

US EPA ARCHIVE DOCUMENT

From: [Velasquez, Ruben I](#)
To: [Wilson, Aimee](#)
Cc: [Mark Mallett](#); [Michael Johns](#); [Robinson, Jeffrey](#)
Subject: Freeport LNG Development, L.P. - Comments to Revised Draft GHG Permit and Statement of Basis- Proposed Liquefaction Plant
Date: Friday, November 08, 2013 2:12:31 PM
Attachments: [ATKINS - FLNG GHG Emissions Summary to EPA 4-10-2013.pdf](#)
[ATKINS-Freeport LNG Liquefaction Project Area Map to EPA 11-8-2013.pdf](#)
[ATKINS - FLNG Discussion of CT Gross Energy Heat Rate to EPA 11-8-2013.pdf](#)
[ATKINS - FLNG Discussion of CCS Cost Analysis to EPA 11-8-2013.pdf](#)

Aimee,

On behalf of Freeport LNG, I am responding to the opportunity to review the revised Draft PSD Greenhouse Gas Permit and the Statement of Basis to authorize construction of the Liquefaction Project proposed by Freeport LNG Development, L.P.

Our understanding of your instructions was that the review of the Draft Permit and Statement of Basis is not to result in another round of comments; however, that we should highlight wording that is not factually correct. With this in mind, we offer the following:

Comments to Draft Permit:

- Page 3 – Project Description – The sentence starting six lines down should include “heavy hydrocarbons” as follows: “The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide (CO₂), sulfur compounds, water, **and** mercury, **and** **heavy hydrocarbons**.”
- Page 4 – Pretreatment Facility Equipment Table – It is suggested that the word “Regenerative” be inserted in the description column (relating to the Amine Unit/Thermal Oxidizers), as follows: “3 **Regenerative** Thermal Oxidizers”
- Page 9 – Table 1 - For clarity and consistency with previous comments, please insert (LHV) after 80% (relating to the Heating Medium Heaters), as follows: “Minimum Thermal Efficiency 80% (**LHV basis**)”
- Page 9 – Table 1 – The value of CO₂e for each Thermal Oxidizer should be **301,341** TPY instead of 301,339. See attached GHG Project Emissions Summary submitted to you on April 10, 2013.
- Page 9 – Table 1 - The PTFFLARE should be described as an “**Emergency** Ground Flare”
- Page 13 – Table 1 – Although the footnote expresses that “total emissions are for information only and do not constitute an emission limit,” the Total Emissions shown in Table 1 should be revised as follows for consistency with the attached emission summary table:

Totals ⁸	CO ₂	1,559,176	CO ₂ e 1,561,531	
	CH ₄	74.7		
	N ₂ O	1.3		

- Page 13 - The table incorrectly refers to the Liquefaction Flare as an “Elevated flare”; it should be described as “**Emergency Ground Flare**”.
- Page 13 – Footer No. 6 – the SF₆ fugitive emission rate for EPN FUG-PTFSF6 should be **58 TPY** of CO₂e (instead of 47.8) and **340 TPY** CO₂e (instead of 239) for EPN FUG-LIQSF6.
- Page 15 – It appears the reference in the last sentence of Special Condition C.1.

- should be revised to Condition III.B.12 rather than III.B.10.
- Page 16 – Special Condition D.3 – it is suggested the sentence should read as follows: “Permittee shall calibrate and perform a preventative ~~a~~ maintenance check of the fuel gas flow meters and document annually.”
- Page 17 – Special Condition E.2 – For clarity and consistency with previous comments and the Draft Statement of Basis, please insert (LHV) after 80% as follows: “80% on a lower heating value (LHV) basis.”
- Page 18 – Special Conditions F. 8, F.9, and F.10. Freeport LNG does not understand the necessity of an in-stack continuous emissions monitoring for oxygen (O₂) for each thermal oxidizer. Each thermal oxidizer will be equipped with an oxygen control sensor that will be relied on for operational control, however, this sensor is very much different from a fully calibrated, RATA tested, cylinder gas audited continuous emissions monitoring system (CEMS) for monitoring oxygen. The use of the monitored values using such an O₂ CEMS is not readily apparent. Since continuous monitoring for stack gas CO₂ is not required, the use of an O₂ CEMS is not necessary, as no correction for oxygen would be necessary to correct CO₂ monitored values. It would appear that the readings from an O₂ CEMS would be monitored and recorded with no apparent limit or standard to compare to and would thus, become an exercise in recordkeeping rather than as a useful monitoring tool. As such, Freeport LNG is requesting that this set of special conditions be removed from the draft permit.
- Page 18 – Special Condition G.3 – For a more concise description, please revise the first sentence of this special condition to read: Both flares are pressure-assisted.
- Page 20 – Special Condition H.10.b – the reference in this special condition should be revised to Special Condition III.H.1. to rather than III.B.7.a.

Comments to the Draft SOB:

- Page 4 - The location indicated for the Liquefaction Facility by the blue dot is incorrect. The one on the previous page for the Pretreatment Facility is questionable but probably close enough. For your reference, attached is an area map showing the benchmark locations for the Pretreatment Facility and the Liquefaction Plant.
- Page 7 – Section VI - Please completeness, please add “Natural gas liquids or heavies removal unit” to the bullet list below the “Mercury removal unit (in-line unit).”
- Page 48 – Table 2 – Please change the comment to the right of “Design Margin” to “Allowance for equipment underperformance and measurement uncertainty” and the comment to right of “Performance Margin” to “Allowance for loss of plant efficiency due to normal and expected gas turbine performance degradation between overhauls” for consistency with the updated table in the attached “Discussion of Gross Energy Heat Rate for Proposed Combustion Turbine/Heat Recovery System.”
- Please make revisions to the corresponding items of the Draft SOB so that it is consistent with Freeport LNG’s comments to the Draft GHG Permit discussed above.

As you suggested, Freeport LNG is also submitting the attached information in support of the Draft Statement of Basis. The attached “Discussion of Gross Energy Heat Rate for Proposed Combustion Turbine/ Heat Recovery System” is intended to provide a more thorough discussion of the degradation factors used in the development of the adjusted net heat rate for the proposed combustion turbine system. The attached “Discussion of BACT Cost Analysis for Carbon Capture and Sequestration” is intended to provide an update to the cost analysis based on more recently published cost factors and to provide additional information for the sake of completeness.

It is requested that this updated information be incorporated into the Draft Statement of Basis to be published in support of the Draft PSD Greenhouse Gas Permit for this project.

As we continue to review and evaluate the draft permit conditions and the Statement of Basis, additional comments may be provided to you for consideration.

I will contact you soon to discuss the suggested revisions and comments and any questions you may have.

Thank you for your consideration and for your hard work!

Sincerely,

Ruben

Ruben I. Velasquez, P.E.
Senior Engineer - Air Quality

ATKINS

6504 Bridge Point Parkway, Suite 200, Austin, TX 78730 | Tel: +1 (512) 342 3395 | Fax: +1 (512) 327 2453 | Cell: +1 (512) 923 0864 |

Email: Ruben.Velasquez@atkinsglobal.com | Web: www.atkinsglobal.com/northamerica www.atkinsglobal.com

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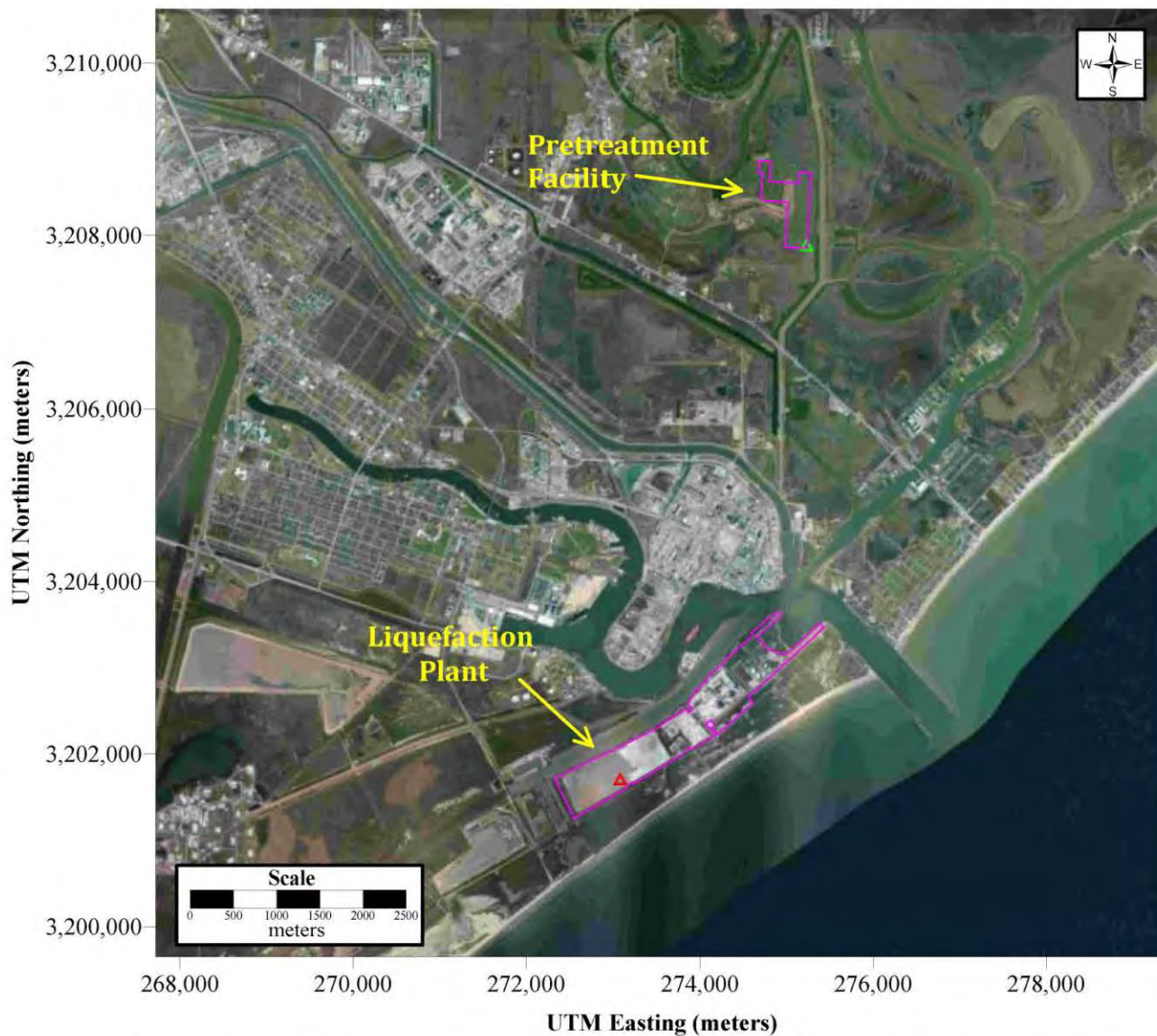
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**Freeport LNG Development, L.P.
GHG Project Summary of Emissions**

**Liquefaction Project GHG Emissions Summary
Freeport LNG**

EPN	Description	Annual Emissions (tons/yr)				
		CO ₂	CH ₄	N ₂ O	SF ₆	CO ₂ e ²
PTFFWP	Fire Water Pump - Pretreatment	37.67	0.002	0.0003	--	38
PTFEG-1	Emergency Generator Train 61	21.54	0.001	0.0002	--	22
PTFEG-2	Emergency Generator Train 62	21.54	0.001	0.0002	--	22
PTFEG-3	Emergency Generator Train 63	21.54	0.001	0.0002	--	22
PTFEG-4	Emergency Generator Utility Area	21.54	0.001	0.0002	--	22
PTFEG-5	Emergency Generator Utility Area	21.54	0.001	0.0002	--	22
PTFEAC-1	Emergency Air Compressor	8.56	0.000	0.0001	--	9
65B-81A	Heating Medium Heater A	24,953.93	0.471	0.0471	--	24,978
65B-81B	Heating Medium Heater B	24,953.93	0.471	0.0423	--	24,977
65B-81C	Heating Medium Heater C	24,953.93	0.471	0.0471	--	24,978
65B-81D	Heating Medium Heater D	2,552.83	0.048	0.0048	--	2,555
65B-81E	Heating Medium Heater E	2,552.83	0.048	0.0048	--	2,555
TO1	Amine Unit / Thermal Oxidizer 61	301,337.99	0.05	4.83E-03	--	301,341
TO2	Amine Unit / Thermal Oxidizer 62	301,337.99	0.05	4.83E-03	--	301,341
TO3	Amine Unit / Thermal Oxidizer 63	301,337.99	0.05	4.83E-03	--	301,341
PTFFLARE	PTF Flare	2,208.07	0.058	0.0085	--	2,212
CT	Combustion Turbine	561,117.99	10.583	1.0583	--	561,668
FUG-TREAT	Pretreatment Fugitives	0.00	26.060	--	--	547
FUG-PTFSF6	Pretreatment Circuit Breakers	0.00	--	--	0.002	58
LIQFWP-1	Fire Water Pump 1	37.67	0.002	0.0003	--	38
LIQFWP-2	Fire Water Pump 2	37.67	0.002	0.0003	--	38
LIQEG-1	Emergency Generator 1	21.54	0.001	0.0002	--	22
LIQEG-2	Emergency Generator 2	21.54	0.001	0.0002	--	22
LIQEG-3	Emergency Generator 3	21.54	0.001	0.0002	--	22
LIQEG-4	Emergency Generator 4	21.54	0.001	0.0002	--	22
LIQEG-5	Emergency Generator - Guard House / Admin Area	21.54	0.001	0.0002	--	22
LIQEAC-1	Emergency Air Compressor	8.56	0.000	0.0001	--	9
LIQEG-6	Emergency Generator - Dock 2	11.41	0.000	0.0001	--	11
LIQFLARE	Ground Flare	11,511.74	0.217	0.0217	--	11,523
FUG-LIQ	Fugitives Liquefaction	--	36.127	--	--	759
FUG-LIQSF6	Liquefaction Circuit Breakers	--	--	--	0.01	340
Project Totals		1,559,176.19	74.71	1.25	0.017	1,561,531

Freeport LNG Liquefaction Project Area Map



- ▲ Benchmark coordinates: 275,226 m E, 3,207,869 m N (UTM NAD83, Zone 15)
3,149,000 E, 13,558,600 N (Texas South Central, NAD83, U.S. Survey Feet)
- ▲ Benchmark coordinates: 273,078 m E, 3,201,689 m N (UTM NAD83, Zone 15)
3,143,000 E, 13,538,000 N (Texas South Central, NAD83, U.S. Survey Feet)

UTM coordinates in Zone 15, NAD83 datum.

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

**Discussion of Gross Energy Heat Rate for Proposed Combustion Turbine/ Heat Recovery
System
Proposed Greenhouse Gas Permit for Liquefaction Project
Freeport LNG Development, L.P.
PSD Permit Number PSD-TX-1302-GHG**

Freeport LNG is submitting the following information to the U.S. Environmental Protection Agency (EPA) Region 6 in support of the Statement of Basis for the Draft Prevention of Significant Deterioration (PSD) Permit for Greenhouse Gas Emissions for Freeport LNG's proposed Liquefaction Plant to be located in Brazoria County, Texas. Freeport LNG previously submitted a discussion of gross energy heat rate for the combustion turbine system associated with the proposed Pretreatment Facility to the EPA by letter dated 14 March 2013. The following is intended to provide a more thorough discussion of the degradation factors used in the development of the adjusted net heat rate for the proposed combustion turbine system. It is requested that this updated information be incorporated into the Draft Statement of Basis to be published in support of the Draft GHG PSD Permit for this project.

For the combustion turbine, Freeport LNG is proposing an output-based CO₂ limit based on equivalent useful energy produced of 738 pounds CO₂ per megawatt-hour. This is based on an adjusted Gross Combustion Turbine Energy Heat Rate of 5,210 Btu per kilowatt-hour (Btu/kWh) after allowances for design margins and initial and long-term degradation in equipment performance. A summary showing the basis for the proposed equivalent useful energy output-based limit is shown in the attached Table 1.

The combustion turbine proposed by Freeport LNG for the Pretreatment Facility is being installed in a combined heat and power (CHP) configuration. Since the combustion turbine exhaust energy is being recovered and harnessed for use along with electrical energy from the generator, more of the fuel burned in a CHP application is recovered as useful energy than in a simple-cycle combustion turbine application. As such, and in order to calculate the energy output-based BACT limit, lb CO₂/MWh, in any meaningful way, the useful thermal energy recovered from the combustion turbine exhaust must be added to the combustion turbine net electrical output to determine the total useful energy recovered from burned fuel. This is the same methodology that requires the electrical output of a steam turbine be added to the electrical output of the combustion turbine in order to arrive at the total useful energy recovered in a combined-cycle combustion turbine application. In the case of CHP proposed for

the Pretreatment Facility, the useful thermal energy recovered from the combustion turbine exhaust converted to the same unit of measure, kW, as the combustion turbine electrical output is analogous to the steam turbine electrical output.

As summarized in Table 1, the useful process thermal energy recovered from the PTF combustion turbine exhaust, in MMBtu/hr, was converted to an equivalent value in kW, as follows:

$$406 \text{ MMBtu/hr} \times 1,000,000 \text{ Btu/MMBtu} \times \text{kW-hr}/3415 \text{ Btu} = 118,887 \text{ kW equivalent}$$

Combining the net electrical energy output of the combustion turbine with the equivalent value for the combustion turbine exhaust energy recovered:

$$\begin{aligned} &84,409 \text{ kW (net combustion turbine electrical energy output)} + 118,887 \text{ kW equivalent} \\ &= 203,296 \text{ kW (equivalent net electric and useful thermal energy output recovered)} \end{aligned}$$

Expressing performance in terms of heat input per kilowatt-hour:

$$\begin{aligned} &906.2 \text{ MMBtu/hr (LHV)} \times 1,000,000 \text{ Btu/MMBtu} / 203,296 \text{ kW} \\ &= 4458 \text{ Btu/kWh (gross combustion turbine energy heat rate)} \end{aligned}$$

To establish an enforceable BACT condition that can be achieved over the life of the facility, the output-based CO₂ limit must account for short-term degradation in performance as the unit is installed, brought on-line, and commissioned; anticipated degradation of the combustion turbine over time between regular maintenance cycles; and potential degradation of other elements of the system over time. Therefore, the following compliance margins are added to the base heat rate limit:

- A 5 percent design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6 percent performance margin reflecting efficiency losses due to equipment performance degradation between maintenance overhauls.
- A 5 percent degradation margin reflecting the degradation of auxiliary plant equipment due to use over time.

A new power plant that is designed, constructed and commissioned properly should be able to operate at the design power and heat rate guaranteed by the supplier. However, the design of a CHP system incorporates many assumptions regarding anticipated performance of the many elements of the plant that are often not reflective of installed operating conditions. To allow for

this occurrence, Freeport LNG estimated a 5 percent design margin to address such items as equipment underperformance (based on contractor design margins) and measurement uncertainty, estimated to be 3.5 percent and 1.5 percent, respectively.

In addition, the power plant's overall performance will gradually decrease over time due to degradation of the plant's components. Degradation is due to wear and tear during operation, startup and shutdown due to contaminants in the fuel or combustion air to the system. Therefore, the BACT limit must also account for anticipated degradation of equipment over time between regular maintenance cycles. Gas turbine degradation can be classified as recoverable or non-recoverable over time. Recoverable loss is usually associated with deposition and compressor fouling and can be partially recovered by water washing or mechanical cleaning of the compressor blades and vanes. Non-recoverable loss is due primarily to wear and tear of machine components, aging, erosion, corrosion, etc., resulting in increased turbine and compressor clearances and changes in surface finish and airfoil contour. This type of loss is recovered through replacement of affected parts at recommended inspection intervals. Based on literature review of axial compressor performance, performance degradation during the first 30,000 hours of operation is estimated to be about 2-6 percent from the performance test measurements when corrected to guaranteed conditions.¹ These degradation rates may be used as benchmarks, but may not represent the actual degradation rate between major overhauls or through the unit's operational life. Even with replacement of degraded parts, the expected performance degradation is from 2-3 percent in capacity in the first year of service, followed by about another 3 percent loss over the next five years². Another study by VY Consult presents a discussion of losses due to degradation for the gas turbine inlet (0.8-1.6 percent), compressor degradation (0.8-4.4 percent) and power turbine degradation (0.4-1.9 percent) for an overall degradation for the combustion turbine of about 2-7.9 percent.³ For purposes of establishing a BACT condition that can be achieved over the life of the proposed combustion turbine, a 6 percent margin was incorporated into the determination of the adjusted net heat rate to account for performance degradation over the life of the unit.

In addition to recoverable and non-recoverable degradation of the combustion turbine, degradation of the combustion turbine's waste heat recovery system caused by tube fouling, thermal degradation, etc., as well as the other elements of the Pretreatment Facility that

¹ Norwegian University of Science and Technology, *Axial Compressor Performance Deterioration and Recovery through Online Washing*, Elisabet Syverud, May 2007.

² EPRI, *Axial Compressor Performance Maintenance Guide Update*, February 2005.

³ VY Consult (Consulting Engineers), Malaysia, *Combined Cycle Power Plant Performance Degradation*, PowerGen Asia, Sept 2008.

depend on the waste heat recovery system (e.g., amine regeneration units) that can potentially cause the overall plant heat rate to rise were also considered. If considered analogous to a heat recovery steam generator, the waste heat recovery system alone could experience from 1.1-5.6 percent degradation due to scaling and increased wall temperatures.³ To allow for possible degradation of this associated equipment, a 5 percent margin was incorporated into the determination of the adjusted net heat limit rate.

These additional margins were combined with the Gross Combustion Turbine Energy Heat Rate to arrive at the Adjusted Gross Combustion Turbine Energy Heat Rate of 5210 Btu/kWh, as follows:

$$4458 \text{ Btu/kWh} \times (1 + 0.05) \times (1 + 0.06) \times (1 + 0.05) = 5210 \text{ Btu/kWh}$$

As a frame of reference, the Gross Combustion Turbine Energy Heat Rate for Freeport LNG's proposed CHP unit was compared to the Gross Combustion Turbine Energy Heat Rate for a CHP as proposed by the EPA in its recent Draft GHG Permit for Air Liquide Large Industries U.S., L.P. Bayou Cogeneration Plant.⁴ In this draft permit, the Gross Combustion Turbine Energy Heat Rate proposed as BACT for each CHP is 7720 Btu_(HHV)/kWh_(gross) equivalent based on a 365-day rolling average.

On the basis of total useful energy recovered in exchange for fuel consumed, the Adjusted Gross Combustion Turbine Energy Heat Rate for Freeport LNG's proposed CHP is essentially 32.5 percent lower than the value proposed for the Air Liquide CHP, as follows:

$$(7,720 - 5210)/7720 = 32.5 \text{ percent}$$

When total useful energy recovered is properly taken into consideration, Freeport LNG's selection of CHP for its combustion turbine installation very much validates the EPA website statement on CHP:

"Because less fuel is burned to produce each unit of energy output, CHP reduces air pollution and greenhouse gas emissions."⁵

⁴ U.S. EPA, *Draft Permit Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions, Air Liquide Large Industries U.S., L.P.*, August 2013

⁵ <http://www.epa.gov/chp/basic/>, accessed November 7, 2013.

Table 1

**Calculation of Output-Based BACT CO₂ Limit
Pretreatment Facility - Combustion Turbine/Waste Heat Recovery System
Freeport LNG Development, L.P.**



Manufacturer	General Electric	
Combustion Turbine	Frame 7EA	
CT Cycle Operating Mode	CHP	
CT Inlet Dry Bulb, F	60	
Gross CT Power Out, kW	87,470	Note: CT Performance from Manufacturer's Data
CT Fuel Input, MMBtu/hr LHV	906.2	
Process Thermal Energy Required, MMBtu/hr	406	
Process Thermal Energy from CT Exhaust, MMBtu/hr	406	
Process Thermal Energy from CT Exhaust, kW	118,873	
Fired Heater Fuel Input, MMBtu/hr LHV	-	
CT Plant Auxiliary Loads, kW (estimated)	(3,061)	-3.5% percent of gross output
Net CT Plant Electrical Output, kW	84,409	
Total Useful Energy Produced, MMBtu/hr	694	Note: Includes net electrical and process thermal output
CT Plant Thermal Efficiency	76.6%	
Gross CT Energy Output, kW equivalent net electric and useful thermal converted to kW	203,281	
Gross CT Energy Heat Rate, Btu/kWh	4,458	CT Fuel Input / Gross CT Energy Output
Design Margin	0.05	Allowance for equipment underperformance and measurement uncertainty.
Performance Margin	0.06	Allowance for loss of plant efficiency due to normal and expected gas turbine performance degradation between overhauls
Degradation Margin	0.05	Allowance for degradation of other elements of the Pretreatment Facility that could cause overall combustion turbine heat rate to rise
Adjusted Gross CT Energy Heat Rate with Compliance Margin, Btu/kWh	5,210	Gross CT Energy Heat Rate * (1 + 0.05) * (1 + 0.06) * (1 + 0.05)
CO ₂ tons/hr	64.17	Estimated based on Mandatory Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas
CO ₂ lb/hr	128,340	
CO ₂ lb/MMBtu	141.62	CO ₂ lb/hr / CT Fuel Input (LHV)
Proposed Output-based CO₂ Limit, lb CO₂/MWhr equivalent useful energy produced	738	Based on Gross CT Energy Output, MW ()

**Discussion of BACT Cost Analysis for Carbon Capture and Sequestration
Proposed Greenhouse Gas Permit for Liquefaction Project
Freeport LNG Development, L.P.
PSD Permit Number PSD-TX-1302-GHG**

Freeport LNG is submitting the following information to the U.S. Environmental Protection Agency (EPA) Region 6 in support of the Statement of Basis for the Draft Prevention of Significant Deterioration (PSD) Permit for Greenhouse Gas (GHG) Emissions for Freeport LNG's proposed Liquefaction Plant to be located in Brazoria County, Texas. Freeport LNG previously estimated the cost of capture and sequestration of emissions of CO₂ from the proposed Amine Units and the Combustion Turbine system associated with the Pretreatment Facility since these emission units would be the larger sources of CO₂ emissions for the proposed Liquefaction Project. A discussion of these costs was provided to the EPA by letter dated 20 July 2012.

The following is intended to provide an update to the cost analysis based on more recently published cost factors and to provide additional information for the sake of completeness. It is requested that this updated information be incorporated into the Draft Statement of Basis to be published in support of the Draft GHG PSD Permit for this project.

Amine Units/Thermal Oxidizers

As discussed in Section 10.4 of the GHG PSD permit application, the primary source of CO₂ emissions is from the separation of CO₂ in the incoming gas stream to the amine units; the separation stream will be routed to the proposed thermal oxidizers for the control of non-greenhouse gas emissions. Process-based CO₂ emission rates were estimated based on the estimated vent rate of CO₂, assuming a two percent concentration of CO₂ in the incoming natural gas stream to the amine units. The evaluation of carbon capture and sequestration (CCS) was based on the capture and transfer of the CO₂-laden stream upstream of the thermal oxidizers.

While the process exhaust stream from the amine units is relatively high in CO₂ content, additional processing of the exhaust gas would be required to implement CCS. These include separation (removal of particulate matter and other pollutants from the combustion gases), capture and compression, transfer, and sequestration of the CO₂ stream. These processes require additional equipment for gas treatment and conditioning, large compression units, and pipelines to transfer CO₂. These additional units would require additional electricity and would generate additional air emissions.

Combustion Turbine

Page 10-4 of Freeport LNG's GHG PSD Permit Application presents a discussion of potential CO₂ control strategies for the proposed PTF Combustion Turbine including a discussion of nine projects that utilize an absorber medium, such as ammonia or amine, to remove CO₂ from the exhaust of coal-fired boilers in the power and industrial sector. Three additional examples were provided of industrial facilities that utilized an absorber based CCS technology. This discussion emphasizes that carbon capture could be accomplished with low pressure scrubbing of CO₂ from the exhaust stream using solvent (e.g., amines and ammonia), solid sorbent, or membrane technology. However, only solvents have been used to-date on a commercial (yet slip stream) scale.

The available post-combustion capture technologies include oxy-combustion; solvent capture and stripping; and post-combustion membranes. 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.¹ Membrane separation of CO₂ from a combustion turbine exhaust stream is limited to relatively small applications. Materials of membrane construction must be made more permeable and less expensive than what is currently available in order for membrane capture to overcome the existing cost disadvantage compared to competing technologies.²

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO₂ capture technology and related implementation challenges:

"...In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO₂ from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries... Amine solvents are effective at absorbing CO₂ from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output..."³

¹ U.S. EPA, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry*, October 2010

² DOE/NETL-401/113009. *Integration of H₂ Separation Membranes with CO₂ Capture and Storage*. November 2009.

³ DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cl:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default

The DOE-NETL adds:

“...Separating CO₂ from flue gas streams is challenging for several reasons:

- *CO₂ is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.*
- *Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO₂ capture processes.*
- *Compressing captured or separated CO₂ from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system...”*

In evaluating alternative CCS techniques, the quality of the exhaust stream from the combustion turbine is of primary consideration. The exhaust steam from the combustion turbine contains a mixture of different constituents including products of combustion of natural gas fuel fired in the turbine; NO_x, SO₂, VOC, CO, and particulate matter. Depending on the final destination of the exhaust stream, these constituents may make the exhaust stream undesirable in terms of equipment or pipeline protection.

Absorber based technology has been applied to processes in the petroleum refining and natural gas processing industries to remove CO₂ from an incoming gas. Therefore, it is considered by Freeport LNG to be technically mature enough to warrant consideration.

Though amine absorption technology for CO₂ capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas turbine exhausts which have considerably large flow volumes and considerably less CO₂ concentrations. Based on a report produced in 2010⁴, the Interagency Task Force on Carbon Capture and Storage supports this suggestion as follows:

“Current technologies could be used to capture CO₂ from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO₂ capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes

⁴ U.S. Department of Energy/U.S. EPA, *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010

necessary for commercial deployment.”

As discussed on Page 10-7 of Freeport LNG’s GHG PSD Permit application, 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.

CO₂ Stream from Combustion Turbine/Amine Units

Freeport LNG conducted a preliminary engineering analysis to evaluate potential options to capture and geologically sequester CO₂ from the amine units at the proposed Pretreatment Facility including geological sequestration to an injection well or capture and transfer of CO₂ to an off-site facility for use in enhanced oil recovery (EOR).

The evaluation of geologic sequestration involved the study and identification of a suitable geological storage reservoir for underground injection near the project site. This option would require compression to bring the captured CO₂ stream to a down-hole injection pressure of about 600 psi. It was assumed no treatment of the gas stream would be necessary.

The analysis of CO₂ capture and transfer for use in EOR assumed the capture and transfer of roughly 42 MMCFD of CO₂ from the amine units via a new pipeline to the Denbury Resources, Inc. (Denbury) Facility, a CO₂-injection EOR facility, in Hastings, Texas about 38 miles away. The transfer of the CO₂ stream would require further treatment to remove contaminants and compression to meet a 1900 psi delivery pressure.

The initial study of carbon capture and transfer to the Denbury facility was based on a preliminary location for the Pretreatment Facility near Stratton Ridge, Texas. The actual location of the Pretreatment Facility has since been determined and will be approximately the same distance to the Denbury Facility depending on the pipeline right-of-way route selected. A discussion of the energy, environmental, and economic impacts of CCS as it might apply to CO₂ from the amine treatments units, assuming the CO₂ stream is captured upstream of the thermal oxidizers is provided in Section 10.4.4 of the GHG PSD permit application.

Based on the results of this preliminary analysis, Freeport LNG has evaluated the estimated costs for implementation of CCS to the CO₂ stream from the amine units combined with the those from the combustion turbine exhaust.

For purposes of the cost analysis, Freeport LNG identified the following alternatives:

- Capture and Geological Sequestration of CO₂ - Based on the preliminary geological and subsurface studies conducted by Freeport LNG.
- Capture and Transfer of CO₂ for EOR - Based on the capture and transfer of CO₂ emissions from the Pretreatment Facility to the Denbury Facility. The transfer of the CO₂ stream would require further treatment to remove contaminants and compression for transfer via a new pipeline.

An initial analysis of these alternatives was submitted to the EPA by letter dated 20 July 2012. In this cost analysis Freeport LNG utilized the March 2010 National Energy Technology Laboratory (NETL) Document, *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL- 2010/1447* to estimate the cost associated with a pipeline and associated equipment. This document provides an appropriate method for estimation of transport, storage, and monitoring costs for a “typical” sequestration project. In this analysis, Freeport LNG estimated the capital and operating and maintenance cost of equipment necessary for separation of the CO₂ from the combustion turbine gas stream and the amine treatment system exhaust stream, compression, and transfer via pipeline to either underground injection or for EOR.

Since the submittal of the analysis to the EPA in July 2012, the NETL has published updated factors for estimation of CO₂ transport and storage costs in its document, *Carbon Dioxide Transport and Storage Costs in NETL Studies*, DOE/NETL-2013/1614. Based on the factors, Freeport LNG has updated its cost analysis for carbon capture and sequestration as shown in the attached Tables 1 and 2.

Geologic Sequestration

As previously discussed, Freeport LNG previously undertook a feasibility study of the capture and long-term geological sequestration of roughly 42 million cubic feet per day (MMCFD) of CO₂, venting at atmospheric pressure, produced by the amine treatment units. Assuming the captured CO₂ from the combustion turbine would be routed to the same pipeline proposed for the amine treatment units, an additional 32 MMCFD of CO₂ (24 MMCFD from the combustion turbine and 8 MMCFD from an auxiliary heater that would be required to support additional gas treatment) would be combined with the 42 MMCFD for a total of 74 MMCFD of CO₂ or about 1.5 MM tons per year of CO₂.

As shown in Table 1, the total capital cost of geological sequestration based on this scenario is projected to be approximately \$445 million. The annual operating and maintenance costs are estimated to be approximately \$65 million. Thus, the average annual CO₂ control cost, based on a 30-year operational

period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly \$105 million, or approximately \$70 per ton of CO₂ sequestered. This cost analysis is based on the following:

- The pipeline cost breakdown was based on information presented in the National Energy Technology Laboratory guidance, *Carbon Dioxide Transport and Storage Costs in NETL Studies*, DOE/NETL- 2013/1614, March 2013.
- The cost of other equipment including compression, additional amine treatment, controls, etc., were based on a scale-up of the site-specific technical and economic analysis conducted by Freeport LNG for capture and sequestration of CO₂ from the proposed amine treatment units.
- The other capital and operating and maintenance costs for geologic sequestration are based on information presented in the National Energy Technology Laboratory guidance, “Estimating Carbon Dioxide Transport and Storage Costs,” DOE/NETL-400/2010/1447, March 2010.
- The total annualized costs were determined by addition of the annual O&M costs to the annualized cost of capital. Capital costs were annualized using a capital recovery factor over a 30-year operational period at 8% interest.

A summary of the assumptions, cost estimation factors, and basic design parameters used in support of this cost analysis is shown in Table 1.

This cost would represent a very burdensome expense for the Pretreatment Facility, increasing its overall operating costs substantially without any revenue or other offset. Therefore, geological sequestration is not regarded as an economically feasible CO₂ control option.

Enhanced Oil Recovery

Freeport LNG also undertook a feasibility study of using the roughly 42 MMCFD of CO₂ from the amine recovery units at the Pretreatment Facility as a supplemental supply to Denbury Resources’ CO₂-injection EOR project in Hastings, Texas about 38 miles away. Again, assuming the captured CO₂ from the combustion turbine would be routed to the same pipeline proposed for the amine treatment units, an additional 32 MMCFD of CO₂ (24 MMCFD from the combustion turbine and 8 MMCFD from the auxiliary heaters) would be combined with the 42 MMCFD for a total of 74 MMCFD or about 1.4 MM tons per year of CO₂.

Denbury requires very clean CO₂ with most of the sulfur compounds and water removed from the CO₂ stream. This CO₂ stream would contain sulfur compounds, particulate matter and other products of combustion, and water which would be removed farther downstream of the Pretreatment Facility. Denbury also requires delivered CO₂ at very high pressures for its EOR project, so compression of the treated CO₂ would be required at the Pretreatment Facility to around 2000 psi. These processes require additional equipment for gas treatment and conditioning, large compression units, and pipelines to transfer CO₂.

As shown in Table 2, the cost for treatment, compression, and delivery to Denbury is estimated to be \$469 million. The annual operating and maintenance expenses were estimated to be approximately \$54 million. Thus, the average annual CO₂ control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly \$96 million; about \$64 per ton of CO₂ captured and transferred. This cost analysis is based on the following:

- The pipeline cost breakdown was based on information presented in the National Energy Technology Laboratory guidance, *Carbon Dioxide Transport and Storage Costs in NETL Studies*, DOE/NETL- 2013/1614, March 2013.
- The cost of other equipment including compression, additional amine treatment, controls, etc., were based on a scale-up of the site-specific technical and economic analysis conducted by Freeport LNG for capture and sequestration of CO₂ from the proposed amine treatment units.
- The total annualized costs were determined by addition of the annual O&M costs to the annualized cost of capital. Capital costs were annualized using a capital recovery factor over a 30-year operational period at 8% interest.

A summary of the assumptions, cost estimation factors and basic design parameters used in support of this cost analysis is shown in Table 2.

Denbury confirmed its potential ability to accept the treated volumes at some time in the future. The purchase price of CO₂ by Denbury is confidential business information, but its current and anticipated future alternative CO₂ purchase price is significantly less than \$64 per ton. Even if Freeport LNG were to sell its CO₂ to Denbury at their alternative purchase price, the net loss to Freeport LNG would represent a very burdensome expense for the Pretreatment Facility. Therefore, the sale of CO₂ to Denbury for EOR is not regarded as a viable or economically feasible CO₂ control option.

Potential Tax Credits

Freeport LNG's analysis did not expressly account for tax credits made available for carbon capture and sequestration. Since 2008, the Internal Revenue Service (IRS) has provided a tax credit for two types of CO₂ sequestration under Section 45Q of the Internal Revenue Code. A credit of \$20 per metric ton may be taken for CO₂ captured at a "qualified facility" and sequestered in a secure geological sequestration (26 U.S.C. § 45Q (a)(1)). A credit of \$10 per metric ton credit is available for qualified CO₂ captured at a qualified facility, used as a "tertiary injectant in a qualified enhanced oil or natural gas recovery project," and disposed of in secure geological storage (26 U.S.C. § 45Q (a)(2)).

Under these rules, the term "qualified facility" means any industrial facility:

- (1) which is owned by the taxpayer,
- (2) at which carbon capture equipment is placed in service, and
- (3) which captures not less than 500,000 metric tons of CO₂ during the taxable year.

As shown in the attached Tables 1 and 2, the anticipated amounts captured from the Amine Units and the Combustion Turbine assumed for this analysis is 1,503,557 tons CO₂ per year which equates to 1,364,004 metric tonnes CO₂ per year, and thus, capture and sequestration of CO₂ at the Pretreatment Facility would qualify as a "qualified facility."

The § 45Q tax credit is capped and ceases to be available once credits have been claimed for sequestering 75,000,000 tons CO₂. Based on the annual report filed with the IRS as of May 14, 2013, the aggregate amount of qualified CO₂ taken into account for purposes of § 45Q is 20,858,926 metric tons.⁵

These credits have been consumed starting with the year 2008 through May 2013. Assuming the annual rate of consumption remains the same, credits will be consumed at an annual rate of about 4,171,785 metric tons per year. At this rate the 75,000,000 tons CO₂ cap would be reached in about the year 2025. Freeport LNG may realize these credits in the earlier years of operation. However, these tax credits are not guaranteed over the anticipated operational life for a CCS facility especially if other sequestration projects come on-line and the available credits are consumed earlier than expected. Therefore, Freeport LNG did not incorporate these credits into the long-term (30-year) economic analyses.

⁵ Internal Revenue Service, *IRS Bulletin 2013-23*

The site specific application does present significant challenges to CCS. Some of those challenges are:

1. **Competing Technologies:** As detailed above, the only technology that Freeport LNG, along with published experts in the field, considers mature enough to warrant serious consideration for CCS is absorption technology.
2. **Economic Feasibility:** The low purity and concentration of CO₂ in the combustion turbine exhaust and the relatively small size of the proposed combustion turbine facility means that the per ton cost of removal and storage will no doubt be much higher than the public data estimates for much larger fossil fuel power facilities due to the loss of economies of scale. Based on the CCS evaluation by Freeport LNG discussed above, the average annual CO₂ control cost, estimated to be about \$64 - \$70 per ton of CO₂, would result in an added cost to the project in the range of \$96MM to \$105MM per year. This is more than three times the “best case” estimated economic benefit derived by the installation of the combustion turbine as a combined heat and power facility. In other words, a capture and storage scheme that costs as high as about \$30 per ton would negate any economic benefit offered by the combustion turbine facility. Thus, the most energy efficient means of providing combined thermal and electrical energy to the proposed project, per the EPA, will not be utilized if CCS is imposed.
3. **Energy Penalty:** The estimated energy penalty associated with the installation of a CCS system would be about 62-63% of produced energy from the combustion turbine, as shown in Table 3. Since the facility thermal energy need is approximately equal to the recoverable exhaust energy of the proposed combustion turbine, a larger combustion turbine would be required to meet the additional energy requirements for CCS. Assuming approximately 30 to 45% more fuel will be required to produce this additional electric output, it is estimated that an additional 3.5 billion cubic feet of natural gas per year would be burned producing an additional 209,000 tons of CO₂ per year just to support the electrical energy requirements for CCS along with a collateral increase in emissions of non-GHG pollutants; NO_x, CO, VOC, PM, and SO₂. At the estimated average annual CO₂ control cost of \$68 - \$74 per ton CO₂ described above, the energy penalty associated with CCS will by itself add an additional economic burden to the project of about \$11,025,000 per year.
4. **Long-term Storage Uncertainty:** A study of the risks associated with long-term geologic storage of CO₂ places those risks on par with the underground storage of natural gas or acid-

gas.⁶ The liability of underground CO₂ storage, however, is less understood. A recent publication from the Massachusetts Institute of Technology (MIT) states that “The characteristics (of long term CO₂ storage) pose a challenge to a purely private solution to liability.”⁷ Since Freeport LNG is a private entity, and the liability issues of long-term CO₂ storage are in a state of flux, the imposition of CCS on the project may cause Freeport LNG to seek a less energy efficient solution than the combustion turbine based combined heat and power system.

5. **Additional Environmental Impacts:** The proposed Liquefaction Project will be located in Brazoria County which is part of the Houston-Galveston-Brazoria (HGB) ozone nonattainment area. In addition to being economically infeasible, the operation of the additional equipment required for implementation of a CCS system would result in an a collateral increase in emissions of non-GHG pollutants; CO, PM, SO₂, and ozone precursors, NO_x and VOC, from the additional utilities and energy demands that would be required for preconditioning, compression, and transfer of the CO₂ gas stream, thus resulting in additional impacts to the air shed. Although the cost of implementing additional control of these collateral emissions is not included in the CCS cost analysis, the addition impacts to the HGB nonattainment area should be considered in the elimination of CCS as BACT.

The capture and storage of CO₂ emissions from the proposed amine units and combustion turbine would add such significant economic burden to the facility that the combustion turbine would no longer be a viable option for the facility. While the overall project will proceed, without the installation of the combustion turbine, the energy efficiency of the combined heat and power facility would be lost.

⁶ Benson, S. 2006. *Carbon Dioxide Capture and Storage, Assessment of Risks from Carbon Dioxide Storage in Deep Underground Geological Formations*. Lawrence Berkley National Laboratory

⁷ de Figueiredo, M., 2007. *The Liability of Carbon Dioxide Storage*, Ph.D. Thesis, MIT Engineering

Table 1

Option One: Geological Sequestration of CO₂ From Amine Units and Combustion Turbine Exhaust Stack
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CO₂ Pipeline/Injection Well Assumptions

Pipeline Length	5 miles
Pipeline Diameter	12 inches
Number of Injection Wells	1
Depth of Well	1,000 meters
Natural Gas for Amine Regeneration	330 MMBtu/hr
Electricity for Compression	21,923 kW
Electricity for Inlet Blower	16,239 kW

CSS Cost Breakdown

Cost Type	Units	Cost	
Pipeline Costs ¹			
Pipeline Materials	\$ Diameter (inches), Length (miles)	\$70,350 + \$2.01 x L x (330.5 x D ² + 686.7 x D + 26,920)	\$902,414
Pipeline Labor	\$ Diameter (inches), Length (miles)	\$371,850 + \$2.01 x L x (343.2 x D ² + 2,074 x D + 170,013)	\$2,827,284
Pipeline Miscellaneous	\$ Diameter (inches), Length (miles)	\$147,250 + \$1.55 x L x (8,417 x D + 7,234)	\$986,095
Pipeline Right of Way	\$ Diameter (inches), Length (miles)	\$52,200 + \$1.28 x L x (577 x D + 29,788)	\$286,157
Other Capital ²			
Inlet Compression / Cooling	\$	\$20,000,000	\$20,000,000
CO2 Compression Equipment	\$	\$27,000,000	\$27,000,000
Cryogenic Units/Amine Units Dehydration	\$	\$378,000,000	\$378,000,000
CO2 Surge Tank	\$	\$3,500,000	\$3,500,000
Pipeline Control System	\$	\$340,000	\$340,000
O&M - Pipeline ³			
Fixed O&M	\$/mile/year	\$8,632	\$43,160
O&M - Capture ²			
Fixed O&M	% of installed capital	5.0%	\$21,442,000
Natural Gas for Amine Regeneration	\$ per MMBtu	\$3.00	\$9,214,128
Electricity for Compression	\$ per kW-hour	\$0.06	\$11,049,104
Electricity for Inlet Blower	\$ per kW-hour	\$0.06	\$8,184,522
Amine Replacement	\$ per year	Engineering Estimate	\$3,000,000
Geologic Storage Costs ³			
Capital			
Site Screening and Evaluation	\$	\$4,738,488	\$4,738,488
Injection Wells	\$/injection well	\$240,714 x e ^{0.0008 x well depth}	\$535,719
Injection Equipment	\$/injection well	\$94,029 x [7389/(280 x # of injection wells)] ^{0.5}	\$483,032
Liability Bond	\$	\$5,000,000	\$5,000,000
Declining Capital Funds			
Pore Space Acquisition	\$/short ton CO ₂	0.334/short ton CO ₂	\$502,188
Total Capital Cost			\$444,599,188
O&M - Geologic Storage ³			
Normal Daily Expenses (Fixed O&M)	\$/injection well	\$11,566	\$11,566
Consumables (Variable O&M)	\$/yr/short ton CO ₂ /day	\$2,995	\$12,829,501
Surface Maintenance (Fixed O&M)	see formula	\$23,478 x [7389/(280 x # of injection wells)] ^{0.5}	\$120,608
Subsurface Maintenance (Fixed O&M)	\$/ft-depth/inject well	\$7.08	\$23,222

Amortized CCS Cost

Total Capital Investment (TCI)	\$444,599,188
Capital Recovery Factor (CRF) = $i(1+i)^n / ((1+i)^n - 1)$	0.09
l = interest rate	0.08
n = equipment life, years	30
Amortized Installation Costs = CRF * TCI	\$39,492,605
Annual O&M Costs	\$65,917,811
Total CCS Annualized Cost	\$105,410,415

Tons CO ₂ per Year Removed (AGRU and CT)	1,503,557
Average Annual Cost per Ton CO ₂ Removed (Assuming 100% Capture and Transfer)	\$70.11

1. National Energy Technology Laboratory, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL- 2013/1614, March 2013.
2. Costs are based on Freeport LNG engineering analysis.

Table 2

Option Two: Enhanced Oil Recovery Using CO2 From Amine Units and Combustion Turbine Exhaust Stack
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CO₂ Pipeline/Injection Well Assumptions

Pipeline Length	38 miles
Pipeline Diameter	14 inches
Natural Gas for Amine Regeneration	330 MMBtu/hr
Electricity for Compression	23,384 kW
Electricity for Inlet Blower	16,239 kW

CSS Cost Breakdown

Cost Type	Units	Cost	
Pipeline Costs ¹			
Pipeline Materials	\$ Diameter (inches), Length (miles)	$\$70,350 + \$2.01 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,920)$	\$7,811,600
Pipeline Labor	\$ Diameter (inches), Length (miles)	$\$371,850 + \$2.01 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$	\$20,713,081
Pipeline Miscellaneous	\$ Diameter (inches), Length (miles)	$\$147,250 + \$1.55 \times L \times (8,417 \times D + 7,234)$	\$7,513,991
Pipeline Right of Way	\$ Diameter (inches), Length (miles)	$\$52,200 + \$1.28 \times L \times (577 \times D + 29,788)$	\$1,893,002
Other Capital ²			
Inlet Compression / Cooling	\$	\$20,000,000	\$20,000,000
CO2 Compression Equipment	\$	\$28,800,000	\$28,800,000
Cryogenic Units/Amine Units Dehydration	\$	\$378,000,000	\$378,000,000
CO2 Surge Tank	\$	\$3,500,000	\$3,500,000
Pipeline Control System	\$	\$340,000	\$340,000
O&M - Pipeline ³			
Fixed O&M	\$/mile/year	\$8,632	\$328,016
O&M - Capture ²			
Fixed O&M	% of installed capital	5.0%	\$21,532,000
Natural Gas for Amine Regeneration	\$ per MMBtu	\$3.00	\$9,214,128
Electricity for Compression	\$ per kW-hour	\$0.06	\$11,785,711
Electricity for Inlet Blower	\$ per kW-hour	\$0.06	\$8,184,522
Amine Replacement	\$ per year	Engineering Estimate	\$3,000,000
Total Capital Cost			
			\$468,571,675

Amortized CCS Cost

Total Capital Investment (TCI)	\$468,571,675
Capital Recovery Factor (CRF) = $i(1+i)^n / ((1+i)^n - 1)$	0.09
i = interest rate	0.08
n = equipment life, years	30
Amortized Installation Costs = CRF * TCI	\$41,622,019
Annual O&M Costs	\$54,044,377
Total CCS Annualized Cost	\$95,666,396

Tons CO ₂ per Year Removed (AGRU and CT)	1,503,557
Average Annual Cost per Ton CO ₂ Removed (Assuming 100% Capture and Transfer)	\$63.63

1. National Energy Technology Laboratory, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL- 2013/1614, March 2013.
2. Costs are based on Freeport LNG engineering analysis.
3. National Energy Technology Laboratory, "Estimating Carbon Dioxide Transport and Storage Costs," DOE/NETL-400/2010/1447, March 2010

Table 3 – Combustion Turbine CCS Energy Penalty Estimate

Combustion Turbine	GE Frame 7EA	GE Frame 7EA
CT Cycle Operating Mode	CHP	CHP
CT Inlet Dry Bulb Temperature, °F	60	60
Gross CT Power Output, kW	87,470	87,470
CT Plant Auxiliary Loads, kW (estimated)	(3061)	(3061)
Net CT Plant Electrical Output, kW	84,409	84,409
CT Natural Gas Fuel Input, MMBtu/hr LHV	906	906
Process Thermal Energy from CT Exhaust, MMBtu/hr	406	406
Total Useful Energy Output, kW equivalent	203,365	203,365
Carbon Capture Method	Amine Absorber	Amine Absorber
Carbon Sequestration Method	Geologic	EOR
Amine Regenerator Heater Fuel Input, MMBtu/hr LHV	303	303
Electrical Input to Inlet Blower/Cooler, kW	16,239	16,239
Electrical Input to CO ₂ Compression, kW	21,293	23,384
Total Energy Penalty, kW Equivalent	129,940	128,401
Energy Penalty, % of Useful Energy Output	62.4%	63.1%

*CHP = Combined Heating and Power