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 CO_2 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 CO_2 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 CO_2 emissions is from the separation of CO_2 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 CO_2 emission rates were estimated based on the estimated vent rate of CO_2, assuming a two percent concentration of CO_2 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 CO_2-laden stream upstream of the thermal oxidizers.

While the process exhaust stream from the amine units is relatively high in CO_2 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 CO_2 stream. These processes require additional equipment for gas treatment and conditioning, large compression units, and pipelines to transfer CO_2. 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 capture technology and related implementation challenges:

> "…*In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 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 CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output*…"[3]

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[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:e0yvzjAh22cJ: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 CO_2 from flue gas streams is challenging for several reasons:*

- *CO_2 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 CO_2 capture processes.*
- *Compressing captured or separated CO_2 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, SO_2, 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 CO_2 from an incoming gas. Therefore, it is considered by Freeport LNG to be technically mature enough to warrant consideration.

Though amine absorption technology for CO_2 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 CO_2 concentrations. Based on a report produced in 2010[4], the Interagency Task Force on Carbon Capture and Storage supports this suggestion as follows:

"Current technologies could be used to capture CO_2 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 CO_2 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.

CO_2 Stream from Combustion Turbine/Amine Units

Freeport LNG conducted a preliminary engineering analysis to evaluate potential options to capture and geologically sequester CO_2 from the amine units at the proposed Pretreatment Facility including geological sequestration to an injection well or capture and transfer of CO_2 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 CO_2 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 CO_2 capture and transfer for use in EOR assumed the capture and transfer of roughly 42 MMCFD of CO_2 from the amine units via a new pipeline to the Denbury Resources, Inc. (Denbury) Facility, a CO_2-injection EOR facility, in Hastings, Texas about 38 miles away. The transfer of the CO_2 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 CO_2 from the amine treatments units, assuming the CO_2 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 CO_2 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 CO_2 - Based on the preliminary geological and subsurface studies conducted by Freeport LNG.

- Capture and Transfer of CO_2 for EOR - Based on the capture and transfer of CO_2 emissions from the Pretreatment Facility to the Denbury Facility. The transfer of the CO_2 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 CO_2 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 CO_2 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 CO_2, venting at atmospheric pressure, produced by the amine treatment units. Assuming the captured CO_2 from the combustion turbine would be routed to the same pipeline proposed for the amine treatment units, an additional 32 MMCFD of CO_2 (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 CO_2 or about 1.5 MM tons per year of CO_2.

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 CO_2 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 CO_2 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 CO_2 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 CO_2 control option.

Enhanced Oil Recovery

Freeport LNG also undertook a feasibility study of using the roughly 42 MMCFD of CO_2 from the amine recovery units at the Pretreatment Facility as a supplemental supply to Denbury Resources' CO_2-injection EOR project in Hastings, Texas about 38 miles away. Again, assuming the captured CO_2 from the combustion turbine would be routed to the same pipeline proposed for the amine treatment units, an additional 32 MMCFD of CO_2 (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 CO_2.

Denbury requires very clean CO_2 with most of the sulfur compounds and water removed from the CO_2 stream. This CO_2 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 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 psi. These processes require additional equipment for gas treatment and conditioning, large compression units, and pipelines to transfer CO_2.

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 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 $96 million; about $64 per ton of CO_2 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 CO_2 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 CO_2 by Denbury is confidential business information, but its current and anticipated future alternative CO_2 purchase price is significantly less than $64 per ton. Even if Freeport LNG were to sell its CO_2 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 CO_2 to Denbury for EOR is not regarded as a viable or economically feasible CO_2 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 CO_2 sequestration under Section 45Q of the Internal Revenue Code. A credit of $20 per metric ton may be taken for CO_2 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 CO_2 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 CO_2 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 CO_2 per year which equates to 1,364,004 metric tonnes CO_2 per year, and thus, capture and sequestration of CO_2 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 CO_2. Based on the annual report filed with the IRS as of May 14, 2013, the aggregate amount of qualified CO_2 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 CO_2 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 CO_2 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 CO_2 control cost, estimated to be about \$64 - \$70 per ton of CO_2, 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 CO_2 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 SO_2. At the estimated average annual CO_2 control cost of \$68 - \$74 per ton CO_2 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 CO_2 places those risks on par with the underground storage of natural gas or acid-

gas.[6] The liability of underground CO_2 storage, however, is less understood. A recent publication from the Massachusetts Institute of Technology (MIT) states that "The characteristics (of long term CO_2 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 CO_2 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, SO_2, 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 CO_2 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 CO_2 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 CO_2 From Amine Units and Combustion Turbine Exhaust Stack
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CO_2 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 \text{ 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 CO2	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 CO2/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**
I = 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.

CO_2 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 x L x (330.5 x D^2 + 686.7 x D + 26,920)	$7,811,600
Pipeline Labor	$ Diameter (inches), Length (miles)	$371,850 + $2.01 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$20,713,081
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$147,250 + $1.55 x L x (8,417 x D + 7,234)	$7,513,991
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$52,200 + $1.28 x L x (577 x 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