**

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V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name: Mr. Michael A. Johns		
Title: Director, Regulatory Affairs		
Mailing Address: 1500 Lamar Street		
City: Quintana	State: TX	ZIP Code: 77541
B. Name of the Public Place: Brazoria County Library		
Physical Address (No P.O. Boxes): 410 Brazosport Boulevard		
City: Freeport	County: Brazoria	ZIP Code: 77541
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Joe King		
Mailing Address: 111 E. Locust St		
City: Angleton	State: Tx	ZIP Code: 77515-4676
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executives of the city and county, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.		
Chief Executive: Mayor Norma Moreno Garcia		
Mailing Address: 200 W. 2nd Street		
City: Freeport	State: Tx	ZIP Code: 77541
Name of the Federal Land Manager: Freeport does not fall within the jurisdiction of a Federal Land Manager		
Title:		
Mailing Address:		
City:	State:	ZIP Code:

V. Public Notice Information (complete if applicable) (continued)	
3. Provide the name, mailing address of the chief executives of the city and county, State, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located. *(continued)*	
Name of the Indian Governing Body: Freeport does not fall within the jurisdiction of any Indian Governing Body	
Title:	
Mailing Address:	
City: / State: / ZIP Code:	
D. Bilingual Notice	
Is a bilingual program **required** by the Texas Education Code in the School District?	☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? Spanish	
VI. Small Business Classification (Required)	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☒ YES ☐ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)	
1. Current Area Map ☒	
2. Plot Plan ☒	
3. Existing Authorizations ☐ Not Applicable	
4. Process Flow Diagram ☒	
5. Process Description ☒	
6. Maximum Emissions Data and Calculations ☒	
7. Air Permit Application Tables ☒	
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☒	
b. Table 2 (Form 10155) entitled, Material Balance ☒	
c. Other equipment, process or control device tables ☒	

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24	Day(s): 7	Week(s): 52	Year(s):
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory? Not Applicable			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
Turbine startup and shutdown activities are being permitted. The turbine will be new so there are no emissions reported to the emissions inventory.			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO

VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D.	Do nonattainment permitting requirements apply to this application?	☒ YES ☐ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
	Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
	If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI.	**Permit Fee Information**	
	Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $ 75,000 **
	Company name on check: Freeport LNG Expansion, L.P.	Paid online?: ☐ YES ☒ NO
	Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
	Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

****One fee is being submitted which covers both the Liquefaction Plant application and the Pretreatment Facility application (per 30 TAC § 116.143).**

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Mr. Mark W. Mallett, P.E.
Signature: MWMallett *Original Signature Required*
Date: 12/19/2011

3. AREA MAP

The proposed Liquefaction Plant will be located to the southwest and adjacent to the existing Quintana Island Terminal. The proposed Pretreatment Facility will be located approximately 6 miles inland to the north of the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route. The location and configuration of the proposed Liquefaction Plant at the Terminal are illustrated in Figure 3-1. As indicated in Figure 3-1, the Liquefaction Plant will be located in the southwest sector of the existing Terminal site and on adjacent industrial property that was formerly a dredged material placement area (DMPA) owned and operated by Port Freeport. The location of the proposed Pretreatment facility is illustrated in Figure 3-2.

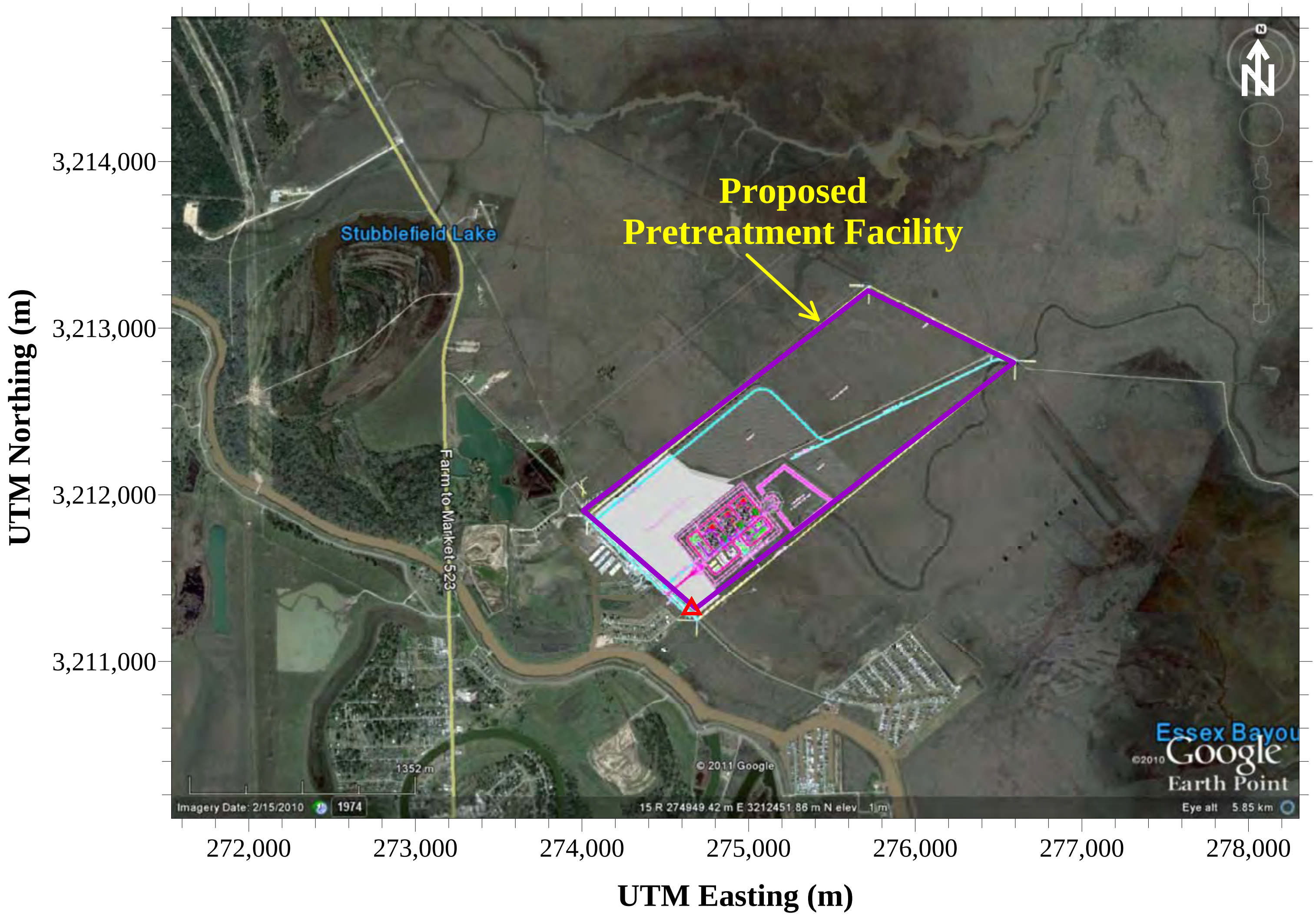
Figure 3-1: Area Map of Proposed Liquefaction Facility

△ Benchmark coordinates: N - 13,537,500, E - 3,144,500 in Texas South Central, NAD83 U.S. Survey Feet.

UTM coordinates in Zone 15, NAD83 datum.

Source: 15R 273,961.45m E 3,203,359.83m N. Google Earth. February 15, 2010. November 14, 2011.

Figure 3-2: Area Map of Proposed Pretreatment Facility



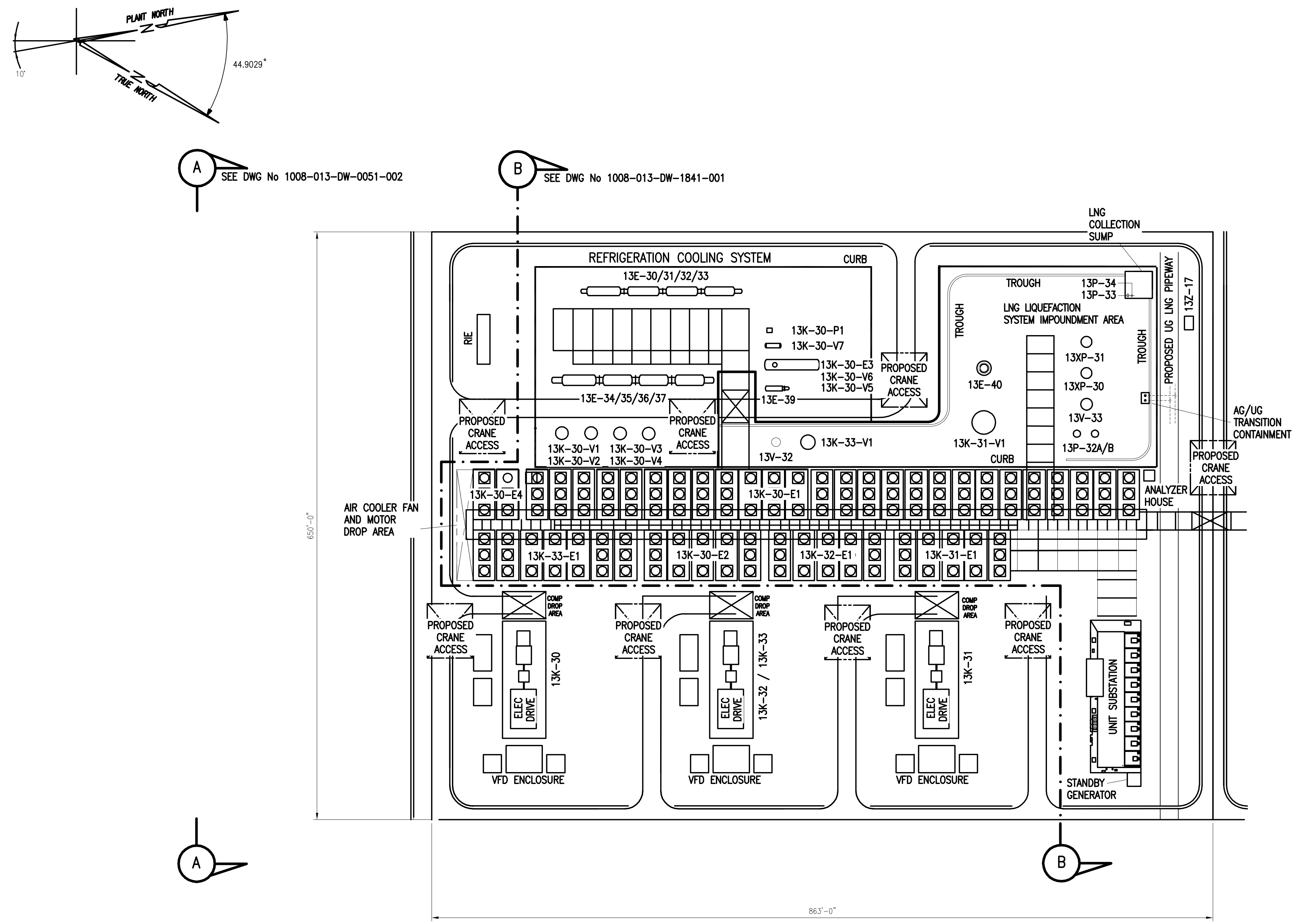
△ Benchmark coordinates: N - 13569747.74, E - 3146627.63 in Texas South Central, NAD83 U.S. Survey Feet.

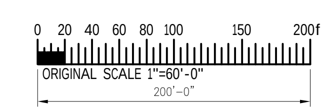
UTM coordinates in Zone 15, NAD83 datum.

Source: 15R 274949.42m E 3212451.86m N. Google Earth. February 15, 2010. October 26, 2011.

4. PLOT PLAN

The following figures depict the site plans for the proposed Liquefaction Project facilities at the Liquefaction Plant and Pretreatment Facility.





TAG	SERVICE		PARENT TAG NUMBER
13E-30	Feed / HHP Propane Vaporizer		
13E-31	Feed / HP Propane Vaporizer		
13E-32	Feed / MP Propane Vaporizer		
13E-33	Feed / LP Propane Vaporizer		
13E-40	Main Cryogenic Heat Exchanger		
13E-34	HP MR / HHP Propane Vaporizer		
13E-35	HP MR / HP Propane Vaporizer		
13E-36	HP MR / MP Propane Vaporizer		
13E-37	HP MR / LP Propane Vaporizer		
13E-39	Defrost Gas Heater		
13K-30	Propane Compressor		
	Propane Desuperheater/Condenser	13K-30-E1	13K-30
	Propane Subcooler	13K-30-E2	13K-30
	Propane Reclaimer Condenser	13K-30-E3	13K-30
	Propane Compressor Recycle Cooler	13K-30-E4	13K-30
	Propane Transfer Pump	13K-30-P1	13K-30
	LP Propane Suction Drum	13K-30-V1	13K-30
	MP Propane Suction Drum	13K-30-V2	13K-30
	HP Propane Suction Drum	13K-30-V3	13K-30
	HHP Propane Suction Drum	13K-30-V4	13K-30
	Propane Accumulator	13K-30-V5	13K-30
	Propane Reclaimer	13K-30-V6	13K-30
	Propane Transfer Drum	13K-30-V7	13K-30
13KM-30	Propane Compressor Motor Driver		
13K-31	LP MR Compressor		
	LP MR Compressor Aftercooler	13K-31-E1	13K-31
	LP MR Suction Drum	13K-31-V1	13K-31
13KM-31	LP MR Compressor Motor Driver		
13K-32	MP MR Compressor		
	MP MR Compressor Aftercooler	13K-32-E1	13K-32
13KM-32	MP/HP MR Compressor Motor Driver		
13K-33	HP MR Compressor		
	HP MR Compressor Aftercooler	13K-33-E1	13K-33
	HP MR Suction Drum	13K-33-V1	13K-33
13V-32	HP MR Separator		
13XP-30	LNG Liquid Turbine		
13XP-31	MR Liquid Turbine		
13V-33	LNG Transfer Drum		
13P-32A/B	LNG Transfer Pumps		
13P-33	Process Area Storm Water Pump		
13P-34	Process Area Storm Water Submersible Pump		
13Z-17	High Expansion Foam System		

Project	Unit	Doc Type	Eng Code	Seq No	Rev
1008	013	DW	0051	001	A

REV	DATE	BY	DESCRIPTION	CHK'D	TECH.	PROJ.	ENG	OPS	P.M.
A	25OCT11	PP	ISSUED FOR FERC SUBMITTAL	DB	RM				

CONTRACTOR | FREEPORT LNG

FILE NAME:

SCALE: NONE

FREEPORT LNG
QUINTANA, TEXAS

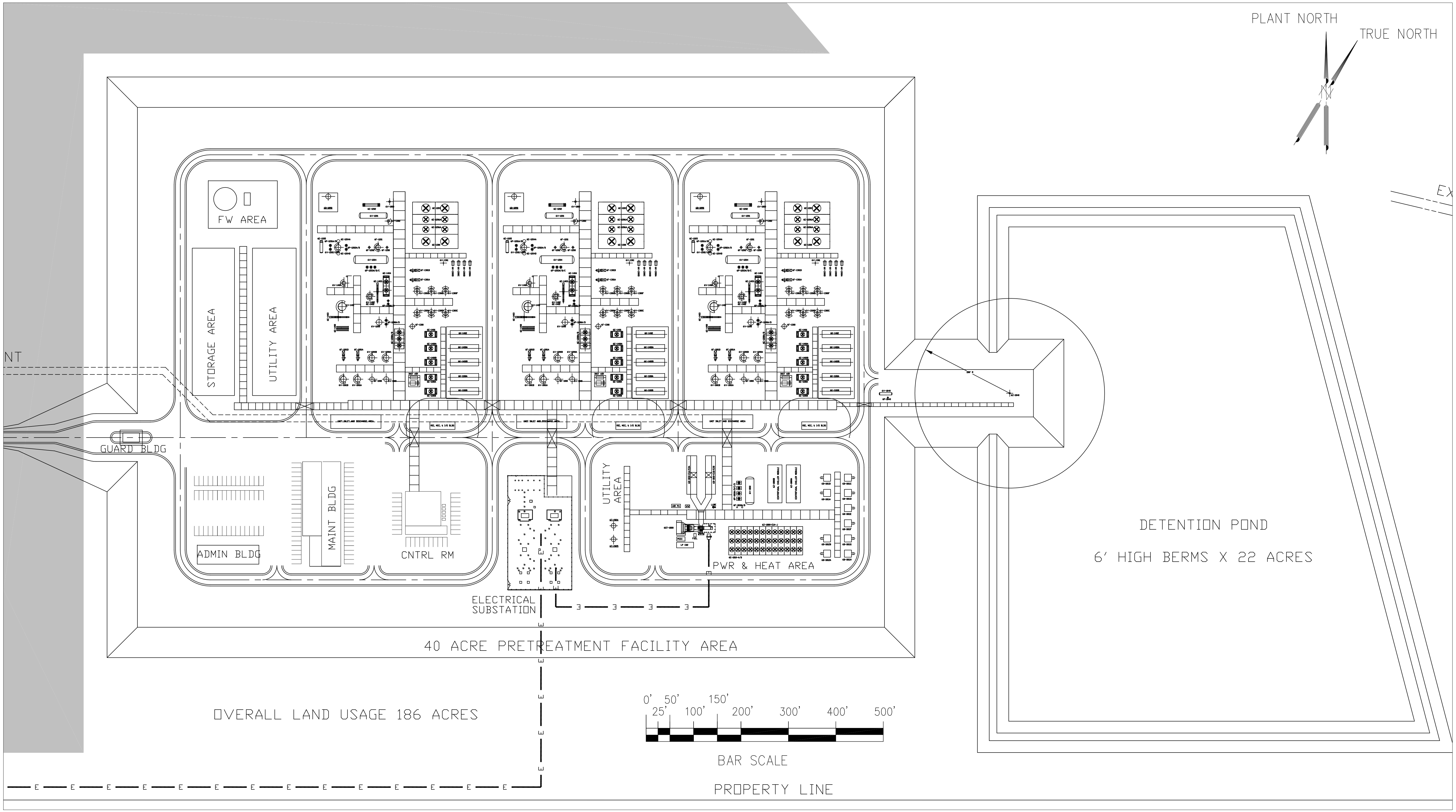
4.4MTPA
LIQUEFACTION UNIT 13
PLOT PLAN

	BY	DATE
DESIGN		
DRAWN		

DRAWING NO.

SHEET:

REV. NO. A



Project	Unit	Doc Type	Eng Code	Seq No	Rev
1009	000	DW	0051	002	A

REV	DATE	BY	DESCRIPTION
A	09/28/11	MJM	ISSUE FOR INFORMATION

CHK'D	TECH.	PROJ.	ENG	OPS	P.M.
CONTRACTOR			FREEPORT LNG		

FILE NAME: 1009-000-DW-0051-001

SCALE: NONE

FREEPORT LNG

FREEPORT LNG

PLOT PLAN

PRETREATMENT FACILITY

	BY	DATE
DESIGN	MJM	08/17/11
DRAWN	MJM	08/17/11

DRAWING NO.

SHEET: 1 OF 1

REV. NO. A

Freeport LNG is proposing to add liquefaction infrastructure to its existing Quintana Island Terminal to provide export capacity of a nominal 13.2 mtpa of LNG, which equates to processing approximately 1.98 BSCFD of pipeline quality natural gas. Pipeline-quality natural gas will be derived from interconnecting intrastate pipeline systems (e.g., Dow Pipeline Company, Kinder Morgan Texas Pipeline, L.P., and Brazoria Interconnector Gas ["BIG"] Pipeline) through Freeport LNG Development's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide (CO_2), sulfur compounds, water, and mercury. The pretreated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG Development's existing 42-inch gas pipeline. At the Liquefaction Plant, the pretreated natural gas will be liquefied and then stored in the LNG storage tanks. LNG will be exported from the Terminal by carriers arriving via marine transit through the Port Freeport channel.

The proposed facilities will be designed such that the addition of liquefaction capability will not preclude the Terminal from operating in vaporization and send-out mode or storage and export mode (authorized under Air Quality Permit 55464) as business conditions dictate. However, due to operational constraints, when the Liquefaction Plant is operational, Freeport LNG will not operate the regasification or BOG liquefaction facilities authorized under Air Quality Permit No. 55464. Also, having dual liquefaction and regasification capabilities will not result in any increase in the number of ship transits, since the total amount of LNG handled, either by liquefying natural gas or by vaporizing LNG, will not exceed the number authorized under previous Federal Energy Regulatory Commission orders approving earlier phases of this project.

5.1 LIQUEFACTION PLANT

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 on adjacent industrial property that was formerly a DMPA owned and operated by Port Freeport. Development of liquefaction infrastructure will necessitate some redesign of and integration with existing and proposed terminal facilities, including utility support systems, pipe connections, and the third LNG storage tank.

In addition to the three liquefaction trains (Trains 1, 2, and 3), peripheral aboveground infrastructure will include the following:

- Refrigerant and utility storage units;
- Pipe racks and pipes;
- Sumps and associated LNG troughs;
- A ground flare;
- A control room;

- A maintenance building;
- Four emergency electrical generators;
- A emergency firewater unit including a firewater pump engine;
- An electrical substation; and
- Plant roads.

Process cooling for the liquefaction trains will be provided by conventional air coolers (fin fans), arranged in longitudinal rows along the pipe-rack in each train. Each train will have independent electric motor-driven refrigeration and other compressors. Make-up refrigerant storage will be common for all three trains.

To convert the pretreated feed gas into LNG, the gas is first cooled with propane refrigerant and enters the Main Cryogenic Heat Exchanger (MCHE). In the MCHE, the gas stream is further cooled inside heat-exchange tubes by a lower temperature mixed refrigerant that flows outside the tubes. As the feed gas flows up the tubes, it starts condensing by transferring heat to the liquid/vapor mixed refrigerant, which warms up and vaporizes as it flows down the exchanger shell. The vaporized mixed refrigerant is then cooled, compressed, and subsequently chilled by propane refrigerant in heat exchangers, where a portion of the refrigerant condenses.

After separating the vapor and liquid streams of mixed refrigerant, both streams are cooled in the MCHE and depressurized into the MCHE shell to provide cooling for the conversion of methane rich gas into LNG. The high pressure LNG exiting the MCHE is depressurized through a liquid expander and delivered to the LNG storage tank at near ambient pressure. Once in the storage tank, the LNG can be pumped through the plant piping to the dock, to be loaded onto ships for export.

5.1.1 LIQUEFACTION FLARE

The Liquefaction Plant flare system will consist of a flare header system and the enclosed ground flare (EPN: LIQFLARE). During normal operation only pilot gas and sweeping (purge) gas (nitrogen or other inert gas) will be sent to the flare. The flare is designed for up to 11 stages; each stage additively firing as the vent gas pressure to the flare increase. Two pilots will be used for each stage for a total of 22 pilots. Each pilot gas rate will be 85,000 Btu/hr for a total of 1.7 MMBtu/hr of natural gas burned on a continuous basis. This system is provided for the safe disposal of hydrocarbon releases from relief valves and other relief on the liquefaction equipment. The flare will also be used to control releases to the atmosphere such as during a planned maintenance, startup and shutdown events.

5.1.2 LIQUEFACTION PLANT PLANNED MAINTENANCE/STARTUP/SHUTDOWN EVENTS

It is anticipated that each train will undergo a planned maintenance, startup and shutdown event on a yearly basis. During these events, certain sections of the train will be blocked off and liquids will be drained and evacuated into the other trains to the extent possible. The remaining vapors in the blocked off section will then be vented to the flare.

For purposes of estimating releases to the flare, it was assumed a startup sequence is based on a normal startup that occurs after a typical shutdown for compressor maintenance. It is not based on the initial startup after the construction phase. Thus, it is assumed that the liquefaction train has been kept under positive pressure with operating fluids in all areas except for those opened for maintenance.

A typical shutdown sequence would apply to a 1 to 2 week duration shutdown where the refrigeration circuits are de-inventoried. Typical activities would include maintenance and repair of compressor and drive systems. This is not a frequent occurrence and typically would occur no more than once a year.

5.1.3 EMERGENCY ENGINES

Four emergency generators powered with diesel-fired engines (EPNs: LIQEG-1, LIQEG-2, LIQEG-3, and LIQEG-4) each rated at 755 horsepower will be installed to serve as a reliable power source for lighting and other emergency equipment in the event of a power failure. Each generator engine will be fired with ultra low sulfur diesel fuel and will be limited to 100 hrs/yr of operation for purposes of maintenance and testing.

A 660-hp, diesel firewater pump (EPN: LIQFWP) will be installed at the facility for the firewater system. The diesel firewater pump engine will also be fired with ultra low sulfur diesel fuel and will be limited to 100 hours per year of operation for purposes of maintenance and testing.

5.1.4 DIESEL FUEL STORAGE TANKS

Ultra low sulfur diesel fuel for the emergency engines will be stored in small, day-tanks integral to the proposed emergency generator and firewater pump engines. These day-tanks (LEGT-1, LEGT-2, LEGT-3, LEGT-4, and LFWT-1) will be fixed roof tanks with a fuel storage capacity of about 300 gallons for each emergency generator engine and 830 gallons for the firewater pump engine, respectively. These tanks will be maintained with fuel in them at all times in case of emergency. The engines will consume diesel fuel during periodic testing or during an emergency situation, and therefore, the associated diesel day tanks will be refilled periodically.

5.2 PRETREATMENT FACILITY

The Pretreatment Facility will be located approximately 6 miles inland to the north of the Quintana Island Terminal near Stratton Ridge. The Pretreatment Facility will be comprised of three natural gas pre-treatment systems; a natural gas liquids (NGL) removal unit; a NGL flare; one atmospheric pressure relief vent stack; a combustion turbine/heat recovery system; two emergency electric generators and one 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);
- 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 low and high temperature heaters in the amine units.

Treated gas from the Pretreatment Facility will be sent via pipeline to the proposed Liquefaction Plant at the Quintana Island Terminal location.

5.2.1 AMINE TREATMENT/GAS PLANT TRAINS

Raw pipeline gas will arrive at Freeport LNG's existing Stratton Ridge meter station. The meter station is approximately 2.8 miles from the location of the proposed Pretreatment Facility. The gas will flow from the metering station, through Freeport LNG's 42-inch pipeline, into the Pretreatment Facility where it will be diverted to each of the three pretreatment trains. Each train will have a rated capacity of 650 MMscfd of incoming natural gas treatment capacity.

In each pretreatment train, the gas will first be separated and metered. Further downstream, mercury will be removed to protect aluminum-based heat exchangers. The gas will then be compressed to meet the downstream NGL recovery plant requirements. Following compression, an amine unit will remove CO_2, sulfur compounds, and light volatile organic compounds in order to satisfy the downstream liquefaction system requirements. Stripped CO_2, sulfur and organic compounds in the stream will be routed to regenerative thermal oxidizers (EPNs: TO1, TO2, and TO3).

After compression and amine treatment, water will be removed from the gas in a molecular sieve dehydration system. The treated gas will then be sent to a NGL recovery system which removes heavy hydrocarbons (i.e. C5+) components from the dry treated gas prior to liquefaction. The NGL system will be a closed-loop system; vapor reliefs of fluids heavier than air will be collected in a flare header and routed to the NGL flare scrubber (knock-out pot). The scrubber will knockout any liquids generated during relief conditions. Vapor from the scrubber will flow to the NGL flare (EPN: NGLFLARE). Any liquids (water or hydrocarbon) collected at the inlet separator, inlet filter coalescer, amine flash drum, LP fuel scrubber, or the NGL flare scrubber will be routed to the slop tanks.

The treatment trains will be supported by eight low temperature (LT) heating medium heaters (EPNs: 6B-1811A, 6B-1811B, 6B-1811C, 6B-1811D, 6B-1811E, 6B-1811F, 6B-1811G, and 6B-1811H) and two high temperature (HT) heating medium heaters (EPNs: 6B-1812A, and 6B-1821B) at the Pretreatment Facility. Each heater has a maximum heat input capacity of 85 MMBtu/hr and may be fired with natural gas and is equipped with an ultra low-NO_X burner with flue gas recirculation for emissions control.

Recovery of energy from the combustion turbine generator exhaust gas will not be sufficient to meet all of the energy supply requirements for all three pretreatment trains. The combustion turbine waste heat recovery unit is designed to meet all of the high temperature requirements, but not all of the low temperature needs. Additional energy is to be provided to the system by the stand-alone (fired) heaters in order to fully meet low temperature heating demands. The LT heating medium heaters are provided to serve this purpose. These heaters will operate in parallel with the waste heat recovery unit. It should be noted that only two of these heaters are required to meet system energy demands when the combustion turbine is operating. The remaining six heaters are provided as backup to the combustion turbine waste heaters should the combustion turbine generator not be in operation. Similarly, stand-alone (fired) HT heating medium heaters are provided as backup to provide the high temperature requirements when the combustion turbine is not in operation.

The Regenerative Thermal Oxidizers (EPNs: TO1, TO2, and TO3) will be equipped with a low-NO_X gas-fired burner that typically will only be used for initial unit start-up (cold-start). Once the burner heats the RTO to operating temperature, the burner will shut off. Due to the abundant oxygen content of the process gas, complete combustion readily occurs when the ignition point is reached in the oxidizer. BOG or natural gas will be fired, as necessary, to supplement the combustion heat requirements of the RTO and maintain the proper combustion temperature.

5.2.2 NGL FLARE

The NGL flare (EPN: NGLFLARE) will service only the NGL removal unit. The flare system will consist of a flare header and an elevated flare to provide for the safe disposal of hydrocarbon releases from relief valves and relief valves/devices on all equipment from the NGL. It was assumed that during normal operations, only the pilot gas would be sent to flare. The pilot gas would be burned through two continuous pilot burners, each rated at 85,000 Btu/hr of fuel gas.

5.2.3 AMINE TREATMENT/GAS PLANT PLANNED MAINTENANCE/STARTUP/SHUTDOWN EVENTS

Before startup of the treatment unit, the thermal oxidizers will be started and brought to operating temperature. Then as the incoming natural gas stream is introduced to each train, the vent gas from the amine unit will flow to the thermal oxidizers for emissions control. Emissions from the shutdown of the amine unit will also be routed to the thermal oxidizers.

The NGL removal unit will be a closed loop system; i.e., no routine vent gas emissions. Should it become necessary to conduct maintenance on the NGL removal unit, the section to be brought down for maintenance will be blocked off and liquids will be drained back into the system to the maximum extent possible. Any residual liquids will be routed through a knock-out pot to the NGL flare for emissions control. Should there be emissions during startup of the NGL removal unit, these emissions will be routed to the NGL flare for emissions control. These planned maintenance, startup, and shutdown events would typically be short term events.

5.2.4 ATMOSPHERIC RELIEF VENT

Pressure relief vents from the amine treatment units will be designed to relieve to an atmospheric vent stack during over pressurization or in an emergency situation. These releases will consist of primarily a natural gas stream or CO_2 stream containing process gas concentrations of sulfur and light volatile organic compounds depending on the location of the pressure relief vents. It is anticipated that these releases to the atmospheric vent will be of limited duration. This atmospheric relief vent stack will be designed and constructed so as assure these potential gas releases will be vented safely to the atmosphere.

5.2.5 COMBUSTION TURBINE

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 CT will have a nominal base-load gross electric power output of approximately 87 megawatts. The waste heat recovery unit will be used to transfer heat to hot oil. The hot oil will be used in the amine sweetening unit and dehydration system units in lieu of burning natural gas fuel in these units.

BOG from the existing Terminal facilities will be piped to the Pretreatment Facility to be used as fuel for the CT. Supplemental pipeline or residue natural gas fuel will be used, as necessary. Ambient air will be drawn through air filtration and cooling intake structures into the inlet compressor section of the turbine, mixed with the BOG, and burned in the combustor.

The CT will normally operate at base load transferring waste heat to hot oil for use in the amine treatment unit. Power generated from the unit will be dispatched for use in the Pretreatment Facility. Excess power will be dispatched for sale to the Electric Reliability Council of Texas power grid.

Freeport LNG will use a dry low-NO_X combustor and Selective Catalytic Reduction (SCR) to reduce NO_X emissions from the combustion turbine system. The SCR will use aqueous ammonia as the reagent, where the catalyst facilitates the reaction of the ammonia with NO_X to create nitrogen and water. Emissions of CO and VOC will be controlled by an Oxidation Catalyst (Ox-Cat).

The exhaust gases from the SCR/catalyst systems will be split and exhausted through two waste heat recovery units, each having its owns flue gas stack, to the atmosphere (EPNs: CT1(A) and CT1(B)). The temperatures and quantity of flue gas will vary with turbine condition, ambient temperature and operational load.

Equipment ancillary to the CT will include the following:

- A turbine lubrication oil recirculation system with vent;
- A lube oil storage tank, a deaerator tank, and a surge tank;
- An SCR system with aqueous ammonia storage and injection system; and
- Natural gas fuel system including piping and metering

5.2.6 TURBINE LUBE OIL RECIRCULATION SYSTEM

The CT will include a closed-loop lubrication oil recirculation system to lubricate moving parts of the turbines. Oil vapor (as VOC) and oil mist (as PM) emissions may be generated by oil vaporization resulting from heating of the lubrication oil in the CT and subsequent condensation of the droplets when the vapor is cooled in the cooler zones of the storage reservoir compartment. Lubrication oil mist emissions from each reservoir compartment will be controlled by a mist eliminator exhausted through a dedicated reservoir vent (EPN LUBVENT).

5.2.7 SCR AND AMMONIA HANDLING SYSTEMS

The SCR system will be comprised of aqueous ammonia storage and handling equipment, an ammonia vaporizer, an ammonia injection grid, and a catalyst bed module. The ammonia injection grid and the catalyst bed will be installed downstream of the CT unit exhaust as an integral part of the waste-heat exchanger. The aqueous ammonia will be injected at a rate slightly above stoichiometric and thus, will be a source of ammonia slip from the CT exhaust stacks (EPNs: CT1(A) and CT1(B)).

The aqueous ammonia (approximately 19% concentration) will be stored in an atmospheric storage tank. Aqueous ammonia will be delivered by tanker truck. Vapor balancing will be used during unloading of the aqueous ammonia from the truck into the tank so as to capture emissions during filling of the storage tank. Piping and fittings associated with the tank and ammonia transfer and injection system will be sources of fugitive emissions (EPN: FUG-CT).

5.2.8 COMBUSTION TURBINE STARTUP/SHUTDOWN

For purposes of estimating emissions during startup and shutdown conditions, it was anticipated that there would be only two startup and shutdown events for tuning and maintenance purposes during a calendar year. Startup and shutdown emissions are included in the combustion emission GHG calculations for the combustion turbine.

5.2.9 EMERGENCY ENGINES

Two emergency generators powered with diesel-fired engines (EPN: PTFEG-1, and PTFEG-2) each rated at 755 horsepower will be installed to serve as a reliable power source for lighting and other emergency equipment in the event of a power failure. Each generator engine will be fired with low sulfur diesel fuel and will be limited to 100 hrs/yr of operation for purposes of maintenance and testing.

A 660-hp, diesel firewater pump (EPN: PTFFWP) will be installed at the facility for the firewater system. The diesel firewater pump engine will also be fired with ultra low sulfur diesel fuel and will be limited to 100 hours per year of operation for purposes of maintenance and testing.

5.2.10 DIESEL FUEL STORAGE TANKS

Ultra low sulfur diesel fuel for emergency engines will be stored in small, day-tanks integral to the proposed emergency generator and firewater pump engines. These day-tanks (PTFEGT-1, PTFEGT-2, and PTFFWT-1) will be fixed roof tanks with a fuel storage capacity of about 300 gallons for each emergency generator engine and 830 gallons for the firewater pump engine, respectively. These tanks will be maintained with fuel in them at all times in case of emergency. The engines will consume diesel fuel during periodic testing or during an emergency situation, and therefore, the associated diesel day tanks will be refilled periodically.

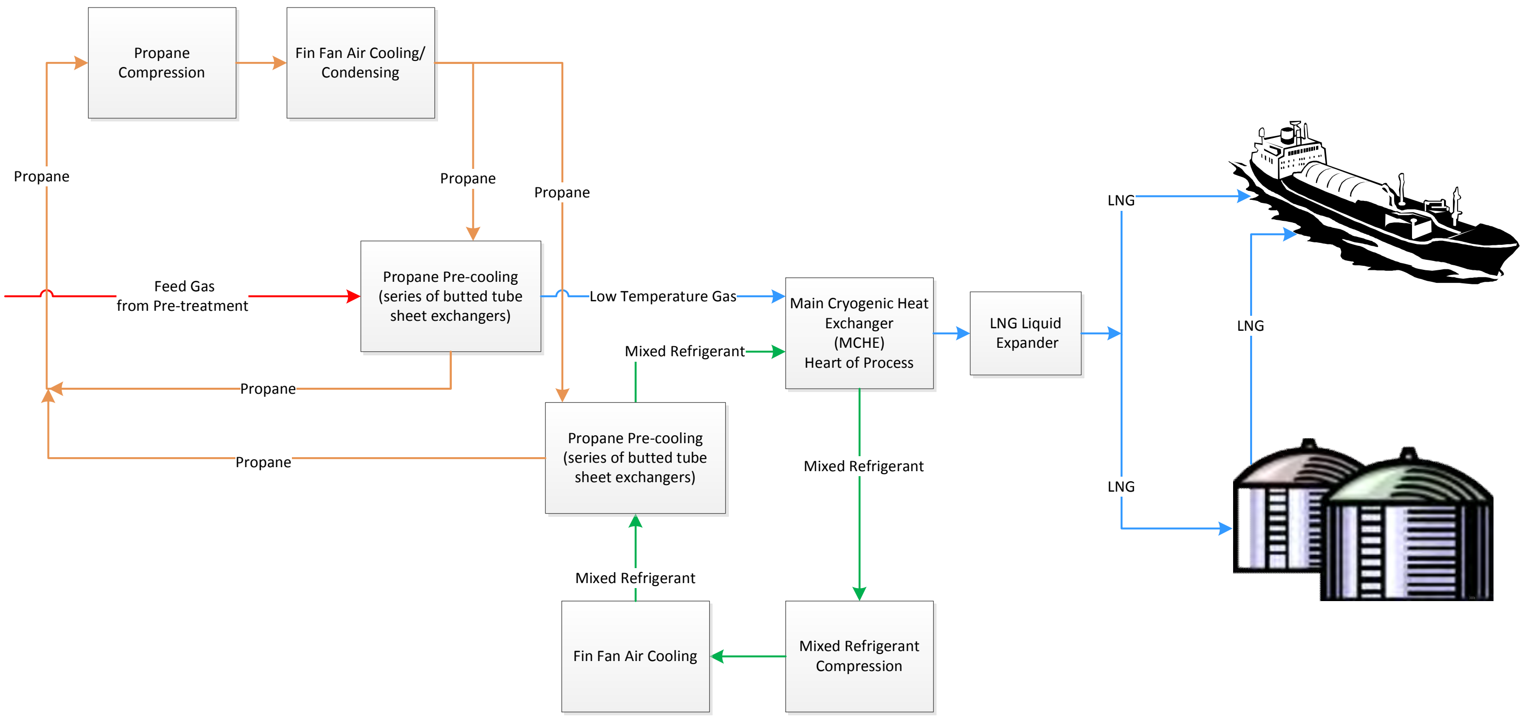
Other storage vessels at the Pretreatment Facility will be used for storage of the following liquids:

- Heat medium (Dowtherm or equivalent)
- Firewater tank
- Water/Glycol Tank
- Diglycol Amine Tanks
- Anti-Foam Injection Tank
- Treatment Water Tanks
- Slop Tank
- Washwater Tank

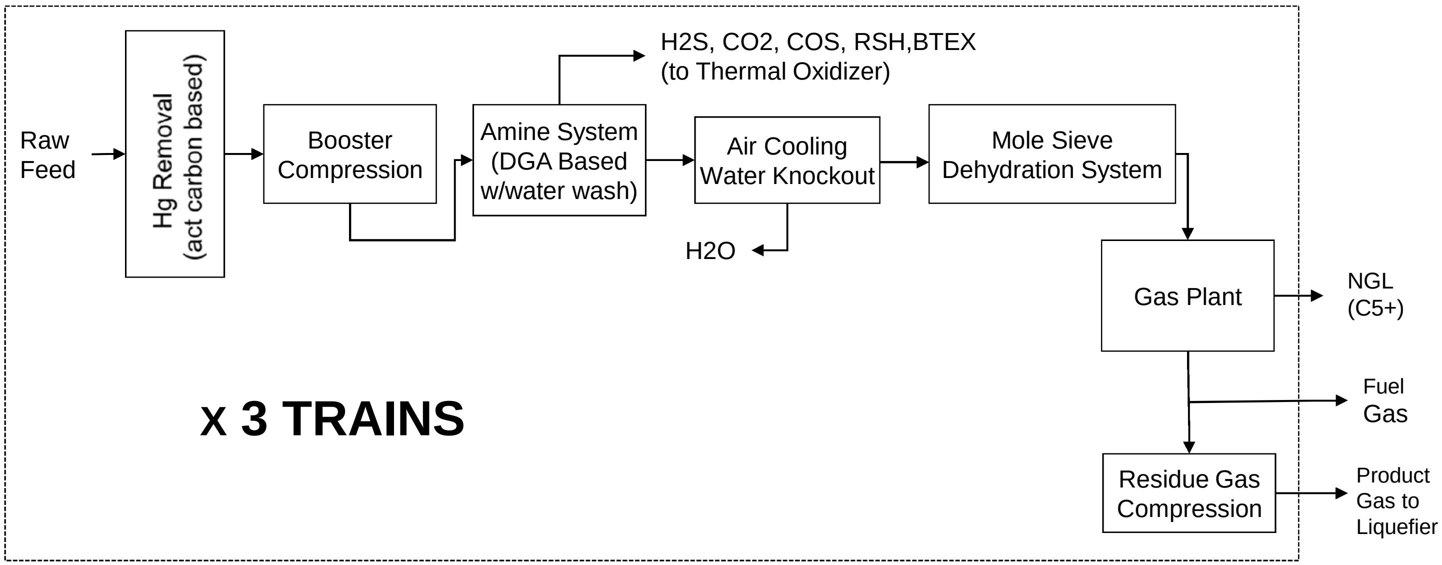
It is anticipated that these tanks contain water; mixtures of oil and water; and organic liquids with low vapor pressure.

6. PROCESS FLOW DIAGRAM

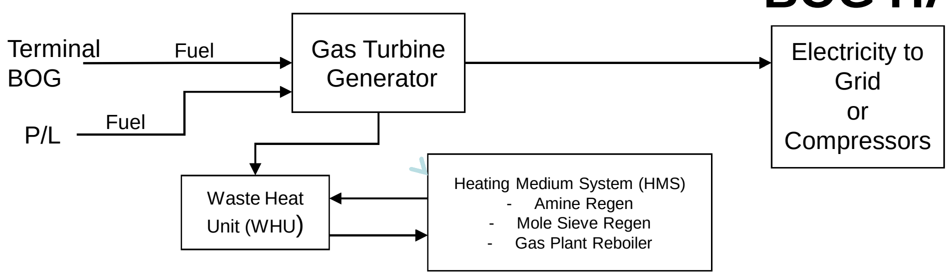
Liquefaction System



Pretreatment System (PTS)



BOG HANDLING



8/9/2011

7. Emission Calculations

This section contains a detailed description of the calculation methodologies used to determine the proposed emission rates for all sources associated with the Liquefaction Project. Detailed emission calculations are included in Appendix A of this submittal.

Potential GHG emissions from the proposed Liquefaction Project will result from the following emission units:

- Pretreatment Facility
  - Ten process heaters (EPNs: 6B-1811A, 6B-1811B, 6B-1811C, 6B-1811D, 6B-1811E, 6B-1811F, 6B-1811G, 6B-1811H, 6B-1812A, and 6B-1821B);
  - Two emergency generators (EPNs: PTFEG-1 and PTFEG-2);
  - One fire water pump (EPN: PTFFWP);
  - Three thermal oxidizers (EPNs: TO1, TO2, TO3);
  - A combustion turbine (EPNs: CT1(A) and CT1(B));
  - NGL flare (EPN: NGLFLARE);
  - Fugitive CH_4 emissions from piping components (EPN: FUG-TREAT); and
  - Fugitive emissions from SF_6 circuit breakers (6) (EPN: FUGPTFSF$_6$).
- Liquefaction Plant
  - Four new emergency generators (EPNs: LIQEG-1, LIQEG-2, LIQEG-3, and LIQEG-4);
  - One firewater pump (EPN: LIQFWP);
  - Liquefaction flare (EPN: LIQFLARE);
  - Fugitive CH_4 emissions from piping components (EPN: FUG-LIQ); and
  - Fugitive emissions from SF_6 circuit breakers (40) (EPN: FUGLIQSF$_6$).

Table 7-1 provides a summary of the potential to emit emissions of GHGs for the proposed Liquefaction Project.

Table 7-1. Freeport LNG - Proposed Liquefaction Project Emissions

Source	Annual Emissions (tpy)				
	CO_2	CH_4	N_2O	SF_6	CO_2e
Proposed Emissions for Pretreatment	1,567,308	33.52	1.27	0.002	1,568,464
Proposed Emissions for Liquefaction	11,719	9.86	0.02	0.015	12,273
Total Project Emissions	**1,579,026**	**43.38**	**1.29**	**0.017**	**1,580,737**

GHG emissions for each emission unit were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel).

According to 40 CFR §52.21(b)(49)(ii), GHG emissions for PSD applicability must show CO_2e emissions calculated by multiplying the mass of each of the six GHGs by the gas's associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Table 7-2. Global Warming Potentials (GWP) for each GHG emitted in the Liquefaction Project.

Table 7-2. Global Warming Potentials

Pollutant[1]	GWP[2]
CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

1. Only those GHGs for which quantifiable emissions are expected due to this project are listed.
2. GWPs are based on a 100-year time horizon, as identified in Table A-1 to 40 CFR Part 98, Subpart A.

Table 7-3 provides a summary of the maximum annual potential to emit from all sources of GHG included in the Liquefaction Project.

Table 7-3: Summary of Maximum Annual Potential to Emit GHG Emission Rates for the Proposed Liquefaction Project

Source	EPN	Description	Annual Emissions (short tons/yr)				
			CO_2	**CH_4**	**N_2O**	**SF_6**	**CO_2e [2]**
Pretreatment Facility	LIQFWP	Fire Water Pump	37.13	0.002	0.003	0.00	37
	PTFEG-1	Emergency Generator 1	42.47	0.002	0.003	0.00	43
	PTFEG-2	Emergency Generator 2	42.47	0.002	0.003	0.00	43
	HRTCAP	LT and HT Heaters	100,388	1.89	0.19	0.00	100,486
	TO1	Amine Unit/Thermal Oxidizer 1	301,338	0.05	0.005	0.00	301,341
	TO2	Amine Unit/Thermal Oxidizer 2	301,338	0.05	0.005	0.00	301,341
	TO3	Amine Unit Thermal Oxidizer 3	301,338	0.05	0.005	0.00	301,341
	NGLFLARE	NGL Flare	642	0.03	0.01	0.00	644
	CT1 (A) & CT1 (B)	Combustion Turbine	562,141	10.60	1.06	0.00	562,693
	FUG-TREAT	Pretreatment Fugitives	0.00	20.85	0.00	0.00	438
	FUG-PTFSF$_6$	Pretreatment Circuit Breakers	0.00	0.00	0.00	0.002	58
Liquefaction Plant	PTFFWP	Fire Water Pump	37.13	0.00	0.00	0.00	37
	LIQEG-1	Emergency Generator 1	42.47	0.00	0.00	0.00	43
	LIQEG-2	Emergency Generator 2	42.47	0.00	0.00	0.00	43
	LIQEG-3	Emergency Generator 3	42.47	0.00	0.00	0.00	43
	LIQEG-4	Emergency Generator 4	42.47	0.00	0.00	0.00	43
	LIQFLARE	Ground Flare	11,512	0.22	0.02	0.00	11,523
	FUG-LIQ	Fugitives Liquefaction	0.00	9.63	0.00	0.00	202
	FUG-LIQSF$_6$	Liquefaction Circuit Breakers	0.00	0.00	0.00	0.015	340
	Project Totals		**1,579,026**	**43.38**	**1.29**	**0.017**	**1,580,737**

8. PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

The proposed Liquefaction Project will be a source of Greenhouse Gas (GHG) emissions and is subject to the U.S. Environmental Protection Agency's (EPA) GHG Prevention of Significant Deterioration (PSD) permitting rules, commonly referred to as the "GHG Tailoring Rule," published June 3, 2010. EPA is implementing the GHG Tailoring Rule in steps. Step 1 commenced January 2, 2011 and ended June 30, 2011. Step 2 commenced July 1, 2011 and ends June 30, 2013. During Step 2, PSD permit requirements cover new projects and modifications to existing facilities solely on the basis of their GHG emissions, even if they do not exceed PSD permitting thresholds for any other pollutant. After July 1, 2011, new sources having the potential to emit more than 100,000 tons/year of GHGs and modifications to existing major sources increasing GHG emissions more than 75,000 tons per year on a carbon dioxide equivalent (CO_2e) basis are subject to GHG review.

The estimated GHG emissions from the proposed Pretreatment Facility are greater than 100,000 tpy on a CO_2e basis and will trigger the requirement for PSD permitting due to being a major source of GHG emissions. The proposed project will also result in a significant net emissions increase for NO_X, PM_{10}, $PM_{2.5}$, H_2SO_4, and SO_2 emissions. Therefore, PSD requirements, including best available control technology (BACT), apply for GHG and NO_X, PM_{10}, $PM_{2.5}$, H_2SO_4, and SO_2 emissions. Freeport LNG will submit two separate, but parallel in time, applications to the TCEQ for authorization of its non-GHG emission increases in accordance with the PSD rules.

Under the PSD regulations, each new source or modified emission unit subject to PSD is required to undergo a Best Available Control Technology (BACT) review. The BACT requirements for GHG emissions from the Liquefaction Project are addressed in Sections 9 and 10 of this application.

9. BEST AVAILABLE CONTROL TECHNOLOGY

This section discusses the approach used in completing the GHG BACT analysis, as well as documenting the emission units for which the GHG BACT analyses were performed.

9.1 BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations 40 CFR §52.21(j)(2):

(j) Control Technology Review.

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations 40 CFR §52.21(b)(12)(emphasis added) in relevant part as:

...<u>an emissions limitation</u> (including a visible emission standard) based on the maximum degree of reduction for <u>each pollutant</u> subject to regulation under Act which would be emitted from any <u>proposed</u> major stationary source or major modification which the Administrator, on a <u>case-by-case basis</u>, taking into account energy, environmental, and economic impacts and other costs, determines is <u>achievable</u> for such source or modification through application of <u>production processes</u> or <u>available</u> methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would <u>exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61</u>.

Although this definition was not changed by the tailoring rule, differences in the characteristics of criteria pollutant and GHG emissions from large industrial sources present several GHG-specific considerations under the BACT definition which warrant further discussion. Those underlined terms in the BACT definition are addressed further below.

9.1.1 EMISSION LIMITATION

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is prefaced upon the application of technologies reflecting the maximum reduction rate achievable, the final result of BACT is an emission limit. Typically, when quantifiable and measurable[1], this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr).[2] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling average.[3]

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[1] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable. 40 CFR §52.21(b)(12).

[2] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a turbine, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[3] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 46.

9.1.2 EACH POLLUTANT

Since BACT applies to "each pollutant subject to regulation under the Act", the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[4] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases and not a single pollutant. In the final tailoring rule preamble, EPA went beyond applying this combined pollutant approach for GHGs to PSD applicability and made the following recommendations that suggest applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG:

However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.[5]

Freeport LNG acknowledges the potential benefits of conducting a single GHG BACT evaluation on a CO_2e basis for the purposes of addressing potential tradeoffs among constituent gases for certain types of emission units. However, for the proposed LNG Liquefaction Project, the GHG emissions are driven primarily by CO_2. CO_2 emissions represent approximately 98% of the total CO_2e for the project as a whole. As such, the following top-down GHG BACT analysis should and will focus on CO_2.

9.1.3 BACT APPLIES TO THE PROPOSED SOURCE

BACT applies to the type of source proposed by the applicant. BACT does not redefine the source. The applicant defines the source (i.e., its goals, aims and objectives). Although BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. A key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. Freeport LNG has provided substantial project discussion in Section 5 of this report to aid the technical reviewers in need and scope of this project and how GHG BACT should be reviewed in light of this detailed information.

[4] 40 CFR §52.21(b)(12)

[5] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule,* June 3, 2010.

9.1.4 CASE-BY-CASE BASIS

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. BACT permit limits are not simply the requirement for a control technology because of its application elsewhere or the direct transference of the lowest emission rate found in other permits for similar sources, applied to the proposed source. EPA has explained how the top-down BACT analysis process works on a case by case basis.

In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.[6]

To assist applicants and regulators with the case-by-case process, in 1990 EPA issued a Draft Manual on New Source Review permitting which included a "top-down" BACT analysis.

The five steps in a top-down BACT evaluation can be summarized as follows:

- ▲ Step 1. Identify all available control technologies;
- ▲ Step 2. Eliminate technically infeasible options;
- ▲ Step 3. Rank the technically feasible control technologies by control effectiveness;
- ▲ Step 4. Evaluate most effective controls; and
- ▲ Step 5. Select BACT.

While this EPA- recommended five step process can be directly applied to GHGs without any significant modifications, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under the PSD regulations.[7]

[6] Draft NSR Manual at B-2. "The NSR Manual has been used as a guidance document in conjunction with new source review workshops and training, and as a guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding Agency regulation, the NSR Manual has been looked to by this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

[7] Pursuant to 40 CFR §52.21(a)(7), emission unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant.

9.1.5 ACHIEVABLE

BACT is to be set at the lowest value that is "achievable." However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals:

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[8]

EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[9]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

9.1.6 PRODUCTION PROCESS

The definition of BACT lists both production processes and control technologies as possible means for reducing emissions.

[8] As quoted in Sierra Club v. U.S. EPA (97-1686).

[9] U.S. EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

9.1.7 AVAILABLE

The term “available” in the definition of BACT is implemented through a feasibility analysis - a determination that the technology being evaluated is demonstrated or available and applicable.

9.1.8 FLOOR

For criteria pollutants, the least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61). Since no GHG limits have been incorporated into any existing NSPS or Part 61 NESHAPs, no floor for a GHG BACT analysis is available for consideration.

9.2 GHG BACT ASSESSMENT METHODOLOGY

GHG BACT for the proposed Project has been evaluated via a “top-down” approach which includes the steps outlined in the following subsections.

It should be noted that the scope of a BACT review was clarified in two ways with respect to GHGs:

- EPA stressed that applicants should clearly define the scope of the project being reviewed. Freeport LNG has provided this information in Section 5 of this application.[10]
- EPA clarified that the scope of the BACT should focus on the Project’s largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review. Because the Project’s GHG emissions are dominated by the pretreatment process amine units via the thermal oxidizers (and more specifically direct CO_2 emissions) and combustion turbine, this BACT analysis focuses mainly on these predominant sources of CO_2e from the Project.

9.2.1 STEP 1 - IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

Available control technologies for CO_2e with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

[10] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, pages 22-23.

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

However, since GHG BACT is a new requirement, the RBLC database search did not result in any records for the GHGs. Primarily, Freeport LNG will rely on items (2) through (5) and preliminary information from the EPA BACT GHG Workgroup for data to establish BACT.

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1. For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. As a natural gas treatment facility, Freeport LNG proposes the use of pipeline quality natural gas only for all on-site combustion equipment, except for the emergency generators and firewater pumps. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (MMBtu) for wide variety of industrial fuel types. Only biogas (captured methane) and coke oven gas result in lower CO_2 emissions per unit heat input than natural gas.

Additionally, EPA's GHG BACT requirements suggests that CCS be evaluated as an available control for substantial, large projects such as steel mills, refineries, and cement plants where CO_2e emissions levels are in the order of 1,000,000 tpy CO_2e, or for industrial facilities with high-purity CO_2 streams. The proposed Pretreatment Facility emissions are approximately 1,500,000 tpy CO_2e. However, the amine units (used to remove CO_2 from the inlet gas) result in a concentrated CO_2 stream with sulfur compound impurities. In addition, the turbine exhaust is not a high-purity CO_2 stream (turbine exhaust has a high flowrate and lower CO_2 concentration). Nonetheless, CCS is evaluated as a control option for the proposed project.

9.2.2 STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling GHG emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[11]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[12] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[13] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

9.2.3 STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

All remaining technically feasible control options are ranked based on their overall control effectiveness for GHG. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

9.2.4 STEP 4 - EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions

[11] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[12] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[13] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the Global Warming Potential (GWP) of CH_4 is 21 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_X emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_X emissions above the reduction of CO emissions, approving low NO_X control strategies as BACT that result in higher CO emissions relative to the uncontrolled emissions scenario.

9.2.5 STEP 5 - SELECT BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard is infeasible, in which case a work practice or operating standard can be imposed.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Freeport LNG proposes only an annual average GHG BACT limit.

9.3 GHG BACT REQUIREMENT

The GHG BACT requirement applies to each new emission unit from which there are emissions increases of GHG pollutants subject to PSD review. The Potential to Emit for GHGs from the existing terminal facilities is greater than 100,000 tpy on a CO_2e basis. Due to the use of electric motors at the proposed Liquefaction Plant, there will be an insignificant increase in GHG emissions at this facility alone when compared with the project emission increases (i.e., Pretreatment Facility and Liquefaction Plant). The estimated emissions increase of GHGs from the Pretreatment Facility, however, will be equal to or greater than 100,000 tpy on a CO_2e basis primarily due to separation of carbon dioxide from the raw natural gas feed stream and the combustion of fuel and boil-off gas. The Liquefaction Project consists of two new sources – the Pretreatment Facility and the Liquefaction Plant. The Pretreatment Plant will be located about 6 miles to the north of the Liquefaction Plant. Because of the interdependence of the Liquefaction Plant and the Pretreatment Facility, the two plants will be considered a single project for PSD permitting purposes.

Potential emissions of GHGs from the proposed Liquefaction Project will result from the following emission units:

- Pretreatment Facility
  - Ten process heaters (EPNs: 6B-1811A, 6B-1811B, 6B-1811C, 6B-1811D, 6B-1811E, 6B-1811F, 6B-1811G, 6B-1811H, 6B-1812A, and 6B-1821B);
  - Two emergency generators (EPNs: PTFEG-1 and PTFEG-2);
  - One fire water pump (EPN: PTFFWP);
  - Three thermal oxidizers (EPNs: TO1, TO2, TO3);
  - A combustion turbine (EPNs: CT1(A) and CT1(B));
  - NGL flare (EPN: NGLFLARE);
  - Fugitive CH_4 emissions from piping components (EPN: FUG-TREAT); and
  - Fugitive emissions from SF_6 circuit breakers (6) (EPN: FUGPTFSF$_6$).
- Liquefaction Plant
  - Four new emergency generators (EPNs: LIQEG-1, LIQEG-2, LIQEG-3, and LIQEG-4);
  - One firewater pump (EPN: LIQFWP);
  - Liquefaction flare (EPN: LIQFLARE);
  - Fugitive CH_4 emissions from piping components (EPN: FUG-LIQ); and
  - Fugitive emissions from SF_6 circuit breakers (40) (EPN: FUGLIQSF$_6$).

Table 7-3 provides a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed Liquefaction Project. GHG emissions for each emission unit were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas).

The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- *PSD and Title V Permitting Guidance For Greenhouse Gases (*hereafter referred to as General GHG Permitting Guidance)[14]

[14] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler* (hereafter referred to as GHG BACT Guidance for Boilers)[15]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry* (hereafter referred to as GHG BACT Guidance for Refineries)[16]

[15] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[16] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/refineries.pdf

10. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed Liquefaction Project following the EPA's five-step "topdown" BACT process. Table 10-1 provides a summary of the propose BACT limits discussed in the following sections:

TABLE 10-1. POTENTIAL BACT LIMITS FOR LIQUEFACTION PROJECT

EPN	Description	**Proposed BACT Limit**
Pretreatment Facility		
PTFFWP	Fire Water Pump	37 tpy CO_2e
PTFEG-1	Emergency Generator 1	43 tpy CO_2e
PTFEG-2	Emergency Generator 2	43 tpy CO_2e
HTRCAP	LT and HT Heaters Emission Cap	100,486 tpy CO_2e
TO1	Amine Unit/Thermal Oxidizer 1	301,341 tpy CO_2e and 650 MMscf/day/train of natural gas treated
TO2	Amine Unit /Thermal Oxidizer 2	301,341 tpy CO_2e and 650 MMscf/day/train of natural gas treated
TO3	Amine Unit /Thermal Oxidizer 3	301,341 tpy CO_2e amd 650 MMscf/day/train of natural gas treated
NGLFLARE	NGL Flare	3 MMscf/yr of vent gas
CT1(A)/CT1(B)	Combustion Turbine	562,693 tpy CO_2e
FUG-PTF	Pretreatment Fugitives	Work Practice
$FUGPTFSF_6$	PTF SF_6 Circuit Breakers	Work Practice
Liquefaction Plant		
LIQFWP	Fire Water Pump	37 tpy CO_2e
LIQEG-1	Emergency Generator 1	43 tpy CO_2e
LIQEG-2	Emergency Generator 2	43 tpy CO_2e
LIQEG-3	Emergency Generator 3	43 tpy CO_2e
LIQEG-4	Emergency Generator 4	43 tpy CO_2e
LIQFlare	Ground Flare	167 MMscf/yr of vent gas
FUG - LIQ	Fugitives Liquefaction	Work Practice
$FUGLIQSF_6$	LIQ SF_6 Circuit Breakers	Work Practice

10.1 OVERALL PROJECT ENERGY EFFICIENCY CONSIDERATIONS

While the five-step BACT analysis is the EPA's preferred methodology with respect to selection of control technologies for pollutants, EPA has also indicated that an overarching evaluation of energy efficiency should take place as increases in energy efficiency will inherently reduce the total amount of GHG emissions produced by the source. As such, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives to be installed in the proposed Liquefaction Project. In particular, two design decisions made by Freeport LNG promote overall energy efficiency for the Liquefaction Project: (1) Freeport LNG's selection of its primary drivers and (2) modularization of the liquefaction trains and natural gas pretreatment units. The primary drivers are the means by which the various compressors and pumps for the Liquefaction Project will be powered. Freeport LNG has determined that electric motor primary drivers are the most energy efficient of the available primary driver alternatives for the Liquefaction Project. Regarding modularization, Freeport LNG's decision to build multiple liquefaction trains each with an accompanying natural gas pretreatment unit promotes energy efficiency notwithstanding the varying throughputs the facility may encounter. With modularization, each of the three liquefaction trains will be operated in tandem with one of three natural gas pretreatment units.

10.1.1 BENEFITS OF ELECTRIC MOTORS

Electric motors, in comparison to other driver alternatives, (1) produce no GHG emissions, (2) do not have their energy efficiency affected by weather or add-on control technologies, (3) have more efficient turndown characteristics for variable output operations, (4) can be sized to allow for a more efficient design and (5) have no waste heat which is readily usable with the design of the Liquefaction Plant. With respect to weather-related inefficiencies, other primary driver alternatives typically lose efficiency (i.e., become de-rated) as temperatures and humidity levels deviate from the design conditions used to engineer the applicable driver. Given the project's location on the Texas Gulf Coast, high temperatures and high humidity are present at the site for much of the year.

Selecting electric motors as the primary drivers for the large compressors and pumps in the Liquefaction Project avoids these inefficiencies. In addition, other primary driver alternatives which produce GHG emissions would likely utilize add-on control technologies (such as selective catalytic reduction units) which cause additional energy inefficiencies for the driver. 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 (in other words, electric motors have more efficient turndown characteristics). Furthermore, electric motors are supplied in a greater number of standard sizes which allows Freeport LNG to pick a motor size that is optimal to the desired design output of the applicable liquefaction train. If a different primary driver was selected, the size of the driver would determine the design output of the train (rather than vice versa) which would lead to Freeport LNG having to design a train size which is larger than desired, thus losing energy efficiency through over-sizing of equipment. As a last point, other primary driver alternatives typically generate a significant amount of heat as a by-product of their operation which, in some instances, can be utilized to increase the efficiency of those drivers (such as through the use of heat recovery steam generator units). Given that the function of the Liquefaction Project is, at its essence, a large refrigeration process (and that the pretreatment units are not located in close proximity to the liquefaction trains), Freeport LNG has no use for the heat that could otherwise be recovered as part of this process and, thus, using a driver that produces heat as an unusable by-product creates further energy inefficiencies. #

10.1.2 BENEFITS OF LIQUEFACTION TRAIN/PRETREATMENT UNIT MODULARIZATION

Notwithstanding that the liquefaction trains and the pretreatment units are separated by a distance of almost six miles, each liquefaction train will be operated in tandem with a comparably sized natural gas pretreatment unit. Rather than build one or two large liquefaction trains or pretreatment units with flexible turndown capabilities, Freeport LNG has 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. While there are operational benefits in this decision, there are also significant energy efficiencies gained 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 a 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.

10.2 COMBUSTION TURBINE – GHG BACT

The proposed combustion turbine (CT) will be a simple cycle, natural gas-fired unit 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 DLNB and SCR are used to reduce NO_X emissions while Ox-Cat is used to reduce CO and VOC emissions. The CT results in three GHGs from fuel combustion: CO_2, CH_4, and N_2O. CO_2 emissions result from the combustion of carbon-containing fuel (i.e. natural gas). CH_4 emissions result from incomplete combustion of natural gas and N_2O emissions result from partial oxidation of nitrogen in the combustion air used and due to catalytic reduction reactions in the SCR system used to control NO_X emissions.

The following section presents BACT evaluations for GHG emissions from the proposed CT.

10.2.1 COMBUSTION TURBINE – CO_2 BACT

10.2.1.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The following table summarizes the available CO_2 emission control strategies for combustion turbines that were analyzed as part of this BACT analysis.

TABLE 10-2. POTENTIAL CO_2 CONTROL STRATEGIES FOR THE COMBUSTION TURBINE

Pollutant	Control Technologies
CO_2	Carbon Capture and Sequestration (CCS)
	Selection of Efficient Combustion Turbine
	Fuel Selection
	Good Combustion, Operating, Maintenance Practices
	Use of an Air Intake Chiller

10.2.1.1.1 CARBON CAPTURE AND SEQUESTRATION

For the combustion turbine, CCS would involve post combustion capture of the CO_2 from the turbine and sequestration of the CO_2 in some fashion. Carbon capture is an established process in some industry sectors although not in the electricity generation sector in continuous and/or seasonal operations (it has only been demonstrated on small slip streams for limited periods at large electric generating units). In general, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with either solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale and solid sorbents and membranes are only in the research and development phase. In terms of post combustion CCS for power plants, the following six (6) projects including carbon capture have taken place on slip streams at coal-fired power plants:

- *AEP Mountaineer* (Sept. 2009- Present): AEP is conducting post-combustion CO_2 capture using Alstom's chilled ammonia process to capture 100,000 tpy CO_2e over a 12 to 18 month period on a 20 MW_e slipstream from the exhaust of its 1,300 MW coal-fired Mountaineer plant in New Haven, West Virginia.

The captured CO_2 is being sequestered in deep geologic formations beneath the Mountaineer site.[17] [18] [19]

- *First Energy R.E. Burger* (Dec. 2008-Present): First Energy has been conducting a CO_2 capture pilot test using Powerspan's $ECO_2^{®}$ technology on a 1 MW slipstream from the outlet of the R.E. Burger Station (near Shadyside, Ohio) demonstration-scale 50 MW ECO unit (Powerspan's multipollutant control system). The ECO system is designed to control SO_2, NO_X, oxidized mercury, and fine particulate matter from a 110,000 scfm slipstream of a 156 MW coal boiler. The $ECO_2^{®}$ CO_2 capture system uses a proprietary ammonia-based solvent in a thermal swing absorption (TSA) process to remove CO_2 from the flue gas. The project handles 20 ton per day (tpd) dried, compressed, and *sequestration-ready* CO_2e, but the literature does not suggest the CO_2 is permanently sequestered in any geologic formation or by any other means.[20] [21]
- *AES Warrior Run* (2000-Present)*:* AES captures 110,000 tpy CO_2e using the ABB/Lummus' monoethanolamine (MEA) solvent-based system from a small slipstream of the 180 MW coal-fired circulating fluidized bed (CFB) power plant at its Warrior Run station in Cumberland, Maryland. The extracted CO_2 is used in the food processing industry and related processes.[22] [23] [24]
- *AES Shady Point* (1991-Present)*:* AES captures 66,000 tpy CO_2e using the ABB/Lummus MEA technology from a small slipstream of a 320 MW coal-fired CFB boiler at its Shady Point station in Panama, Oklahoma. The extracted CO_2 is used for

[17] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 31

[18] *Carbon Capture Journal*, "Alstom and AEP Commission Mountaineer CCS Demonstration", October 30, 2009, http://www.carboncapturejournal.com/displaynews.php?NewsID=475.

[19] MIT Carbon Capture & Sequestration Technologies, *AEP Alstom Mountaineer Fact Sheet: Carbon Dioxide Capture and Storage Project*, July 23, 201?, http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html.

[20] McLarnon, Christopher and Jones, Morgan D., *Testing Ammonia Based CO2 Capture with Multi-Pollutant Control*, Presented at the Power Plant Air Pollutant Control "Mega" Symposium, August 2008. http://secure.awma.org/presentations/Mega08/Papers/a91_1.pdf.

[21] Powerspan, FirstEnergy $ECO_2^{®}$ Pilot Facility, http://www.powerspan.com/FirstEnergy-ECO2-Carbon-Capture-Pilot-Facility.aspx.

[22] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 31.

[23] International Energy Agency GHG Research & Development Program, *RD&D Database: Warrior Run Plant CO_2 Capture Commercial Project*, http://www.ieaghg.org/index.php?/RDD-Database.html.

[24] Dooley, JJ et. al., U.S. Department of Energy, *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009*, June 2009, http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18520.pdf.

food processing, freezing, beverage production, and chilling purposes.[25]

- *IMC Chemicals (formerly Searles Valley Minerals)* (1978-Present)*:* IMC Chemicals captures 270,000 tpy CO_2e from the flue gas of two 52-56 MW industrial coal boilers using amine scrubbing technology at its soda ash production plant in Trona, California. The captured CO_2 is used for the carbonation of brine from Searles Lake, and the brine is subsequently used in the soda ash production process.[26 27 28]

- *WE Energy Pleasant Prairie* (June 2008-Oct. 2009): WE Energy captured 16,500 tpy CO_2 using Alstom's chilled ammonia process from a 1.7 MW_e slipstream of the 1,210 MW coal-fired power plant at its Pleasant Prairie station in Pleasant Prairie, Wisconsin. The literature does not suggest the CO_2 was permanently sequestered in any geologic formation or by any other means.[29]

Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a coal-fired power plant's emissions using various solvent based scrubbing processes, until these post combustion technologies are installed fully on a power plant, they are not considered "available" in terms of BACT.

In addition to the coal fired power projects deploying CO_2 capture at a small scale, Florida Power & Light (FP&L) conducted CO_2 capture to produce 320-350 tpd CO_2 using the Fluor Econamine FGSM scrubber system on 15 percent of the flue gas from its 320 MW 2 x 1 natural gas combined cycle unit in Bellingham, Massachusetts from 1991 to 2005. Due to increases in natural gas prices in 2004-2005, FP&L changed from a base/intermediate load plant to a peaking plant which made the continued operation of the capture plant uneconomical. The captured CO_2 was compressed and stored on site for sale to two nearby major food processing plants.[30 31]

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[25] International Energy Agency GHG Research & Development Program, *RD&D Database: Shady Point Power Plant CO_2 Capture Commercial Project*, http://www.ieaghg.org/index.php?/RDD-Database.html.

[26] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 31.

[27] International Energy Agency GHG Research & Development Program, *RD&D Database: IMC Global Inc. Soda Ash plant, Trona CO_2 Capture Commercial Project,* http://www.ieaghg.org/index.php?/RDD-Database.html.

[28] Electrical Power Research Institute, *CO_2 Capture and Storage Newsletter*, "Visit to the Trona plant MEA CO_2 Removal System in Trona, California, in September 2006", Issue #2 December 2006, http://mydocs.epri.com/docs/public/000000000001014698.pdf.

[29] Commodity Online, *Alstom Achieves Milestones in Carbon Capture*, May 17, 2010, http://www.commodityonline.com/news/Alstom-achieves-milestones-in-carbon-capture-28256-3-1.html.

[30] International Energy Agency GHG Research & Development Program, *RD&D Database: Florid Light and Power Bellingham CO_2 Capture Commercial Project*, http://www.ieaghg.org/index.php?/RDD-Database.html.

The following larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed[32]:

"CCPI is pursuing three pre-combustion and three post-combustion CO_2 capture demonstration projects using currently available technologies (see Appendix A, Table A-8) . . . The post-combustion projects will capture CO_2 from a portion of the PC plant's flue gas stream. The specific projects include the following:

- *Basin Electric: amine-based capture of 900,000 tonnes per year of CO_2 from a 120 MW equivalent slipstream at a North Dakota plant for use in an EOR application and/or saline storage.*
- *NRG Energy: amine-based capture of 400,000 tonnes per year of CO_2 from a 60 MW equivalent slipstream at a Texas plant for use in an EOR application.*
- *American Electric Power: ammonia-based capture of 1.5 million tonnes per year of CO_2 from a 235 MW equivalent slipstream at a West Virginia plant for saline storage."*

None of these demonstration projects proposed post combustion capture of CO_2 from a natural gas treatment facility, or even a simple cycle, gas-fired turbine. Rather they are for post combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. The exhaust from a PC plant would typically have a significantly higher concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas (approximately 12-14 percent for a coal-fired boiler versus 6-8 percent for a typical gas-fired combustion turbine).[33] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[34]

Given the limited deployment of only slipstream/demonstration applications, CCS is not commercially available as BACT for the combustion turbine and is therefore considered infeasible and not BACT for the proposed combustion turbine. This is supported by EPA's assertion that CCS is considered "available" for projects that

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[31] Reddy, Satish, et. al., Fluor's Econamine FG Plus[SM] Technology for CO_2 Capture at Coal-fired Power Plants, Power Plant Air Pollutant Control "Mega" Symposium, August 25-28, 2008, Baltimore, Maryland.

[32] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. 32.

[33] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. A-7.

[34] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 29.

emit CO_2 in "large" amounts.[35] Freeport LNG's combustion turbine, by comparison, emits CO_2 in small amounts and low-CO_2 stream.

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however not commercially demonstrated.

Beyond power plant CCS demonstration projects, the report also discusses three relevant industrial CCS projects that are being pursued under the Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application.
- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding in June 2010 and are moving onto a construction/demonstration phase. Therefore, they are not yet demonstrated. In addition, the Department of Energy is providing significant financial assistance for these projects to offset the cost and make these projects economically feasible.

In addition, the August 2010 federal Interagency Task Force for Carbon Capture and Storage (CCS) report noted the following four (4) fundamental near-term and long-terms concerns for CCS:[36]

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[35] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 32. *"For the purposes of a BACT analysis for GHGs, U.S. EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] for facilities emitting CO_2 in large amounts, 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).* The proposed project is not any of the cases U.S. EPA suggests above.

[36] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf,, p. 53.

- The existence of *market failures*, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.
- The need for a *legal/regulatory framework* for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO_2 can be stored safely and securely.
- Clarity with respect to the *long-term liability for CO_2 sequestration*, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
- Integration of *public information, education, and outreach* throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

10.2.1.1.2 SELECTION OF EFFICIENT COMBUSTION TURBINE

The Pretreatment Facility will utilize a high efficiency GE Frame 7EA electric turbine consisting of a natural gas-fired simple cycle combustion turbine which is the most suitable design for the operational parameters of the project. Waste heat will be recovered from the combustion turbine using a heat recovery system. The waste heat recovery unit will be used to transfer heat to hot oil which will be used in the amine sweetening unit and dehydration system units in lieu of burning natural gas fuel in these units. The use of the waste heat recovery system will allow for heat transfer to the amine and dehydration units without additional fuel use, 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 simple cycle turbine.

10.2.1.1.3 FUEL SELECTION

Only natural gas (BOG supplemented with natural gas) fuel will be fired in the proposed combustion turbine. Natural gas has the lowest carbon intensity of any available fuel for the combustion turbine.

10.2.1.1.4 GOOD COMBUSTION, OPERATING, AND MAINTENANCE PRACTICES

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

10.2.1.1.5 INSTALLATION OF AN AIR INTAKE CHILLER

An intake air chiller system will maintain the incoming combustion turbine air at 60°F. Chilling the incoming air in this way increases its thermal and power efficiency of the combustion turbine, thus reducing GHG emissions.

10.2.1.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the combustion turbine and is therefore considered infeasible and not BACT for the proposed combustion turbine. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts and high purity CO_2 streams.[37] This emission unit, by comparison, emits CO_2 in small amounts and low purity CO_2 stream.

All other control options are technically feasible.

10.2.1.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Installation of the most efficient combustion turbine (i.e., combustion turbine with waste heat recovery) suitable for the operational parameters of the project design; low carbon fuel selection; implementation of good combustion, operating, and maintenance practices; and the installation of an air intake chiller are the remaining technically feasible control options for minimizing CO_2 emissions from the CT. Since Freeport LNG proposes to implement all these control options, ranking these control options is not necessary.

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[37] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 32. "*For the purposes of a BACT analysis for GHGs, U.S. EPA classifies CCS as an add-on pollution control technology*[86] *that is "available"*[87] *for facilities emitting CO_2 in large amounts, 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).* The proposed project is not any of the cases U.S. EPA suggests above.

10.2.1.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

No adverse energy, environmental, or economic impacts are associated with the proposed turbine selection; low-carbon fuel selection; good combustion, operating, and maintenance practices; and installation of intake air chiller.

10.2.1.5 STEP 5 – SELECT CO_2 BACT FOR THE COMBUSTION TURBINE

Freeport LNG proposes the following design elements and work practices as BACT for CO_2:

- Installation of an efficient CT with waste heat recovery suitable for the operational parameters of the project;
- Use of natural gas (BOG supplemented with natural gas) as fuel;
- Implementation of good combustion, operating and maintenance practices; and
- Installation of an intake air chiller.

As mentioned previously, the resulting BACT standard is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions limit infeasible, in which case a work practice or operating limit can be imposed. For the proposed CT, Freeport LNG proposes a CO_2e BACT emission limit of 562,693 short tons of CO_2e per year for all GHG emissions based on a 12-month rolling average basis. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with Appendix A of the application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling short tons of CO_2e/yr emission rate does not exceed this limit.

Through this proposed BACT limit, Freeport LNG limits the maximum fuel consumption and CO_2e emissions, effectively requiring efficient operation at the design heat rate, when operating at 100% load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective).

10.2.2 COMBUSTION TURBINE – CH_4 BACT

10.2.2.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The available control options identified for minimizing CH_4 emissions from the combustion turbines are selection of an efficient CT; use of an oxidation catalyst;

use of low-carbon fuel; use of good combustion, operating, and maintenance practices to minimize unburned fuel; and installation of an intake air chiller.

10.2.2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Installation of the most efficient combustion turbine (with waste heat recovery) suitable for the operational parameters of the project; the use of oxidation catalyst; use of low carbon fuel selection; implementation of good combustion, operating, and maintenance practices; and installation of an intake air chiller are technically feasible control options for minimizing CH_4 emissions from the CT.

10.2.2.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Since Freeport LNG proposes to implement all these control options, ranking these control options is not necessary.

10.2.2.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

No adverse energy, environmental, or economic impacts are associated with the selection of the most efficient combustion turbine (with waste heat recovery) suitable for the operational parameters for the project; use of an oxidation catalyst; use of low-carbon fuel selection; implementation of good combustion, operating, and maintenance practices; and the installation of intake air chiller for reducing CH_4 emissions from the combustion turbine.

10.2.2.5 STEP 5 – SELECT CH_4 BACT FOR THE COMBUSTION TURBINE

Freeport LNG proposes the following design elements and work practices as BACT for CH_4:

- Installation of an efficient CT with waste heat recovery;
- Use of an oxidation catalyst
- Use of natural gas (BOG supplemented with natural gas) as fuel;
- Implementation of good combustion, operating and maintenance practices; and
- Installation of an intake air chiller.

For the proposed CT, Freeport LNG proposes a CO_2e BACT emission limit of 562,693 short tons of CO_2e per year for all GHG emissions based on a 12-month rolling average basis. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with Appendix A of the application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e/yr emission rate does not exceed this limit.

Through this proposed BACT limit, Freeport LNG limits the maximum fuel consumption and CH_4 emissions, effectively requiring efficient operation at the design heat rate, when operating at 100% load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective).

10.2.3 COMBUSTION TURBINE - N_2O BACT

For the proposed Project, the contribution of N_2O to the CO_2e is small. There are five (5) primary pathways of NO_X production in gas-fired combustion turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. For turbines using Dry Low NOx (DLN) combustors, the N_2O pathway is an important mechanism of NO_X formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with the N_2O molecule, creating N_2 and NO.[38] In premixed gas flames, N_2O is primarily formed in the flame front or oxidation zone. Once formed the N_2O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N_2O emissions from premixed gas flames like DLN combustor flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the N_2O formation zone can increase N_2O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream which are all common NO_X control measures.[39]

Freeport LNG proposes the use of SCR as BACT for controlling NO_X emissions. However, the SCR is expected to contribute to N_2O emissions from the CT due to catalytic reduction reactions. Elimination of SCR would result in an increase in NO_X emissions. Therefore, there is a tradeoff between NO_X and N_2O emissions when developing a combustion control strategy which influences the BACT selection process.

10.2.3.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

N_2O catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[40] Through this technology, tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst. A N_2O catalyst is not effective in the control N_2O emissions from gas-fired combustion turbines due to the very low N_2O concentrations present in exhaust streams (approximately 1 ppm). In comparison, the application of a catalyst in the nitric acid industry sector

[38] Angello, L., Electric Power Research Institute, *Fuel Composition Impacts on Combustion Turbine Operability,* March 2006, http://mydocs.epri.com/docs/public/000000000001005035.pdf

[39] American Petroleum Institute, Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, February 2004, http://www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf

[40] http://www.catalysts.basf.com/Main/mediaroom/10years_worldscale_experience_in_reducing_nitrous_.be

has been effective due to the high (1,000-2,000 ppm) N_2O concentration in the exhaust stream.

Elimination of SCR is another option to reduce N_2O emissions. However, as discussed above, this would result in an increase in NO_X emissions. Therefore elimination of SCR is not considered as a control option for N_2O BACT.

With N_2O catalysts and elimination of SCR eliminated, other options identified for the control of N_2O emissions are the selection of an efficient CT and good combustion, operating, and maintenance practices.

10.2.3.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Selection of an efficient CT and good combustion, operating, and maintenance practices are technically feasible control options for reducing N_2O emissions from the combustion turbines.

10.2.3.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Since both turbine selection and good combustion practice are evaluated in the remaining steps of the BACT analysis, no ranking of control options is required.

10.2.3.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

As indicated in EPA's guidance on GHG BACT, GHG control strategies may have the potential to increase emissions of criteria pollutants as in the case of the competing NO_X and N_2O combustion control strategies for Freeport LNG's combustion turbine. In such cases, the guidance suggests that the applicant should consider the effects of increases in emissions of other regulated pollutants that may result from the use of that GHG control strategy, and based on this analysis, the permitting authority can determine whether or not the application of that GHG control strategy is appropriate given the potential increases in other pollutants.[41]

Given the low N_2O emissions relative to NO_X emissions from the combustion turbine; the recent proposed strengthening of the 8-hr ozone NAAQS indicating EPA's continued concern over adverse impacts from ozone formation due to NO_X and VOC emissions; and the recent promulgation of 1-hr NO_2 NAAQS, Freeport LNG does not consider it appropriate to control the combustion processes of the combustion turbine to reduce N_2O emissions due to the counteractive increase in NO_X emissions. Therefore, good combustion practice for the purposes of minimizing N_2O formation is eliminated on the basis of adverse criteria pollutant impacts.

[41] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 39.

10.2.3.5 STEP 5 – SELECT N_2O BACT FOR THE COMBUSTION TURBINE

For the proposed CT, Freeport LNG proposes a CO_2e BACT emission limit of 562,693 short tons of CO_2e per year for all GHG emissions based on a 12-month rolling average basis. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with Appendix A of the application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e/yr emission rate does not exceed this limit.

Through this proposed BACT limit, Freeport LNG limits the maximum fuel consumption and N_2O emissions, effectively requiring efficient operation at the design heat rate, when operating at 100% load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective).

10.2.4 COMBUSTION TURBINE - BACT DURING STARTUP AND SHUTDOWN

It is not technically feasible to use CCS or the other control technologies proposed above during turbine startup or shutdown. BACT is achieved by minimizing the time for startup and shutdown. Freeport LNG proposes two startup and two shutdown events per year.

Therefore, Freeport LNG is proposing that BACT during startup and shutdown of the combustion turbine is to minimize the frequency and duration of these events, consistent with good maintenance practices, and to engage the pollution control equipment (e.g., SCR and oxidation catalyst) as soon as practicable, based on vendor recommendations and guarantees.

10.3 PROCESS HEATERS – GHG BACT

GHG emissions from the proposed process heaters result from the combustion of natural gas. 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 two LT Heaters and 336 hours per year for the additional six LT Heaters and two HT Heaters.

The following section presents BACT evaluations for GHG emissions from the proposed process heaters.

10.3.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The available GHG emission control strategies for process heaters that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Use of Waste Heat Recovery in the CT;
- Efficient Heater Design; and
- Limiting Hours of Operation.

10.3.1.1 CARBON CAPTURE AND SEQUESTRATION

It is possible to design and engineer a system to capture, transfer, and sequester the CO_2 separated from the heater exhaust stream. However, the feasibility of CCS is highly dependent on a continuous CO_2 laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Due to the limited hours of operation of the LT and HT heaters, CCS is not a technically feasible option for these heaters.

Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heaters.

10.3.1.2 FUEL SELECTION

The proposed process heaters will be fired with only natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel for the process heaters.

10.3.1.3 GOOD COMBUSTION, OPERATING, AND MAINTENANCE PRACTICES

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the process heaters. Good combustion practices also include proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications.

10.3.1.4 USE OF WASTE HEAT RECOVERY FROM COMBUSTION TURBINE

The Pretreatment Facility will have a natural gas-fired CT exhausting to a heat exchanger for waste heat recovery. The waste heat recovery unit will be used to transfer heat to hot oil. The hot oil will be used in the amine sweetening unit and dehydration system units in lieu of burning natural gas fuel in the process heaters serving these units. The use of waste heat recovery in the combustion turbine will provide the energy requirements from the heaters and therefore, will reduce the GHG emissions from fuel combustion in the heaters.

10.3.1.5 EFFICIENT HEATER DESIGN

Efficient heater design improves mixing of fuel and creates more efficient heat transfer. Since the Freeport LNG is proposing to install new heaters, these heaters will be designed to optimize combustion efficiency.

10.3.1.6 LIMITING HOURS OF OPERATION

Limiting the hours of operations inherently reduces GHG emissions. Six of the eight LT heaters and the two HT heaters proposed as part of this project will be limited to operation only when the combustion turbine is down for maintenance; approximately 336 hours per year on a rolling 12-month basis.

10.3.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

As discussed above, the use of CCS is technically infeasible and economically not reasonable for the process heaters; therefore, it is not considered as a control option for further analysis. All other control options are technically feasible.

10.3.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

With elimination of CCS as a control option, low carbon fuel selection; implementation of good combustion, operating, and maintenance practices; use of waste heat recovery in the CT; efficient heater design; and limiting the hours of operation are the remaining technically feasible control options for minimizing GHG emissions from the process heaters.

Since Freeport LNG proposes to implement all these control options, ranking these control options is not necessary.

10.3.4 STEP 4 – EVALUATE MOST EFFECTIVE OF CONTROL OPTIONS

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

10.3.5 STEP 5 – SELECT BACT FOR THE PROCESS HEATERS

Freeport LNG proposes the following design elements and work practices as BACT for the process heaters:

- Use of natural gas as fuel;
- Implementation of good combustion, operating, and maintenance practices,
- Use of waste heat recovery in the CT;
- Efficient heater design; and
- Limit hours of operation for six of the LT heaters and the two HT heaters to only when the combustion turbine is down for maintenance; approximately 336 hours per year (based on a 12-month rolling total).

Freeport LNG would like the flexibility to utilize any heater as operationally necessary and apply the GHG emission and operational hours limit to the group of heaters. Therefore Freeport LNG proposes a CO_2e emission limit cap of 100,486 tpy CO_2e for all the heaters as a group.

10.4 AMINE UNITS / THERMAL OXIDIZERS – GHG BACT

Amine units at the Pretreatment Facility will be used to remove CO_2 in order to meet downstream liquefaction system requirements. Stripped CO_2 emissions will be routed to three regenerative thermal oxidizers. GHG emissions from the thermal oxidizers result from the combustion of natural gas or BOG as well as the process waste gas removed from the amine units. The BACT analysis includes emissions from the combination of these sources.

Since only CO_2 (with minor VOCs and CH_4 entrained in the gas stream) from amine units will be routed to the thermal oxidizers, process-based CO_2 emissions from the thermal oxidizers are based on the estimated flow rates of CO_2, assuming 2% of the incoming natural gas is CO_2. Any VOCs and CH_4 emissions present in the vent gas routed to the thermal oxidizers will be converted to CO_2 in the combustion zone, and CO_2 has a lower GWP compared to CH_4.

The following section presents a BACT evaluation for GHG emissions from the thermal oxidizers.

10.4.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The available GHG emission control options for the process emissions sent to the thermal oxidizers include:

- Carbon Capture and Sequestration

The available GHG emission control strategies for the thermal oxidizer combustion emissions include:

- Carbon Capture and Sequestration
- Proper Thermal Oxidizer Design and Operation
- Fuel Selection
- Proper Thermal Oxidizer Design and Operation
- Good Combustion Practices, Operating, Maintenance Practices

10.4.1.1 CARBON CAPTURE AND SEQUESTRATION

The primary source of CO_2 emissions from the thermal oxidizers will be from routing of CO_2 emissions from the amine units. A small fraction of the CO_2 emissions emitted from the thermal oxidizers will result from the combustion of BOG or natural gas. Since the amine units will be used to remove CO_2 and sulfur compounds in order to meet the downstream liquefaction process specifications, the CO_2 emissions are inherent to the process. The gas stream from the amine units will also contain relatively small amounts of CH_4 and VOCs entrained in the gas. The vent gas stream from each amine unit will be routed to a thermal oxidizer in which CH_4 and VOCs will be is converted to CO_2 in the combustion zone. Therefore, CO_2 will be the major component of GHG emissions from the thermal oxidizers.

While the process exhaust stream from the thermal oxidizer is relatively high in CO_2 content, additional processing of the exhaust gas will be required to implement CCS. These include separation (removal of PM and other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, large compression units, and pipelines to transfer CO_2. These additional units would require additional electricity and generate additional air emissions.

The available post-combustion capture technologies include oxy-combustion; solvent capture and stripping; and post-combustion membranes. [42] The oxy-combustion technology is still in the research stage and solvent capture and stripping technology is being implemented in the chemical industry. The post-combustion membrane technology is still in the research stage, and its industrial application is at least 10 years away. [42]

Freeport LNG conducted research and analysis to determine the technical feasibility of CCS. Since most of the CO_2 emissions from the proposed project are generated from the amine units, Freeport LNG conducted studies to evaluate potential options to capture and geologically sequester CO_2 from the amine units or transfer the CO_2 to an off-site facility for Enhanced Oil Recovery (EOR). Based on these studies, Freeport LNG identified the following options as technically feasible:

- **Capture and Geological Sequestration of CO_2 (without any post-processing):** Based on the geological and subsurface studies conducted by Freeport LNG, capture and sequestration of CO_2 from the amine treatment units is technically feasible.

- **Capture and Transfer of CO_2 (with post-processing) for EOR:** Based on the results of these studies, capture and transfer of CO_2 from the amine treatment units for use in EOR is technically feasible. A study was performed to evaluate the potential options for capture and transfer of CO_2 from the Pretreatment Facility (located near Stratton Ridge, TX) to Denbury Resources, Inc. (Denbury) Facility (in Hastings, TX). The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer via a new pipeline.

Since both the capture and geological sequestration and capture and transfer of CO_2 for EOR are technically feasible for the proposed project, these options are further evaluated for energy, environmental, and economic impacts.

[42] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry*, U.S. EPA, October 2010, Section 5.1.4

10.4.1.2 PROPER THERMAL OXIDIZER DESIGN, OPERATION, AND MAINTENANCE

Good thermal oxidizer design can be employed to destroy any VOCs and CH_4 entrained in the waste gas removed from the amine units. Good thermal oxidizer design includes flow measurement and monitoring/control of waste gas heating values. In addition, periodic tune-up and maintenance will be performed per the manufacturer recommendation.

10.4.1.3 FUEL SELECTION

The fuel for firing the proposed thermal oxidizers will be limited to boil-off gas (BOG) or natural gas fuel. BOG and natural gas have the lowest carbon intensity of any available fuel for the thermal oxidizers.

10.4.1.4 GOOD COMBUSTION, OPERATING, AND MAINTENANCE PRACTICES

Good combustion and operating practices are a potential control option for improving the fuel efficiency of the thermal oxidizers. Good combustion practices include proper maintenance and tune-up of the thermal oxidizers at least annually per the manufacturer's specifications.

10.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

All control options identified in Step 1 are technically feasible.

10.4.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

CCS (i.e., sequestration or transfer of CO_2) is the most effective control option for the control of the CO_2 streams from the amine units to the thermal oxidizers. Good thermal oxidizer design and operation result in approximately 1-15% and 1-10% reduction in GHG emissions, respectively. [43]

Low carbon fuel selection and the implementation of good combustion, operating, maintenance practices are technically feasible control options for minimizing GHG emissions from fuel combustion. Since Freeport LNG proposes to implement all these control options, ranking these control options is not necessary.

10.4.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

The energy, environmental, and economic impacts of CO_2 sequestration and transfer options are discussed below.

[43] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry*, U.S. EPA, October 2010, Section 3.

10.4.4.1 GEOLOGICAL SEQUESTRATION OF CO_2 EFFLUENT FROM AMINE UNITS

Freeport LNG undertook a feasibility study of geological sequestration underneath the Pretreatment Facility site of the roughly 42 million cubic feet per day (MMCFD) of atmospheric-pressure CO_2 produced by the amine recovery units there. This CO_2 stream, which equates to about 896,000 tons per year of CO_2-equivalent, contains sulfur compounds and water which would be removed farther downstream in the Pretreatment Facility, if not captured at this point for sequestration.

The first step in the feasibility study was an evaluation to determine if the subsurface geologic setting beneath the Pretreatment Facility site would provide a viable option for long-term geological sequestration of the CO2 stream. The subsurface characterization included: hydrogeology; storage reservoir depth, thickness, porosity/permeability, injectivity and storage capacity; confining zone thickness, continuity and integrity; trapping and containment mechanisms; and faulting. Artificial penetrations in the surrounding area were surveyed as well. The characterization determined that the Jasper aquifer within the Oakville Sandstone in the Lower Miocene was a strong candidate for successful sequestration. This aquifer is used extensively along the Texas Gulf Coast for disposal of various media.

The second step in the feasibility study was the development of a geological simulation model and analysis. The analysis studied the migration of the 42 MMCFD CO_2 stream over 30 years when injected into the Jasper aquifer below the Pretreatment Facility site at several different levels with varying fault integrity assumptions. The modeling showed that the CO_2 injection rate would be maintained in all cases over the 30 year period; that the CO_2 plume remains within about one mile of the injection well and within or near the fault boundaries in all cases; and that plume growth across any faults would be minimal.

Having demonstrated the potential technical viability of CO_2 geological sequestration, the final step in the feasibility study was a preliminary cost analysis of sequestration. The estimated cost of the injection well was estimated to be approximately $4 million. The cost of electric-driven compression facilities to force the CO_2 into the aquifer with a wellhead injection pressure of around 1500 psia was estimated to be around $39 million. Thus, the total capital cost of geological sequestration was projected to be approximately $43 million. The annual operating and maintenance costs were estimated to be approximately $9 million, with almost 90% of the cost being power for the compressors. 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, was estimated to be nearly $13 million, or approximately $14/ton of CO_2 sequestered. This would represent a very burdensome expense for the Pretreatment Facility, increasing its overall operating costs substantially without any revenue or other offset, so geological sequestration is not regarded as an economically feasible CO2 control option.

This cost estimate does not even take into account liability and long-term stewardship responsibilities in the context of geologic sequestration of anthropogenic CO_2. A full liability regime has yet to be established for Texas, although Texas law assigns ownership of anthropogenic carbon dioxide stored in a geologic storage facility to the storage operator, or the storage operator's heirs, successors or assigns. Tex. Nat. Resource Code, § 120.002.

10.4.4.2 ENHANCED OIL RECOVERY USING CO_2 EFFLUENT FROM AMINE UNITS

Freeport LNG undertook a feasibility study of using the roughly 42 MMCFD of atmospheric-pressure CO_2 produced by the amine recovery units at the Pretreatment Facility as a supplemental supply to Denbury Resources' CO_2-injection EOR project in Hastings, Texas some 37 miles away. This CO_2 stream contains sulfur compounds and water which would be removed farther downstream in the Pretreatment Facility. The principal CO_2 supply for Denbury's EOR project is its Jackson Dome in Mississippi and is delivered to Hastings by its Green Pipeline affiliate. Supplemental supply will come from, among other alternatives, Leucadia Energy's petroleum coke-to-chemicals project near the Green Pipeline in Louisiana which is under development and partially funded by the Department of Energy.

The first step in the feasibility study was an analysis undertaken to develop a preliminary route, design and cost estimate for a pipeline from the Pretreatment Facility to Denbury's EOR project. A possible route was identified that paralleled existing utility rights-of-way for more than 80% of the distance and skirted sensitive environmental areas and population centers wherever possible. The cost of the pipeline was estimated to be around $55 million.

The second step in the feasibility study was an evaluation undertaken to develop a preliminary design and cost for the necessary treatment and compression facilities. Denbury requires very clean CO_2, with most of the sulfur compounds and water removed from the CO_2 effluent of the amine units. Denbury also requires delivered CO_2 at very high pressures for its EOR project, so compression of the treated CO_2 would be required at the Pretreatment Facility to around 2000 psia. The cost for treatment, compression, and delivery to Denbury is estimated to be $114 million. The annual operating and maintenance expenses were estimated to be approximately $9.5 million, with about 80% of the cost being power. 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, was estimated to be nearly $20 million, or more than $22/ton of CO_2.

The final step in the feasibility study was to engage Denbury in commercial discussions regarding possible terms and conditions for the sale of FLNG's CO_2. Denbury confirmed its potential ability to accept the treated volumes at some time in the future, but its current and anticipated future alternative CO_2 supply costs are significantly less than $22/ton. If Freeport LNG were to sell its CO_2 to Denbury at their alternative cost, the net loss to Freeport LNG would represent a very burdensome expense for the Pretreatment Facility. Therefore, sale of CO_2 to Denbury for EOR is not regarded as a viable or economically feasible CO_2 control option.

Therefore, based on the additional energy, environmental, and economic analysis and lack of commercial demonstration of these technologies on a large scale, the use of sequestration or transfer of CO_2 for EOR is not considered BACT for the proposed project.

No adverse energy, environmental, or economic impacts are associated with the other control options identified.

10.4.5 STEP 5 – SELECT BACT FOR THE THERMAL OXIDIZERS

Freeport LNG proposes the following design elements and work practices as BACT for the thermal oxidizers:

- Proper Thermal Oxidizer Design and Operation;
- Use of BOG or natural gas as fuel; and
- Implementation of good combustion, operating, and maintenance practices.

In addition, Freeport LNG proposes the following as numerical BACT limits for total GHG emissions emitted from the amine unit/thermal oxidizers:

- 301,341 short tons of CO_2e per year for each thermal oxidizer (based on a 12-month rolling average)
- Limit natural gas pretreatment rate to 650 MMscf per day for each pretreatment train

Compliance with these emission limits and throughput limits will be demonstrated by monitoring inlet gas throughput rate and performing calculations consistent with Appendix A of the application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average throughput and CO_2e/yr emission rates do not exceed these limits.

10.5 FLARES – GHG BACT FOR PROCESS EMISSIONS AND COMBUSTION EMISSIONS

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.

The flare venting will be limited to 167.2 MMscf/yr for the Liquefaction Flare and 3 MMscf/yr for the NGL flare from MSS activities. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas to the flare.

CO_2 emissions from flaring process gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the flare during MSS events and the pilot fuel. CO_2 emissions from the flare are based on the estimated flared carbon-containing gases derived from heat and material balance data. In addition, minor CH_4 emissions from the flare are produced due to incomplete combustion of CH_4.

The flares are an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[44]

The following sections present a BACT evaluation for GHG emissions from combustion of vent gas released to the flare during planned startup and shutdown events.

10.5.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The available GHG emission control strategies for the flares that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration
- Flare Gas Recovery
- Good Flare Design
- Limited vent gas releases to flare

10.5.1.1 CARBON CAPTURE AND SEQUESTRATION

A detailed discussion of the feasibility and availability of CCS technology is provided in Section 10.4. CO_2 emissions from the flares will result from the combustion of CH_4 and VOC present in the process gas. Incomplete combustion of CH_4 and VOCs will also result in CH_4 emissions from the flare. With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option. Pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent process gas streams routed to a flare. In addition, the CO_2 has already been removed (in the amine units) from the vent gas that is sent to either the Liquefaction or NGL flares. Flaring will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates resulting in a

[44] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2 (0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

very intermittent CO_2 stream; thus, CCS is not considered a technically feasible option.

10.5.1.2 FLARE GAS RECOVERY

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable. Flaring will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates. Due to infrequent MSS activities and the amount of gas sent to the flare , it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control.

10.5.1.3 GOOD FLARE DESIGN

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.

10.5.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

As discussed in Section 10.5.1.1, CCS is not technically feasible for intermittent sources such as the flares proposed in the Liquefaction Project. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial process flares; however as stated above, the amount of flare gas produced by this project will not sustain a flare gas recovery system. For this project, flare gas recovery is infeasible.

Use of a good flare design with appropriate instrumentation and control is a demonstrated and available option.

10.5.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

With elimination of CCS and flare gas recovery as technically infeasible control options, use of a good flare design with appropriate instrumentation and control is the only remaining option for the flare. Natural gas-fired pilots and good flare design will be applied as CO_2 GHG BACT for the flares in order to minimize emissions.

10.5.4 Step 4 – Evaluate Most Effective Control Options

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with operating a flare to control vent gas or using good flare design are expected.

10.5.5 Step 5 – Select BACT for the Flares

Use of a good flare design with appropriate instrumentation and control is the only remaining option. Natural gas-fired pilots and good flare design will be applied as GHG BACT for the flare in order to minimize emissions from the flare. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled.

Freeport LNG also proposes the following as numerical BACT limits for process-based GHG emissions:

- NGL Flare – Limiting vent gas releases to the flare to no more than 3 MMscf/yr during planned startup and shutdown events
- Liquefaction Flare - Limiting vent gas releases to the flare to no more than 167 MMscf/yr during planned startup and shutdown events

Compliance with these throughput limits will be demonstrated by monitoring inlet gas throughput rate/flare vent gas flow rate and performing calculations consistent with Appendix A of the application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average throughput and CO_2e/yr emission rates do not exceed these limits.

10.6 Emergency Generators and Firewater Pumps – GHG BACT

The proposed Liquefaction Project will use a total of six 755-hp emergency generators (two units at the Pretreatment Facility and four units at the Liquefaction Plant) to serve as a reliable power source for lighting and other emergency equipment in the event of a power failure. The engines will be diesel-fuel fired units and used for emergency purposes only except for weekly readiness and maintenance testing. In addition, two 660-hp firewater pumps will be used for the proposed project, one at each plant, for the facility's firewater systems. The firewater pumps will also use diesel fuel. Each emergency generator and firewater pump will be limited to 100 hours of operation per year for purposes of maintenance and testing. CO_2 emissions from the generator engines are produced from the combustion of hydrocarbons present in the diesel fuel. CH_4 emissions result from incomplete combustion of hydrocarbons present in the diesel fuel. N_2O emissions from diesel-fueled units form solely as a byproduct of combustion.

The following sections present a BACT evaluation of GHG emissions from the emergency generator engines and the firewater pumps.

10.6.1 Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for emergency generators and firewater pumps that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Selection of fuel efficient engines;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices

10.6.1.1 CARBON CAPTURE AND SEQUESTRATION

CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process.

10.6.1.2 EFFICIENT ENGINE DESIGN

Since the Freeport LNG is proposing to install new emergency generators and firewater pumps, the equipment is designed to optimal combustion efficiency.

10.6.1.3 FUEL SELECTION

The only technically feasible fuel for 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.

10.6.1.4 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 per the manufacturer's specifications.

10.6.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

As discussed above, CCS is not technically feasible for the emergency equipment. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

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.

All other control technologies are considered feasible.

10.6.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Freeport LNG will select engines and firewater pumps with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

10.6.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

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

10.6.5 STEP 5 – SELECT CO_2 BACT FOR EMERGENCY GENERATOR ENGINES

Based on the selection of a fuel efficient generators and firewater pumps and implementing good combustion, operating and maintenance practices, Freeport LNG proposes a CO_2e BACT limit of 43 short tons per year on a 12-month rolling average basis for each of the six emergency generators and CO_2e BACT limit of 37 short tons per year on a 12-month rolling average basis for each of the two firewater pumps. To comply with the proposed CO_2e BACT limits, Freeport LNG will purchase emergency generator/firewater pump internal combustion engines (ICEs) certified by the manufacturer to meet applicable emission standards and will also monitor diesel fuel usage on a monthly basis.

Actual CO_2e emissions from the generator engines will be calculated based on the fuel usage records and the emission factor for distillate fuel oil No. 2 combustion from Table C-1 to Subpart C of the MRR. Operation of each generator ICE and firewater pump, for purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance), will be limited to 100 hours per year.

10.7 FUGITIVE COMPONENTS – GHG BACT

The following sections present a BACT evaluation of fugitive CO_2 and CH_4 emissions. It is anticipated that the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4; therefore, the BACT evaluation for these two pollutants has been combined into a single analysis. Fugitive components at the proposed Liquefaction Project include: valves, pressure relief valves, pump seals, compressor seals, and sampling connections.

GHG emissions from leaking pipe components (fugitive emissions) from the proposed project include CH_4 and CO_2. The ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. For purposes of the GHG calculations, it was assumed all piping components are in a rich CH_4 stream.

10.7.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified:

- ▲ Installing leakless technology components to eliminate fugitive emission sources;
- ▲ Implementing various 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 for compounds; and
- ▲ Designing and constructing facilities with high quality components and materials of construction compatible with the process.

10.7.2 Step 2 – Eliminate Technically Infeasible Options

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as 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 hydrocarbons.

Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods. The fuel gases and process fluids in Liquefaction Project piping components are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

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. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

10.7.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL 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 bellow, 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 is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97%.

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. 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.

10.7.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

With leakless components eliminated from consideration, Freeport LNG proposes to implement the most effective remaining control option. Instrumented monitoring implemented through the 28 MID LDAR program, with control effectiveness on 97%, is considered top BACT. In addition, Freeport will utilize an AVO program to monitor for leaks in between instrumented checks. The proposed project will also utilize high quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed. Since Freeport is implementing the most effective control options available, additional analysis is not necessary.

10.7.5 Step 5 – Select CH_4 BACT for Fugitive Emissions

Fugitive CH_4 is the major component of the GHG emissions from piping components, Freeport LNG proposes to implement a work practice as BACT. The 28MID LDAR program will be used to detect any leaks and repairs will be performed as soon as practicable. In addition, Freeport LNG will implement an AVO program in between LDAR checks.

10.8 Circuit Breakers – GHG BACT (SF_6 Emissions)

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, releases from gas cylinders used for equipment maintenance and repair operations, and SF_6 handling operations. The following section proposes appropriate GHG BACT for SF_6 emissions.

10.8.1 Step 1 – Identify All Available Control Technologies

In determining whether a technology is available for controlling and reducing SF_6 emissions from circuit breakers, permits and permit applications and EPA's RBLC were consulted. In addition, currently available literature was reviewed to identify emission reduction methods.[45,46,47] Based on these resources, the following available control technologies were identified:

- 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.

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[45] 10 Steps to Help Reduce SF_6 Emissions in T&D, Robert Mueller, Airgas Inc., available at: http://www.airgas.com/documents/pdf/50170-120.pdf.

[46] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, U.S. Environmental Protection Agency, December 2008, available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

[47] SF^6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), June 2006, available at: http://www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.

10.8.2 Step 2 – Eliminate Technically Infeasible Options

Of the control technologies identified above, only substitution of SF_6 with other non-GHG substance is determined as technically infeasible. While dielectric oil or compressed air circuit breakers have been used historically, these units require large equipment components to achieve the same insulating capabilities of SF_6 circuit breakers. In addition, per the EPA,

"No clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[48]

All other control technologies are technically feasible. Freeport LNG proposes to implement these methods to reduce and control SF_6 emissions.

10.8.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Since Freeport LNG proposes to implement feasible control options, ranking these control options is not necessary.

10.8.4 Step 4 – Evaluate Most Effective Control Options

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

10.8.5 Step 5 – Select SF_6 BACT for Circuit Breakers

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 (the current maximum leak rate standard established by the International Electrotechnical Commission [IEC]);
- 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.

[48] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, U.S. Environmental Protection Agency, December 2008, available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

APPENDIX A

EMISSION CALCULATIONS

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	12/16/2011	Permit No.:	TBD	Regulated Entity No.:	RN103196689/TBA
Area Name:	Freeport LNG Development, L.P.			Customer Reference No.:	CN601720345

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TPY
HRTCAP	HRTCAP	Low Temperature and High Temperature Heater Cap	CO_2e	--	100486.45
			CO_2	--	100388.00
			N_2O	--	0.19
			CH_4	--	1.89
6B-1811A	6B-1811A	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811B	6B-1811B	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811C	6B-1811C	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811D	6B-1811D	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811E	6B-1811E	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811F	6B-1811F	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811G	6B-1811G	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1811H	6B-1811H	Low Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TPY
6B-1812A	6B-1812A	High Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
6B-1812B	6B-1812B	High Temperature Heating	CO_2e	9945.22	--
		Medium Heater	CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
TO1	AU1/TO1	Amine Unit / Thermal Oxidizer 1	CO_2e	68799.20	301340.50
			CO_2	68798.63	301337.99
			N_2O	0.00	0.005
			CH_4	0.01	0.05
TO2	AU2/TO2	Amine Unit / Thermal Oxidizer 2	CO_2e	68799.20	301340.50
			CO_2	68798.63	301337.99
			N_2O	0.00	0.005
			CH_4	0.01	0.05
TO3	AU3/TO3	Amine Unit / Thermal Oxidizer 3	CO_2e	68799.20	301340.50
			CO_2	68798.63	301337.99
			N_2O	0.00	0.005
			CH_4	0.01	0.05
CT1 (A) & CT1 (B)	CT1 (A) & CT1 (B)	Combustion Turbine	CO_2e	128468.78	562693.25
			CO_2	128342.91	562141.93
			N_2O	0.24	1.06
			CH_4	2.42	10.60
NGLFLARE	NGLFLARE	NGL Flare	CO_2e	26.85	644.38
			CO_2	26.75	642.05
			N_2O	0.00	0.01
			CH_4	0.00	0.03
PTFFWP	PTFFWP	Fire Water Pump - Pretreatment	CO_2e	755.84	37.25
			CO_2	753.30	37.13
			N_2O	0.01	0.000
			CH_4	0.03	0.002
PTFEG-1	PTFEG-1	Emergency Generator 1 - Pretreatment	CO_2e	864.63	42.61
			CO_2	861.73	42.47
			N_2O	0.01	0.000
			CH_4	0.03	0.002
PTFEG-2	PTFEG-2	Emergency Generator 2 - Pretreatment	CO_2e	864.63	42.61
			CO_2	861.73	42.47
			N_2O	0.01	0.000
			CH_4	0.03	0.002
FUG-TREAT	FUG-TREAT	Pretreatment Fugitives	CO_2e	99.96	437.82
			CO_2	0.00	0.000
			N_2O	0.00	0.000
			CH_4	4.76	20.85
FUG-PTFSF6	FUG-PTFSF6	Pretreatment Circuit Breakers	CO_2e	13.34	58.44
			SF_6	0.001	0.002
LIQFWP	LIQFWP	Fire Water Pump - Liquefaction	CO_2e	755.84	37.25
			CO_2	753.30	37.13
			N_2O	0.01	0.000
			CH_4	0.03	0.002

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TPY
LIQEG-1	LIQEG-1	Emergency Generator 1 - Liquefaction	CO_2e	864.63	42.61
			CO_2	861.73	42.47
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQEG-2	LIQEG-2	Emergency Generator 2 - Liquefaction	CO_2e	864.63	42.61
			CO_2	861.73	42.47
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQEG-3	LIQEG-3	Emergency Generator 3 - Liquefaction	CO_2e	864.63	42.61
			CO_2	861.73	42.47
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQEG-4	LIQEG-4	Emergency Generator 4 - Liquefaction	CO_2e	864.63	42.61
			CO_2	861.73	42.47
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQFLARE	LIQFLARE	Ground Flare - Liquefaction	CO_2e	160.04	11523.03
			CO_2	159.89	11511.74
			N_2O	0.00	0.02
			CH_4	0.00	0.22
FUG-LIQ	FUG-LIQ	Liquefaction Fugitives	CO_2e	46.19	202.31
			CO_2	0.00	0.000
			N_2O	0.00	0.000
			CH_4	2.20	9.63
FUG-LIQSF6	FUG-LIQSF6	Liquefaction Circuit Breakers	CO_2e	77.52	339.56
			SF_6	0.003	0.014

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		**Permit No.:**		**Regulated Entity No.:**	**RN103196689/TBA**
Area Name:	**Freeport LNG Development, L.P.**			**Customer Reference No.:**	CN601720345

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Tab

AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building	**6. Height Above**	**7. Stack Exit Data**			**8. Fugitives**		
EPN (A)	**FIN (B)**	**Name ©**	**Zone**	**East (Meters)**	**North (Meters)**	**Height (Ft.)**	**Ground (Ft.)**	**Diameter (Ft.) (A)**	**Velocity (FPS) (B)**	**Temperature (°F) (C)**	**Length (Ft.) (A)**	**Width (Ft.) (B)**	**Axis Degrees (C)**
6B-1811A	6B-1811A	Low Temp Htr	15	275075	3211868		50.00	4.00	81.00	500			
6B-1811B	6B-1811B	Low Temp Htr	15	275069	3211875		50.00	4.00	81.00	500			
6B-1811C	6B-1811C	Low Temp Htr	15	275086	3211888		50.00	4.00	81.00	500			
6B-1811D	6B-1811D	Low Temp Htr	15	275092	3211881		50.00	4.00	81.00	500			
6B-1811E	6B-1811E	Low Temp Htr	15	275099	3211873		50.00	4.00	81.00	500			
6B-1811F	6B-1811F	Low Temp Htr	15	275105	3211866		50.00	4.00	81.00	500			
6B-1811G	6B-1811G	Low Temp Htr	15	275111	3211858		50.00	4.00	81.00	500			
6B-1811H	6B-1811H	Low Temp Htr	15	275117	3211851		50.00	4.00	81.00	500			
6B-1812A	6B-1812A	High Temp Htr	15	275101	3211838		50.00	4.00	81.00	500			
6B-1812B	6B-1812B	High Temp Htr	15	275095	3211845		50.00	4.00	81.00	500			
TO1	AU1/TO1	Amine Unit / Thermal Oxidize	15	274704	3211819		80.00	2.50	50.00	170			
TO2	AU2/TO2	Amine Unit / Thermal Oxidize	15	274799	3211891		80.00	2.50	50.00	170			
TO3	AU3/TO3	Amine Unit / Thermal Oxidize	15	274892	3211965		80.00	2.50	50.00	170			
CT1 (A)	CT1 (A)	Combustion Turbine	15	275003	3211827		80.00	14.67	35.40	431			
CT1 (B)	CT1 (B)	Combustion Turbine	15	275011	3211832		80.00	14.67	35.40	431			
NGLFLARE	NGLFLARE	NGL Flare	15	275131	3211991		110	5.75	20.00	1832			
PTFFWP	PTFFWP	Fire Water Pump - Pretreatment	15	274663	3211785		10	0.83	140.00	1,187			
PTFEG-1	PTFEG-1	Emergency Generator 1 - Pretreatment	15	274750	3211699		10	0.5	220	810			
PTFEG-2	PTFEG-2	Emergency Generator 2 - Pretreatment	15	274876	3211718		10	0.5	220	810			
FUG-TREAT	FUG-TREAT	Pretreatment Fugitives	15	274880	3211850								
FUG-PTFSF6	FUG-PTFSF6	Pretreatment Circuit Breakers	15	274880	3211850								
LIQFWP	LIQFWP	Fire Water Pump - Liquefaction	15	273885	3202680		10	0.83	140.00	1,187			
LIQEG-1	LIQEG-1	Emergency Generator 1 - Liquefaction	15	273469	3202105		10	0.5	220	810			
LIQEG-2	LIQEG-2	Emergency Generator 2 - Liquefaction	15	273638	3202214		10	0.5	220	810			
LIQEG-3	LIQEG-3	Emergency Generator 3 - Liquefaction	15	273806	3202327		10	0.5	220	810			
LIQEG-4	LIQEG-4	Emergency Generator 4 - Liquefaction	15	273513	3202248		10	0.5	220	810			
LIQFLARE	LIQFLARE	Ground Flare - Liquefaction	15	273205	3202040		7	0.25	0.00	1832			
FUG-LIQ	FUG-LIQ	Liquefaction Fugitive	15	273890	3202680								
FUG-LIQSF6	FUG-LIQSF6	Liquefaction Circuit Breakers	15	273890	3202680								

Liquefaction Project GHG Emissions Summary
Freeport LNG

EPN	Description	Annual Emissions (short tons/yr)				
		CO_2	CH_4	N_2O	SF_6	CO_2e [2]
LIQFWP	Fire Water Pump	37.13	0.002	0.0003	--	37
PTFEG-1	Emergency Generator 1	42.47	0.002	0.0003	--	43
PTFEG-2	Emergency Generator 2	42.47	0.002	0.0003	--	43
6B-1811A	Low Temp Heater 1	43,517.36	0.821	0.0821	--	43,560
6B-1811B	Low Temp Heater 2	43,517.36	0.821	0.0821	--	43,560
6B-1811C	Low Temp Heater 3	1,669.16	0.031	0.0031	--	1,671
6B-1811D	Low Temp Heater 4	1,669.16	0.031	0.0031	--	1,671
6B-1811E	Low Temp Heater 5	1,669.16	0.031	0.0031	--	1,671
6B-1811F	Low Temp Heater 6	1,669.16	0.031	0.0031	--	1,671
6B-1811G	Low Temp Heater 7	1,669.16	0.031	0.0031	--	1,671
6B-1811H	Low Temp Heater 8	1,669.16	0.031	0.0031	--	1,671
6B-1812A	High Temp Heater 1	1,669.16	0.031	0.0031	--	1,671
6B-1812B	High Temp Heater 2	1,669.16	0.031	0.0031	--	1,671
TO1	Amine Unit / Thermal Oxidizer 1	301,337.99	0.048	0.0048	--	301,341
TO2	Amine Unit / Thermal Oxidizer 2	301,337.99	0.048	0.0048	--	301,341
TO3	Amine Unit / Thermal Oxidizer 3	301,337.99	0.048	0.0048	--	301,341
NGLFLARE	NGL Flare	642.05	0.029	0.0056	--	644
CT1 (A) & CT1 (B)	Combustion Turbine	562,141.93	10.602	1.0602	--	562,693
FUG-TREAT	Pretreatment Fugitives	0.00	20.848	--	--	438
FUG-PTFSF6	Pretreatment Circuit Breakers	0.00	--	--	0.002	58
LIQFWP	Fire Water Pump	37.13	0.002	0.0003	--	37
LIQEG-1	Emergency Generator 1	42.47	0.002	0.0003	--	43
LIQEG-2	Emergency Generator 2	42.47	0.002	0.0003	--	43
LIQEG-3	Emergency Generator 3	42.47	0.002	0.0003	--	43
LIQEG-4	Emergency Generator 4	42.47	0.002	0.0003	--	43
LIQFLARE	Ground Flare	11,511.74	0.217	0.0217	--	11,523
FUG-LIQ	Fugitives Liquefaction	--	9.634	--	--	202
FUG-LIQSF6	Liquefaction Circuit Breakers	--	--	--	0.01	340
Project Totals		**1,579,026.77**	**43.38**	**1.29**	**0.017**	**1,580,737**

Pretreatment Facility GHG Summary of Emissions

EPN	Description	Annual Emissions [1] (short tons/yr) CO_2	CH_4	N_2O	SF_6	CO_2e [2]
LIQFWP	Fire Water Pump	37.13	1.51E-03	3.01E-04	--	37
PTFEG-1	Emergency Generator 1	42.47	1.72E-03	3.45E-04	--	43
PTFEG-2	Emergency Generator 2	42.47	1.72E-03	3.45E-04	--	43
6B-1811A	Low Temp Heater 1	43,517.36	0.82	0.08	--	43,560
6B-1811B	Low Temp Heater 2	43,517.36	0.82	0.08	--	43,560
6B-1811C	Low Temp Heater 3	1,669.16	0.03	3.15E-03	--	1,671
6B-1811D	Low Temp Heater 4	1,669.16	0.03	3.15E-03	--	1,671
6B-1811E	Low Temp Heater 5	1,669.16	0.03	3.15E-03	--	1,671
6B-1811F	Low Temp Heater 6	1,669.16	0.03	3.15E-03	--	1,671
6B-1811G	Low Temp Heater 7	1,669.16	0.03	3.15E-03	--	1,671
6B-1811H	Low Temp Heater 8	1,669.16	0.03	3.15E-03	--	1,671
6B-1812A	High Temp Heater 1	1,669.16	0.03	3.15E-03	--	1,671
6B-1812B	High Temp Heater 2	1,669.16	0.03	3.15E-03	--	1,671
TO1	Amine Unit / Thermal Oxidizer 1	301,337.99	0.05	4.83E-03	--	301,341
TO2	Amine Unit / Thermal Oxidizer 2	301,337.99	0.05	4.83E-03	--	301,341
TO3	Amine Unit / Thermal Oxidizer 3	301,337.99	0.05	4.83E-03	--	301,341
NGLFLARE	NGL Flare	642.05	0.03	5.58E-03	--	644
CT1 (A) & CT1 (B)	Combustion Turbine	562,141.93	10.60	1.06	--	562,693
FUG-TREAT	Pretreatment Fugitives	--	20.85	--	--	438
FUG-PTFSF6	Pretreatment Circuit Breakers	--	--	--	2.45E-03	58
	Total Emissions	**1,567,308.02**	**33.52**	**1.27**	**0.002**	**1,568,464**

[1] Annual Emissions (short tons/yr) = Annual Emissions (metric tons/yr) * 1.1023 (short tons/metric tons)

[2] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

Liquefaction Plant GHG Summary of Emissions

EPN	Description	Annual Emissions [1] (short tons/yr) CO_2	CH_4	N_2O	SF_6	CO_2e [2]
LIQFWP	Fire Water Pump	37.13	1.51E-03	3.01E-04	--	37
LIQEG-1	Emergency Generator 1	42.47	1.72E-03	3.45E-04	--	43
LIQEG-2	Emergency Generator 2	42.47	1.72E-03	3.45E-04	--	43
LIQEG-3	Emergency Generator 3	42.47	1.72E-03	3.45E-04	--	43
LIQEG-4	Emergency Generator 4	42.47	1.72E-03	3.45E-04	--	43
LIQFLARE	Ground Flare	11,511.74	0.22	0.02	--	11,523
FUG-LIQ	Fugitives Liquefaction	--	9.63	--	--	202
FUG-LIQSF6	Fugitives Liquefaction	--	--	--	0.01	340
	Total Emissions	**11,718.75**	**9.86**	**0.02**	**0.01**	**12,273**

[1] Annual Emissions (short tons/yr) = Annual Emissions (metric tons/yr) * 1.1023 (short tons/metric tons)

[2] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting* , Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

Sources of GHG Emissions

Parameter	Units	Fire Water Pump	Emergency Generator 1	Emergency Generator 2	Low Temp Heater 1	Low Temp Heater 2	Low Temp Heater 3	Low Temp Heater 4	Low Temp Heater 5	Low Temp Heater 6	Low Temp Heater 7	Low Temp Heater 8	High Temp Heater 1	High Temp Heater 2	Amine Unit / Thermal Oxidizer 1	Amine Unit / Thermal Oxidizer 2	Amine Unit / Thermal Oxidizer 3	Combustion Turbine
EPN	-	LIQFWP	PTFEG-1	PTFEG-2	6B-1811A	6B-1811B	6B-1811C	6B-1811D	6B-1811E	6B-1811F	6B-1811G	6B-1811H	6B-1812A	6B-1812B	TO1	TO2	TO3	CT1 (A) & CT1 (B)
Rated Capacity [1]	MMBtu/hr	4.62	5.29	5.29	85	85	85	85	85	85	85	85	85	85	5	5	5	1098
Hours of Operation per Year	hrs/yr	100	100	100	8,760	8,760	336	336	336	336	336	336	336	336	8,760	8,760	8,760	8,760
Natural Gas Potential Throughput [2]	scf/yr	--	--	--	724,319,066	724,319,066	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	42,607,004	42,607,004	42,607,004	9,356,498,054
Diesel Potential Throughput [2]	gal/yr	3,300	3,775	3,775	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Natural Gas High Heat Value (HHV) [3]	MMBtu/scf	--	--	--	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
No.2 Fuel Oil High Heat Value (HHV)	MMBtu/gal	0.138	0.138	0.138	--	--	--	--	--	--	--	--	--	--	--	--	--	--

[1] Per AP-42 Table 3.3-1 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines Brake Specific Fuel Consumption Factor = 7,000 BTU/hp-hr

[2] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value

[3] High heating value for No.2 Fuel Oil and Natural Gas obtained from 40 CFR Part 98, Subpart C, Table C-1.

GHG Emission Factors for Diesel Engine

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel.

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1, 2] (metric tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [1, 2, 3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
LIQFWP	Fire Water Pump	No.2 Fuel Oil	Tier I	34	1.37E-03	2.73E-04	34	753	0.03	6.11E-03	756
PTFEG-1	Emergency Generator 1	No.2 Fuel Oil	Tier I	39	1.56E-03	3.13E-04	39	862	0.03	6.99E-03	865
PTFEG-2	Emergency Generator 2	No.2 Fuel Oil	Tier I	39	1.56E-03	3.13E-04	39	862	0.03	6.99E-03	865
6B-1811A	Low Temp Heater 1	Natural Gas	Tier I	39,479	0.74	0.07	39517	9,935	0.19	0.02	9945
6B-1811B	Low Temp Heater 2	Natural Gas	Tier I	39,479	0.74	0.07	39517	9,935	0.19	0.02	9945
6B-1811C	Low Temp Heater 3	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1811D	Low Temp Heater 4	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1811E	Low Temp Heater 5	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1811F	Low Temp Heater 6	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1811G	Low Temp Heater 7	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1811H	Low Temp Heater 8	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1812A	High Temp Heater 1	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
6B-1812B	High Temp Heater 2	Natural Gas	Tier I	1,514	0.03	2.86E-03	1516	9,935	0.19	0.02	9945
TO1	Amine Unit / Thermal Oxidizer 1	Natural Gas	Tier I	2,322	0.04	4.38E-03	2325	584	0.01	1.10E-03	585
TO2	Amine Unit / Thermal Oxidizer 2	Natural Gas	Tier I	2,322	0.04	4.38E-03	2325	584	0.01	1.10E-03	585
TO3	Amine Unit / Thermal Oxidizer 3	Natural Gas	Tier I	2,322	0.04	4.38E-03	2325	584	0.01	1.10E-03	585
CT1 (A) & CT1 (B)	Combustion Turbine	Natural Gas	Tier I	509,972	9.62	0.96	510472	128,343	2.42	0.24	128469
			Total	608,120.77	11.47	1.15	608,717	231,927.70	4.43	0.45	232,161
			Total CO_2e Emissions [4]	-	-	-	608,717	-	-	-	232,161

[1] CO_2 emissions from No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

[3] kg to lb conve 2.2046 lb/kg

[4] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Freeport LNG Development, L.P.
Liquefaction Plant GHG Emissions from Combustion Sources

Sources of GHG Emissions

Source Name	Units	Fire Water Pump	Emergency Generator 1	Emergency Generator 2	Emergency Generator 3	Emergency Generator 4
EPN	-	PTFFWP	LIQEG-1	LIQEG-2	LIQEG-3	LIQEG-4
Rated Capacity	hp	660	755	755	755	755
Heat Input Capacity [1]	MMBtu/hr	4.62	5.29	5.29	5.29	5.29
Hours of Operation per Year	hrs/yr	100	100	100	100	100
Potential Throughput [2]	gal/yr	3,300	3,775	3,775	3,775	3,775
No.2 Fuel Oil High Heat Value (HHV) [3]	MMBtu/gal	0.138	0.138	0.138	0.138	0.138

[1] Per AP-42 Table 3.3-1 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines Brake Specific Fuel Consumption Factor = 7,000 BTU/hp-hr
[2] 1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu.
[3] High heating value for No.2 Fuel Oil obtained from 40 CFR Part 98, Subpart C, Table C-1.

GHG Emission Factors for Diesel Engine

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1, 2] (metric tons) CO_2	CH_4	N_2O	CO_2e	Hourly Emissions [1, 2, 3] (lb/hr) CO_2	CH_4	N_2O	CO_2e
PTFFWP	Fire Water Pump	No.2 Fuel Oil	Tier I	33.68	1.37E-03	2.73E-04	34	753.30	3.06E-02	6.11E-03	756
LIQEG-1	Emergency Generator 1	No.2 Fuel Oil	Tier I	38.53	1.56E-03	3.13E-04	39	861.73	3.50E-02	6.99E-03	865
LIQEG-2	Emergency Generator 2	No.2 Fuel Oil	Tier I	38.53	1.56E-03	3.13E-04	39	861.73	3.50E-02	6.99E-03	865
LIQEG-3	Emergency Generator 3	No.2 Fuel Oil	Tier I	38.53	1.56E-03	3.13E-04	39	861.73	3.50E-02	6.99E-03	865
LIQEG-4	Emergency Generator 4	No.2 Fuel Oil	Tier I	38.53	1.56E-03	3.13E-04	39	861.73	3.50E-02	6.99E-03	865
			Total	187.80	7.62E-03	1.52E-03	188	4,200.23	0.17	0.03	4,214
			Total CO_2e Emissions [4]		-	-	188		-	-	4,214

[1] CO_2 emissions from No.2 Fuel Oil combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions No.2 Fuel Oil combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.
[3] kg to lb conversion 2.2046 lb/kg
[4] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting* , Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Thermal Oxidizer GHG Potential Emission Calculations

FIN	EPN	Source Name	Total Molar Flow for CO_2 [1] (lbmol/hr)	Annual Hours of Operation (hr/yr)	Hourly Emissions for CO_2 [2] (lb/hr)	Annual Emissions for CO_2 [3] (tpy)
AU1/TO1	TO1	Amine Unit / Thermal Oxidizer 1	1,550.32	8,760	68,214	298,778
AU2/TO2	TO2	Amine Unit / Thermal Oxidizer 2	1,550.32	8,760	68,214	298,778
AU3/TO3	TO3	Amine Unit / Thermal Oxidizer 3	1,550.32	8,760	68,214	298,778
				Total CO_2 Emissions	**204,643**	**896,334**

[1] Total molar flow for carbon dioxide obtained from Anguil Environmental Systems Thermal Oxidizer Proposal dated September 28, 2011.

[2] Hourly Emissions (lb/hr) = Total Molar Flow (lbmol/hr) * Molecular Weight of CO_2

$$\text{EPN TO1 } CO_2 \text{ Hourly Emissions (lb/hr)} = \frac{1{,}550.32 \text{ lb mol}}{\text{hr}} \left| \frac{44 \text{ lb}}{\text{lbmol}} \right. = 68{,}214 \text{ lb/hr}$$

[3] Annual Emissions (tpy) = Hourly Emissions (lb/hr) * Annual Operating Hours (hrs/yr) * 1 / 2,000 (ton/lb)

$$\text{EPN TO1 } CO_2 \text{ Annual Emissions (tpy)} = \frac{68{,}214 \text{ lb}}{\text{hr}} \left| \frac{8{,}760 \text{ hr}}{\text{yr}} \right| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 298{,}778 \text{ tpy}$$

Flare Design and Operational Parameters

Flare Parameters [1]	Value	Units
Pilot Gas Flow	1,870,000	Btu/hr
Annual Pilot Gas Flow	16,381	MMBtu/yr
Molecular Weight	18.3	lb/lbmol
Heating Value of Flare Gas	1,080	Btu/scf
Flare Design Basis	945,000	lb/hr
Flare Design Basis	19,984,426	scf/hr
Annual volumetric flow rate based on MSS events	167,212,461	scf/yr [2]
Annual mass flow rate based on MSS events	3,953	tpy [3]

[1] Data obtained from Callidus Flare Proposal 10/3/2011
[2] Flow rate (scf/yr) calculated by Mr. Ruben Velasquez (Atkins) submitted to Mr. John Barrientez via email on October 24,2011. The total flow is equivalent to one start-up and shut-down event each year.
[3] Annual Mass Flow rate Based on MSS Events (tpy) = Volumetric Flow Rate (scf/yr) * Molecular Weight (lb/mol) * 1 / 2,000 (ton/lb) / 387 (scf/lbmol)

$$\text{Annual mass flow rate based on MSS events (tpy)} = \frac{167{,}212{,}461\ \text{scf}}{\text{yr}} \left| \frac{18.3\ \text{lb}}{\text{lbmol}} \right| \frac{1\ \text{ton}}{2{,}000\ \text{lb}} \left| \frac{\text{lbmol}}{387\ \text{scf}} \right. = 3{,}953\ \text{tpy}$$

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Emission Factor [1] (kg/MMBtu)
CO_2	53.02
CH_4	1.0E-03
N_2O	1.0E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates From the Flare

Heat Input Capacity [1] (MMBtu/yr)	Annual Emissions [2] (metric tons/yr) CO_2	CH_4	N_2O	CO_2e [3]
196,970.66	10,443.38	0.20	0.02	10,453.63

[1] Heat Input Capacity (MMBtu/yr) = Annual Natural Gas Flowrate (scf/yr) * Higher Heating Value (Btu/scf) * 1 / 1,000,000 (Btu/MMBtu) + Pilot Gas Annual Flowrate (MMBtu/yr)

$$\text{Heat Input Capacity (MMBtu/yr)} = \frac{167{,}212{,}461\ \text{scf}}{\text{yr}} \left| \frac{1{,}080\ \text{Btu}}{\text{scf}} \right| \frac{\text{MMBtu}}{1{,}000{,}000\ \text{Btu}} + \frac{16{,}381\ \text{MMBtu}}{\text{yr}} = 196{,}970.66\ \text{MMBtu/yr}$$

[2] Annual Emissions (metric tons/yr) = Emission Factor (kg/MMBtu) * Heat Input Capacity (MMBtu/yr) * 0.001 (metric ton/kg)

$$\text{Annual Emissions of } CO_2 \text{ (metric tons/yr)} = \frac{53.02\ \text{kg}}{\text{MMBtu}} \left| \frac{196{,}970.66\ \text{MMBtu}}{\text{yr}} \right| \frac{0.001\ \text{metric tons}}{1\ \text{kg}} = 443.38\ \text{metric tons/yr}$$

[3] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Flare Design and Operational Parameters

Flare Parameters [1]	Value	Units
Pilot Heat Input[2]	170,000	Btu/hr
Annual Pilot Heat Input	1,489	MMBtu/yr
Heating Value of Flare Gas	2,695	Btu/scf
Waste Gas Flow Rate	379,981	scf/hr
Waste Gas Annual Venting Basis	8	hrs/yr

[1] Data obtained from Callidus Flare Proposal dated 9/12/2011.

[2] Based on two pilots each 85,000 Btu/hr.

GHG Emission Factors - Natural Gas and Propane Combustion

Greenhouse Gas	Natural Gas Emission Factors [1] (kg/MMBtu)	Propane Emission Factor [2] (kg/MMBtu)
CO_2	53.02	61.46
CH_4	1.0E-03	3.00E-03
N_2O	1.0E-04	6.00E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*.

[2] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*.

GHG Emission Rates From the Flare

Annual Pilot Heat Input (MMBtu/yr)	Waste Gas Heat Input [1] (MMBtu/yr)	Annual Emissions [2] (metric tons/yr)			
		CO_2	CH_4	N_2O	CO_2e [3]
1,489	8,192.39	582.46	2.61E-02	5.06E-03	584.58

[1] Waste Gas Heat Input (MMBtu/yr) = Waste Gas Flowrate (scf/hr) * Heating Value of Flare Gas (Btu/scf) * 1 / 1,000,000 (Btu/MMBtu) * Waste Gas Annual Venting Basis (hrs/yr)

$$\text{Heat Input Capacity (MMBtu/yr)} = \frac{379{,}981\text{ scf}}{\text{hr}} \;\Big|\; \frac{2{,}695\text{ Btu}}{\text{scf}} \;\Big|\; \frac{\text{MMBtu}}{1{,}000{,}000\text{ Btu}} \;\Big|\; \frac{8\text{ hrs}}{\text{yr}} = 8{,}192.39\text{ MMBtu/yr}$$

[2] Annual Emissions (metric tons/yr) = Natural Gas Emission Factor (kg/MMBtu) * Annual Pilot Heat Input (MMBtu/yr) * 0.001 (metric ton/kg) + Propane Emission Factor (kg/MMBtu) * Waste Gas Heat Input (MMBtu/yr) * 0.001 (m

$$\text{Annual Emissions of } CO_2 \text{ (metric tons/yr)} = \frac{53.02\text{ kg}}{\text{MMBtu}} \;\Big|\; \frac{1{,}489.20\text{ MMBtu}}{\text{yr}} \;\Big|\; \frac{0.001\text{ metric tons}}{1\text{ kg}} + \frac{61.46\text{ kg}}{\text{MMBtu}} \;\Big|\; \frac{8{,}192.39\text{ MMBtu}}{\text{yr}} \;\Big|\; \frac{0.001\text{ metric tons}}{1\text{ kg}} = 582.46\text{ metric tons/yr}$$

[3] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Freeport LNG

Pretreatment Facility

FIN/EPN: FUG-TREAT

Pretreatment VOC Fugitives

Components [1]	Phase	Oil and Gas Production Factors [1] (lb/hr/component)	Actual Component Count [2]	Assumed % CH_4 content	28 MID Credit %[1]	Controlled VOC Emission Rates [3,4] (lb/hr)	(tpy)
Valves	Gas/ Vapor	0.00992	2,947	91.40	97	0.80	3.51
	Light Liquid	0.0055	697	91.40	97	0.11	0.46
	Heavy Liquid	0.0000185	434	91.40	0	7.34E-03	0.03
Pressure Relief Valves	Gas/Vapor	0.0194	115	91.40	97	0.06	0.27
Pump Seals	Light Liquid	0.02866	9	91.40	93	0.02	0.07
	Heavy Liquid	0.00113	5	91.40	0	5.16E-03	0.02
Flanges/Connectors	Gas/ Vapor	0.00086	6,382	91.40	30	3.51	15.38
	Light Liquid	0.000243	1,424	91.40	30	0.22	0.97
	Heavy Liquid	0.00000086	1,161	91.40	30	6.39E-04	2.80E-03
Compressor Seals	Gas/Vapor	0.0194	24	91.40	95	0.02	0.09
Open Ended Lines	All	0.00441	0	91.40	97	--	--
Sampling Connections	All	0.033	9	91.40	97	8.14E-03	0.04
TOTAL EMISSIONS (CH_4)						**4.76**	**20.85**
TOTAL EMISSIONS (CO_2e) [5]						**99.96**	**437.82**

[1] Values obtained from *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Air Permits Division, TCEQ* (October 2000).

[2] Data provided by Mr. Ruben Velasquez (Atkins) to Ms. Melissa Dakas (Trinity Consultants) via email on October 7, 2011 and October 13, 2011.

[3] Hourly Controlled CH_4 Emission Rate (lb/hr) = Oil and Gas Factor * Component Count * (%CH_4 content in LNG / 100)*(1-28MID Credit % / 100)

Hourly Emission Rate for Valves from Gas/Vapor (tpy) = $\frac{9.92\text{E-03 MMbtu}}{\text{hr/component}} \cdot 2{,}947 \cdot \frac{91.40}{100} \cdot \frac{97.00}{100}$ = 0.80 lb/hr

[4] Annual Controlled CH4 Emission Rate (tpy) = Hourly CH_4 Emission Rate (lb/hr) * 8,760 (hr/yr) / 2,000 (lb/ton)

Annual Emission Rate for Valves from Gas/Vapor (tpy) = $\frac{0.8\text{ lb}}{\text{hr}} \cdot \frac{8{,}760\text{ hr}}{\text{yr}} \cdot \frac{1\text{ ton}}{2{,}000\text{ lb}}$ = 3.51 tpy

[5] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting* , Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21

Liquefaction Fugitives

Components	Phase	Oil and gas Production Factors [1] (lb/hr/component)	Actual Component Count [2]	Assumed % CH_4 content	28 MID Credit %	Controlled VOC Emission Rates[3,4] (lb/hr)	(tpy)
Valves	Gas/ Vapor	0.0099	1,509	91.40	97	4.10E-01	1.79
Pressure Relief Valves	Gas/Vapor	0.0194	60	91.40	97	3.19E-02	0.14
Pump Seals	Light Liquid	0.0287	3	91.40	93	5.51E-03	0.02
Flanges/Connectors	Gas/ Vapor	0.0009	3,017	91.40	30	1.74E+00	7.61
Compressor Seals	Gas/Vapor	0.0194	8	91.40	95	7.09E-03	0.03
Open Ended Lines	All	0.0040	0	91.40	97	0.00E+00	0.00
Sampling Connections	All	0.0330	9	91.40	97	8.14E-03	0.04
Other	All	0.0194	0	91.40	97	0.00E+00	0.00
TOTAL EMISSIONS (CH_4)						**2.20**	**9.63**
TOTAL EMISSIONS (CO_2e)[5]						**46.19**	**202.31**

[1] Values obtained from *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Air Permits Division, TCEQ* (10/00).

[2] Data provided by Mr. Ruben Velasquez (Atkins) to Ms. Melissa Dakas (Trinity Consultants) via email on October 7, 2011.

[3] Hourly Controlled CH_4 Emission Rate (lb/hr) = Oil and Gas Factor * Component Count * (%CH_4 content in LNG / 100)*(1-28MID Credit % / 100)

Hourly Emission Rate for Valves from Gas/Vapor (tpy) =	9.90E-03 lb	1509	91.40	97.00	=	0.41 lb/hr
	MMBtu		100	100		

[4] Annual Controlled CH_4 Emission Rate (tpy) = Hourly CH_4 Emission Rate (lb/hr) * 8,760 (hr/yr) / 2,000 (lb/ton)

Annual Emission Rate for Valves from Gas/Vapor (tpy) =	4.10E-01 lb	8,760 hr	1 ton	=	1.79 tpy
	hr	yr	2,000 lb		

[5] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting* , Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21

Liquefaction Project SF_6 Inventory

Area	Liquefaction	Liquefaction	Pretreatment
Breaker Rating	138 kV	69 kV	138 kV
Number of Breakers	13	27	6
SF_6 lb per Breaker	163	132	163

Liquefaction Project SF_6 GHG Emissions

Component	Liquefaction		Pretreatment	
Total Project SF_6 Capacity (lb)	5683	lb	978	lb
Leak Rate	0.50%	% per year	0.50%	% per year
Potential Annual Leakage	28.42	lb SF_6/year	4.89	lb SF6/year
	0.014	ton/year.	0.002	ton/year.
	0.003	lb/hr	0.001	lb/hr
Annual CO_2e emissions [1]	339.56	ton/year.	58.44	ton/year.
	77.52	lb/hr	13.34	lb/hr

[1] Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting* , Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
SF_6	23,900