BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF

SABINE PASS LNG, LP AND SABINE PASS LIQUEFACTION, LLC

To continue operations of the LNG vaporization facility and to construct and operate four (4) natural gas liquefaction trains and associated equipment at the Sabine Pass LNG Terminal in Johnsons Bayou, Cameron Parish, Louisiana

Part 70 Operating Permit Modification No. 0560-00214-V3

Issued by the Louisiana Department of Environmental Quality.

PETITION REQUESTING THE ADMINISTRATOR TO OBJECT TO THE PART 70 OPERATING PERMIT MODIFICATION NO. 0560-00214-V3 ISSUED TO SABINE PASS LNG, LP AND SABINE PASS LIQUEFACTION, LLC

Pursuant to section 505(b) of the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7661(b)(2) and 40 C.F.R. § 70.8(d), the Gulf Coast Environmental Labor Coalition ("GCELC" or "Petitioner") petitions the Administrator of the United States Environmental Protection Agency ("EPA" or "the Agency") to object to the Part 70 Operating Permit Modification No. 0560-00214-V3 issued on December 6, 2011, by the Louisiana Department of Environmental Quality ("LDEQ") to Sabine Pass LNG, LP, and Sabine Pass Liquefaction, LLC ("Project Proponents"), to continue operations of the liquid natural gas ("LNG") vaporization facility and to construct and operate four (4) natural gas liquefaction trains and associated equipment in Johnsons Bayou, Cameron Parish, Louisiana.

Petitioners ask the Administrator to object to the Permit modification because the Permit modification fails to comply with the "applicable requirements" of the Act, including: Louisiana's State Implementation Plan ("SIP"), New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") permitting requirements. *See* 40 C.F.R. § 70.2 (defining "applicable requirement" as used in the CAA). Specifically, the Administrator must object to the Permit modification for the following reasons:

- Meaningful public participation was thwarted by errors in calculations, omissions, improper regulatory determinations and data not made publicly available during the comment period
- Air emissions and adverse air quality impacts that will result from the proposed modifications to the Sabine Pass LNG Terminal have been underestimated due to modeling errors, omission of sources, data errors and calculation errors
- Modifications to the Sabine Pass LNG Terminal, as permitted by LDEQ, will cause significant adverse air quality impacts in Texas including environmental justice communities such as Beaumont and Port Arthur in Jefferson County
- LDEQ failed to conduct a proper top-down Best Available Control Technology ("BACT") analysis as represented to the public
- Permit does not require BACT for ozone and other National Ambient Air Quality Standards ("NAAQS") pollutants
- Permit does not require BACT for greenhouse gases ("GHGs")

LEGAL FRAMEWORK

"The Title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units in a single document….

Such applicable requirements include the requirement to obtain preconstruction permits that comply with applicable new source review requirements." *In re Monroe Elec. Generating Plant,* Petition No. VI-1999-02 at 2 (EPA Adm'r 1999). The Administrator, therefore, must determine whether an emission unit has gone through the proper NSR or PSD permitting process, complies with the Louisiana SIP, and whether the Title V permit contains accurate "applicable requirements," including BACT limits. 40 C.F.R. § 70.2; *In re Chevron Prod. Co., Richmond, Cal.,* Petition No. IX-2004-08 at 11-12 n.13 (EPA Adm'r 2005). If the Administrator objects to the Permit, "the Administrator shall modify, terminate, or revoke" the Permit. 42 U.S.C. § 7661d(b)(3).

The CAA requires the Administrator to issue an objection if Petitioner demonstrates that a permit is not in compliance with the requirements of the CAA. 42 U.S.C. § 7661d(b)(2). *See also* 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group (NYPIRG) v. Whitman*, 321 F.3d 316, 333 n. 11 (2d Cir. 2003). When specifically reviewing a petition to object to a Title V permit that raises concerns about a State's PSD permitting decision, EPA looks to see whether the petitioner has shown that the state agency failed to comply with its SIP-approved regulations governing PSD permitting or that state agency's exercise of discretion under such regulations was unreasonable or arbitrary. *In re American Electric Power Service Corp., Fulton, Ark.*, Petition No. VI-2008-01 at 3 (EPA Adm'r 2009).

Pursuant to 40 C.F.R. § 70.8(d), Petitioner shall base its Petition "only on objections to the permit that were raised with reasonable specificity during the public comment period provided for in § 70.7(h) of this part, unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period." In the instant matter, the permit application, EPA Region VI's comments, the

LDEQ transcript of oral comments, GCELC's oral and written comments, and LDEQ's responses to those comments and other documents in the public record comprise the permit record for EPA's review and form the basis of this Petition. GCELC's objections, as discussed in more detail below, were raised specifically in oral or written comments submitted during the public comment period, further elaborate on objections raised by public commenters, including GCELC and EPA, or in certain circumstances are based on grounds for objection that arose after the close of the public comment period per section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2).

The Administrator must grant or deny this Petition within sixty days after it is filed. *Id.* If the Administrator determines that the Permit does not comply with the requirements of the CAA, or fails to include any "applicable requirement," she must object to issuance of the permit. 42 U.S.C. § 7661d(b); 40 C.F.R. § 70.8(c)(1) ("The Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part."). "Applicable requirements" include, *inter alia*, any provision of the Louisiana SIP, including PSD requirements, any term or condition of any preconstruction permit, any standard or requirement under CAA §§ 111, 112, 114(a)(3), or 504, acid rain program requirements. 40 C.F.R. § 70.2; *In re Monroe Electric Generating Plant*, Petition No. VI-1999-02 at 2 (EPA Adm'r 1999).

In addition, the Administrator has grounds to object to a proposed permit based on procedural flaws pursuant to 40 C.F.R. § 70.8(c)(3) even where the Administrator has not determined applicable requirements or requirements of Part 70 have been violated:

> Failure of the permitting authority to do any of the following also shall constitute grounds for an objection:(i) Comply with paragraphs (a) [requiring the Permitting Authority to transmit the proposed permit, the permit application, and other information needed to effectively review the proposed permit] or (b) [requiring

> the Permitting Authority to give notice of the proposed permit to any affected state] of this section; (ii) Submit any information necessary to review adequately the proposed permit; or (iii) Process the permit under the procedures approved to meet § 70.7(h) of this part [governing public participation] except for minor permit modifications.

PROCEDURAL BACKGROUND

Project Proponents submitted their permit application on December 17, 2010, for a modification to the Title V Operating Permit for the proposed Sabine Pass Liquefaction Project.[1] On June 30, 2011, LDEQ issued the draft permit modification, noticed a public hearing and requested public comment on the proposed permit modification.[2] LDEQ held a public hearing on the proposed permit modification on August 11, 2011, and invited public comments through August 15, 2011. A copy of the permit is available on the LDEQ website.[3] GCELC and its individual members provided oral comments at the August 11, 2011, LDEQ public hearing. A copy of the August 11, 2011, hearing transcript is contained at the LDEQ EDMS database, Document No. 8106009.[4] In addition, GCELC filed written comments submitted to LDEQ prior to the close of the public comment period on August 15, 2011 (hereinafter "GCELC Written Comments"). A true and accurate copy of the GCELC Written Comments is attached as Exhibit 1. On August 15, 2011, EPA Region VI submitted comments on the proposed permit to LDEQ (hereinafter "EPA Comment Letter"). A copy of the EPA Comment Letter is attached as Exhibit 2. LDEQ responded to GCELC's and EPA Region VI's public comments through a memorandum (hereinafter "LDEQ Response"), a copy of which is attached as Exhibit 3. LDEQ sent the proposed the Permit modification to EPA on October 21, 2011. *See* E-mail from Brad

[1] A copy of the permit application is contained at the LDEQ EDMS database, Document No. 7772249, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=8106009&ob=yes&child=yes.
[2] A copy of the public notice and permit documents released are available on the LDEQ EDMS database at Document No. 7998449, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=7998449&ob=yes&child=yes.
[3] A copy of the public notice and permit documents released are available on the LDEQ EDMS database at Document No. 7998449, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=7998449&ob=yes&child=yes.
[4] A copy of the hearing transcript is contained at the LDEQ EDMS database, Document No.8106009, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=8106009&ob=yes&child=yes.

Toup to Susan Eckert transmitting the D. Nguyen (LDEQ) e-mail to EPA Region VI, (October 21, 2011) (hereinafter "LDEQ Permit Transmittal E-mail") attached as Exhibit 4. Counsel for GCELC sent a FOIA request to EPA Region VI relating to the Permit and Proposed Project on September 2, 2011, (hereinafter "GCELC FOIA Request") a copy of which is attached as Exhibit 5. EPA Region VI sent an acknowledgment of GCELC's FOIA Request on September 7, 2011, (hereinafter "EPA FOIA Acknowledgment") a copy of which is attached as Exhibit 6. On February 3, 2011, EPA Region VI for the first time provided documents in response to the GCELC FOIA Request with a partial denial letter received by GCELC on the afternoon of February 3, 2012 (hereinafter "EPA FOIA Response"), attached as Exhibit 7.

THE PETITION IS TIMELY

GCELC's Petition is timely since Petitioner is filing the Petition with EPA within 60 days following the end of EPA's 45-day review period as required by the CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). EPA received LDEQ's proposed revisions to the Title V permit on October 21, 2011. *See* E-mail from D. Nguyen to EPA Region VI, (October 21, 2011) (Exhibit 4). Therefore, the deadline to file a timely Petition with the Administrator relating to the Title V permit revisions is February 3, 2011.

I. LDEQ ISSUANCE OF THE PERMIT BASED ON AN INCOMPLETE APPLICATION THAT OMITTED REQUISITE DATA AND CALCULATIONS VIOLATES THE CAA AND PART 70 REGULATIONS

As more fully described below in section II *infra* at 12-28, the permit application for the proposed modification of the Sabine Pass LNG Terminal omitted emission-related information including data and calculations necessary to determine and assure compliance with all applicable CAA requirements. Federal regulations for state operating permit programs set forth at 40 C.F.R. § 70.5(a)(2) require the submission of a complete application with sufficient information “to evaluate the subject source and its application and to determine all applicable requirements.” The Part 70 regulations further provide in pertinent part that a complete application must contain the following emissions-related information:

> (i) All emissions of pollutants for which the source is major, and all emissions of regulated air pollutants. **A permit application shall describe all emissions of regulated air pollutants emitted from any emissions unit…. The permitting authority shall require additional information related to emissions of air pollutants sufficient to verify which requirements are applicable to the source, and other information necessary to collect permit fees**….
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> (ii) **Identification and description of all points of emissions … in sufficient detail to establish the basis for fees and applicability of requirements of the Act**.
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> (iii) **Emissions rate in tpy and in such terms as are necessary to establish compliance consistent with the applicable standard reference test method**. For emissions units subject to an annual emissions cap, tpy can be reported as part of the aggregate emissions associated with the cap, except where more specific information is needed, including where necessary to determine and/or assure compliance with an applicable requirement.... [and]
>
> (viii) **Calculations on which the information in paragraphs (c)(3)(i) through (vii) of this section is based**. (Emphasis supplied.).

40 C.F.R. § 70.5(c)(3). *See also* CAA § 503(c), 42 U.S.C. § 7661b(c).

The Part 70 regulations specifically require that the permit application must include “information needed to determine the applicability of, or to impose, any applicable requirement.” 40 C.F.R. § 70.5(c). As noted in GCELC’s Comments at 27-32 and section II *infra* at 12-28, the permit application failed to provide the requisite information to evaluate the subject source and determine all applicable requirements. Moreover, LDEQ failed to provide the requisite information in the LDEQ Response to Comment 15 at 21, Comment 19 at 26, Comment 26 at 41 and Comment 29 at 44-45 to ensure that the public record is complete. Finally, in response to certain comments, LDEQ has committed to imposing additional conditions or revision of Permit conditions; however, such Permit terms and conditions have not been incorporated into the public record or made available to the public for review and comment per 40 C.F.R. § 70.7(h). *See, e.g.*, LDEQ Response to Comment 3 at 4-5 (new permit condition presented but not made available for public review and comment); and LDEQ Response to Comment 14 at 19 (new permit terms and conditions referenced but not provided in LDEQ Response or made available for public review and comment). The Administrator, therefore, should object to the Sabine Pass LNG Terminal Title V permit pursuant to 40 C.F.R § 70.8(c)(3) because the permit is not in compliance with Part 70 the procedural requirement since the permit application lacks emission-related information critical for determining applicable requirements and setting appropriate limits and conditions.

The importance of a complete permit application that contains the requisite emission-related information thereby allowing LDEQ, EPA and the public to verify and confirm emissions information and applicability determinations derived therefrom is underscored by the apparent miscalculations in the permit application more fully described below *infra* at 12-28. Contrary to LDEQ's Response to Comments 15 and 19, the CAA and the Part 70 regulations do not allow LDEQ to simply "accept" emission calculations and rely on certain process data based solely on the certification of the Project Proponents and a licensed professional engineer. Rather, LDEQ has an affirmative obligation to verify the accuracy of all data provided in the permit application and relied upon by LDEQ to characterize air emissions and make applicability determinations. *See, e.g.*, 40 C.F.R. § 70.5(a)(2).

Moreover, the public participation requirements of the CAA and the Part 70 regulations mandate that such information be made available to the public during the comment period to allow the public (and EPA) to independently review and confirm that all emissions are properly identified and all applicable requirements and appropriate limits and conditions are included in the permit in accordance with the Act. *See* 40 C.F.R. § 70.7(h)(2).

In an effort to obtain missing information and other documents relating to the Proposed Project, counsel for GCELC sent a FOIA request to EPA Region VI on September 2, 2011, (Exhibit 5). EPA Region VI sent an acknowledgment letter on September 7, 2011, (Exhibit 6), but did not provide any documents to counsel for GCELC in response to this FOIA request until February 3, 2012, (Exhibit 7). EPA Region VI's failure to provide the documents requested in a timely fashion before the filing petition deadline for this Petition has further compromised GCELC's ability to participate in the permit process and file this Petition in violation of FOIA, 5 U.S.C. § 552(a), as well as President Obama's directives to executive agencies regarding federal government transparency and Open Government.[5] GCELC reserves the right to supplement the Petition upon review of the FOIA documents from EPA Region VI.

With regard to LDEQ, GCELC notes that the LDEQ has been scrutinized by the federal judiciary recently for failing to ensure that the public is provided access to all necessary information to be able to meaningfully participate in the LDEQ permitting process. *See Zen-Noh Grain Corp. v. Leggett*, 2009 U.S. Dist. LEXIS 35238 at 2-3 (E.D. La 2009) (dismissed without prejudice on other grounds) ("The crux of Zen-Noh's argument in this case is that it does not have access to all of the information submitted in support of Nucor's permit application, and that it is therefore unable to meaningfully participate in the permitting process. The Court is not unmindful of this concern. As the Court explained at oral argument, it is clear that everybody

[5] President Barack Obama's Memorandum of January 21, 2009 – Freedom of Information Act, Transparency and Open Government, 74 Fed. Reg. 4683 (January 26, 2009). http://www.whitehouse.gov/the_press_office/Transparency_and_Open_Government/; and Open Government Directive, Memorandum for the Heads of Executive Departments and Agencies, from Peter R. Orszag, Director of the Executive Office of the President (December 8, 2009). http://www.whitehouse.gov/open/documents/open-government-directive.

will be better off if the permitting process for this controversial project is conducted as openly and conscientiously as possible. In this regard, it should be noted that the Department promised the Court to make more modeling information available on its website and that the U.S. Environmental Protection Agency is maintaining an active role in the permitting process. It is the Court's hope that the Department of Environmental Quality and Nucor act in a manner to permit full disclosure.”).

LDEQ also failed to adequately respond to GCELC Written Comments identifying data gaps in the permit application and public record. As stated by EPA in a recent order granting the Title V petition to veto another LDEQ permit:

> LDEQ has an obligation to respond adequately to significant comments on the draft title V permit. Section 502(b)(6) of the Act, 42 U.S.C. § 7661a(b)(6), requires that all title V permit programs include adequate procedures for public notice regarding the issuance of title V operating permits, “including offering an opportunity for public comment.” *See also,* 40 C.F.R. § 70.7(h). It is a general principle of administrative law that an inherent component of any meaningful notice and opportunity for comment is a response by the regulatory authority to significant comments. *Home Box Office* v. *FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977) (“the opportunity to comment is meaningless unless the agency responds to significant points raised by the public.”). *See also, e.g., In the Matter of Louisiana Pacific Corporation,* Petition V-2006-3, at 4-5 (November 5, 2007) *(Louisiana Pacific Order).*

In re matter of Murphy Oil USA, Inc., Petition Number VI-2011-02 at 5 (EPA Adm’r 2011).

As in *Murphy Oil USA,* LDEQ again has refused to provide the public with the missing data that the Project Proponents and LDEQ relied upon in support of the Draft Permit as requested in the GCELC Written Comments. Instead, LDEQ in its response to public comments cites to the certification of the Project Proponents and professional engineer in the permit application as the basis for LDEQ’s acceptance of certain process data. *See* LDEQ Response at 21 and 26. LDEQ has failed to provide an adequate response to GCELC’s comment and clearly explain how the permit record is complete within the meaning of 40 C.F.R. §§ 70.5(a)(2) and

70.5(c) with proper citations, and ensure that the record contains sufficient information to evaluate the source and determine all applicable requirements. Under the circumstances, LDEQ's issuance of the Permit violates the requirements of Part 70 since the permit application was not "sufficient to evaluate the subject source and its application and to determine all applicable requirements" per 40 C.F.R. § 70.5(a) and (c). GCELC, therefore, respectfully requests that EPA object to the Permit as required by 40 C.F.R. § 70.8(c)(3).

II. SOURCE OMISSIONS AND DATA AND CALCULATION ERRORS RESULT IN UNDERESTIMATION OF SABINE PASS LNG TERMINAL AIR EMISSIONS AND ADVERSE AIR QUALITY IMPACTS

The following material errors and omissions in the permit application and LDEQ's analysis resulted in the underestimation of Sabine Pass LNG Terminal air emissions and adverse air quality impacts in Louisiana and Texas:

- Calculation errors relating to Acid Vent System air emissions;
- Failure to accurately calculate the increase of air emissions resulting from increased LNG tanker traffic;
- Omissions in reported emissions rates including emissions from ships idling, berthing or hoteling to conduct operations resulting from modification of the Sabine Pass LNG Terminal;
- Failure to accurately calculate the increase in air emissions from wet and dry gas flares that are not permitted to operate under the CAA other than on pilot mode and will be treated as unpermitted Comprehensive Environmental Response Compensation and Liability Act ("CERCLA") releases;
- Misrepresented emissions that do not conform to federal or state requirements to accurately characterize the potential to emit ("PTE") of an emission source. The PTE

may only be limited by terms that are federally enforceable and enforceable as a practical matter. The basis of permit includes emissions rates lower than the maximum rate for the process when the maximum rate is not limited by terms that are federally or practically enforceable; and

- Emissions calculations errors that invalidate the dispersion modeling and air quality impacts assessments as the emissions rates contained in the models substantially underestimate emissions of pollutants that will adversely impact human health.

Contrary to LDEQ's claim in the LDEQ Response at 26, the permit application does not contain all of the emission-related information required by 40 C.F.R. § 70.5. Moreover, these errors and omissions have resulted in failure of the Permit to require compliance with all applicable requirements including, *inter alia*, NSR. Errors and omissions relating to calculation of emissions from the Acid Vent System are the most significant – resulting in a gross underestimation of the emissions by a factor of 1,000 for certain pollutants – and impact multiple pollutants. Discussion of Acid Vent System errors, therefore, is presented first.

A. Acid Vent System Calculation Errors

Contrary to LDEQ's Response to Comment, emissions from the Acid Vent System have been underestimated by a factor of 1,000 due to a calculation error relative to molar flow as demonstrated by GCELC Permit Comments at 15-16 and LDEQ's response to public comments on the Sabine Pass LNG Terminal Modification Air Permits.[6] Furthermore, the Project Proponents represent the maximum emissions rate to be 10% greater than the average emissions rate; independent mass balance calculations performed by GCELC establish that this assumption does not represent the maximum potential for calculation of PTE as required by federal and state

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[6] http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=8207429&ob=yes&child=yes.

law as demonstrated in greater detail in Exhibit 8 – Calculation Errors in the Air Permit regarding Acid Gas Vents per LDEQ PTE requirements (“Acid Gas Calculations”).

Table II-A-1 illustrates the magnitude of error resulting from the error in the mass flow based emissions calculations set forth in the permit application. This table reinforces that the material balance calculations in the GCELC Written Comments support the conclusion that the Acid Gas Vent System emissions are substantially underestimated. The permit application only added 10% to their average mass flow calculations to represent the maximum PTE. Table II-A-1 also shows that for CO_2 this 10% factor (when corrected by a factor of 1,000 resulting from a failure to correct for a conversion of kilograms to grams) substantially underestimates the PTE for CO_2. The materials balance approach used in the independent calculations was based on the regulatory limit of 2% CO_2 in pipeline gas which, lacking federally and practically enforceable limits, is representative of the maximum amount of CO_2 that could be extracted by the amine system in purification of the pipeline gas. The H_2S independent calculations are also based on regulatory limits on H_2S content in pipeline gas.

This mass or materials balance approach could not be performed for VOC emissions from the Acid Vent System because the permit application and public record did not contain any reliable information or basis for estimation. The VOC content of natural gas is very high; it is reported that an amine system will selectively strip higher molecular weight VOCs including BTEX materials (*see infra* at 18-20). Without reliable information on the interaction of the amine system and VOC emissions from the Acid Vent System, meaningful public participation is compromised in violation of 40 C.F.R. § 70.7(h).

Table II-A-1: Magnitude of Error in LDEQ Permit and Dispersion Modeling

Pollutant	Corrected Acid Gas Mass Flow lb/hr	Bechtel Pollutant Specific lb/lb acid gas	Corrected Pollutant Specific lb/hr	Corrected tpy	Independent Calculations in Comments - PTE tpy	Independent Calculations in Comments - average tpy	Permit and Bechtel Uncorrected tpy
CO2	39,083.1	0.9591	37,485	164,183	1,085,656	NA	164
VOC	39,083.1	0.0002	7.82	34.2	NA	NA	0.03
H2S	39,083.1	0.0007	27.36	119.8	203.4	135.6	0.12

Note – The Permit based calculations are represented to be the average plus 10% contingency. VOC independent calculations are discussed above, but included in the table above due the range of error and uncertainty in the information available to the public (*see infra* at 18-20, VOC discussion at A.3. below).

1. Independent Calculation of H_2S Emissions from Acid Vent System Establishes TRS PTE and Actual Emissions Above the Significance Level of 10 Tons Per Year ("TPY") for the Proposed Modifications at the Sabine Pass LNG Terminal Facility

Calculation of H_2S emissions from the Acid Vent System emissions for the proposed modification of Sabine Pass Liquefaction Project cannot be replicated without additional data that was not included in the permit application or public record in violation of 40 C.F.R. §§ 70.5(a) and (c) and 70.7(h). However, H_2S emissions have been independently estimated based on publicly available data as set forth in Table II-A-2 and Table II-A-3 below. For H_2S, the amount of H_2S released to the environment may be estimated based on the assumption that the pipeline gas can contain up to 0.3 grains ("gr") per standard cubic foot ("scf") of H_2S by specification. Removal of this 0.3 gr/scf from the pipeline gas (or at least 0.2 gr/scf to meet the specification for natural gas of 0.1 gr/scf) provides a basis for calculating the PTE and the future actual emissions of the proposed modification to the Sabine Pass LNG Terminal. Pipeline natural gas contains up to 0.3 gr per 100 scf of H_2S. The exported natural gas is presumed to meet the 0.1 gr/scf standard for natural gas by removing 0.2 gr/scf[7] with the capacity of the facility is reported to be 2.6 billion cf per day.

Table II-A-2 and Table II-A-3 below set forth the PTE and projected actual emissions for the AGV H_2S after the proposed modifications to the Sabine Pass LNG Terminal Facility:

Table II-A-2: Potential to Emit for AGV H_2S	
0.3	grains H_2S/100 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.56	tons per day H_2S
203.4	tons per year

Table II-A-3: Projected Actual Emissions for AGV H_2S	
2,000	grains H_2S /1,000,000 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.37	tons per day H_2S
135.6	tons per year

Note: In comparison, the Sabine Pass Liquefaction Project Air Permit reports 0.48 tpy of H_2S for the entire Sabine Pass LNG Terminal Facility after modification according to the LDEQ Air Permits Briefing Sheet – Toxics Emissions Table attached to the draft Letter from Sam L. Phillips (LDEQ, Assistant Secretary) to Patricia Outtrim (Cheniere LNG, Inc.).[8]

[7] http://www.epa.gov/airmarkt/emissions/gasdef.html.
[8] http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=7998449&ob=yes&child=yes.

In response to the GCELC Written Comments regarding the inability of the public to reproduce and verify Acid Gas Vent emissions calculations, the LDEQ Response at 22 provided a sample equation for H_2S that is replicated below and more fully documented in Exhibit 8:

Acid gas flow = 419.6 kg-mol/hr * 42.25 g/mol * 1 lb/453.6 g = 39.08 lb/hr

H_2S = 39.08 lb/hr * 0.0007 lb/lb acid gas * 8760 hr/yr * ton/2000 lb = 0.12 tons/yr

The LDEQ provided equation, however, does not address GCELC's Comments relating to Acid Gas Vent System calculations. The fundamental step in verification of any scientific calculation is cancelling terms. This means that the algebraic factoring of the units associated with each step of calculation must be cancelled and must produce the final terms (in this case lb/hr) for the equation to be valid. Even with a correction and substitution of the molecular weight term of 42.25 g/mol with the more complete term 42.25 grams/gram-mole, a problem remains. It is clear that an additional factor must be inserted for the equation to result in the calculation of pounds per hour (lb/hr) and that term is 1,000 grams/kilogram (g/kg). Multiplying 0.12 tons/yr by this missing factor of 1,000 produces a value of 120 tpy of H_2S. This value is calculated to be 119.8 tpy in Table II-A-1 above (which rounds to 120 tpy).

These independent calculations establish that potential and actual emissions from the proposed modifications to the Sabine Pass LNG Terminal Facility will be greater than the 10 tpy significance level for Total Reduced Sulfur ("TRS") – which includes H_2S – under the applicable federal and state PSD regulations[9] (*see* 40 C.F.R. § 51.166(b)(23)(i) and LAC 33:III.509.B). Accordingly, the Permit is legally and technically insufficient since neither the permit application nor the public record includes the requisite PSD review for TRS from all emission sources including leaks from pipelines and process vessels at the Sabine Pass LNG Terminal

[9] http://www.deq.state.la.us/portal/portals/0/planning/regs/pdf/AQ253fin_w_TA.pdf.

Facility in accordance with federal and state requirements and BACT has not been properly applied these emissions.

2. Independent Calculations Establish that CO_2 Emissions from Acid Vent Systems Have Been Underestimated

Pipeline natural gas can contain up to 2% CO_2 by specification. The Permit states that the CO_2 must be removed prior to liquefaction. As shown in Table II-A-4, this 2% GHG from the 2.6 billion scf of natural gas to be processed, on average per day, by the plant results in an estimate of 1.085 million additional tpy of GHG released by the Acid Vents.

Table II-A-4: Potential to Emit CO_2 from Acid Vents	
2.0%	percent CO_2 in pipeline gas
2,600,000,000	cf/day
52,000,000	cf/day CO_2
0.11	lb/ft3
5948800.00	lb. per day H_2S
2974.4	tons per day
1,085,656	tons per year

As discussed above for H_2S, in response to the GCELC Written Comments regarding the inability of the public to reproduce and verify Acid Gas Vent emissions calculations, the LDEQ Response at 22 provided a sample equation for CO_2 that is replicated below and more fully documented in Exhibit 8:

Acid gas flow = 419.6 kg-mol/hr * 42.25 g/mol * 1 lb/453.6 g = 39.08 lb/hr

CO_2 = 39.08 lb/hr * 0.9591 lb/lb acid gas * 8760 hr/yr * ton/2000 lb = 164 tons/yr

Based on the same analysis as set forth above for H_2S calculations, an additional factor of 1,000 grams/kilogram (g/kg) must be inserted into the calculation to correctly cancel terms. In this instance, multiplying 164 tpy by the missing factor of 1,000 produces a value of 164,000 tpy of CO_2. This value is calculated to be 164,183 tpy in Table II-A-1 above (which rounds to 164,000 tpy).

Accordingly, GCELC respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) because the permit is not in compliance with the Part 70 regulation procedural requirement since the permit application lacks emission-related information critical for determining applicable requirements and setting appropriate limits and conditions. EPA also should direct LDEQ and the Project Proponents to address all data gaps, internally inconsistent data, and apparent emission calculation errors identified herein, and explore potential strategies to reduce adverse air quality impacts resulting from uncontrolled releases of CO_2 from the Proposed Project.

3. Independent Calculations Establish that VOC Emissions from Acid Vent Systems Have Been Underestimated

The amine system removes VOCs from natural gas along with H_2S and GHG. This removal rate varies with operational characteristics of the system. The permit application and the LDEQ public record, however, do not provide any information to the public on this aspect of the control system. In addition, the Permit does not require control or mitigation of VOC emissions in any manner that would limit PTE. VOC emissions from amine contact systems depend on operational parameters and include aromatic VOCs, such as BTEX.[10] Until this omission is corrected, the PTE for the Proposed Project should be considered in the range from several hundred to several million tons per year of VOC. The 34.2 tpy shown in Table II-A-1

[10] Skinner, F.D., D.L. Reif, A.C. Wilson, and J.M. Evans, "Absorption of BTEX and Other Organics and Distribution Between Natural Gas Sweetening Unit Streams," *SPE 37881 Society of Petroleum Engineers*, Presented at 1997 SPE/EPA Exploration and Production Environmental Conference, Dallas, Texas, March 3-5, 1997; and Bullin, Polasek, and Fitz (Bryan Research & Engineering, Inc. Bryan, TX), "The Impact of Acid Gas Loading on the Heat of Absorption and VOC and BTEX Solubility in Amine Sweetening Units."

supra at 14 corrects the calculation errors in the Air Permit, but is not a reflection of the true PTE.

The VOC maximum emissions rate was not calculated on a mass balance basis in the Air Permit. A representative VOC content for natural gas is about 7.5% on a molar basis and, therefore, higher on a mass basis.[11] As the Permit does not impose enforceable conditions or operational limits on the amine and Acid Gas Vent System operations, a VOC PTE rate of over 3,000,000 tpy appears to be appropriate.

Another way of comprehending the magnitude of the underestimation for VOC in the permit application and public record is to correct the factor of 1,000 from the Project Proponents' calculation error. After this correction for CO_2, the Project Proponents' approach of using the expected average value plus a 10% factor was still 6.6 times less than the PTE based on the specification of a maximum content of 2% CO_2 in pipeline gas (1,085656/164,183 = 6.6). Applying this to the corrected emissions rate of 34.2 tpy would give a value of 225.7 tpy of VOC as a minimal and conservative estimation of the amount of VOC that could potentially be emitted from the Acid Vent System. The Acid Gas System, therefore, should be considered the largest source of VOCs at the Sabine Pass LNG Terminal. As the amine system is reported to selectively extract higher molecular weight hydrocarbons from natural gas, including BTEX, the Acid Vent System should be considered a major source of Hazardous Air Pollutants ("HAPs") based on PTE until such time LDEQ effectively addresses this issue and limits this potential with enforceable permit terms.

[11] Center for Energy and Economics, "Interstate Natural Gas – Quality Specifications & Interchangeability, Center for Energy Economics" at 22. http://www.beg.utexas.edu/energyecon/lng/documents/CEE_Interstate_Natural_Gas_Quality_Specifications_and_Interchangeability.pdf.

As discussed above for H_2S and CO_2, in response to the GCELC Written Comments regarding the inability of the public to reproduce and verify Acid Gas Vent emissions calculations, the LDEQ Response at 22 provided a sample equation for VOC that is replicated below and more fully documented in Exhibit 8:

Acid gas flow = 419.6 kg-mol/hr * 42.25 g/mol * 1 lb/453.6 g = 39.08 lb/hr

VOC = 39.08 lb/hr * 0.0002 lb/lb acid gas * 8760 hr/yr * ton/2000 lb = 0.03 tons/yr

As discussed above with regard to the H_2S and CO_2 calculations, an additional factor of 1,000 grams/kilogram (g/kg) must be inserted into the calculation to correctly cancel terms. Multiplying 0.03 tpy by this missing factor of 1,000 produces a value of 30 tpy of VOC. This value is calculated to be 34.2 tpy in Table II-A-1 above (which rounds to 30 tpy).

Accordingly, GCELC respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) because the Permit is not in compliance with Part 70 the procedural requirement since the permit application lacks emission-related information critical for determining applicable requirements and setting appropriate limits and conditions. EPA should direct LDEQ and the Project Proponents to address all data gaps, internally inconsistent data, and apparent emission calculation errors identified herein and explore potential strategies to reduce adverse air quality impacts resulting from uncontrolled releases of VOCs from the Proposed Project.

B. Ozone Precursor Emissions from Flares and Ship Port Operations Have Been Omitted or Underestimated

Substantial omissions in the Permit, and LDEQ public record including the permit application relating to associated dispersion modeling were revealed by LDEQ's Response at 7-8 to Comment 7, which states:

> As discussed in LDEQ Response to Comment No. 6, the NO_2/NO_X in-stack ratio for the generator turbines and refrigeration compressor turbines was based on performance test data supplied by GE.
>
> The only other sources of NO_X emissions included in the 1-hour NO2 modeling exercises were Marine Flare No. 1 (EQT 0047), Wet Gas Flare Nos. 1 & 2 (EQT 0048 & 0049), and Dry Gas Flare Nos. 1 & 2 (EQT 0050 & 0051). In the aggregate, these sources contribute only 2.57 tons per year (TPY) of NO_X emissions and do not have an appreciable impact on the modeling results.

The modeling of the flares in the permit application is flawed. Moreover, LDEQ's Response at 24-25 to Comment 18 regarding proposed operation of the flare did not address or correct error in the Permit. It is evident from this comment that the Wet and Dry Gas Flare operating emissions have not been modeled and are not permitted under the CAA (only those emissions from standby or pilot flame emissions). These emissions evidently will be treated as emergency or unplanned releases subject to emergency release reporting under section 103 of the CERCLA and section 304 of the Emergency Planning Community Right-to-Know Act.

The explanation in the LDEQ Response to Comment 18 regarding the new operating mode for the Marine flare fails to include basis of calculation or permit conditions. A need mode of operation was introduced for the first time in the LDEQ Response, which appears to express the intent to replace this flare as a protective device for venting a warm ship. The new mode of operation seems to describe near continuous operation; the public record does not explain why the emissions rates and dispersion characteristics of this flare have not been changed. In any case, no basis for the reported emissions calculations or permit language to effectively limit Marine Flare operation has been provided to the public for review.

The LDEQ Response at 7-8 to Comment No. 7 also clarifies to the public that the idling, berthing and hoteling emissions from the 400 ships associated with operation of liquefaction operation were not modeled, which is a significant omission. Review of the LDEQ public record reinforces that modeling apparently was never performed for the vaporization operation of ship traffic. Hence, LDEQ's assertion that ship emissions were already accounted is incorrect. In addition, documents have been recently discovered establishing that ship traffic for the Sabine Pass LNG Terminal prior to modification have been in the range of about 7 ships per year. LDEQ is required to evaluate these ship emissions.[12] Furthermore, LDEQ is required to perform the emissions calculations by evaluating the actual emissions for approximately 7 ships per year compared to the PTE of 400 ships for the modified Sabine Pass LNG Terminal that has not yet begun normal operations.

Moreover, as touted by the Project Proponents, the Sabine Pass LNG Terminal has been authorized bidirectional operation to export and import LNG at the same time[13] with authorized ship handling capacity of 400 ship callings per year.[14] As noted in the Draft Sabine Pass Liquefaction Project Environmental Assessment ("EA")[15] at 2-46:

> **The facility's modified Title V permit** was issued by LDEQ on December 6, 2011, and **included provisions allowing operation as both an export and import facility, with no restrictions on simultaneous operation of export and import equipment** (i.e., bidirectional operation). (Emphasis supplied.).

The increased ship traffic from 7 (on average) to as much as 400 ships per year will result in increased air emissions from the operations of the ship boilers and other sources. The original Final Environmental Impact Statement for the Sabine Pass LNG Terminal at 213[16] stated that

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[12] Letter from Charles Sheehan (EPA Region VI) to Michael Cathey (El Paso Energy Bridge Gulf of Mexico, LLC) and and Diana Dutton (Akin, Gump, Strauss, Hauer & Feld, LLP (October 28, 2003) at 8. http://www.epa.gov/region07/air/nsr/nsrmemos/20031028.pdf. ("Our determination that vessel emissions generated in handling LNG at the port should be included in the applicability determination stems from our reading of the plain language of the CAA. Specifically, its definition of "stationary source" gives EPA the authority to consider emissions from external combustion engine vessels in preconstruction and operating permits.")

[13] Pipeline and Gas Technology, 20 January 2011: "Cheniere Signs MOU for Bi-Directional Processing Capacity at the Sabine Pass LNG Terminal." http://www.prnewswire.com/news-releases/cheniere-signs-mou-with-edf-trading-for-bi-directional-processing-capacity-at-the-sabine-pass-lng-terminal-114270714.html.

[14] Sabine Pass Liquefaction LLC. FERC Docket No. 10-85-LNG DOE/FE Order No. 2833 (Sept. 7, 2010) at 3.

[15] http://energy.gov/nepa/downloads/ea-1845-final-environmental-assessment.

[16] http://elibrary.ferc.gov/idmws/Doc_Family.asp?document%5Fid=4253068.

300 ship callings would produce the following air emissions from the combustion of residual fuel oil: NOx – 494 tons/year; CO – 60 tpy; PM_{10} – 28.3 tpy; VOC – 23.4 tpy; and SO_2 – 264 tpy. Since the Permit authorizes 400 ship calls, these emissions totals from ship traffic should be multiplied by 33%, to reflect that these calculations are based on the traffic from 300 ships annually for an accurate PTE analysis. As these emissions were not modeled in the original Sabine Pass LNG Terminal Air Permit, air emissions and air quality impacts have been underestimated for NOx (~ 657 tpy) and VOC (~31.1 tpy).

This underestimation of ship traffic emissions impacts both ozone and NO_x air quality impacts and renders the existing air quality modeling work invalid. The air quality analyses also must be redone to include emissions from flares. Moving these flare emissions off-permit and passing the burden of regulation from the CAA to CERCLA means that the public is neither informed about the magnitude of potential emissions nor protected by dispersion modeling that omitted consideration of these emissions. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(1) and (3) due to the failure to provide emission-related information relating to ship traffic and flares in the permit application and public record and the absence of practically enforceable permit conditions to control these emission sources in the Permit.

F. Modeling Implications of Errors and Omissions Underestimate Air Emissions of the Proposed Project

1. Ozone Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

VOCs and NO_x are the primary precursors to the formation of ambient air levels of ozone. An assessment of the Proposed Project's impact on ambient air levels of ozone must be based on identification of all emission sources and accurate estimates of emission rates of VOCs and NO_x of these sources. As discussed above, emission calculations for VOCs and NOx provided in permit application appear to underestimate emissions of VOCs and NO_x from the Proposed Project from numerous sources and the Permit does not contain operational constraints on the acid gas vents and other emissions units. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(1) and (3) due to the inaccurate modeling of ozone air quality impacts of the Proposed Project and the absence of practically enforceable permit conditions to control these emission sources in the Permit.

2. Particulate Matter Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

As noted above, the modeling in the public record does not take into account emissions of particulate matter from increased ship traffic[17] and from new compressors, which total another 40 tpy, or about a 20% increase over what was modeled.[18] VOC emissions from the acid gas vents are capable of condensing to form aerosols – a type of particulate matter. The primary method of mitigating of releases of air pollution is through proper application of BACT as required under the PSD Program for the Proposed Sabine Pass Liquefaction Project. Failure to install BACT on turbines and the Acid Gas System results in elevated emissions of $PM_{2.5}$ including precursors and condensable aerosols. As noted above, the VOC emissions from the Acid Vent System are likely to contain larger chain, more toxic organic constituents. These same compounds also are likely to be capable of condensing to form aerosols. Emissions from

[17] According to a recent DOE Report, the Sabine Pass LNG Facility had only 29 tanker visits in 4 years: 2008 – 3 ships; 2009 – 9 ships; 2010 – 12 ships; and 2011 – 5 ships. DOE, Detailed Monthly and Annual LNG Import Statistics, 2004-2011, (July 29, 2011) at 5. http://fossil.energy.gov/programs/oilgas/storage/publications/LNG_Historical_Data_Slides.pdf.

[18] The Proposed Project's permitted PM emissions are 248.6 tpy and air modeling was likely based on that level of emissions. However, an additional compressor station on the Creole Pipeline will likely add about another 18 tpy of PM if emissions are similar to the Chehalis compressor station. Furthermore, an additional 300 ships will emit about another 28 tpy of PM, according to the original FEIS, for a total of about 46 tpy of PM. That emissions figure is conservative since 400 ships are expected. These PM sources would add a total of 46 tpy or almost 20% to the Proposed Project's permitted emissions of 248.6 tpy, and would likely trigger almost a 20% increase in ground level impacts, if added to the modeled impacts.

the turbines include both direct sources and precursors of $PM_{2.5}$. NO_x is not properly evaluated for mitigation as noted by EPA and GCELC. In response to these comments, LDEQ asserted that while LDEQ may have failed to require a "Top-Down BACT" analysis for the proposed modifications to the Sabine Pass LNG Terminal, such an analysis is not required. This assertion is plainly flawed as it contradicts LDEQ's assertions about the Sabine Pass LNG Terminal Air Permit itself as well as the standard language of LDEQ's prior PSD permits. *See infra* Section IV at 34-39.

In addition, as discussed above, the Permit does not contain reasonable estimates for emissions of particulate matter from the flare systems. Finally, as noted above, PM emissions for the ships idling, berthing or hoteling are omitted from the Permit. The identification and control of these emissions are necessary elements of the Permit to properly characterize and mitigate adverse air quality impacts. Accordingly, GCELC respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(1) and (3) due to the inaccurate modeling of PM air quality impacts of the Proposed Project and the absence of practically enforceable permit conditions to control these emission sources in the Permit.

3. Carbon Monoxide Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

Modeling of the significant impact area for CO did not use maximum potential emissions from the Sabine Pass LNG facility as required by NSR guidelines. The Significant Impact Area ("SIA") assessment for the PSD permit models only proposed sources for the Liquefaction Project and not existing sources from the Vaporization Project. Including emissions from the permitted Vaporization and Liquefaction Emissions Cap (EQT: GRP 0008) found in the Title V and PSD permits for the Proposed Project would increase modeled CO emissions by over 600 tpy or approximately a 13% increase in emissions as set forth in Table II-A-5 below.

Table II-A-5: Emissions for the Significant Impact
Analysis Modeling for the Proposed Sabine Pass LNG Project

	CO Tpy	CO g/s
Modeled Emissions	4772.18	137.2780
Vaporization and Liquefaction Emissions	5394.43	155.1822

GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R § 70.8(c)(3) due to the inaccurate modeling of CO air quality impacts of the Proposed Project.

4. Nitrogen oxides (NO_x) Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

Modeling of the significant impact area for NO_x and the impacts to the NO_x 1-hour, annual NAAQS and PSD NO_x increment also did not use maximum potential emissions from the Sabine Pass LNG facility as required by NSR guidelines. The SIA assessment for the PSD permit modeled only proposed sources for the Liquefaction Project and not existing sources from the Vaporization Project. Using the allowable emissions from the permitted Vaporization and Liquefaction Emissions Cap (EQT: GRP 0008) found in the Title V and PSD permits would increase the modeled NO_x emissions by over 500 tpy or nearly a 20% increase in emissions.

Modeling of the impacts from the proposed project on the 1-hour NO_x standard does not include existing sources from the Vaporization Project. The 1-hour NO_x NAAQS modeling does not meet requirements for PSD modeling. In response, LDEQ has included a permit condition requiring 1-hour NO_x NAAQS modeling if and only if emissions reach a certain level for a sustained period of time. This condition would only take effect if the calculated NO_x emissions from the natural-gas fired generator turbines, submerged combustion vaporizers, flares, and refrigeration compressor turbines exceed 637.29 pounds per hour for more than 175 hours in any 12 consecutive month period. The Permit allows for a vaporization and liquefaction annual average emissions cap for NO_x emissions of 733.28 pounds NO_x per hour. PSD permitting requires modeling of emissions from the maximum PTE not typical or average emissions. Annual NO_x NAAQS and PSD increment modeling calculate NO_x impacts from average emission rates of the existing vaporization portion of the Facility instead of maximum potential emissions set forth in the Permit. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) due to the inaccurate modeling of NO_x air quality impacts of the Proposed Project.

5. Hydrogen Sulfide (H_2S) Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

GCELC's calculations of H_2S emissions from acid gas vents ("AGVs") shows that potential and actual emissions of TRS would be above the significance level of 10 tpy for the proposed modifications at the Sabine Pass LNG Terminal Facility. H_2S is extremely hazardous and noxious. Accurate modeling of ambient air impacts of uncontrolled releases of H_2S from pipelines and process vessels at the proposed Sabine Pass LNG Liquefaction Facility has not been provided in the permit application or the public record. If the H_2S is combusted as a result of application of BACT, then the SO_2 released would be approximately 383 tpy (mw of SO_2/H_2S = 64/34). However, the amine treatment used to remove the H_2S from the pipeline natural gas would allow for proper control by converting the H_2S to elemental sulfur using a Claus Plant, which would likely represent the top tier of a BACT hierarchy. This analysis is wholly lacking from the permit application or the public record. GCELC, therefore, respectfully requests that EPA object to the Permit for not being in compliance with all applicable requirements pursuant to 40 C.F.R. § 70.8(c)(1).

6. GHGs Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

GCELC's calculations show that that CO_2 emissions from Acid Gas System and other sources have been underestimated. Pipeline natural gas can contain up to 2% CO_2 by specification. The Permit states that the CO_2 must be removed prior to liquefaction. As shown in Table II-A-4 *supra* at 17, this 2% GHG from the 2.6 billion scf of natural gas to be processed, on average per day, by the plant results in an estimate of 1.085 million additional tpy of GHG released by the Acid Vents alone. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) due to the inaccurate modeling of CO_2 and other GHGs air quality impacts of the Proposed Project.

III. THE PERMITTED AUTHORIZED INCREASES IN AIR EMISSIONS WILL CAUSE SIGNIFICANT ADVERSE AIR QUALITY IMPACTS IN TEXAS INCLUDING ENVIRONMENTAL JUSTICE COMMUNITIES SUCH AS BEAUMONT AND PORT ARTHUR

A. Increased Emissions from the Sabine Pass LNG Terminal Modifications will Cause Significant Impacts on Texas Ambient Air Ozone Levels

EPA Region VI expressed concerns that modeling in the permit application underestimated the Proposed Project's potential ozone impacts from increases in ambient ozone levels in the Environmental Justice communities of Beaumont and Port Arthur, Texas, in the EPA Comment Letter, Enclosure at 5 (Exhibit 2). EPA further opined that increased emissions authorized by the Permit would cause significant impacts on Texas's ambient air ozone levels:

> Looking at the spatial plots of the maximum impacts on Sundays that were modeled, we observed estimated impacts due to Cheniere's emissions on the older of more than 1 ppb on Sundays in early and late June when ozone exceedances were recorded in BPA [Beaumont-Port Arthur], with base values as high as 95 ppb. **If the underestimation that is factored into the modeling of less than daily maximum emission rates is considered, it is possible that Cheniere's emissions could have modeled impacts of one to ppb on values monitored well above the 75 ppb ozone standard. Even Cheniere's analysis indicates that they impact grid cells above 1 ppb on a number of days. While EPA is**

not defined significance levels for ozone for single source, we have recently to find impacts from a state's emissions on another state's ozone levels as being significant when it was above 0.85 ppb on the DV. From the analysis that Cheniere has completed, it is not entirely clear if the emissions could result in levels above the 0.85 ppb unspecific exceedances values, but the science of the impact does raise concern that emissions during the afternoon period (noon to 6 p.m.) should be prevented in the permit as they were modeled. (Emphasis supplied.).

EPA Comment Letter, Enclosure at 5-6 (Exhibit 2).

LDEQ, however, ignored EPA's concerns that adverse air quality impacts resulting from the proposed modification of the Sabine Pass LNG Terminal are significant and issued the Permit as proposed. EPA's concerns regarding ozone impacts to human health in these Environmental Justice communities resulting from increased emissions due to Sabine Pass LNG Terminal modifications are justified. Significant human health effects have been documented for exposures to levels of ozone far below the present-day 8-hour ozone NAAQS of 75 ppb.[19] According to EPA's latest Integrated Science Assessment for Ozone and Related Photochemical Oxidants:

An important consideration in characterizing the association of O3 with morbidity and mortality is the shape of the concentration-response relationship across the O3 concentration range. In this ISA, studies have been identified that attempt to characterize the shape of the O3 concentration-response curve along with possible O3 "thresholds" (i.e., O3 levels which must be exceeded in order to elicit a physiological response). These studies have indicated **a generally linear concentration-response function with no indication of a threshold for O3 concentrations greater than 30 or 40 ppb, thus if a threshold exists, it is likely at the lower end of the range of ambient O3 concentrations**. (Emphasis added).[20]

Jefferson County, Texas, includes the cities of Beaumont and Port Arthur, which have sizeable populations. Ground-level ozone is a problem in Jefferson County, where levels have

[19] Presently, the 8-hour NAAQ for ground-level ozone is 0.075 ppm. However, in January 2010, EPA proposed strengthening the standard to a level between 0.06 and 0.07 ppm. National Ambient Air Quality Standards for Ozone - Proposed Rule.75 Fed. Reg. 2938 (Jan. 19, 2010). http://www.epa.gov/air/ozonepollution/fr/20100119.pdf.
[20] EPA, "Integrated Science Assessment for Ozone and Related Photochemical Oxidants," (March 2011). http://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=217463.

been around 77 ppb.[21] In August 2011, maximum daily 8-hour ozone averages reached as high as 96 ppb.[22] Recent census data indicates that 252,273 persons reside in Jefferson County, of which 118,296 reside in the city of Beaumont, and 57,755 reside in the city of Port Arthur. Recent demographic information for the State of Texas indicates that the general population includes 6.8% children between the ages of 1-6; application of this data results in an estimated 17,155 children between these sensitive ages residing in Jefferson County (8,044 in the city of Beaumont and 3,927 reside in the city of Port Arthur).

Moreover, scientists with the New York State Department of Health published findings showing that every 1 ppb increase in ambient ozone levels results in a 16-22% increase in hospital admissions of children between the ages of 1 and 6 years suffering from respiratory distress:

> The risk of hospital admissions increased 22% with a 1-ppb increase in mean ozone concentration during the ozone season.[23]

Application of the same baseline hospital admission rate of children for respiratory distress of 0.87%[24] indicates that over any given five-year period <u>an increase in ozone levels of only 0.5 ppb associated with the Proposed Project would cause an estimated additional 12 to 16 hospital admissions every five years for respiratory distress among young children in Jefferson County</u>. Additionally, scientists with the Yale University, School of Forestry and Environmental Studies and Johns Hopkins School of Public Health presented findings that every 1 ppb increase in ambient ozone levels results in a 0.087% increase in overall human mortality:

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[21] "New pollution rules could hit area" (The Port Arthur News) – June 8, 2010. http://panews.com/local/x1910030847/New-pollution-rules-could-hit-area/print.

[22] *See* TCEQ, Daily Maximum Eight-Hour Ozone Averages for August 2011, Beaumont-Port Arthur Monitoring Stations. http://www.tceq.state.tx.us/cgi-bin/compliance/monops/8hr_monthly.pl.

[23] Lin, S.H., *et al,*"Chronic Exposure to Ambient Ozone and Asthma Hospital Admissions," Environmental Health Perspectives, 116(12):1725-1730. http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2599770/pdf/ehp-116-1725.pdf.

[24] *Id.*

In the meta-analysis, a 10-ppb increase in daily ozone at single-day or 2-day average of lags 0, 1, or 2 days was associated with an 0.87% increase in total mortality).[25]

Recent demographic information for the State of Texas suggests that the baseline rate of annual mortality in Jefferson County would be an estimated 1694 deaths per year.[26] Therefore, over any given five-year period, an increase in ozone levels of only 0.5 ppb associated with the Proposed Project would cause an estimated additional 3.7 mortalities (premature deaths) among residents of Jefferson County.

B. Increased Emissions from the Sabine Pass LNG Terminal Modifications will Cause Significant Impacts on Texas Ambient Air PM Levels

Notwithstanding the modeling errors resulting from omission of PM emissions from certain emission units at the Sabine Pass LNG Terminal after the proposed modification as describe above at *supra* at 24-25, air modeling in the permit application demonstrated that air emissions from the authorized by the Permit would cause more than 10% increase in $PM_{2.5}$ concentrations in nearby Port Arthur. The permit application modeled the increase of $PM_{2.5}$ levels in Port Arthur at 1.17 ug/M3, compared to the existing $PM_{2.5}$ design value of 11.3 ug/M3, which was the 2005-7 average presented in a Minerals Management Air Quality Study for the Gulf Coast.[27] Put another way, PM emissions authorized by the LDEQ Permit would produce total PM concentrations of 12.7 ug/M3.

Many scientific studies demonstrate conclusively that increased of levels of air pollutants directly and immediately harm public health, even if the pollutant concentrations do not exceed the legal standards. With respect to fine particulate matter (PM_{10} and $PM_{2.5}$), several studies

[25] Bell, M.L., *et al*., "A Meta-Analysis of Time-Series Studies of Ozone and Mortality With Comparison to the National Morbidity, Mortality, and Air Pollution Study," Epidemiology, 16(4):436-445 (2005). http://host231.virtual.yale.edu/uploads/publications/Bell_2005_Epidemiology.pdf.
[26] http://www.cdc.gov/nchs/data/nvsr/nvsr58/nvsr58_19.pdf.
[27] http://www.data.boem.gov/PI/PDFImages/ESPIS/4/4903.pdf.

were recently summarized by the California Air Resources Board ("CARB"), demonstrating that an increase in the concentrations of fine particulate produced more attacks of aggravated asthma and lung ailments, and increased death rates among the exposed population, even if standards were not exceeded.[28] The CARB Report draws on the authenticated research in several earlier reports, including the "Harvard Six Cities" study, and other groundbreaking work by Dockery and Schwartz, of how elevated PM causes increased death rates and illnesses. The "Six Cities" and other studies' results originally caused the recent tightening of the PM standards by EPA.

The CARB study demonstrates that PM levels that exceeded 12 ug/m^3 (the State standard), even if did not exceed the federal standard of 15 ug/m^3, would still cause elevated death and illness rates. The Proposed Project's PM emissions will cause exceedance of the 12 ug/m^3 level that will cause adverse human health impacts in the Environmental Justice communities of Jefferson County, Texas.

C. Environmental Justice Implications of Increased Ozone and PM Levels in Beaumont and Port Arthur, Texas

The LDEQ Permit sanctions significant adverse air quality impacts to environmental justice communities in Jefferson County, Texas, including Port Arthur and Beaumont, Texas. According to the United States Civil Rights Commission in its analysis of environmental justice issues, the two major cities in Jefferson County – Beaumont and Port Arthur – are predominately minority and suffer disparate environmental impacts from hazardous exposures associated with multiple sources of air pollution in the vicinity.

> Beaumont, with a population of slightly more than 113,000, is 45.8 percent African American and 7.9 percent Hispanic; while Port Arthur, with 57,755 residents, is 43.7 percent African American and 17.5 percent Hispanic. Clark

[28] California ARB, "Methodology for Estimating Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California," (12/07/09). http://www.arb.ca.gov/research/health/pm-mort/pm-mort_final.pdf.

> Refining and Marketing, Inc., in Port Arthur, and Mobile Oil Corporation, in Beaumont, each ranked in the worst 10 percent in the country for criteria air pollutant emissions in 1999. In addition to these two facilities, 19 other chemical plants and refineries and related industries operate in just these two cities. In the two mostly white communities in the same area of Jefferson County, Port Neches and Winnie, there are only three facilities. (Citations omitted.).[29]

Consequently, Port Arthur is one of 10 locations chosen for EPA's 2010 national Showcase Project initiative to address environmental justice challenges using collaborative, community-based approaches to improve public health and the environment.[30] EPA Region VI has noted that Port Arthur is more than 50 percent African American and Hispanic with a disproportionate amount of chemical plants and refineries and a hazardous waste incinerator. As part of this national initiative, EPA is specifically looking at the cumulative effects of multiple environmental impacts in Port Arthur.[31] Through the Environmental Justice Showcase Community project, residents of Port Arthur have expressed concerns about local air quality, odor issues, air monitoring, and industrial facilities' green house emissions, incident air emissions and releases into the environment.[32]

Executive Order 12898 on Federal Actions To Address Environmental Justice In Minority Populations and Low-Income Populations states:

> [E]ach Federal agency shall make achieving environmental justice part of its mission by indentifying and addressing, as appropriate, disproportionately high adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations in the United States….

[29] United States Civil Rights Commission, "Not in My Backyard: Executive Order 12898 and Title VI as Tools for Achieving Environmental Justice" (Chapter 2) (last modified in 2010). http://www.usccr.gov/pubs/envjust/ch2.htm.
[30] EPA, Port Arthur Community Showcase, http://www.epa.gov/region6/6dra/oejta/ej/index.html; EPA, Showcase Project Update, http://www.epa.gov/region6/6dra/oejta/ej/ej_pdfs/showcase_update_08-17-10.pdf.
[31] EPA, Environmental Justice Showcase Communities. http://www.epa.gov/compliance/environmentaljustice/grants/ej-showcase.html.
[32] http://www.epa.gov/region6/6dra/oejta/ej/ej_pdfs/showcase_input.pdf.

EPA has express a strong commitment to environmental justice including consideration by state permitting agencies of environmental justice impacts in permitting decisions and stressing the need for early, meaningful engagement of and participation by the local environmental justice communities into the permitting decision-making.[33]

The Environmental Justice implications of the Permit on Texas ambient air quality should be addressed to ensure that increased emissions from the proposed modification of the Sabine Pass LNG Terminal in Louisiana do not significantly increase ozone levels in Beaumont and Port Arthur. GCELC, therefore, respectfully requests that EPA object to the Permit because emissions are authorized by this Permit pursuant to the Louisiana SIP in violation of section 110(a)(1)(D)(i) of the Act, 42 U.S.C. § 7410(a)(1)(D)(i), that prohibits any source or emission activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment or will interfere with measures to prevent significant deterioration of air quality in another State.

IV. LDEQ CONDUCTED A FLAWED TOP-DOWN BACT ANALYSIS

A. A Top-Down BACT Analysis is Required

The CAA forbids the construction of, or modifications to, a major emitting facility unless the facility uses BACT. 42 U.S.C. § 7475(a)(4). The Louisiana SIP specifically requires that major modifications "shall apply best available control technology for each regulated NSR

[33] *See* EPA's Plan 2014, http://www.epa.gov/compliance/ej/plan-ej/; EPA's Action Development Process, Interim Guidance on Considering Environmental Justice during the Development of an Action (July 2010). http://www.epa.gov/compliance/ej/resources/policy/considering-ej-in-rulemaking-guide-07-2010.pdf; EPA Region II's Environmental Justice and Permitting Guidelines. http://www.epa.gov/region2/ej/permit.htm; National Environmental Justice Advisory Council, Environmental Justice in the Permitting Process, (1999) at 12-13. http://www.epa.gov/compliance/ej/resources/publications/nejac/permit-recom-report-0700.pdf.

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pollutant." La. Admin. Code Tit. 33, § III:509(J)(3).[34] At its core, BACT is an emissions limitation based on an "application of production processes or available methods, systems, and techniques." La. Admin. Code Tit. 33, § III:509(B); *In re Three Mountain Power, LLC,* 10 E.A.D. 39, 54 (E.A.B. 2001) ("BACT means an emission limitation rather than a particular control technology."). The goal of a BACT analysis is to reach an emissions limit for each pollutant. The underlying technology or standard is the means to achieve the limits. Only if "the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible," may the administrative authority allow a "design, equipment, work practice, operational standard, or combination thereof" to satisfy the BACT requirement instead. *Id.*

The Supreme Court held in *Alaska Dept. of Envt'l. Conservation v. EPA*, 540 U.S. 461, 502 (2004), that EPA has the authority to rule on the reasonableness of BACT decisions by state permitting agencies concerning pollution-emitting facilities and may properly block construction permitted by a state agency at a facility when the BACT determination is not based on a reasoned analysis under the CAA. The Supreme Court noted that the top-down approach as set forth in EPA's draft *New Source Review Workshop Manual* ("NSR Manual") (EPA, Oct. 1990) is commonly used by state permitting agencies for BACT determinations. *Alaska Dept. of Envtl.*, 540 U.S. at 476, n. 7.

EPA's NSR Manual explains the process for determining BACT using the top-down five-step approach. Although EPA's NSR Manual's top-down BACT approach is not a binding regulation nor mandated by the CAA, the top-down BACT approach is widely applied and

[34] Louisiana's EPA approved state implementation plan for PSD is codified at La. Admin. Code Tit. 33, § III:509. 40 C.F.R. § 52.986.

recognized to be an accurate statement of EPA's policy for PSD issues. *In re Newmont Nev. Energy Inv., L.L.C.*, 2005 EPA App. LEXIS 29 at 18-19 (EAB 2005) (The Environmental Appeal Board consistently approves of the use of the NSR Manual's top-down BACT analysis and is considered by the Board "to be a statement of the Agency's thinking on certain PSD issues."). "A careful and detailed analysis of the criteria identified in the regulatory definition of BACT is required, and the methodology described in the NSR Manual provides a framework that assures adequate consideration of the regulatory criteria and consistency within the PSD permitting program." *In re Cardinal FG Co.*, 2005 EPA App. LEXIS 6 at 25 (EAB 2005)*; see also In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 183 (EAB 2000) ("This top-down analysis is not a mandatory methodology, but it is frequently used by permitting authorities to ensure that a defensible BACT determination, involving consideration of all requisite statutory and regulatory criteria, is reached."). Indeed, the Ninth Circuit has considered the top down approach the expected way to determine BACT. *See Citizens for Clean Air v. EPA*, 959 F.2d 839, 845 (1992).

While recognizing that the NSR Manual does not constitute a final policy, EPA continues to support the use of the NSR Manual's top-down BACT analysis by permitting agencies for PSD permits:

> [I]t remains EPA's policy to use the five-step, top-down process to satisfy the Best Available Control Technology ("BACT") requirements when PSD permits are issued by EPA and delegated permitting authorities, and we continue to interpret the BACT requirement in the Clean Air Act and EPA regulations to be satisfied when BACT is established using this process, as it has been described in decisions of the Environmental Appeals Board.

72 Fed. Reg. 31372, 31380 (2007).

EPA's top-down approach as set forth in the NSR Manual consists of five steps: (1) Identify all control technologies; (2) Eliminate technically infeasible options; (3) Rank remaining control technologies by control effectiveness; (4) Evaluate most effective controls and document results; and (5) Select BACT. *See In re Prairie State Generating Co.*, 2006 EPA App. LEXIS 38 at 31-34 (EAB 2006) (summarizing and describing steps in the top-down BACT analysis); *NSR Manual* at B.6. The CAA only recognizes energy, environmental, and economic impacts as acceptable grounds for rejecting the most stringent technically feasible control alternative. 42 U.S.C. § 7479(3). These impacts are evaluated in Step 4 of the top-down analysis. If the applicant rejects the most stringent alternative, the burden is on the applicant to justify the rejection. *NSR Manual* at B.26-29.[35] Therefore, in the instant case, LDEQ is required to apply the most stringent controls in the Permit unless the Project Proponents demonstrates that the control is not technologically feasible or cost effective, or that the control causes unique adverse energy or environmental collateral impacts. NSR Manual at B.24. The NSR Manual further clarifies the control alternative rejection process as involving "a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology." NSR Manual at B.29.

"[I]n selecting BACT, [permitting authorities are required] to consider 'application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques.'" *In re Spurlock Generating Station*, Permit No. V-06-007, U.S. EPA Pet. No. IV-2006-4 (2007) at 37 ("*Spurlock* Order") (quoting 42 U.S.C. § 7479(3). Permitting authorities "must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations." *Spurlock* Order at 30; *Indeck-Elwood, LLC*, 2006 EPA App.

[35] "The applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information…. Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT…. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record." *Id.*

LEXIS 44 at 56 (EAB 2006). "A permit issuer must, therefore, articulate with reasonable clarity the reasons for its conclusions and must adequately document its decision making." *Id.*

In *Spurlock*, the EPA said: "While permitting authorities have discretion in making the case-by-case technical assessments necessary to determine BACT for a specific source, in exercising that discretion, they must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations. *Id.* at 30.

Once a state agency purports to follow the top-down BACT analysis from the NSR Manual, the state agency must conduct the top down BACT analysis in a reasoned and justified manner. *Alaska Dept. of Envt'l. Conservation v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002) *aff'd*, 540 U.S. 461, 487 (2004) (upholding EPA's long-standing policy to overturn permitting decisions that are not based on "reasonable grounds properly supported on the record, described in enforceable terms, and consistent with all applicable requirements"). EPA decisions on BACT clearly show that the permitting agency's analysis must be sweeping and well-documented.

> Not merely an option gathering exercise with casually considered choices, the NSR Manual or any BACT analysis calls for a searching review of industry practices and control options, a careful ranking of alternatives, and a final choice able to stand as first and best. If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.

In re: Northern Michigan University Ripley Heating Plant, 2009 EPA App. LEXIS 5 at 29-30 (EAB 2009). Moreover, the EAB has recognized that "[a]n incomplete BACT analysis, including failure to consider all potentially applicable control alternatives, constitutes clear error and, therefore, is grounds for remand." *In re: Prairie State Generating Co.,* 2006 EPA App. LEXIS 38 at 36 (EAB 2006).

Finally, LDEQ, as the permitting agency, has consistently represented that under current PSD regulations, EPA's top-down BACT analysis was required for the control of each regulated pollutant emitted from a modified major source in excess of the specified significant emission rates. *See, e.g.*, Dolet Hills Power Station, CLECO Corporation, Mansfield, DeSoto Parish, AI No. 584 (2006); Consolidated Environmental Management, Inc. – Nucor Steel, Louisiana AI No. 157847 (2010); Alliance Refinery, ConocoPhillips Co., AI No. 2418 (2003); Louisiana Generating LLC – Big Cajun II Power Plant, AI No. 38867 (2006). Moreover, in the instant case, LDEQ represented to the public that a top-down BACT analysis has been performed and that the selection of BACT was based on the top-down approach with regard to the Project Proponent's requested permit modifications. However, as discussed in detail below, LDEQ did not conduct a proper top-down BACT analysis. As a result, control technologies were improperly rejected by LDEQ as being technologically infeasible or economically unachievable. The Permit, therefore, is not in compliance with all applicable requirements.

B. Improper BACT Determination for Ozone and Other NAAQS Pollutants

GCELC's comments regarding proper application of BACT in the Permit remain essentially unresolved. The one positive step adopted by LDEQ was an intent to address emissions from the combustion turbines ("CTs") by requiring sulfur-free natural gas fuel (albeit without public review or comment in violation of 40 C.F.R. § 707(h)). This is a positive step and, to the extent it is supported by appropriate permit language, would address concerns about sulfur dioxide emissions from the CTs. Other concerns raised by GCELC, however, remain unresolved.

1. Improper Application of the Top-Down BACT Procedure

As more fully described above, the Top-Down BACT procedure contains five essential steps:

A. Step 1 - Identify all control technologies

B. Step 2 - Eliminate technically infeasible options

C. Step 3 - Rank remaining control technologies by control effectiveness

D. Step 4 - Evaluate most effective controls and document results

E. Step 5 - Select BACT

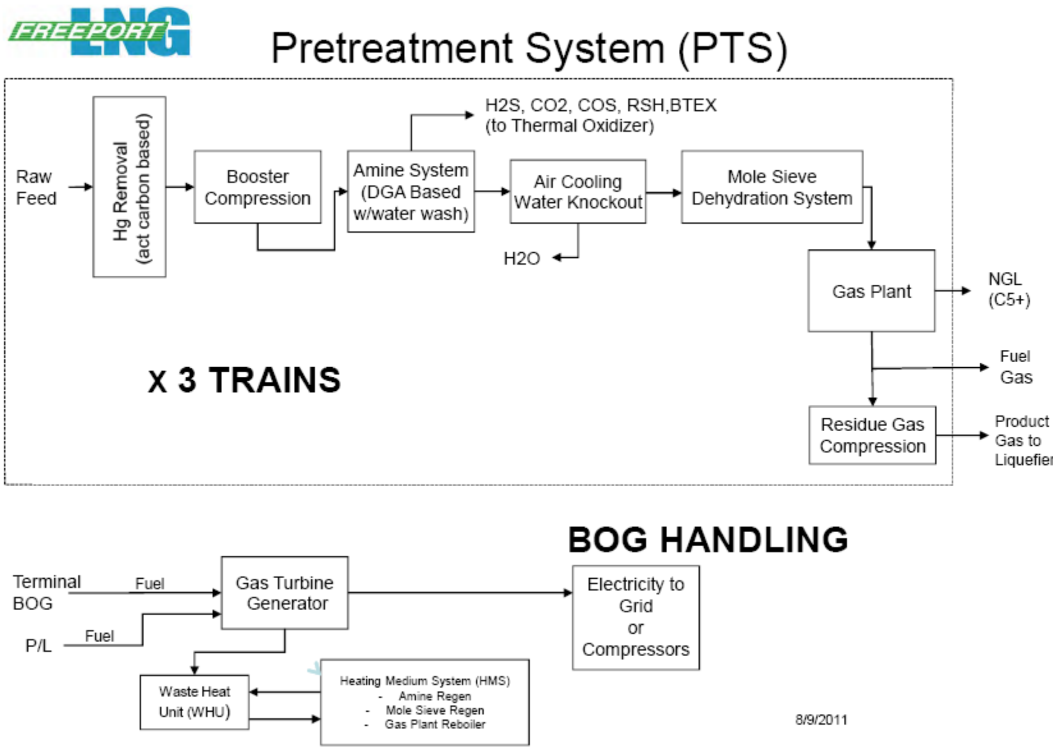
a. Step 1 - Identify all control technologies

Due to errors and omissions noted in Section II.A *supra* at 12-20. regarding the Acid Gas Vent System, LDEQ has failed to identify control options for emissions of VOC, TRS and GHGs from this system. Due to these errors and omissions, LDEQ has failed to identify control options for emissions from ship in port for the pollutants VOC, NO_x, CO and PM. These pollutants are regulated by the CAA and emitted in quantities that make them significant under the PSD program. While Selective Catalytic Reduction ("SCR") and SCONOX are identified as control options for the combustion turbines, combined cycle operation and replacement of the turbines with electric motors are not identified and are not analyzed in subsequent steps of a proper BACT analysis. The LDEQ Response to Public Comments contains cryptic discussion of public comments regarding combined cycle operation, so it may be presumed that combined cycle operation of the turbines has been identified at this point. LDEQ and the permit application, however, failed to consider the use of electric motors to liquefy LNG in the BACT determination, which would substantially reduce on-site emissions and lessen air quality impacts to ambient air quality. Notably, electric motors are identified as BACT in the permit application for the proposed Freeport LNG Liquefaction Project that would be located in Brazoria County, Texas, dated December 16, 2011 (after the close of the Sabine Pass LNG Terminal Draft Permit comment period).[36]

The use of a thermal oxidizer ("TO") to control emissions from the amine system is another control technology identified as BACT in the Freeport LNG Liquefaction Project permit application that was not considered in the Sabine Pass LNG Terminal permit application or the LDEQ public record. While LDEQ is permitting the free-venting of the emissions from the amine system, the Freeport LNG Liquefaction Project permit application proposes use of a TO for control of these emissions. The Freeport LNG Liquefaction Project permit application also includes a diagram that notes the TO is required to control emissions of H_2S and BTEX. This illustrates a gap in control for the Sabine Pass LNG Terminal modifications and confirms the contentions of GCELC that these emissions are significant (*see* section II.A.1 *supra* at 14-17) and may be controlled via BACT. Figure V.B.1 below shows the TO for control of BTEX, H_2S and other reduced sulfur compounds in the upper center of the diagram for the pretreatment system:

Figure V.B.1 – Freeport LNG Compression Project Thermal Treatment Diagram for Acid Gas Vents

[36] http://www.epa.gov/region6/6pd/air/pd-r/ghg/freeport_lng_app.pdf.



b. Step 2 - Eliminate Technically Infeasible Options

The elimination of technically infeasible options is the second step of BACT. LDEQ erred in its BACT analysis by elimination of technically feasible options. One of the most significant errors is the use of economic factors in consideration of technical feasibility. It is appropriate to consider economic impacts of control alternatives in BACT but not at Step 2. A complete economic analysis that contains both cost effectiveness comparisons and a discussion of control costs in comparison to other BACT determinations is a necessary component of BACT selection in Steps 3, 4 and 5. But, it is inappropriate to eliminate an option as infeasible merely because the option would involve additional expenses. *See* EPA's Top-Down BACT Guidance at 21-22 and identical language contained in EPA's NSR Manual at B.19-B.20:

Where the resolution of technical difficulties is a matter of cost, the applicant

> should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process. A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology.

LDEQ's Response to comments from both EPA and GCELC regarding the failure to properly consider SCR for the CTs is based on a mixture unsubstantiated assertions and innuendo rather than specific citations to support technical infeasibility. The context of these assertions is that, in some unsubstantiated manner, the load and temperature profiles for turbines operating in natural gas compression are intrinsically different than turbines operating in other applications where SCR is commonly employed. LDEQ, however, has failed to substantiate these claims in the public record. The model of CT proposed in the permit application – the General Electric LM 2500 – is commonly used in electrical generation to power ships and a wide variety of other applications. The fact that this model is commonly controlled by SCR imposes a large burden for LDEQ to show that some aspect of the use for compression operation creates a difference that makes application of control technologies (i.e., SCR and SCONOX) technically impossible. Decreasing control effectiveness, increasing adverse environmental impacts (e.g., ammonia slip) or increasing cost must be considered in Step 4 of the BACT analysis and are inappropriate as criteria at Step 2.

The discussion in the LDEQ Response regarding the difference in load in comparing generating and compression turbines also is unsubstantiated. Innuendo is an improper basis for eliminating an option as technically unfeasible in an appropriate BACT analysis. Load varies substantially in electrical generation. LDEQ has not established that load varies for the Proposed Project are any greater than in electrical generation as many turbines operate in a load-following or in a peaking mode where their purpose is to take up the variation in system load requirements. Apparently, LDEQ is claiming that the control efficiency of SCR would suffer under temperature and load swings. This factor may be appropriate for consideration under Step 4 as a possible environmental impact, but is not a valid basis to support an argument for technical infeasibility. For comparison to the undocumented load swings at the Proposed Project, the Kapaia Power Station operates a GE LM 2500 turbine with SCR installed that can maintain its emissions limits at a 50% turndown rate.

> In 2002, KIUC purchased the Kapaia Power Station (KPS). KPS includes a General Electric LM2500PH steam injected combustion turbine. The unit can burn either Naphtha or No.2 fuel oil. Steam is injected at approximately 10,000#/hr for NOx control and 56,000#/hr for power augmentation. The unit has an Innovative Steam Technologies once thru steam generator with a Selective Catalytic Reduction (SCR) system and an associated ammonia injection grid for NOx control. Dry urea is converted into ammonia in the ammonia reactor for injection into the SCR catalyst. KPS has a minimum turndown limited to 50% load or approximately 14MW in order to operate within environmental compliance.[37]

Tandem turbines offer more flexibility in meeting load requirement. LNG stations like Sabine Pass are classified as "base loaded" meaning that their operation is expected to be relatively constant and at nearly full load. In order for LDEQ to substantiate these claims, a complete evaluation of expected operating scenarios, load, gas temperatures and emissions rates must be evaluated and made available for public review in comparison to those characteristics for all turbines operating with SCR installed. A complete Top-Down BACT analysis would include an economic evaluation of different levels of control performance that would result from

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[37] Feasibility Study Port Allen Power Station, at 1-2. http://www.kiuc.coop/IRP/Tariff/Appendix%20D%20GT-1%20Report.pdf.

operation outside of optimal temperature windows. The cost difference between high temperature and "normal" catalysts may be considered at Step 4 of the BACT analysis.

The LDEQ Response to Comment 12 that larger turbines would be required to install heat recovery steam generators for the propane compressors also is unsubstantiated and an inappropriate basis to eliminate a control technology at Step 2 particularly for turbines that have not been installed at the Facility. PSD is a preconstruction permit program. BACT is only required on new or newly modified equipment so that the equipment can be constructed to meet BACT. Relevant to Step 2, LDEQ has failed to establish that SCR and SCONOX are technically infeasible and the BACT analysis should proceed to Step 3.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

LDEQ is obligated under the Top-Down BACT procedure to construct a hierarchal analysis of the BACT control options and combination of control options for each pollutant and newly constructed or modified emissions source where a plant-wide significant net emissions increase in a pollutant regulated by the Act occurs. Step 3 is essential to ensure that public participation in the BACT process under federal NSR and Title V permit requirements. The Top-Down BACT methodology requires consideration and full documentation to support elimination of the highest performing technology first before moving down to the next ranked technology. Without establishing a proper hierarchy based on comparable performance factors (e.g., an emissions limitation in ppm) that allow an "apples to apples" comparison of performance, a proper Top-Down analysis cannot be performed. LDEQ erred by failing to properly evaluate higher performing control options before selecting lower performing options.

After the BACT emissions hierarchy is created, economic, energy and environmental impacts are analyzed. A second hierarchal table that summarizes emissions performance and economic, environmental and energy impacts must be prepared per the NSR Manual at B.25-B.28. The control technology impacts table summarizes the review of key factors including:

- Expected emission rate (tpy, pounds per hour);
- Emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);
- Expected emissions reduction (tpy);
- Economic impacts (total annualized costs, cost effectiveness, incremental cost effectiveness);
- Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and the relative ability of each control alternative to control emissions of toxic or hazardous air contaminants); and
- Energy impacts (indicate any significant energy benefits or disadvantages).

LDEQ's failure to perform Step 3 of the Top-Down BACT procedure materially compromised the ability of the public to participate in the Top-Down BACT process. Moreover, failure to establish a proper hierarchy of controls and analysis of other impacts leads to errant and unsupported decisions at Step 4.

d. Step 4 - Evaluate Most Effective Controls and Document Results

Most of the errors in the LDEQ BACT determination come from improperly mixing economic, environmental and energy arguments with technical feasibility arguments. Analysis of these other impacts is properly performed at Step 4 and is not related to technical feasibility that was considered at Step 2. The LDEQ Response to Public Comments provides additional information that should be investigated at this Step. LDEQ Response to Comment 12 asserts:

> The turbines driving the propane compressors are projected to be fully loaded, so the backpressure created by the exhaust gases passing over and through the tubes in the waste heat recovery units would reduce LNG production and increase fuel consumption. Therefore, larger turbines would be required to achieve the same capacity.
>
> Assuming two heat recovery steam generators (HRSG) and one condensing steam turbine were added to the two gas turbines driving the methane compressors in each train, approximately 17 megawatts (MW) of electrical power could be generated if both turbines were operational. Each LNG train will consume about 16 to 18 MW of electrical power, mostly to drive the air cooler fans and pump motors. However, given that the LNG train will also be capable of operating at part load conditions, including in half train mode with one methane compressor down, not all 17 MW would be available continuously. Consequently, a gas turbine-powered generator would still be required for startup and to provide power during a number of operating scenarios.
>
> Moreover, the capital, operating, and maintenance costs of a HRSG, steam turbine, condenser, generator, switchgear, etc. would be significant; additional water would have to be sourced for steam make-up; and additional land would be required. While the space requirements of such equipment may not necessarily be a major concern in most circumstances, significant time and expense is required to prepare the property surrounding the Sabine Pass LNG Terminal so that it can bear the weight of process equipment.

The first paragraph of LDEQ's Response as discussed under Step 2 is inappropriate for equipment that has not yet been constructed. The second paragraph provides information to the public for the first time that should have been provided in the permit application and public record prior to the close of the public comment period per 40 C.F.R. § 70.7(h). The second paragraph states that reconfiguring the site to include 2 HRSGs per train couple with one steam generator would provide essentially all the power required to operate each train at full power. The additional costs described in the third paragraph are not detailed as required in a Top-Down BACT analysis. Other options such as using purchased electricity during the times when on-site generated electricity are insufficient and mixing compressors powered with electrical motors alone or in conjunction with HRSGs are not evaluated at all. Cost savings from using waste heat to generate steam also are not considered.

LDEQ's misunderstanding regarding consideration of technical feasibility (Step 2) and energy, environmental and economic impacts (Step 4) is demonstrated in LDEQ's Response to Comment 13:

> SCR units require an exhaust temperature of 450°F to 750°F for the catalyst to operate effectively. Maintaining the exhaust temperature in this range is not typically problematic at a power plant; however, the refrigeration compressor turbines equipped with waste heat recovery units (WHRUs) will not always have temperatures within this range necessary for the catalyst to be effective. This is because the heat required by liquefaction processes is not totally dependent on the gas turbine load (as is the case for power plants), but rather on independent variables such as ambient temperature; feed gas pressure, flow rate, and CO_2 concentration; the timing of regeneration; liquefaction turndown; etc. The exhaust gas temperature will be below 450°F if the WHRU load is high and can swing above 750°F if the WHRU load is low. There is also a danger that a "traditional" SCR catalyst could be irreversibly damaged if the exhaust temperature goes above 850°F.

LDEQ's comment is clearly aimed at "traditional" SCR and fails to address other catalyst options and stands in stark contrast to LDEQ's Response to Comment 1:

> The first step in a "top-down" analysis is to identify, for the emissions unit in question, all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Cheniere identified selective catalytic reduction (SCR) as a potentially applicable control option,[3] citing "numerous entries in RBLC database" and the corresponding emission limit.[4] LDEQ makes no distinction between "high temperature" SCR and "traditional" SCR.

LDEQ's claim of technical infeasibility in Comment 13 is inconsistent with the claim in Comment 1 that LDEQ makes no distinction between "high temperature" SCR and "traditional" SCR. In any case, the temperature swings would only impact the overall control efficiency and the amount of time the system is operating in an optimal control mode, which is already true of system start-up and shut-down periods and this efficiency loss is factored into setting appropriate emissions limitations. LDEQ has again erred by substituting innuendo for appropriate Top-Down BACT analysis. Nothing in LDEQ's Response addresses technical feasibility; however, environmental and economic impacts of these temperature swings may be evaluated under Step 4 of the Top-Down BACT process.

Similarly, in the LDEQ Response to Comment 13, LDEQ improperly cites environmental impacts that must be quantified and included under Step 4 of the Top-Down BACT process to support a technical infeasibility claim:

> The injection rate of ammonia used in the SCR would need to follow the exhaust gas temperature swings as well as the exhaust gas flow rate. Operating an SCR in this fashion would be very difficult and may create large swings in ammonia slippage (typically 2 to 6%) to the turbine exhaust.

LDEQ further responds that a cost analysis was performed and determined a cost effectiveness of between $9,830 and $14,189 per ton of emissions controlled. This is based on an estimation of capital cost for each turbine of $21.54 million. A technical paper written by Chevron Corporation engineers discusses installation of SCR on GE LM 2500 turbines and also has vendor quotes in excess of $20 million. However, the final installed cost was only $3.25 million and the annual cost effectiveness was reported to be $1,281 per ton of NOx controlled:

> The journey from dreams to reality is reflected in the perception of cost to achieve the desired result. The "reduction" of the perceived cost, largely owing to the application of management tools at each stage of development of the project, is striking:
>
> - $14-million Original Estimate – Initial DA
> - $26-million - 3rd Party Engineering Estimate (Oops***!***)
> - $14-million – In-house Project Resources Check Estimate
> - $8-million DA / CPDEP / PEP
> - $6-million CPDEP / PEP / FEL / IPA
> - $4-million CPDEP / PEP / FEL

- $3.25-million AFE ("**<u>A</u>**uthorization **<u>F</u>**or **<u>E</u>**xpenditure," the Corporate-management blessed "Thou Shalt Not Exceed" number***!***)[38]

In addition, since there are 24 turbines operating in a block of 6 per train, the opportunity of substantial cost savings by controlling multiple turbines with the SCR also should have been evaluated. LDEQ's conclusion that SCR is too expensive is not adequately substantiated; LDEQ has failed to demonstrate that SCR control costs are higher than the control costs other permittees have borne to control NO_x.

Not only is the overall magnitude of the LDEQ economic analysis questionable, it is flawed in concept. The proposed SCR would be used in combination with the Low-NOx technology and water injection. The likely top of the Top-Down BACT hierarchy would either be Low-NOx with water injection and SCR or Low-NOx with water injection and SCONOX. The BACT analysis for the Proposed Project at 21 indicates that the water injection Low-NOx technology is achieving an approximate 60% reduction in NOx emissions. This emissions reduction and the cost of this control must be considered as part of the overall cost of control in evaluating BACT as opposed to looking solely at SCR control costs in a vacuum. The poorly documented cost effectiveness analysis relied upon by LDEQ improperly focuses only on the incremental cost of adding SCR to the existing controls that LDEQ has already reported to be BACT.

e. Step 5 - Select BACT

Top-down BACT is a process that, when correctly followed, leads to selection of the best control technology for a specific site considering prevention of air quality deterioration, environmental, economic and energy impacts of the project and the control equipment. Both

[38] Gas Turbine NOx Reduction Retrofit. http://home.earthlink.net/~jim.seebold/id5.html.

EPA's "Draft Top-Down Best Available Control Technology Guidance Document (March 15, 1990) at 55, and EPA's NSR Manual at B-53 state that [i]t is important to note that, regardless of the control level proposed by the applicant as BACT, the ultimate BACT decision is made by the permit issuing agency after public review." A proper BACT determination cannot be made based on the permit application and the available record. The opportunity for meaningful public participation in the BACT determination as required by the Part 70 regulations cannot be achieved until a complete and adequately BACT analysis has been performed for the Sabine Pass LNG Terminal Permit and provided to the public for review and comment.

In sum, LDEQ has not properly identified BACT due to the failure to conduct a proper Top-Down BACT analysis for emission units for the proposed Sabine Pass LNG Terminal modifications and failed to provide relevant emission-related information for public review. Accordingly, GCELC respectfully requests that EPA object to the Permit due to LDEQ's failure to conduct a proper BACT analysis and the omission of relevant emission-related information in the permit application and the public record pursuant to 40 C.F.R. § 70.8(c)(3) and the Permit's failure to require proper conduct and identification of BACT to control emissions of NAAQS and related pollutants – an applicable requirement – pursuant to pursuant to 40 C.F.R. § 70.8(c)(1).

C. LDEQ Failed to Conduct a Proper BACT Determination for GHGs

The LDEQ Response at 29-38 rejected without adequate basis GCELC's assertion that a top-down BACT analysis for GHGs is required and that carbon capture and sequestration ("CCS") is BACT for GHG emissions including CO_2 from the Sabine Pass LNG Terminal's amine pretreatment plant. Recent evidence set forth in the permit application for the proposed Freeport LNG Liquefaction Project in Brazoria County, Texas, dated December 16, 2011 (after the close of the Sabine Pass LNG Terminal Draft Permit comment period) reinforces that CCS is BACT for the control of CO_2 emissions from amine pretreatment plants. The Freeport LNG Liquefaction Project permit application and references cited therein establish that technology is viable, and the estimated cost of using CCS for control of CO_2 emissions from an amine pretreatment plant – $14 per metric ton of CO_2 – is far below what the United States Interagency Working Group on Social Cost of Carbon has determined to be the social cost of CO_2 emissions – $21.4 per metric ton of CO_2.[39]

As discussed *supra* at 17-18, natural gas deposits contain significant amounts of unwanted CO_2 that must be removed before natural gas can be compressed into LNG by liquefaction plants. CO_2 is removed from natural gas using amine solvents in an amine pretreatment plant. All of the CO_2 is then vented into the atmosphere during amine regeneration.

The magnitude of CO_2 emissions from amine pretreatment plants also is documented in the Freeport LNG Liquefaction Project application, which included a PSD analysis for gas emissions from its proposed liquefaction plant and pretreatment facility. The Freeport LNG Liquefaction Project proposes to use nearly identical technology for the pretreatment of natural gas as the Project Proponent's propose for the Sabine Pass LNG Terminal. The Freeport LNG Liquefaction Project application also reinforces that CO_2 emissions from amine pretreatment dominate any other source at the proposed facility, comprising 99.17% (1,567,308 tpy out of a total of 1,580,737 tpy) of total GHG emissions.

[39] "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" (February 2010) at 1-1. http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf.

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

The data provided in the Freeport LNG Liquefaction Project application indicates that CO_2 emissions from the proposed modification of the Sabine Pass LNG Terminal appear to have been underestimated in the permit application and LDEQ public record by orders of magnitude. Estimated CO_2 emissions of 1,567,308 tpy provided in the Freeport LNG Liquefaction Project application are similar to GCELC's estimate that the Proposed Project's amine pretreatment system would emit 1,085,656 tpy of CO_2. *See supra* at 17.

The LDEQ Response at 35 to Comment 23 states that CCS of CO_2 emissions is not economically achievable due to the low volume of CO_2 emissions from the Proposed Project:

> Capture of CO_2 from Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) may be technical feasible. However, CO_2 emissions from these four sources total only 656 tons per year (LDEQ Response to Comment No. 19). Therefore, unless the capture of CO_2 emissions from the refrigeration compressor turbines and generator turbines is also technically feasible (addressed in LDEQ Response to Comment Nos. 21 and 22 above), carbon capture and storage (CCS) for the acid gas vents is clearly not economically viable.

LDEQ's estimate that Sabine Pass LNG's proposed amine pretreatment system (including Acid Gas Vent's Nos. 1-4) would be only 656 tpy is an error by several orders of magnitude; therefore, LDEQ's conclusion that CCS is "clearly not economically viable" is not supported by the public record. In comparison, the cost estimate for CCS of CO_2 emissions from the amine pretreatment system set forth in the Freeport LNG Liquefaction Project application is listed as $14 per metric ton of CO_2:

> Having demonstrated the potential technical viability of CO_2geological 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.** (Emphasis supplied.).

Conversely, the permit application and public record do not provide a similar cost analysis of using CCS to capture CO_2 emissions from the Sabine Pass LNG Terminal amine pretreatment system. However, the costs of CCS to capture CO_2 emissions from the Sabine Pass LNG Terminal amine pretreatment system is likely to be similar since the projects share many common elements and the Sabine Pass LNG Terminal is located within 200 miles of the proposed Freeport LNG Liquefaction Facility, which also raises an essential – but unanswered – question of whether Freeport LNG and Sabine Pass LNG could lower the cost of using CCS by coordinating and achieving economies of scale.

GCELC, therefore, respectfully requests that EPA object to the Permit due to the inaccurate calculation and modeling of Proposed Project's CO_2 and other GHG air quality impacts pursuant to 40 C.F.R. § 70.8(c)(3) and the Permit's failure to require proper conduct and identification of BACT to control GHG emissions – an applicable requirement – pursuant to pursuant to 40 C.F.R. § 70.8(c)(1).

V. CONCLUSION

For the reasons set forth above, GCLEC respectfully requests that EPA object to the issuance of the Permit because the Permit is not in compliance with applicable requirements and the requirements of the Part 70 regulations.

Dated this 3rd day of February, 2012.

Respectfully submitted,

/s/

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LIST OF EXHIBITS

1. GCELC Written Comments
2. EPA Comment Letter
3. LDEQ Response to Public Comments
4. LDEQ Proposed Permit Transmittal E-Mail
5. GCELC FOIA Request
6. EPA FOIA Acknowledgment
7. EPA FOIA Response
8. Calculation Errors in the Air Permit regarding Acid Gas Vents