NORTHWEST ENVIRONMENTAL DEFENSE CENTER
10015 S.W. Terwilliger Blvd., Portland, Oregon 97219
Phone: (503) 768-6673 Fax: (503) 768-6671
www.nedc.org

April 15, 2014

SUBMITTED BY EMAIL TO: Hamman.Patricia@deq.state.or.us

Oregon Department of Environmental Quality
ATTN: Patricia Hamman
Air Quality Permit Coordinator
750 Front St., Suite 120
Salem, OR 97420

Re: Public comment submission regarding the proposed issuance of a pre-construction Standard Air Contaminant Discharge and Prevention of Significant Deterioration Permits for the Jordan Cove Energy Project

The Northwest Environmental Defense Center, Oregon Coast Alliance, Oregon Shores Conservation Coalition, and Cascadia Wildlands (collectively, Commenters) respectfully submit the following comments to Oregon's Department of Environmental Quality (DEQ) regarding the proposed issuance of a pre-construction Standard Air Contaminant Discharge Permit (ACDP) and a Prevention of Significant Deterioration (PSD) permit for the Jordan Cove Energy Project in Coos Bay, OR. Commenters have a significant interest in ensuring the air quality along the Oregon coast. Commenters have members and/or supporters who work, visit, recreate, or live near or in the vicinity of the proposed project. As a major emitter of various air pollutants, this facility will impact air quality within the local air shed, the health of the surrounding environment and community, and impact global climate.

DEQ is proposing to issue a new Standard ACDP and PSD permit for the Jordan Cove Energy Project (JCEP). Commenters are concerned about the adverse impacts of emissions likely to result from the construction and operation of the JCEP, and believe that certain aspects of the permit must be modified to conform with the requirements of the federal Clean Air Act (CAA) and Oregon's State Implementation Plan (SIP) before DEQ may issue the permit.

Comments

I. The proposed permit fails to consider all possible harmful sources in its calculation of likely emissions.

a. JCEP will be a significant source of greenhouse gas emissions.

JCEP will be a major source of greenhouse gas (GHG) emissions under the PSD program. Sources that emit over 100,000 tons per year of carbon dioxide equivalent pollutants

(CO_2e) are regulated under the PSD program. JCEP far exceeds this parameter and DEQ should require stringent GHG emission controls or alternative technologies for JCEP. Such requirements would be consistent with Oregon's goal of curbing GHG emissions to reduce the impacts of local and global climate.

In addition, JCEP seems to grossly understate the potential GHG emissions from its facility. For example, a similar facility in Louisiana, Cheniere, applied for a PSD permit and reported potential GHG emissions of over 8 million tons per year of CO_2e. *See* Cheniere, Draft Resource Report 9 (attached as Exhibit 5). The JCEP facility has reported well under that number, which seems inconsistent with similar facilities. JCEP should, at the very least, explain why its estimates for GHG emissions are much lower than similar facilities in other states.

b. JCEP's application fails to consider fugitive emissions of compounds used as refrigerants in the LNG liquefaction process that are harmful GHGs.

Although JCEP considers CO2 and methane in its GHG BACT analysis, it does not consider refrigerant compounds utilized in the liquefaction process, such as hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs). These compounds have global warming potentials (GWPs) hundreds to thousands of times greater than CO2 and methane. *See* EPA Global Warming Potential of ODS Substitutes (attached as Exhibit 1). *See also* EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) (attached as Exhibit 6), page 8-9 (listing HFCs and PFCs as two of the six gases encompassed by the definition of GHGs). These compounds may not be emitted from a stack. However, it is very likely such compounds will be released as fugitive emissions. JCEP should be required to analyze fugitive emissions of these compounds under its BACT analysis for fugitive GHG emissions. *See* JCEP Air Permit Application, pages 4-32. Because it fails to account for these fugitive GHG emissions, JCEP's suggested monitoring program is insufficient for controlling the fugitive emissions of such potent GHGs.

To reduce the adverse impacts of these fugitive emissions, DEQ should consider requiring JCEP to use alternative refrigerants or processes with smaller GWPs for JCEP's liquefaction process. For instance, JCEP could employ a liquefaction process that utilizes inert noble gases, such as Xenon, which have little to no GWP, and present less of a safety risk because of the low reactivity and flammability characteristics of noble gases. Use of such gases has been deemed possible, and more efficient, in an ExxonMobil study regarding the natural gas liquefaction process. *See* Denton, et al., *LNG Liquefaction Process Selection: Alternative Refrigerants to Reduce Footprint and Cost*, Gas Technology Institute (attached as Exhibit 2).

The Clean Air Act is a technology forcing program, and given the magnitude of the GHG emissions from JCEP, DEQ should require JCEP to use new processes that would significantly reduce GHG emissions while still maintaining the functionality of the plant. Such requirements would be in line with Oregon's stated goal of curbing GHGs to reduce Oregon's impact on climate change. At the very least, JCEP should be required to install the best systems and equipment in order to prevent fugitive emissions from escaping during the liquefaction process, as well as a very stringent monitoring program to insure that any and all leaks are promptly fixed and the amount of GHG emissions are as low as possible.

II. JCEP's application fails to provide a proper BACT analysis to identify appropriate control technology.

A major new source subject to the PSD program must apply the Best Available Control Technology (BACT). BACT is determined by a top down analysis. *See* Exhibit 6 at 17-44. The top down analysis starts by determining the Lowest Achievable Emissions Rate (LAER). From that baseline, JCEP has the burden of showing why LAER is not economically achievable and to demonstrate what level of BACT would be achievable. *See* Exhibit 6 at 18 (stating that at step one of the BACT analysis, "[t]he top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not 'achievable' in that case"). Thus the control technologies that represent LAER will be considered BACT unless the permit applicant demonstrates that these control technologies are not achievable.

Here, JCEP fails to meet its burden in justifying why certain technologies are not achievable. For example, in determining BACT for the combined cycle unit's NOx emissions, JCEP identified four control technologies: Lean Burn Combustion, Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction and XONON. JCEP did not attempt to explain why these four technologies were chosen, even though JCEP notes at the outset of its analysis that the best performing natural gas-fired combined cycle combustion turbine projects use SCR in addition to dry low-NOx (DLN) or low-NOx burner (LNB) technology. JCEP should have evaluated the addition of DLN or LNB technology to SCR in step one of its BACT analysis. Further, JCEP wholly fails to explain why Lean Burn Combustion, DLN or LNB are not feasible control technology options. It is JCEP's burden to demonstrate why the identified control technologies in step one are not achievable. Absent this justification from JCEP, EPA's guidance supports that DEQ should select the top-ranked options as BACT. In the very least, DEQ should require additional analysis from JCEP that comports with the top down approach to support the final determination of BACT for each pollutant.

III. DEQ should not rely on JCEP's improper calculation of Hazardous Air Pollutant emissions.

The CAA regulates the emission of Hazardous Air Pollutants (HAPs) from stationary sources under the National Emission Standards for Hazardous Air Pollutants (NESHAPs) program. 42 U.S.C. § 7412. The CAA defines HAPs as any air pollutant listed under § 112(b). 42 U.S.C. § 7412(a)(6). Practically speaking, a HAP is a pollutant that is not covered by the National Ambient Air Quality Standards (NAAQS) and which "causes or contributes to air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious, irreversible or incapacitating irreversible illness." *U.S. v. Walsh*, 783 F.Supp. 546, 552 (W.D. Wash. 1991). Given the increased risks associated with exposure to HAPs, Congress set relatively low emissions thresholds to trigger the NESHAPs program for major sources.

Specifically, the CAA defines a "major source" under the NESHAPs program as "any stationary source or group of stationary sources" that "emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." 42 U.S.C. §

7412(a)(1). Major sources that meet the threshold are required to meet the Maximum Achievable Control Technology (MACT) as determined by the U.S. Environmental Protection Agency (EPA) Administrator, and failure to do so results in a violation of the CAA. 42 U.S.C. § 7412(g)(2). The MACT requirement applies after the promulgation of emissions limitation standards for specific HAPs by the EPA. 42 U.S.C. § 7412(d).

In its PSD permit application, JCEP reports that the proposed Combustion Turbines, Duct Burners, Emergency Generators, South Dunes Fire Pump, Liquefaction Area Fire Pumps, Thermal Oxidizers, and Flares will emit 40 different types of HAPs in the form of either Volatile Organic Compounds (VOCs), Polycyclic Organic Compounds (POM), or Metal-HAPs. *See* Permit Application, Table B-12. The application purports that the facility will emit 2.5 tons per year (tpy) for a maximum individual HAP (Hexane) and 8.9 tpy of total HAPs for all 40 pollutants taken together. The three highest single HAP emissions are for Formaldehyde (1.7 tpy), Hexane (2.5 tpy), and Toluene (1.9 tpy). Congress included all three of these HAPs in its initial list of HAPs published in 1990. 42 U.S.C. § 7412(b)(1).

a. *JCEP arbitrarily relies on a non-EPA emission factor to achieve more favorable numbers in its calculation of potential formaldehyde emissions.*

For 39 of the 40 HAPs that it has a potential to emit, JCEP calculates potential emissions using EPA-established emission factors set out in its AP-42 emission factor guidance document. For one of the HAPs, formaldehyde, JCEP uses the emission factor employed by the California Air Resource Board (CARB) in the natural gas firing combustion turbine phase. CARB's emission factor (1.10E-04) for formaldehyde is less than EPA's emission factor (7.10E-4) by a factor of seven. Using EPA's emission factor would substantially alter the facility's projections for emissions of formaldehyde. To support this single variance in its assumptions, the application states that EPA's emission factor for formaldehyde "is based on old testing data with limited data points that are not representative of the proposed units."

However, EPA's AP-42 document also contains ratings for each of its emission factors. Formaldehyde earned an "A" rating in the guidance document. An "A" rating signifies an "excellent" and that the method is representative of facilities in the source category. EPA describes A-rated emission factors as:

> developed primarily from A and B rated source test data taken from mainly randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.

EPA, Technology Transfer Network Clearinghouse for Inventories & Emissions Factors, *AP 42 Frequent Questions* (attached as Exhibit 3). EPA's emission factor for formaldehyde is based on current projections and sound science. Further, JCEP uses EPA emission factors for other HAPs (including 1,3-Butadiene, Propylene Oxide, Acetaldehyde, Toluene, among others) that earned ratings of "C" ("Average") or "D" ("Below Average"). The discrepancy in selecting which emission factor to employ appears to be arbitrary, based simply on achieving a more favorable emission calculation.

Formaldehyde is the "most significant HAP" emitted from natural gas turbines and generally constitutes two-thirds of the total HAP emissions at such a facility. *See* EPA, Compilation of Air Pollutant Emission Factors: Volume I: Stationary Point and Area Sources, *3.1 Stationary Gas Turbines* (attached as Exhibit 4). At present, the formaldehyde emissions constitute 19% of total HAP emissions at JCEP. Despite a carbon monoxide oxidation catalyst that will reduce formaldehyde emissions, the HAP's potential pollution capacity is not reflected in the application document. Before moving forward, DEQ must require JCEP to further explain its rationale, including the legal permissibility of using CARB's emission factor over EPA's emission factor for formaldehyde.

b. JCEP fails to consider the likely hexane emissions in its calculation of emissions from the natural gas firing of new combustion turbines.

Next, JCEP has the potential to emit 2.5 tpy of hexane from the facility. This calculation stems from hexane emissions from natural gas firing duct burners, gas firing thermal oxidizers, and gas firing flares. Notably, a projection of hexane emissions is missing from the calculation for natural gas firing of new combustion turbines. It is unclear why hexane emissions are expected from all other natural gas fired elements of the facility's process, but not in combustion in a turbine. DEQ should require JCEP to explain and justify its omission of hexane calculations in the natural gas firing new combustion turbines category before moving forward.

c. The application is missing information that is essential to its potential emissions calculations.

Lastly, JCEP omits a reference to source data for the ultra-low sulfur distillate firing South Dunes Fire Pump and Liquefaction Area Fire Pump on Table B-12 of the application. Before moving forward, JCEP should identify the source of this emission factor data in its calculations. With assumptions and CARB substitutions in its emissions factors, the facility will not qualify as a major source of HAPs under the CAA's NESHAPs program. For the reasons stated above, JCEP must more fully explain and support its calculation assumptions before DEQ assesses its submission that the facility will not be a major source of HAPs.

IV. Under Oregon law, and consistent with federal policy, JCEP is required to consider emissions from LNG marine vessels while engaged as part of JCEP's facility.

JCEP failed to consider emissions from marine vessels when engaged in active loading and unloading operations in support of the facility's primary purpose in its application. JCEP claims that such emissions are exempt from permitting requirements because they are not considered direct emissions from the facility. *See* Permit Application at 2-2. JCEP claims that vessel emissions need not be considered because the South Dunes power plant will provide power for pumping activities, thus there are no direct emissions from vessels docked at the facility. This reasoning is inadequate for two reasons.

First, under Oregon's regulations, secondary emissions must be included in PSD emissions calculations once the "major source" threshold has been met. OAR 340-224-0100 ("Once a source or modification is identified as being major, secondary emissions are added to the primary emissions"). Secondary emissions are defined as "emissions that are a result of the construction and/or operation of a source or modification, but that do not come from the source itself." OAR 340-200-0020(109). The JCEP facility is a major source. *See* Permit Application at 1-2. LNG vessel emissions are emissions that result from the operation of the facility, but not coming from the facility itself. Therefore, JCEP is, at the very least, required to include LNG vessel emissions in its PSD emissions calculations as secondary emissions.

Second, it is arguable that LNG vessel emissions are better considered as direct/primary emissions form the facility. "Secondary emissions" may include, but are not limited to, "[e]missions from ships and trains coming to or from the facility." OAR 340-200-0020(109)(a). If Oregon wished to characterize emissions from onsite ships as secondary, it could have done so by not expressly limiting the definition of secondary emissions to emissions from ships coming *to or from* the facility. This omission is significant in that it indicates that emissions from onsite ships are not secondary but rather must be attributed to the stationary source itself. Thus in Oregon, emissions from vessels at the proposed vessel loading operation are not simply secondary emissions and therefore must be included in the stationary source's direct emissions calculations.

Indeed, DEQ itself has embraced this interpretation of its regulations. On January 17, 2008, DEQ determined that:

> emissions from LNG carriers that are directly associated with terminal activities are part of the stationary source's emissions. Emissions from the LNG carriers that are directly associated with terminal activities include, but are not limited to: emissions attributable to providing power for the ship-board LNG transfer system, including pumps used to transfer liquid or vapor LNG to or from the carrier; *fugitive emissions from ship-board LNG piping and pumping systems; and any other emissions that can be directly attributed to terminal activities*.

See Jordan Cove Energy and Pacific Connector Gas Pipeline Project, Final Environmental Impact Statement: Volume I 4.11-9 (emphasis added). Even if the emissions associated with pumping the LNG to and from vessels result from the South Dunes power plant, JCEP must consider all fugitive emissions and any other emissions from the vessels that are attributable to terminal activities. There will be significant emissions from the vessels that do not result from pumping and JCEP must include these emissions in its permit application.

Other permit applicants in Oregon have taken vessel emissions into account when determining which air quality provisions apply to their projects. For example, for the Federal Energy Regulatory Commission ("FERC") review, project developers of the Oregon Liquefied Natural Gas ("LNG") Terminal and Pipeline Project included emissions from vessels docked at port while transferring LNG between land and the vessel in the PSD analysis and dispersion modeling analysis. *See* Oregon LNG Terminal and Oregon Pipeline Project FERC Review Comment/Response Matrix, at 4-5 (attached as Exhibit 7). Consistent with that approach, DEQ should require JCEP to take into account the emissions of docked vessels at the facility that are directly associated with the facility and further the purpose of the facility.

Consideration of mobile source emissions when on-site and part of an industrial process as primary emissions is not only consistent with Oregon Law, but also with federal policy. It is true that federal policy decisions regarding ship and train emissions do not control in this situation because DEQ implements its own CAA program in the state, as governed by its SIP. However, federal case law and EPA's guidance documents are instructive in understanding how a court would interpret Oregon's regulations implementing the CAA.

In 1980, EPA promulgated a definition of stationary source that would "encompass the activities of a marine terminal and only those dockside activities that would serve the purpose of the terminal directly and would be under the control of its owner or operator." *Natural Resource Defense Council v. U.S. Envtl. Prot. Agency*, 725 F.2d 761, 765 (D.C. Cir. 1984) (quoting 45 Fed. Reg. 52,696 (1980)). Under this definition, dockside activities were limited to "those activities in which ships would engage while docked at the terminal . . . [and which] would directly serve the purpose of the terminal, such as loading and unloading . . . [and] over which the owner or operator of the terminal would have control." *Id.* "On June 25, 1982 EPA revoked the vessel emissions requirements in their entirety," meaning that emissions from docked vessels could never be considered direct emissions. *Id.* In *NRDC v. USEPA*, the D.C. Circuit vacated EPA's new regulations. *Id.* at 766-67. Looking at the statutory language and the legislative history of the 1977 amendments, the court disagreed with EPA that EPA could never regulate emissions from docked vessels because they were mobile sources. *Id.* at 768-71.

Since, *NRDC v. USEPA*, EPA has considered emissions from vessels when berthed at port in furtherance of the onshore facility to be attributable to the stationary source's potential to emit calculations. In 1990, John Calagni, the Director of the Air Quality Management Division for EPA Region VI, wrote a letter to the President of Waid and Associates explaining EPA's position on emissions from docked vessels. *See* Jan. 8, 1990 Letter from John Calagni to Ken Waid (attached as Exhibit 8). This letter briefly covers the history of EPA's regulations governing emissions from vessels and the outcome of the *NRDC* case.

As a result of the *NRDC* case "the August 7, 1980 PSD regulations (with the exception of to and fro emissions counting) shall apply to determinations on how to treat vessel emissions." *Id.* at 2. The letter notes that the preamble to the 1980 regulations explain that "emissions from certain activities of a ship docked at a terminal (i.e., when the vessel is stationary) may be considered emissions of the terminal if the activities would 'directly serve the purpose of the terminal and be under the control of its owner or operator to a substantial extent.'" *Id.* EPA has consistently maintained this position since the NRDC case. *See, e.g.*, Oct. 28, 2003 Letter from Charles J. Sheehan to Michael Cathey and Diana Dutton, in EPA Title V Policy and Guidance Database, at 7 (attached as Exhibit 9) (stating that vessel emission associated with LNG regasification and the transfer of gas to the port should be included in the applicability determinations for CAA preconstruction and operating permits).

Therefore, whether considered as primary or secondary emissions, JCEP must include emissions from LNG vessels docked at its terminal in its permit application. JCEP may not shirk this requirement simply because one aspect of the vessel on-loading operation will be powered by the South Dunes power plant. Rather, JCEP must include all emissions from all LNG vessel activity at the terminal in its permit application.

Conclusion

We urge DEQ to address the omissions and inconsistencies identified above and incorporate any new information or analysis into new proposed permits for JCEP. Proper analysis of the facility's potential emissions that is consistent with the CAA and Oregon's own rules under its SIP is critical to protecting Oregon's air quality. Commenters also request a response to these comments, as well as notification when the permit is approved.

Sincerely,

Matthew Ring
Air Group Project Coordinator
Northwest Environmental Defense Center

Jeff Speir
Law Clerk
Northwest Environmental Defense Center

Cameron La Follette
Land Use Director
Oregon Coast Alliance

Phillip Johnson
Executive Director
Oregon Shores Conservation Coalition

Francis Eatherington
Conservation Director
Cascadia Wildlands

Enclosures:

- Exhibit 1 – EPA, *Global Warming Potentials of ODS Substitutes*
- Exhibit 2 – ExxonMobile Upstream Research Co., *LNG Liquefaction Process Selection: Alternative Refrigerants to Reduce Footprint and Cost*
- Exhibit 3 – EPA, *AP 42 Frequent Questions*
- Exhibit 4 – EPA, *Stationary Gas Turbines*
- Exhibit 5 – Cheniere, *Draft Resource Report 9*
- Exhibit 6 – EPA, *PSD and Title V Permitting for Greenhouse Gases*
- Exhibit 7 – FERC Review, *Oregon LNG Terminal Comment/Response Matrix*
- Exhibit 8 – EPA Region VI Letter to Waid and Associates
- Exhibit 9 – EPA Region VI Letter to Michael Cathey and Diana Dutton

Environmental Protection Agency, available at http://www.epa.gov/ozone/geninfo/gwps.html

Global Warming Potentials of ODS Substitutes

The global warming potential (GWP) represents how much a given mass of a chemical contributes to global warming over a given time period compared to the same mass of carbon dioxide. Carbon dioxide's GWP is defined as 1.0.

Why are there three values given for the GWP and atmospheric lifetime?

> All GWP values represent global warming potential over a 100-year time horizon. Dashes indicate that the source did not include a GWP value for the given compound. The first value in each of the second and third columns is from Table 1-6 of the *Scientific Assessment of Ozone Depletion, 2002*. The second and third values in each of these columns are from the Intergovernmental Panel on Climate Change (IPCC EXIT Disclaimer) *Second Assessment Report: Climate Change 1995* and the *IPCC Third Assessment Report: Climate Change 2001*, respectively.

For more specific information on how many of these chemicals are used as substitutes for ozone-depleting substances, please visit the SNAP Program's web site.

The HFCs are numbered according to the ASHRAE Standard 34 scheme. None of the chemicals listed below depletes the ozone layer. GWP values for ozone-depleting substances are available in another table.

HFCs and PFCs

Chemical	Atmospheric Lifetime (years)	GWP	Use
HFC-23 (CHF_3)	270 264 260	12,240 11,700 12,000	Byproduct of HCFC-22 used in very-low temperature refrigeration blend and component in fire suppression. Also used for plasma etching and cleaning in semiconductor production.
HFC-32 (CH_2F_2)	4.9 5.6 5.0	543 650 550	Blend component of numerous refrigerants.
HFC-41 (CH_3F)	2.4 3.7 2.6	90 150 97	Not in use today.
HFC-43-10mee	15.9	1,610	Cleaning solvent

($C_5H_2F_{10}$)	17.1 15	1,300 1,500	
HFC-125 (C_2HF_5)	29 32.6 29	3,450 2,800 3,400	Blend component of numerous refrigerants and a fire suppressant.
HFC-134 (CHF_2CHF_2)	9.6 10.6 9.6	1,090 1,000 1,100	Not in use today.
HFC-134a (CH_2FCF_3)	14 14.6 13.8	1,320 1,300 1,300	One of the most widely used refrigerant blends, component of other refrigerants, foam blowing agent, fire suppressant and propellant in metered-dose inhalers and aerosols.
HFC-143 ($C_2H_3F_3$)	3.5 3.8 3.4	347 300 330	Not in use today.
HFC-143a ($C_2H_3F_3$)	52 48.3 52	4,400 3,800 4,300	Blend component of several refrigerant blends.
HFC-152a ($C_2H_4F_2$)	1.4 1.5 1.4	122 140 120	Blend component of several refrigerant blends and foam blowing agent. Also used as an aerosol propellant.
HFC-227ea (C_3HF_7)	34.2 36.5 33.0	3,660 2,900 3,500	Fire suppressant and propellant for metered-dose inhalers, and refrigerant.
HFC-236fa ($C_3H_2F_6$)	240 209 220	9,650 6,300 9,400	Refrigerant and fire suppressant.
HFC-236ea ($C_3H_2F_6$)	10.7 -- 10.0	1,350 -- 1,200	Not in use today.
HFC-245ca ($C_3H_3F_5$)	6.2 6.6 5.9	682 560 640	Not in use today; possible refrigerant in the future.
HFC-245fa ($C_3H_3F_5$)	7.6 -- 7.2	1,020 -- 950	Foam blowing agent and possible refrigerant in the future.
HFC-365mfc ($C_4H_5F_5$)	8.6 -- 9.9	782 -- 950	Some use as a foam blowing agent; possible refrigerant in the future.
Perfluoromethane (CF_4)	50,000 50,000 50,000	5,820 6,500 5,700	Plasma etching and cleaning in semiconductor production and low temperature refrigerant.
Perfluoroethane (C_2F_6)	10,000 10,000 10,000	12,010 9,200 11,900	Plasma etching and cleaning in semiconductor production.

Perfluoropropane (C_3F_8)	2,600 2,600 2,600	8,690 7,000 8,600	Plasma etching and cleaning in semiconductor production, low temperature refrigerant and fire suppressant.
Perfluorobutane (C_4F_{10})	2,600 2,600 2,600	8,710 7,000 8,600	Fire suppressant and refrigerant where no other alternatives are technically feasible.
Perfluorocyclobutane (C_4F_8)	3,200 3,200 3,200	10,090 8,700 10,000	Not used much if any. Refrigerant where no other alternatives are technically feasible.
Perfluoropentane (C_5F_{12})	4,100 4,100 4,100	9,010 7,500 8,900	Not used much if any. Precision cleaning solvent-low use refrigerant where no other alternatives are technically feasible.
Perfluorohexane (C_6F_{14})	3,200 3,200 3,200	9,140 7,400 9,000	Precision cleaning solvent-low use, refrigerant and fire suppressant where no other alternatives are technically feasible.

NF3

Chemical	Atmospheric Lifetime (years)	GWP	Use
NF_3	740 -- --	10,970 -- --	Plasma etching and cleaning in semiconductor production.

SF6

Chemical	Atmospheric Lifetime (years)	GWP	Use
Sulfur hexafluoride (SF_6)	3,200 3,200 3,200	22,450 23,900 22,200	Cover gas in magnesium production, casting dielectric gas and insulator in electric power equipment fire suppression. Also used as a discharge agent in military systems and formerly an aerosol propellant.

HFEs

Chemical	Atmospheric Lifetime (years)	GWP	Use
HFE-7100 ($C_4F_9OCH_3$)	5.0 -- 5.0	397 -- 390	Cleaning solvent and heat transfer fluid.
HFE-7200 ($C_4F_9OC_2H_5$)	0.77 -- 0.77	56 -- 55	Cleaning solvent and heat transfer fluid.

LNG LIQUEFACTION PROCESS SELECTION: ALTERNATIVE REFRIGERANTS TO REDUCE FOOTPRINT AND COST

Russell H. Oelfke
Robert D. Denton
Michael R. Miller
ExxonMobil Upstream Research Company

1 ABSTRACT

This paper describes recent work at ExxonMobil Upstream Research Company to identify novel refrigerants and processes for production of liquefied natural gas (LNG) in large-scale floating and onshore LNG facilities. The goal of the research was to reduce the footprint and cost of baseload LNG plants through the use of non-flammable or reduced flammability refrigerants.

Process results are presented and discussed for two novel liquefaction cycles: a mixed refrigerant process and a cascade process. The performance aspects of each process are discussed, and tradeoffs in process complexity and equipment flexibility are considered.

2 BACKGROUND

2.1 Incentives

The design of an efficient refrigeration system is of paramount importance for effective and economic LNG production. Several commercially available refrigeration cycles are currently in use at baseload LNG plants. Most of these cycles share a common feature: the use of flammable hydrocarbon refrigerants, such as methane, ethane or ethylene, propane, isobutane, isopentane, and their mixtures (often with nitrogen as well).

Facility space is significantly more costly for floating LNG (FLNG) plants than for onshore plants. The use of flammable refrigerants and the requirement for appropriate spacing and other measures to prevent adverse consequences in the event of refrigerant release increases the capital costs of FLNG projects. Requirements for safe refrigerant makeup, handling, storage, and import on to floating vessels also increase FLNG costs relative to onshore plants.

Replacing hydrocarbon refrigerants with non-flammable, or reduced flammability, refrigerants offers the potential for reducing the capital costs of FLNG projects. There are also potential cost reductions for onshore LNG plants, as requirements for “buffer zone” land surrounding and within plant sites may be reduced. These economic benefits can only be realized if the liquefaction cycles using the alternate refrigerants have comparable thermal efficiency and equipment requirements relative to the conventional liquefaction processes.

2.2 Alternative Refrigerants

In considering alternative refrigerants for baseload LNG projects, we evaluated several classes of refrigerants, including hydrofluorocarbons (HFCs), noble gases, and fluorocarbon refrigerants with reduced greenhouse warming potential.

A list of selected conventional and alternative refrigerant candidates appears in Table 1. The table uses the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) “R-code” numbering system, which numerically identifies refrigerants based on their chemical structure.[1] The R-codes will be used to refer to specific refrigerants in the balance of this paper. Table 1 also lists the chemical name, chemical formula, molecular weight, normal boiling point, melting point, critical temperature, safety group, and greenhouse warming potential for each of the refrigerants.

Table 1. Selected conventional and alternative refrigerants for use in LNG refrigeration cycles

ASHRAE Number	Chemical Name	Formula	MW	NBP (°F)	MP (°F)	Crit. T (°F)	Safety Group	GWP_{100}
R-14	Tetrafluoromethane	CF_4	88	−198	−298	−50	A1	7,390
R-23	Trifluoromethane	CHF_3	70	−116	−247	79	A1	14,800
R-41	Fluoromethane	CH_3F	34	−109	−223	112	A3	92
R-116	Hexafluoroethane	C_2F_6	138	−109	−149	68	A1	12,200
R-32	Difluoromethane	CH_2F_2	52	−62	−213	173	A2L	675
R-410A	R-32 / 125 (50 / 50 wt%)	—	74	−61	—	160	A1	2088
R-125	1,1,1,2,2-pentafluoroethane	C_2HF_5	120	−56	−153	151	A1	3,500
R-143a	1,1,1-trifluoroethane	CH_3CF_3	84	−54	−168	163	A2L	4,470
R-218	Octafluoropropane	C_3F_8	188	−35	−234	161	A1	8,830
R-1234yf	2,3,3,3-tetrafluoropropene	$C_3H_2F_4$	114	−21	−242	202	A2L	4
R-134a	1,1,1,2-tetrafluoroethane	CH_2FCF_3	102	−15	−154	214	A1	1,430
R-152a	1,1-difluoroethane	CH_2CHF_2	66	−13	−179	236	A2	124
R-1234ze	1,3,3,3-tetrafluoropropene	$C_3H_2F_4$	114	−2	—	—	A2L	6
R-227ea	1,1,1,2,3,3,3-heptafluoropropane	CF_3CFHCF_3	170	3	−204	215	A1	3,220
R-C318	Octafluorocyclobutane	$(\text{-}CF_2\text{-})_4$	200	21	−40	239	A1	10,300
R-236fa	1,1,1,3,3,3-hexafluoropropane	$CF_3CH_2CF_3$	152	29	−140	257	A1	9,810
R-245fa	1,1,1,3,3-pentafluoropropane	$CF_3CH_2CHF_2$	134	59	−152	309	B1	1,030
R-245ca	1,1,2,2,3-pentafluoropropane	$CHF_2CF_2CH_2F$	134	77	−116	346	B1	693
R-347mcc	1-methoxyheptafluoropropane	$C_3F_7OCH_3$	200	93	−189	328	—	450
R-728	Nitrogen	N_2	28	−320	−346	−232	A1	0
R-740	Argon	Ar	40	−303	−309	−188	A1	0
R-784	Krypton	Kr	84	−244	−251	−83	A1	0
—	Xenon	Xe	131	−163	−169	62	A1	0
R-744	Carbon dioxide	CO_2	44	−70*(s)*	−109	88	A1	1
R-50	Methane	CH_4	16	−259	−296	−117	A3	25
R-1150	Ethylene	C_2H_4	28	−155	−273	48	A3	< 25
R-170	Ethane	C_2H_6	30	−127	−297	90	A3	< 25
R-290	Propane	C_3H_8	44	−44	−306	206	A3	< 25
R-600a	Isobutane	CH_3CHCH_3	58	11	−255	274	A3	< 25
R-601a	Isopentane	$(CH_3)_2CHCH_2CH_3$	72	82	−256	369	A3	< 25

Notes :
1. The Ozone Depletion Potentials (ODPs) for all components in this Table are 0. All comply with the Montréal Protocol.
2. The GWP_{100} is the relative 100 year Greenhouse Warming Potential, with CO_2 as "1".
3. The Safety Group is an ASHRAE designation, "A" meaning Occupational Exposure Limit (OEL) above 400 ppm allowed, "B" meaning the OEL is below 400 ppm. A number of "1" indicates non-flammable, "2" means slightly flammable, and "3" means highly flammable. An "L" suffix indicates very low flame propagation speed.

Safety and environmental considerations helped define the list of candidate refrigerants. The primary safety criteria were flammability and toxicity. ASHRAE maintains a safety classification scheme that designates both the flammability and toxicity of refrigerants.[1] Initial alternative refrigerant candidates were mostly within toxicity class 'A' (essentially non-toxic) and completely nonflammable (class '1').

Environmental regulations also influenced the selection of refrigerants. Laws governing the Ozone Depletion Potential (ODP) of refrigerants were enacted by many governments following the Montréal Protocol.[2] It was discovered in the 1970s that chlorinated and brominated halocarbons deplete the ozone layer via free radical chain reactions.[3] Nevertheless, halocarbons that contain fluorine as the only halogen were found not to react with ozone. Therefore, compounds containing chlorine and bromine were excluded from the set of candidate refrigerants.

2.2.1 Hydrofluorocarbons (HFCs)

Hydrofluorocarbons (HFCs) are a class of refrigerants that first came into widespread use in the 1990s for small-scale applications (relative to baseload LNG) in response to regulations phasing out the previous generation of chlorofluorocarbon (CFC) refrigerants.[2] Many HFCs are non-flammable, non-toxic, and non-reactive. Moreover, the HFC family has a wide range of normal boiling points (NBPs) that are similar to the NBPs of the hydrocarbon refrigerants used in most natural gas liquefaction processes.

The Kyoto Protocol specifically identifies HFCs and perfluorocarbons (PFCs) as greenhouse gases.[4] One measure of the greenhouse warming effect of a compound is its global warming potential over 100 years, or GWP_{100}. The GWP_{100} is defined as the equivalent mass of CO_2 needed to have the same greenhouse effect as releasing a unit mass of refrigerant over a 100-year period.[4] Most HFCs have relatively high global warming potentials. The chemical stability of many HFCs is the main cause for their greenhouse potential. Some countries, in conjunction with carbon taxation schemes, have begun to tax refrigerants on the basis of GWP_{100}.[5]

2.2.2 Noble Gases

Most of the noble gases—in particular argon, krypton, and xenon—are candidates for alternative LNG refrigerants. These noble gases are non-toxic, non-flammable, non-ozone-depleting and have no greenhouse potential. Xenon and krypton are of particular interest, as their NBPs are in the appropriate range to cover the colder portion of the LNG cooling curve.

2.2.3 Refrigerants with Lower Greenhouse Impact

Adding hydrogen atoms to HFC molecules increases their rates of atmospheric degradation, but also tends to increase their flammability and reactivity. Of the refrigerants identified in Table 1, the heavily fluorinated methane derivatives R-14 and R-23 have high GWP_{100} values (7,390 and 14,800, respectively) and no flammability. R-32, which has two hydrogen atoms, has a significantly lower GWP_{100} of 675, but is classified as 2L (weakly flammable). R-41, with only one fluorine and three hydrogen atoms, has an even lower GWP_{100} of 97, but greater flammability (class 3 — flammable).

HFCs can include unsaturated bonds, in which case they are designated hydrofluoroolefins (HFOs).[6] HFOs tend to be more reactive and flammable due to the presence of unsaturated bonds, but they also degrade more rapidly in the environment. HFOs were developed in anticipation of EU regulations limiting the GWP_{100} of automotive air-conditioning refrigerants to values less than 150.[6] For example, R-1234yf (GWP_{100} = 4) was designed as a replacement for R-134a (GWP_{100} = 1,430). Despite its ASHRAE classification as slightly flammable (2L), R-1234yf has been approved by the Society of Automotive Engineers for use in vehicle air conditioners.[6]

Oxygen atoms can also hasten degradation of HFCs. Hydrofluoroethers (HFEs) and fluorinated ketones have been developed as low-GWP_{100} cleaning solvents, refrigerants, and fire suppressants.[7] In particular, R-347mcc ($C_3F_7OCH_3$) may be a promising warm end component for an LNG mixed refrigerant due to its desirable combination of properties, including complete non-flammability, low MP and GWP_{100}, and high NBP.[7]

3 METHODS

3.1 Refrigerant Selection

When selecting a refrigerant for a particular service, the NBP and the melting point (MP) are important. It is desirable for the refrigerant vapor pressure to be greater than atmospheric pressure throughout the entire cycle to avoid vacuum conditions in the chillers. Consequently, the coldest-boiling refrigerants should have NBPs below the lowest chiller temperature. In addition, the refrigerant should not be allowed to form solids, which could cause plugging. Thus, the MP for all the components should also lie below the lowest chiller temperature. However, there is some flexibility in the MP for mixed refrigerants, since mixtures generally freeze at temperatures below the pure component MPs (see Section 3.3.2).

Furthermore, the critical temperatures and NBPs of successive refrigerants used in cascade refrigeration processes must overlap in an appropriate manner to ensure cycle efficiency. The critical temperature of a colder-boiling refrigerant should be well above the NBP of the warmer-boiling refrigerant that condenses it. For example, xenon (crit. temp. = 62°F) is easily condensed by refrigerant R-32 (NBP = −62°F), but more compression horsepower would be required if R-236fa (NBP = 29°F) were used as the warm-stage refrigerant. This is because xenon would have to be compressed closer to its critical point to condense at the warmer temperature.

3.2 Simulation of Process Alternatives

3.2.1 Basis of Design and Simulation

A basis of design was devised to ensure that the performance criteria of the different liquefaction processes were judged according to uniform standards. This basis included feed gas composition and inlet conditions, as well as rotating machinery and heat exchanger parameters.

All process designs were “fuel balanced” to ensure that enough fuel was available from appropriate sources (backend flash and feed gas) to satisfy demands for refrigeration and power. Nitrogen contents and heating values of the resulting fuel gas streams were checked to ensure that they would work with suitable gas turbines.

Aspen HYSYS V7.2 was used to carry out the process simulation work. The HYSYS version of the Peng-Robinson Equation of State (EoS) was used to model the feed gas and LNG streams. The Aspen Properties version of the Peng-Robinson EoS was used to model refrigerants, because the HYSYS component databanks did not contain many of the refrigerant compounds studied. As will be discussed in Section 3.3, custom values for refrigerant binary interaction parameters, derived from experimental and literature VLE data, were manually entered when unavailable from the Aspen Properties databanks.

3.2.2 Process Alternatives

Multiple process alternatives were evaluated. Two representative and promising processes have been selected for discussion here: a pure refrigerant cascade process and a single mixed refrigerant (SMR) process. Both processes include a high-pressure nitrogen rejection unit (NRU) followed by feed gas auto-refrigeration to accomplish full LNG chilling.

3.2.2.1 R-410A–Xe–Feed Gas Cascade

A schematic of the cascade process is shown in Fig. 1.This process uses several pressure levels of R-410A (NBP = −61°F), a nonflammable, nearly azeotropic refrigerant mixture commonly used in commercial and home air conditioning systems, to achieve cooling to ~ −55°F. The compressed refrigerant vapors are condensed against ambient temperature media (i.e., sea water or air), which is efficient due to R-410A’s relatively high critical temperature (160°F). R-410A can be seen as analogous to propane in conventional cascade LNG processes.

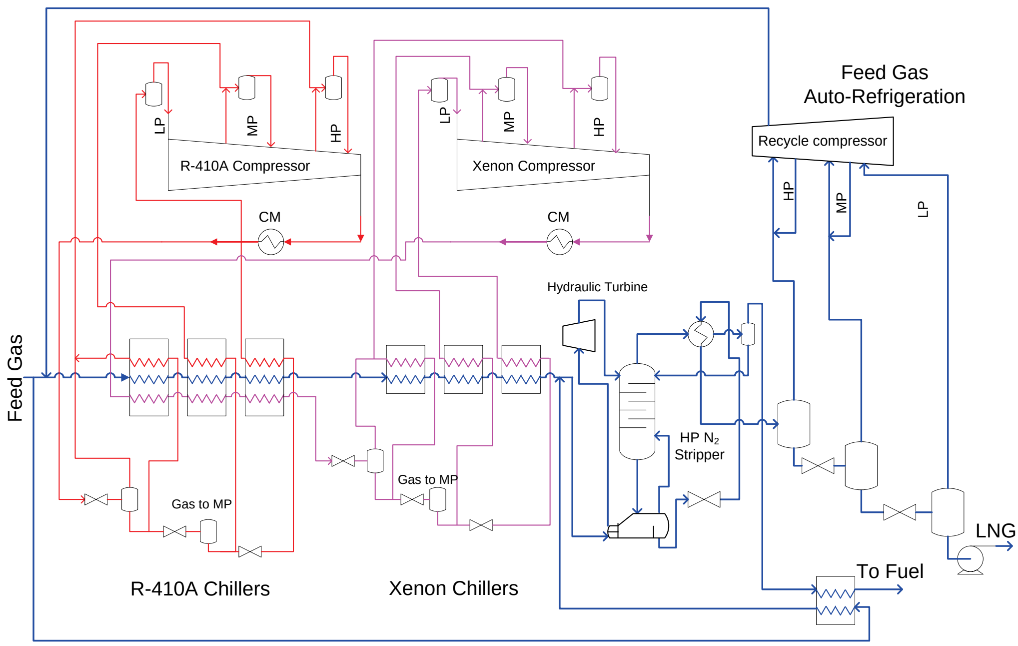

Figure 1. R-410A–Xe–Feed Gas Cascade process for natural gas liquefaction

The next stage of cooling is accomplished by several levels of xenon refrigeration, which chills the feed gas to about −155°F. Xenon can be seen as an analogue to ethylene in a traditional cascade LNG process, as both have similar NBPs and critical temperatures (NBP = −163°F vs. −155°F and crit. temp. = 62°F vs. 48°F for xenon and ethylene, respectively). Furthermore, because xenon's critical temperature is much higher than the NBP of R-410A, xenon is easily condensed against R-410A.

The liquefied, high-pressure feed is further cooled by providing reboiler duty to the nitrogen rejection unit (NRU) column. The feed is then expanded across a hydraulic turbine to an intermediate pressure and fed to the NRU column. The overhead gas from the NRU is condensed to control its methane content to that required for plant fuel. The methane-enriched column bottoms liquid is flashed to the first auto-refrigeration pressure level to provide refrigeration for the overhead condenser. The remaining liquid is then flashed in stages to atmospheric storage pressure to chill it fully to LNG conditions.

The feed gas vapors flashed off the auto-refrigeration separators are compressed and combined with the fresh feed gas. The residual nitrogen in the LNG from the NRU bottoms is flashed off in the auto-refrigeration system and recycled to feed, allowing the final LNG product to have very low nitrogen content. The nitrogen content of the NRU bottoms product is controlled such that the total recycle stream has the same nitrogen content as the fresh feed gas.

A process simulation was prepared to estimate the compression power and heat exchanger area necessary to implement this scheme. The pressures of the refrigerant stages were optimized to achieve minimum compressor horsepower, subject to a minimum temperature approach constraint inside the LNG exchangers. The results of the simulation work are presented in Section 4.1.

3.2.2.2 Mixed Refrigerant (MR) / Feed Gas Auto-Refrigeration

A schematic of the mixed refrigerant / feed gas auto-refrigeration process is depicted in Fig. 2. This process evaporates a low-pressure, mostly liquid HFC mixed refrigerant (MR) in order to cool and condense a mixed stream of feed and recycle gas. The evaporated HFC mixture is compressed and partially condensed by ambient temperature media, after which it is fully condensed and sub-cooled by the low-pressure HFC MR inside the main cryogenic heat exchanger (MCHE). This sub-cooled mixture is then expanded to low pressure and reintroduced to the cold side of the MCHE to provide refrigeration.

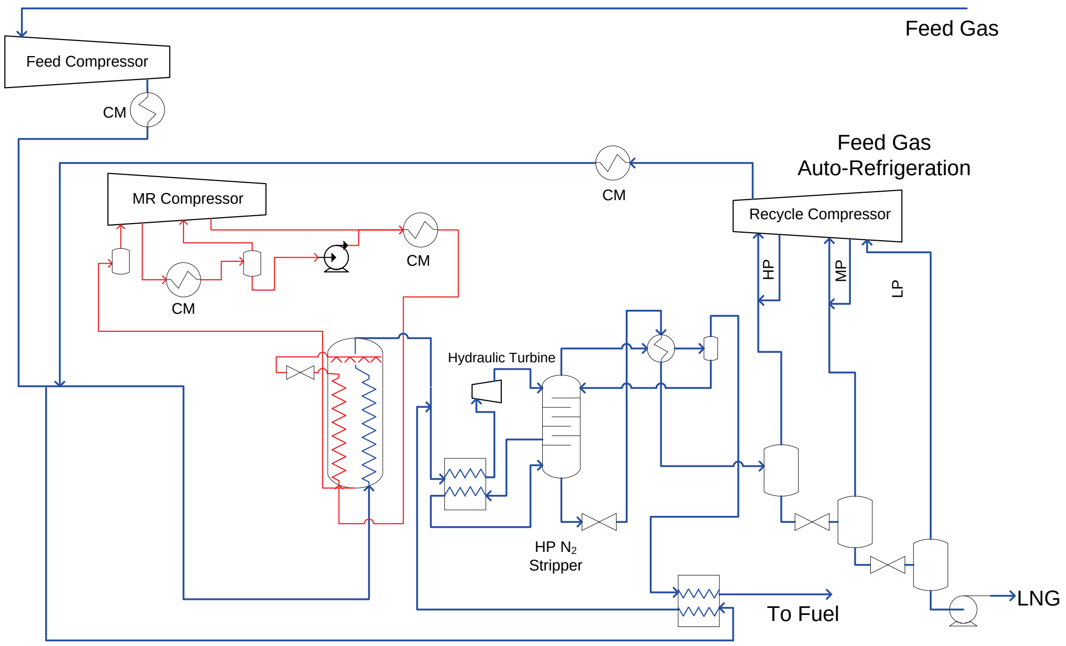

Figure 2. Mixed Refrigerant-Feed Gas Cascade process for natural gas liquefaction

Three components were chosen for the MR: R-245fa (NBP = 59°F), R-41 (NBP = −109°F), and R-14 (NBP = −198°F). The selection of these components was driven primarily by the availability of experimental binary vapor liquid equilibrium (VLE) data (see Section 3.3.1) at the time of writing. R-41 was specifically included to reduce the GWP_{100} of the MR, despite its flammability.

The highest boiling component, R-245fa, which is analogous to isopentane in a hydrocarbon-based single mixed refrigerant process, has an MP of −152°F. As a consequence, it was decided to use the MR to cool the feed gas down to only −155°F in order to prevent freezeout. The remaining refrigeration was achieved using a feed gas auto-refrigeration / NRU section, similar to that described for the R-410A–Xe–Feed Gas Cascade process in Section 3.2.2.1.

A process simulation for the MR-Feed Gas Auto-Refrigeration cycle was prepared, and the refrigerant composition and compressor suction and discharge pressures were optimized to achieve minimum compressor horsepower, subject to a minimum temperature approach constraint inside the MCHE. The results of the simulation work are presented in Section 4.1.

3.3 Phase Equilibrium Data Collection

3.3.1 Vapor-Liquid Equilibrium (VLE) Experiments

3.3.1.1 Need for Data

During the process simulation work, it was discovered that binary interaction data was unavailable for some pairs of potential MR components. Because accurate VLE data are necessary to estimate refrigerant compressor horsepower and heat exchanger area, it was decided to acquire the needed VLE data through a laboratory measurement program.

Prior to this activity, it was necessary to ensure that any VLE data collected could be independently evaluated. The Aspen Data Regression System (DRS), a feature of Aspen Plus, allows import of several types of VLE and calorimetric data for binary and pure-component systems. Regression can then be performed to determine interaction parameters for equations of state or temperature-dependent parameters (e.g., Antoine vapor pressure coefficients) for pure components.

It was decided to fit a single, temperature-independent binary interaction parameter to the Peng-Robinson equation of state for each binary studied. This choice worked well, as the fit of the regression (as measured through sum-of-squares metrics) was good across a wide temperature range for each binary studied.

3.3.1.2 Literature Search and Correlation

A literature search was conducted to identify existing binaries for which VLE data were available. Much of the academic literature regarding VLE of HFC mixtures is focused on isothermal "Pxy" experiments. In this type of experiment, quantities of each of the two compounds under study are introduced to an equilibrium cell that is cooled to a constant temperature by a bath. After sufficient circulation or mixing to reach equilibrium, samples of liquid and vapor are analyzed by gas chromatography. The pressure of the system is measured, and the process is repeated after introducing an additional quantity of one of the components to the cell.[8]

If the system pressure has been measured at a known temperature, it is only necessary to measure one of the phase compositions in order to derive the interaction parameter(s). Indeed, some investigators measure only the composition of the liquid phase, as the vapor composition can be difficult to measure accurately.[9] Nevertheless, composition data for both phases is useful, as it allows one to perform "consistency tests" that can confirm or refute the quality of the data.[9] The main disadvantages of the Pxy approach are the time and error associated with measuring compositions. These drawbacks are addressed by the "TPF" procedure, discussed in the following section, which does not require measurement of composition.

3.3.1.3 Experimental VLE Data collection

VLE data were collected experimentally for the R-245fa / R-14 and R-245fa / R-41 binaries, for which no open literature data could be found. Experiments were performed at two temperatures for each system (14°F and 95°F for R-245fa / R-41, and 14°F and 68°F for R-245fa / R-14) to ascertain if the interaction parameters exhibited significant temperature dependence. The experiments were conducted according to the "TPF" procedure that has become common in industry and, increasingly, in academia.

In a TPF experiment, known masses of each compound are charged into a constant-temperature cell of known volume. After degassing to remove impurities, the masses of chemicals are re-determined, and a stable vapor pressure is measured.[8] By combining material balance and thermodynamic equilibrium constraints with equations of state and mixing rules, one can determine the binary interaction parameters that best fit the data.[8] The primary advantages of this method are cost, speed, and precision, as no compositions are measured. However, unlike the more traditional Pxy procedure, the TPF method assumes thermodynamic consistency, so a "consistency test" is not possible.

3.3.2 Solid-Liquid Equilibrium Calculations

In general, the cycle conditions must be such that the refrigerants will not form solids, which can cause plugging in heat exchangers and other equipment. For a mixed refrigerant, the melting point of each component would ideally be below the coldest chilling temperature. However, there is some flexibility because in a mixture some melting point depression typically occurs when a high-MP component is diluted in other liquid components. Thus, R-245fa (MP = −152°F), the warm-melting component of the mixed refrigerant, can likely be used at temperatures below its MP, if it is at a sufficiently low concentration in the mixture.

The initial freezeout temperature of a component in a liquid mixture can be estimated according to:[10, Ch. 11]

$$\ln\left(\frac{f_{lmix}}{f_s}\right) = \frac{\Delta H_{fus}}{RT_t}\left(\frac{T_t}{T} - 1\right) \qquad (1)$$

where f_{lmix} is the mixture's liquid fugacity, f_s is the pure component's solid fugacity, ΔH_{fus} is the pure component's enthalpy of fusion, R is the gas constant, T_t is the triple point temperature of the pure component, and T is the initial freezeout temperature of the pure component.

The pure component's ΔH_{fus} has a large impact on determining the solubility of a component in the mixture. As the enthalpy of fusion for a component increases, the thermodynamic favorability of solid formation grows due to the exothermic nature of crystallization. Therefore, components with large enthalpies of fusion will freeze out of solution at higher temperatures. In addition, f_{lmix} has a significant effect on the solubility of a pure component in a liquid mixture. This effect can be seen by varying the interaction parameter(s) between the component freezing out and the remaining liquid component(s). Repulsive interactions in the liquid will tend to cause freezeout at higher temperatures, whereas attractive interactions will further depress the initial freezeout temperature.

Knowing both ΔH_{fus} for the component of interest and the set of interaction parameters between all pairs of components in the liquid phase is essential to estimating the freezeout temperature. When ΔH_{fus} for an organic refrigerant is unknown experimentally, it may be possible to obtain a reasonable estimate using group contribution methods, such as those of Chickos *et al.*[11] and Joback and Reid.[12]

In this work, the initial freezeout temperature of R-245fa over a range of concentrations was estimated according to the model of Equation 1. As literature data for ΔH_{fus} of R-245fa was unavailable, group contribution methods were used to estimate that parameter. Results of these calculations are given in Section 4.2.2.

4 RESULTS

4.1 Simulation Results

Performance results from the process simulations of the R-410A–Xe–Feed Gas Cascade and MR / Feed Gas Auto-Refrigeration processes are presented in Table 2.

Table 2. Performance comparison between R-410A-Xe-Feed Gas Cascade and MR / Feed Gas Auto-Refrigeration processes.

	R-410A-Xe-Feed Gas	MR-Feed Gas
kWhr/tonne LNG	309	324
MW/MTA LNG	35.3	37.0
UA x 10^6, BTU/F-hr/MTA LNG	27.5	39.2
Min. Approach (°F)	3.6	7.0

The R-410A-Xe-Feed Gas Cascade process required 4.6% less power per unit LNG than the MR-Feed Gas Auto-Refrigeration process. In addition, the R-410A–Xe–Feed Gas Cascade required almost 30% less heat exchanger UA than the MR-Feed Gas Cascade, even though the minimum temperature approach was relaxed from 3.6°F for the R-410A–Xe–Feed Gas Cascade to 7.0°F for the MR-Feed Gas Auto-Refrigeration process.

The composite heat exchange curves for the R-410A–Xe–Feed Gas Cascade and MR-Feed Gas Auto-Refrigeration processes are presented in Fig. 3 and Fig. 4, respectively.

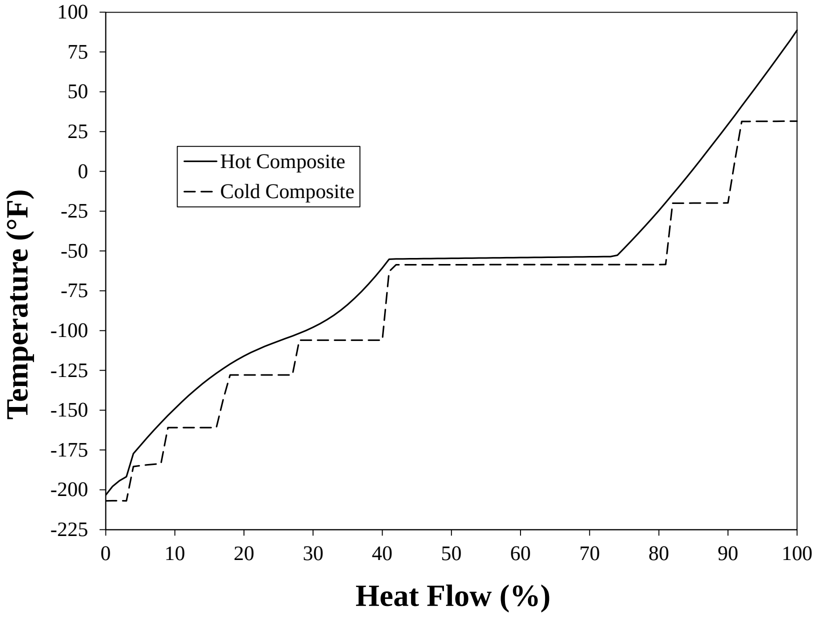

Figure 3. Composite heat exchanger curves for R-410A–Xe–Feed Gas Cascade. Relatively large temperature differences exist in most of the cycle, except where xenon is condensed (40–75% heat flow).

We believe the superior performance of the R-410A–Xe–Feed Gas Cascade is mostly attributable a sub-optimal mixed refrigerant composition in the MR-Feed Gas Auto-Refrigeration process. The mixed refrigerant components used in this work were limited to R-245fa, R-41, and R-14, largely due to availability of VLE data. As further binary VLE data become available for other compounds identified in Table 1, we expect to improve the performance of the MR-Feed Gas Auto-Refrigeration process.

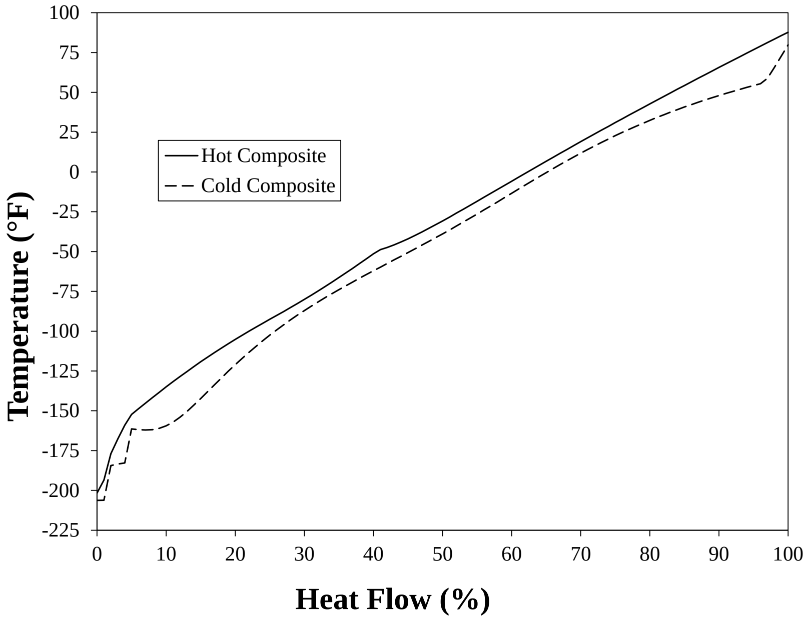

Figure 4. Composite heat exchanger curves for MR-Feed Gas Auto-Refrigeration process. Temperature approaches between hot and cold composite curves are close throughout most of the process.

4.2 Phase Equilibrium Results

4.2.1 Binary Interaction Parameters

Large positive interaction parameters were observed for the R-245fa / R-14 and R-14 / R-41 pairs,[13] while a small, slightly negative interaction parameter was observed for the R-245fa / R-41 binary. This agrees with a trend seen in the literature, where PFCs such as R-14 and R-116 tend to have strong repulsive interactions with polar HFCs,[13,14,15] while polar HFCs tend to have small interactions with each other.[16,17,18,19] This is very different from hydrocarbon-hydrocarbon interaction parameters, which are usually small. These results reinforce the importance of measuring interaction parameters for HFC-HFC binaries.

4.2.2 R-245fa Solid Liquid Equilibrium Estimation

The estimated freezeout temperatures for different concentrations of R-245fa in the mixed refrigerant are shown in Fig. 5. The optimized MR contained less than 25 mol% R-245fa, so freezeout is expected to occur around −200°F, well below the lowest expected MR temperature of −160°F.

ΔH_{fus} for R-245fa was estimated to be 8.0 kJ/mol by the methods of both Chickos *et al.*[11] and Joback and Reid.[12] A 25% margin was applied to this value, and ΔH_{fus} = 10 kJ/mol was used to predict initial freezeout. Proportions of the other refrigerants in mixture (R-41 and R-14) were held constant as the concentration of R-245fa was varied.

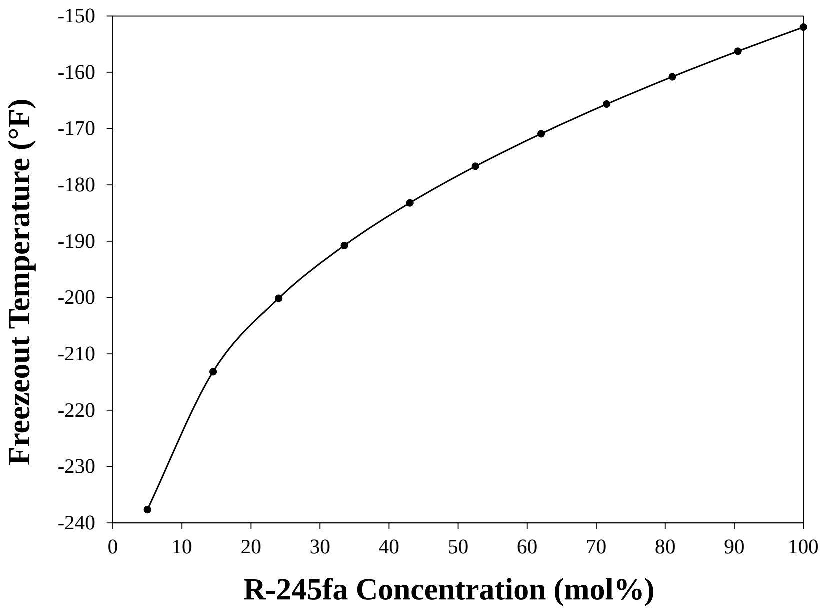

Figure 5. Estimated freezeout temperatures for R-245fa in the MR as a function of concentration

5 DISCUSSION

The chief advantage of the MR-Feed Gas Auto-Refrigeration process is its relative simplicity. Fewer compressor and heat exchanger services are required compared to the R-410A–Xe–Feed Gas Cascade process, and runs of cryogenic piping are expected to be shorter and less complex. This simplicity facilitates modularization, making the process particularly suited to FLNG applications.

Nevertheless, the design of an alternative refrigerant-based MR process can require more experimental data collection than a cascade process. Knowledge of VLE between components in the mixed refrigerant is essential to achieve the close match between composite heating and cooling curves needed for an efficient MR liquefaction cycle. Because cascade processes use refrigerants that are pure components or azeotropic mixtures, less effort is required for the acquisition of thermodynamic data.

Heat exchanger selection is another key difference between the processes. For the MR-Feed Gas Auto-Refrigeration process, the main cryogenic exchanger must be either a brazed aluminum plate-fin exchanger or a spiral wound exchanger in order to obtain the close temperature approaches needed for efficiency. For the R-410A–Xe–Feed Gas Cascade process, kettle chillers or plate-fin exchangers can be used for all refrigerant services, as the refrigerants boil at fixed temperatures.

6 CONCLUSIONS

In this work, we have demonstrated the feasibility of natural gas liquefaction using HFC and noble gas refrigerants and discussed the potential benefits of applications of this technology to baseload LNG plants. While this paper focuses on two possible configurations, we have studied a wider range of possible process schemes which we continue to expand as we learn more about potential alternative refrigerants. We are confident this technology has the potential to positively impact FLNG and land-based project economics in the future.

7 ACKNOWLEDGMENTS

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8 ABBREVIATIONS

ASHRAE....... American Society of Heating, Refrigeration, and Air Conditioning Engineers

BIP .... Binary Interaction Parameter

CFC .... Chlorofluorocarbon

DRS .... Data Regression System

EoS .... Equation of State

FLNG .... Floating LNG

GWP_{100} .... Global Warming Potential over a 100-year interval

HFC .... Hydrofluorocarbon

HFE............... Hydrofluoroether

HFO .... Hydrofluoroolefin

MCHE .... Main Cryogenic Heat Exchanger

MP .... Melting point

MR .... Mixed refrigerant

MTA .... Million Tonnes per Annum

NBP .... Normal boiling point

NRU .... Nitrogen Rejection Unit

ODP .... Ozone Depletion Potential over a 100-year interval

PFC............... Perfluorocarbon

SMR .... Single Mixed Refrigerant

VLE .... Vapor Liquid Equilibrium

9 SYMBOLS

f_{lmix}.............. Fugacity of liquid mixture

f_s .... Fugacity of pure component solid

ΔH_{fus} .... Heat of fusion of pure component

R .... Gas constant

T.................... Temperature of initial freezeout of pure component

T_t .... Triple point temperature of pure component

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Environmental Protection Agency, available at http://www.epa.gov/ttn/chief/faq/ap42faq.html

AP 42 Frequent Questions

CAN I DOWNLOAD AP 42 SECTIONS FROM THE INTERNET?

Yes! The *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* is available on the Emissions Factors & Policy Applications Center web site.

CAN I DOWNLOAD EMISSIONS FACTORS FOR MOBILE SOURCES FROM THE INTERNET?

AP 42 Volume II: Mobile Sources is no longer maintained. More current mobile source emissions factors are available using the Office of Transportation and Air Quality (OTAQ) mobile source models.

However, for reference purposes, OTAQ continues to post parts of the most recent mobile sources AP 42, Volume II on their web site. In particular, Appendix H is still useful in documenting the emissions factors produced by MOBILE5, and in some cases carried over into MOBILE6 without additional documentation.

I HAVE BEEN USING SECTIONS OF AP 42 TO OBTAIN EMISSIONS FACTORS. HOWEVER, I HAVE QUESTIONS ABOUT HOW THESE EMISSIONS FACTORS ARE OBTAINED. IS THERE A WAY TO GET THE TEST METHODOLOGIES THAT WERE USED TO DETERMINE THE EMISSIONS FACTORS?

The AP 42 Background Documents provide background information on how the AP 42 emissions factors were obtained. These documents include a literature review, emissions factor methodologies and reference materials. Most background documents are available on this site under the corresponding AP 42 chapter page.

WHAT DO THE EMISSIONS FACTORS RATINGS MEAN?

The following information is from the Introduction of the *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*.

Emissions factor ratings are best characterized as follows:

- A = Excellent. Emission factor is developed primarily from A and B rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.
- B = Above average. Emission factor is developed primarily from A or B rated test data from a moderate number of facilities. Although no specific bias is evident, is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
- C = Average. Emission factor is developed primarily from A, B, and C rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
- D = Below average. Emission factor is developed primarily from A, B and C rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.
- E = Poor. Factor is developed from C and D rated test data from a very few number of facilities, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.
- U = Unrated (Only used in the L&E documents). Emission factor is developed from source tests which have not been thoroughly evaluated, research papers, modeling data, or other sources that may lack supporting documentation. The data are not necessarily "poor," but there is not enough information to rate the factors according to the rating protocol. "U" ratings are commonly found in L&E documents and FIRE rather than in AP 42.

CAN I USE DRAFT SECTIONS OF AP42?

AP-42 sections designated as 'final' have completed the public comment process and all issues have been resolved. Sections designated as 'draft' reflect the fact that the comment period on these sections has passed, but not all issues have been resolved. EPA might receive additional data or comments that would cause a re-evaluation of the available data and possibly open another comment period. Users are encouraged to use factors from finalized sections, if available, but may decide that the draft emissions factors provide better estimates after reviewing the supporting documentation.

THERE ARE MANY SECTIONS OF AP 42 THAT HAVE NOT BEEN COMPLETED. THE DESCRIPTION OF THEIR STATUS WAS RECENTLY CHANGED FROM "WORK IN PROGRESS," OR "WORK SUSPENDED - AT THIS TIME, THERE ARE NO PLANS TO UPDATE THIS SECTION" TO "THIS IS A PLACEHOLDER HEADING SHOULD EPA DETERMINE AT SOME FUTURE DATE THAT DEVELOPMENT OF A SECTION IS WARRANTED." WHY WAS THE DESCRIPTION CHANGED?

The new wording is a better indication of the actual status of EPA's efforts in these areas. Years ago, work was initiated in these areas, however, in most cases, no emissions data were made available for review and the sections were not developed. EPA has no plans to develop new sections for the placeholder headings at this time.

Last updated on 11/29/2012

3.1 Stationary Gas Turbines

3.1.1 General[1]

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.[2] The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.[3]

3.1.2 Process Description[1,2]

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_X combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600^{o}F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.[2] Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site’s steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_X), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO_2) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_X) will only appear in a significant quantity if heavy oils are fired in the turbine. Emissions of sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_X, which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_X is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_X formed from natural gas combustion is thermal NO_X. Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_X from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_X controls. Otherwise, thermal NO_X is the predominant NO_X formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_X formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_X. Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_X formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.[4] Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature is the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X.

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter[13] -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases[5-11] -

Carbon dioxide (CO_2) and nitrous oxide (N_2O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH_4) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N_2O is minimized when combustion temperatures are kept high (above 1475^oF) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine’s exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies[12]

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_X and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_X and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_X and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NO_X and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_X is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_X emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_X emissions associated with the high temperature pilot flame are insignificant. Low NO_X emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H_2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_X generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_X formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_X emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850°F) cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_X emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_X, O_2, and NH_3, to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_X reduction catalyst for simultaneous CO/NO_X control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems[14,15] -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_X and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_X emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer’s claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_X, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_X. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_X levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (http://www.epa.gov/ttn/chief).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/10^6 ft^3 (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO_2 factor was revised and a new set of N_2O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO_2 factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

EPA, available at http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines[b]		Digester Gas-Fired Turbines[d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[e]	Emission Factor Rating
CO_2[f]	50	D	27	C
Lead	ND	NA	< 3.4 E-06[g]	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO_2	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.
[b] SCC for landfill gas-fired turbines is 2-03-008-01.
[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.
[d] SCC for digester gas-fired turbine include 2-03-007-01.
[e] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.
[f] For landfill gas and digester gas, CO_2 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).
[g] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[h] Based on adding the formaldehyde emissions to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.
[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".
[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.
[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.
[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	B
Naphthalene	3.5 E-05	C
PAH	4.0 E-05	C

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 1.1 E-05	D
Beryllium[d]	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel[d]	< 4.6 E-06	D
Selenium[d]	< 2.5 E-05	D

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Acetonitrile[d]	< 1.2E-05	D
Benzene	2.1E-05	B
Benzyl Chloride[d]	< 1.2 E-05	D
Carbon Tetrachloride[d]	< 1.8 E-06	D
Chlorobenzene[d]	< 2.9 E-06	D
Chloroform[d]	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroethylene[d]	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene[d]	< 1.9 E-06	D
Vinyl Chloride[d]	< 1.6 E-06	D
Xylenes	3.1 E-05	B

[a] SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Ratings
1,3-Butadiene[d]	< 9.8 E-06	D
1,4-Dichlorobenzene[d]	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tetrachloride[d]	< 2.0 E-05	D
Chlorobenzene[d]	< 1.6 E-05	D
Chloroform[d]	< 1.7 E-05	D
Ethylene Dichloride[d]	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride[d]	< 1.3 E-05	D
Tetrachloroethylene[d]	< 2.1 E-05	D
Trichloroethylene[d]	< 1.8 E-05	D
Vinyl Chloride[d]	< 3.6 E-05	D
Vinylidene Chloride[d]	< 1.5 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average digester gas heating value (HHV) of 600 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 2.3 E-06	D
Cadmium[d]	< 5.8 E-07	D
Chromium[d]	< 1.2 E-06	D
Lead[d]	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

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Sabine Pass Liquefaction, LLC
Sabine Pass LNG, L.P.
Liquefaction Expansion Project

Cheniere Creole Trail Pipeline, L.P.
CCTPL Expansion Project

Resource Report 9 — Air and Noise Quality
PF13-8-000

July 2013

TABLE OF CONTENTS

LIST OF TABLES

APPENDICES

ACRONYMS AND ABBREVIATIONS

49 U.S.C.	Title 49 of the United States Code
μg/m^3	micrograms per cubic meter
AQCR	air quality control region
AQCR 106	Southern Louisiana - Southeast Texas Interstate AQCR
ANR	ANR Pipeline Company
BACT	Best Available Control Technology
Bcf/d	billion cubic feet per day
BD	blow down
CAA	Clean Air Act
CCTPL	Cheniere Creole Trail Pipeline, L.P.
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CGT	Columbia Gulf Transmission Company
CH_4	methane
CI	compression ignition
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalentdB decibel
dBA	A-weighting frequency scale in decibels
F	degrees Fahrenheit
FERC or Commission	Federal Energy Regulatory Commission
GE	General Electric
GHG	greenhouse gas
GJ/hr	gigajoules per hour
g/hp-hr	grams per horsepower hour
g/VMT	grams per vehicle mile traveled
HAP	hazardous air pollutant
HDD	horizontal directional drill
hp	horsepower
ICE	internal combustion engines
LAC	Louisiana Administrative Code
L_{Aeq}	A-weighted L_{eq} in decibels
LAAQS	Louisiana Ambient Air Quality Standards
lb/MMBtu	pound per million British thermal units
L_d	day sound level in decibels
L_{dn}	day-night sound level in decibels
L_{eq}	equivalent sound level in decibels
LDEQ	Louisiana Department of Environmental Quality
L_n	night sound level in decibels
LNG	liquefied natural gas

MACT	Maximum Achievable Control Technology
m^3	cubic meters
MOVES	USEPA Mobile Vehicle Emissions Simulator
MMBtu/hr	million British thermal units per hour
M&R	metering and regulating
MSS	maintenance, start-up, and shutdown
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NCDC	National Climatic Data Center
NFPA	National Fire Protection Association
NNSR	Nonattainment New Source Review
NO_2	nitrogen dioxide
N_2O	nitrous dioxide
NO_x	nitrogen oxides
NSA	Noise Sensitive Areas
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	ozone
Pb	lead
PHMSA	Pipeline and Hazardous Materials Safety Administration
Plan	FERC's *Upland Erosion Control, Revegetation, and Maintenance Plan*
PM	particulate matter
PM_{10}	particulate matter with a nominal aerodynamic diameter of 10 microns or less
$PM_{2.5}$	particulate matter with a nominal aerodynamic diameter of 2.5 microns or less
PPEC	Pine Prairie Energy Center
ppm	parts per million
ppmvd @ 15% O_2	parts per million by volume corrected to 15% oxygen at dry conditions
Project	Liquefaction Expansion Project and CCTPL Expansion Project,
PSD	Prevention of Significant Deterioration
psia	pounds per square inch absolute
RICE	reciprocating internal combustion engine
RMP	risk management plan
Sabine Pass	Sabine Pass Liquefaction Expansion, LLC; Sabine Pass Liquefaction, LLC, and Sabine Pass LNG, L.P.
SAC	Single Annular Combustor
SER	significant emission rate
SIP	State Implementation Plan
SPLNG Terminal	Sabine Pass LNG Terminal
SO_2	Sulfur dioxide

T	Trace
TAP	Toxic Air Pollutant
TGT	Texas Gas Transmission, LLC
Title V	40 CFR Part 70 operating permit program
tpy	tons per year
U.S.	United States
USDOT	U.S. Department of Transportation
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compounds
WRAP	Western Regional Air Partnership

RESOURCE REPORT 9 – AIR AND NOISE QUALITY	
Filing Requirement	**Location in Environmental Report**
Describe existing air quality, including background levels of nitrogen dioxide and other criteria pollutants which may be emitted above EPA-identified significance levels. (18 CFR § 380.12(k)(1))	Section 9.2.2
Quantitatively describe existing noise levels at noise-sensitive areas, such as schools, hospitals, or residences and include any areas covered by relevant state or local noise ordinances. (18 CFR § 380.12 (k)(2)). (i) Report existing noise levels as the Leq (day), Leq (night), and Ldn and include the basis for the data or estimates. (ii) For existing compressor stations, include the results of a sound level survey at the site property line and nearby noise-sensitive areas while the compressors are operated at full load. (iii)..For proposed new compressor station sites, measure or estimate the existing ambient sound environment based on current land uses. (iv) Include a plot plan that identifies the locations and duration of noise measurements, the time of day, weather conditions, wind speed and direction, engine load, and other noise sources present during each measurement.	Section 9.3
Estimated the impact of the project on air quality, including how existing regulatory standards would be met. (18 CFR § 380.12(k)(3)) (i) Provide the emission rate of nitrogen oxides from existing and proposed facilities, expressed in pounds per hour and tons per year for maximum operating conditions, include supporting calculations, emission factors, fuel consumption rates, and annual hours of operation. (ii) For major sources of air emissions (as defined by the Environmental Protection Agency), provide copies of applications for permits to construct (and operate, if applicable) or for applicability determinations under regulations for the prevention of significant air quality deterioration and subsequent determinations.	Section 9.2.4
Provide a quantitative estimate of the impact of the project on noise levels at noise-sensitive areas, such as schools, hospitals, or residences. (18 CFR § 380.12(k)(4)) (i) Include step-by-step supporting calculations or identify the computer program used to model the noise levels, the input and raw output data and all assumptions made when running the model, far-field sound level data for maximum facility operation, and the source of the data. (ii) Include sound pressure levels for unmuffled engine inlets and exhausts, engine casings, and cooling equipment; dynamic insertion loss for all mufflers; sound transmission loss for all compressor building components, including walls, roof, doors, windows and ventilation openings; sound attenuation from the station to nearby noise-sensitive areas, the manufacturer's name, the model number, the performance rating; and a description of each noise source and noise control component to be employed at the proposed compressor station. For proposed compressors the initial filing must include at least the proposed horsepower, type of compression, and energy source for the compressor.	Section 9.3

RESOURCE REPORT 9 – AIR AND NOISE QUALITY	
Filing Requirement	**Location in Environmental Report**
(iii) Far-field sound level data measured from similar units in service elsewhere, when available, may be substituted for manufacturer's far-field sound level data. (iv) If specific noise control equipment has not been chosen, include a schedule for submitting the data prior to certification. (v) The estimate must demonstrate that the project will comply with applicable noise regulations and show how the facility will meet the following requirements: (A) The noise attributable to any new compressor station, compression added to an existing station, or any modification, upgrade or update of an existing station, must not exceed a day-night sound level Ldn of 55 dBA at any pre-existing noise-sensitive area (such as schools, hospitals, or residences). (B) New compressor stations or modifications of existing stations shall not result in a perceptible increase in vibration at any noise sensitive area.	Section 9.3
Describe measures and manufacturer’s specifications for equipment proposed to mitigate impact to air and noise quality, including emission control systems, installation of filters, mufflers, or insulation of piping and buildings, and orientation of equipment away from noise-sensitive areas. (18 CFR § 380.12(k)(5))	Sections 9.2 and 9.3

9.0 AIR AND NOISE QUALITY

9.1 INTRODUCTION

Sabine Pass Liquefaction Expansion, LLC, Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P. (collectively referred to as "Sabine Pass") proposes to expand the existing Sabine Pass liquefied natural gas ("LNG") Terminal ("SPLNG Terminal") in Cameron Parish, Louisiana. The Liquefaction Expansion Project will primarily consist of the addition of two liquefaction trains (Trains 5 and 6). Trains 5 and 6 comprise Stage 3 of the Sabine Pass Liquefaction Project, of which Stages 1 and 2 (Trains 1 through 4) are currently under construction at the SPLNG Terminal.

To deliver pipeline gas to Trains 5 and 6, Cheniere Creole Trail Pipeline, L.P. ("CCTPL") proposes to expand and extend the existing CCTPL pipeline system in Cameron, Calcasieu, Beauregard, Allen, and Evangeline Parishes, Louisiana. The CCTPL Expansion Project will involve the addition of approximately 103.9 miles of pipeline, including two loops (Loop 1 and Loop 2), an Extension, and four laterals with interconnections to ANR Pipeline Company ("ANR"), Columbia Gulf Transmission Company ("CGT"), Pine Prairie Energy Center ("PPEC"), and Texas Gas Transmission, LLC ("TGT"). In addition, CCTPL will install a new compressor station (known as the Mamou Compressor Station) to provide an additional 1.5 billion cubic feet per day of capacity to the SPLNG Terminal, and four metering and regulating ("M&R") stations for the interconnections with ANR, CGT, PPEC, and TGT.

This Resource Report 9 describes the ambient air and noise conditions for the Liquefaction Expansion Project and CCTPL Expansion Project (collectively referred to as the "Project"), and provides an assessment of construction and operation impacts, primarily as they relate to the addition of liquefaction Trains 5 and 6 at the SPLNG Terminal, and CCTPL's new Mamou Compressor Station and pipelines. It also desribes the existing noise envionment and provides an assessment of impacts on Noise Sensitive Areas ("NSA") (e.g., schools, hospitals, or residences).

9.2 AIR QUALITY

9.2.1 Stationary Air Emission Sources

9.2.1.1 SPLNG Terminal Trains 1 through 4

There are no new stationary emission sources proposed for the SPLNG Terminal Trains 1 through 4. Sabine Pass proposes to modify operations of Trains 1 through 4. More specifically, Sabine Pass proposes to:

- Update emissions from the twenty four Single Annular Combustor ("SAC") LM2500 natural gas-fueled refrigeration compressor turbines to reflect the final detailed design operating parameters; and
- Update flare emissions to reflect recently identified vent streams that will be routed to the wet/dry flares during routine, start-up, shutdown, and maintenance operations.

9.2.1.2 SPLNG Terminal Trains 5 and 6

New stationary air emission sources associated with the proposed SPLNG Terminal Trains 5 and 6 include the following:

- Twelve (12) General Electric ("GE") LM2500 natural gas-fueled refrigeration compressor turbines, each with a capacity of 43,013 horsepower ("hp").
- Two (2) GE LM2500 natural gas-fueled power generation combustion turbines, each with a capacity of 43,013 hp.
- Two diesel-fueled emergency generators, model and manufacturer to be determined, each with a rating of 2,220 hp.
- One (1) natural gas-fueled wet flare with four pilots, model and manufacturer to be determined, each with a heat input capacity of 0.065 MMBtu/hr.
- One (1) natural gas-fueled dry flare with four pilots, model and manufacturer to be determined, each with a heat input capacity of 0.065 MMBtu/hr.
- Two acid gas vent thermal oxidizer, model and manufacturer to be determined, each with a heat input capacity of 23.08 MMBtu/hr.

Table 9.2-1 is a complete list of the current and proposed compressor units at the SPLNG Terminal.

9.2.1.3 CCTPL Pipeline Expansion

No new stationary air emission sources are associated with the proposed CCTPL Pipeline Expansion or the four associated M&R stations. Small quantities of fugitive volatile organic compounds ("VOC") emissions from valve or fitting leaks may occur.

9.2.1.4 Mamou Compressor Station

New stationary air emission sources associated with the proposed Mamou Compressor Station include the following:

- Three (3) natural gas-fueled compressor combustion turbines, Taurus 70-1080S, manufactured by Solar, each with a capacity of 10,836 hp.
- One (1) natural gas-fueled compressor combustion turbine, Titan 130-20502S, manufactured by Solar, with a capacity of 20,617 hp.
- Two (2) natural gas-fueled emergency generators, each with a rating of 543 hp.
- One (1) 4,300-gallon vertical fixed-roof condensate storage tank.
- Fugitive equipment leak emissions.
- Maintenance, Start-up, and Shutdown ("MSS") activities.

Table 9.2-2 summarizes the Mamou Compressor Station compressor units.

TABLE 9.2-1
SPLNG Terminal Compressor Horsepower Summary

Unit	Manufacturer	Model	Energy Source	Rated Output (Horsepower)			
				Current	Proposed Retirement	Proposed Addition	Proposed Total
1	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
2	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
3	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
4	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
5	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
6	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
7	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
8	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
9	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
10	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
11	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
12	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
13	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
14	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
15	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
16	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
17	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
18	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
19	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
20	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
21	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
22	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
23	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
24	General Electric	LM2500	Natural Gas	43,013	--	--	43,013
25	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
26	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
27	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
28	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
29	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
30	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
31	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
32	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
33	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
34	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
35	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
36	General Electric	LM2500	Natural Gas	--	--	43,013	43,013
Total				**1,032,312**	**--**	**516,156**	**1,548,468**

TABLE 9.2-2 Mamou Compressor Station Compressor Horsepower Summary							
Unit	Manufacturer	Model	Energy Source	Rated Output (Horsepower)			
				Current	Proposed Retirement	Proposed Addition	Proposed Total
Turbine A	Solar	Taurus 70-1080S	Natural Gas	--	--	10,836	10,836
Turbine B	Solar	Taurus 70-1080S	Natural Gas	--	--	10,836	10,836
Turbine C	Solar	Taurus 70-1080S	Natural Gas	--	--	10,836	10,836
Turbine D	Solar	Titan 130-20502S	Natural Gas	--	--	20,617	20,617
Total				**--**	**--**	**53,125**	**53,125**

9.2.2 Existing Conditions

9.2.2.1 Climate

SPLNG Terminal Trains 5 and 6

The SPLNG Terminal is located in Cameron Parish, Louisiana. The climate type is humid sub-tropical, characterized by summers which are hot and humid, winters which are short and mild, and no dry season. The regional climate can be represented by National Climatic Data Center ("NCDC") data for Port Arthur, Texas. Table 9.2-3 provides climate data for Port Arthur.

TABLE 9.2-3
Regional Climate Data for Port Arthur, Texas

Parameter	Years	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Normal Daily Minimum Temperature (F)	30	43.2	46.5	52.2	59	67	72.7	74.2	74	69.7	60.5	51.8	44.8	59.6
Normal Daily Maximum Temperature (F)	30	62.1	65.3	71.8	78.1	84.8	89.6	91.7	92.2	88.2	80.6	71.7	63.7	78.3
Normal Daily Mean Temperature (F)	30	52.7	55.9	62	68.6	75.9	81.2	83	83.1	79	70.6	61.7	54.3	69
Normal Heating Degree Days	30	393	270	148	39	1	0	0	0	1	33	161	355	1,401
Normal Cooling Degree Days	30	11	15	55	146	339	484	556	561	419	205	64	22	2,877
Average Percentage of Possible Sunshine	26	42	52	52	52	64	69	65	63	62	67	57	47	58
Mean Number of Days with ≥ 0.01 inch Precipitation	59	9	8	7	6	6	8	11	11	9	6	7	9	97
Normal Precipitation (inches)	30	5.26	3.58	3.53	3.21	5.23	7.09	5.95	5.38	5.97	5.58	4.40	5.29	60.5

TABLE 9.2-3
Regional Climate Data for Port Arthur, Texas

Parameter	Years	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Average Total Snowfall (including ice pellets) (inches)	43	0.1	0.2	0	T	T	0	T	0	0	0	T	0	0.3

Source: Data reported for Port Arthur, Texas in Comparative Climatic Data for the United States Through 2012, National Climatic Data Center

F = degrees Fahrenheit

T = Trace

Mamou Compressor Station

The Mamou Compressor Station is located in Evangeline Parish, Louisiana. The climate type is humid sub-tropical, characterized by summers which are hot and humid, winters which are short and mild, and no dry season. The regional climate has been represented by using the NCDC data for Lake Charles, Louisiana. Table 9.2-4 provides climate data for Lake Charles.

TABLE 9.2-4
Regional Climate Data for Lake Charles, Louisiana

Parameter	Years	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Normal Daily Minimum Temperature (F)	30	42.3	45.5	51.3	58.2	66.6	72.7	74.6	74.1	69.1	59.4	50.7	44.1	59.1
Normal Daily Maximum Temperature (F)	30	61.4	64.6	71.4	77.9	84.6	89.3	91.1	91.9	88.2	80.8	71.6	63.5	78.1
Normal Daily Mean Temperature (F)	30	51.8	55	61.4	68.1	75.6	81	82.9	83	78.6	70.1	61.1	53.8	68.6
Normal Heating Degree Days	30	417	291	162	45	1	0	0	0	1	35	171	367	1,491
Normal Cooling Degree Days	30	10	13	49	136	330	480	553	558	411	193	56	20	2,809
Average Percentage of Possible Sunshine	19	62	66	74	71	72	78	83	81	78	75	67	59	72
Mean Number of Days with ≥ 0.01 inch Precipitation	51	9	8	7	6	7	9	11	10	8	6	7	9	97
Normal Precipitation (inches)	30	5.23	3.46	3.66	3.33	5.2	6.85	5.63	4.86	5.26	4.9	4.43	4.68	57.4
Average Total Snowfall (including ice pellets) (inches)	36	0.2	0.1	T	T	T	0.0	T	0.0	0.0	0.0	T	T	0.3

Source: Data reported for Lake Charles, Louisiana in Comparative Climatic Data for the United States Through 2012, National Climatic Data Center

F = degrees Fahrenheit. T = Trace

9.2.2.2 National and State Ambient Air Quality Standards

The United States ("U.S.") Environmental Protection Agency ("USEPA") has promulgated National Ambient Air Quality Standards ("NAAQS") to protect human health and welfare. The NAAQS include primary standards, which are designed to protect human health, including the health of sensitive subpopulations such as children and those with chronic respiratory problems, and secondary standards, which are designed to protect public welfare, including economic interests, visibility, vegetation, animal species, and other concerns. NAAQS currently apply to the following criteria pollutants:

- Particulate matter ("PM") with a nominal aerodynamic diameter of 10 microns or less ("PM_{10}");
- PM with a nominal aerodynamic diameter of 2.5 microns or less ("$PM_{2.5}$");
- Nitrogen dioxide ("NO_2");
- Sulfur dioxide ("SO_2");
- Carbon monoxide ("CO");
- Ozone ("O_3"); and
- Lead ("Pb").

Each NAAQS is expressed in terms of a concentration level and an associated averaging period. The current NAAQS for these criteria pollutants are summarized in Table 9.2-5. The NAAQS apply in all Project areas. Notes to Table 9.2-5 list the form of the statistic used to assess compliance with each NAAQS.

TABLE 9.2-5
National Ambient Air Quality Standards

Pollutant	Averaging Time	Primary Standard		Secondary Standard		Form
		(ppm)	(ug/m^3)	(ppm)	(μg/m^3)	
Respirable Particulate (PM_{10})	24-hour	---	150	---	150	Not to be exceeded more than once per year on average over 3 years
Fine Particulate ($PM_{2.5}$)	24-hour	---	35	---	35	98th percentile, averaged over 3 years
	Annual	---	12	---	15	Annual mean, averaged over 3 years
Nitrogen Dioxide (NO_2)	1-hour	0.100	188	---	---	98th percentile, averaged over 3 years
	Annual	0.053	100	0.053	100	Annual Mean
Sulfur Dioxide (SO_2)	1-hour	0.075	196	---	---	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	3-hour	---	---	0.5	1,300	Not to be exceeded more than once per year
Carbon Monoxide (CO)	8-hour	9	10,300	---	---	Not to be exceeded more than once per year
	1-hour	35	40,000	---	---	Not to be exceeded more than once per year

TABLE 9.2-5
National Ambient Air Quality Standards

Pollutant	Averaging Time	Primary Standard		Secondary Standard		Form
		(ppm)	(ug/m^3)	(ppm)	(μg/m^3)	
Ozone (O_3)	1-hour	0.12	236	0.12	236	Not to be exceeded more than once per year
	8-hour (2008)	0.075	147	0.075	147	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years
	8-hour (1997)	0.08	157	0.08	157	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years
Lead (Pb)	3-month rolling	---	0.15	---	0.15	Not to be exceeded

ppm = parts per million
μg/m^3 = micrograms per cubic meter.
Source: http://www.epa.gov/air/criteria.html accessed 05/30/13

States may adopt standards that are more stringent than the NAAQS. The Louisiana Department of Environmental Quality ("LDEQ") has adopted the Louisiana Ambient Air Quality Standards ("LAAQS"), which are found Title 33, Part III, Chapter 7, Section 711 of the Louisiana Administrative Code ("LAC") and summarized in Table 9.2-6. Notes to Table 9.2-6 list the form of the statistic used to assess compliance with each LAAQS.

TABLE 9.2-6
Louisiana Ambient Air Quality Standards

Pollutant	Averaging Period	LAAQS	
		Primary	Secondary
PM_{10}	24-hour [2]	150 μg/m^3	150 μg/m^3
$PM_{2.5}$	Annual [1]	15.0 μg/m^3	15.0 μg/m^3
	24-hour	35 μg/m^3	35 μg/m^3
NO_2	Annual [1]	100 μg/m^3 (0.05 ppm)	100 μg/m^3 (0.05 ppm)
SO_2	Annual [1]	0.03 ppm (80 μg/m^3)	--
	24-hour [2]	365 μg/m^3 (0.14 ppm)	--
	3-hour [2]	--	1,300 μg/m^3 (0.5 ppm)
CO	8-hour [2]	10,000 μg/m^3 (9 ppm)	10,000 μg/m^3 (9 ppm)
	1-hour [2]	40,000 μg/m^3 (35 ppm)	40,000 μg/m^3 (35 ppm)
O_3	8-hour [3]	0.08 ppm	0.08 ppm
Pb	Calendar quarter [1]	1.5 μg/m^3	1.5 μg/m^3

Form of Statistic:
1. Arithmetic mean.
2. Not to be exceeded more than once per year.
3. Compliance based on 3-year average of the annual fourth highest daily maximum 8-hour average ozone concentration at a monitor.

ppm = parts per million by volume.
μg/m^3 = micrograms per cubic meter.
From Louisiana Administrative Code 33:III.711.A & B, compiled June 2013.

9.2.2.3 Existing Ambient Air Quality

Pollutant concentration data characteristic of air quality in the Project areas were obtained from the USEPA AIRDATA database. Ambient air quality monitoring data for 2010 through 2012 (except as noted) are summarized in Tables 9.2-7 and 9.2-8 for the monitors that are nearest or most representative of the SPLNG Terminal Trains 5 and 6 area and the Mamou Compressor Station area, respectively. For each pollutant and averaging period shown in Tables 9.2-7 and 9.2-8, the rank generally corresponds to the form of the statistic. In the case of Pb, three-month rolling average data are not available at nearby monitoring locations, and annual arithmetic mean data are reported.

While the concentrations in Tables 9.2-7 and 9.2-8 are the best available data, they are not necessarily representative of present actual air quality in the immediate vicinity of the each of the Project areas. Sabine Pass collected background data for NO_x in 2012 and may use data different than shown in Tables 9.2-7 and 9.2-8 for the LDEQ air permit application.

TABLE 9.2-7
Existing Ambient Air Quality Estimated for the SPLNG Terminal Area

Pollutant	Monitoring Station ID	Miles from SPLNG Terminal	Averaging Time	Years	Concentrations (ppm)	Concentrations (μg/m³)	Rank
CO	48-245-1035	43	8-hour	2010-2012	0.567	649	Second high
			1-hour		0.824	944	Second high
Pb	48-201-1039	78	3-month rolling	2012	---	0.0026	Annual average
NO_2	48-245-1035	43	1-hour	2010-2012	0.029	54.5	98th percentile
			Annual		0.0119	22.5	Annual Mean
O_3	48-245-0101	24	8-hour	2010-2012	0.080	158	Fourth high
			1-hour		0.112	220	Second high
$PM_{2.5}$	22-019-0009	62	Annual	2011-2012	---	8.7	Annual mean
			24-hour		---	19.2	98th percentile
PM_{10}	48-167-0004	63	24-hour	2010-2012	---	46.5	Second high
SO_2	22-019-0008	37	1-hour	2010-2012	0.038	98.4	99th percentile
			3-hour		0.040	104.4	Second high
			24-hour		0.017	45.5	Second high

Monitoring Station Key
48-245-1035: 135 Hare Road, Nederland, TX
48-201-1039: 4514 1/2 Durant St, Deer Park, TX
48-245-0101: 5200 Mechanic, Port Arthur, TX
22-019-0009: 2284 Paul Bellow Road, Vinton, LA
48-167-0004: 2516 Texas Avenue, Texas City, TX
22-019-0008: 2646 John Stine Road, Westlake, LA

ppm = parts per million
$\mu g/m^3$ = micrograms per cubic meter.

TABLE 9.2-8
Existing Ambient Air Quality Estimated for the Mamou Compressor Station

Pollutant	Monitoring Station ID	Miles from Mamou CS	Averaging Time	Years	Concentrations (ppm)	Concentrations (μg/m³)	Rank
CO	22-033-0009	77	8-hour	2010-2012	1.867	2,138	Second high
			1-hour		2.187	2,504	Second high
Pb	22-033-0014	71	3-month rolling	2010-2012	---	0.0036	Annual average
NO_2	22-019-0008	59	1-hour	2010-2012	0.032	60.4	98th percentile
			Annual		0.0144	27.1	Annual Mean
O_3	22-055-0007	41	8-hour	2010-2012	0.072	142	Fourth high
			1-hour		0.085	167	Second high
$PM_{2.5}$	22-055-0007	41	Annual	2011-2012	---	11.8	Annual mean
			24-hour		---	20.6	98th percentile
PM_{10}	22-055-0007	41	24-hour	2010-2012	---	64.2	Second high
SO_2	22-019-0008	59	1-hour	2010-2012	0.038	98.4	99th percentile
			3-hour		0.040	104.4	Second high
			24-hour		0.017	45.5	Second high

Monitoring Station Key
22-033-0009: 1061-A Leesville Ave, Baton Rouge, LA
22-033-0014: 1400 West Irene Road, Zachary, LA
22-019-0008: 2646 John Stine Road, Westlake, LA
22-055-0007: 646 Cajundome, Lafayette, LA

ppm = parts per million
μg/m³ = micrograms per cubic meter.

9.2.2.4 Attainment Status

An air quality control region ("AQCR"), as defined in Section 107 of the Clean Air Act ("CAA"), is a federally-designated area in which NAAQS must be met. An implementation plan is developed for each AQCR describing how ambient air quality standards will be achieved and maintained.

USEPA designates the attainment status of an area on a pollutant-specific basis based on whether an area meets the NAAQS. Areas that meet the NAAQS are termed "attainment areas." Areas that do not meet the NAAQS are termed "nonattainment areas." Areas for which insufficient data are available to determine attainment status are termed "unclassifiable areas." Areas formerly designated as nonattainment areas that subsequently reached attainment are termed "maintenance areas."

The attainment status designations appear in Title 40 of the Code of Federal Regulations ("CFR") Part 81. The attainment status of the area in which a source is located, and the source's potential air emissions or air emissions increases, determine the permitting process for that source. The Project is located in Allen, Beauregard, Calcasieu, Cameron, and Evangeline Parishes within the Southern Louisiana - Southeast Texas Interstate AQCR ("AQCR 106"). Table 9.2-9 summarizes the attainment status of these parishes in AQCR 106.

TABLE 9.2-9
Attainment Status of Project Area

Pollutant	Designation Date	Status / Designation	Comment
PM_{10}	11/15/1990	Unclassifiable	
24-hour $PM_{2.5}$	12/13/2009	Unclassifiable / Attainment	
Annual $PM_{2.5}$	04/05/2005	Unclassifiable / Attainment	
NO_2	NA	Cannot be classified or better than national standards	1
SO_2	NA	Better than national standards	1
CO	11/15/1990	Unclassifiable / Attainment	
1-hour O_3	10/18/2000	Attainment	2
8-hour O_3	06/15/2004	Unclassifiable / Attainment	
Pb	01/06/1992	Not Designated	

Comments
1. No designation date.
2. The 1-hour ozone standard was revoked effective June 15, 2005 for all areas in Louisiana. Beauregard Parish is a maintenance area for the 1-hour NAAQS for the purposes of 40 CFR 51 Subpart X (Provisions for Implementation of 8-hour Ozone NAAQS).

9.2.3 Air Quality Permitting Requirements

LDEQ is the lead air permitting agency for the Project. LDEQ's air permitting requirements are codified in LAC Title 33, Part III. Facilities can trigger additional review by the USEPA if emissions of one or more regulated air pollutant exceed the applicable Prevention of Significant Deterioration ("PSD") or Nonattainment New Source Review ("NNSR") major source thresholds. PSD applies to a major source located in an attainment area, and NNSR applies to a major source located in a nonattainment area. A facility can undergo both types of review, depending on the potential emissions of each pollutant and the air quality attainment status.

A 40 CFR Part 70 operating permit program (known as "Title V") consolidates all applicable air quality requirements for a facility into a single document.

9.2.3.1 Prevention of Significant Deterioration

PSD regulations apply to new major stationary sources and major modifications. A major stationary source is a source that emits or has the potential to emit over 250 tons per year ("tpy") (or 100 tpy if the source belongs to one of the 28 listed source categories) of at least one criteria pollutant. Neither LNG terminals nor natural gas compressor stations are one of the 28 listed categories. Therefore, the 250 tpy major source threshold applies to the SPLNG Terminal and the Mamou Compressor Station. A new source is also subject to PSD if its potential or actual greenhouse gas ("GHG") emissions equal or exceed 100,000 tpy on a carbon dioxide equivalent ("CO_2e") basis, and the applicable major source threshold on a mass-basis. GHGs include carbon dioxide ("CO_2"), methane ("CH_4"), nitrous oxide ("N_2O"), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

A major modification is a physical change or a change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated New Source Review ("NSR") pollutant and a significant net emissions increase of that pollutant from the major stationary source. An emission increase is considered significant for a regulated pollutant if it exceeds the applicable Significant Emission Rate ("SER"). For a new source, if the potential emissions of any regulated pollutant exceed the applicable major source threshold, any other pollutant whose potential emissions exceed its SER threshold is also subject to PSD review.

SPLNG Terminal

Table 9.2-10 summarizes the potential emissions from the existing SPLNG Terminal, nitrogen oxides ("NO_x") emissions increase from Trains 1 through 4 equipment (i.e., refrigeration compressor combustion turbines and flares), and potential emissions increase from the Trains 5 and 6. It also summarizes the applicable PSD, SER, and Title V major source thresholds. The existing SPLNG Terminal is a PSD major source for NO_x, CO, PM_{10}, $PM_{2.5}$, and GHG. The NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG emissions increases due to the addition of Trains 5 and 6, and other modifications to the SPLNG Terminal exceed the applicable SER threshold, and therefore are also subject to PSD review. Note that the SPLNG Terminal has no existing or planned Pb emissions sources.

TABLE 9.2-10
SPLNG Terminal Potential Emissions and PSD and Title V Thresholds

Source	Potential Emissions (tpy)									
	NO_x	CO	VOC[1]	PM_{10}	$PM_{2.5}$	SO_2	Total HAPS	Single HAP	GHG as CO_2e	GHG Mass Basis
Existing SPLNG Terminal Potential Emissions	3,302.79	5,487.91	119.8	254.18	254.13	17.29	39.82	26	5,734,190	--
Existing Trains 1-4 Emissions Increases[3]	666.86	548.72	94.84	0.2	0.2	0.7	1.08	0.7	139,634	--
SPLNG Terminal Trains 5 and 6 Potential Emissions	1,820.83	2,800.6	90.4	117.8	117.8	6.20	19.14	13.17	2,543,099	--
Estimated Total	5,790.5	8,837.2	305.0	372.2	372.2	24.2	60.0	39.9	8,416,923	--

TABLE 9.2-10
SPLNG Terminal Potential Emissions and PSD and Title V Thresholds

Source	Potential Emissions (tpy)									
	NO_x	CO	VOC[1]	PM_{10}	$PM_{2.5}$	SO_2	Total HAPS	Single HAP	GHG as CO_2e	GHG Mass Basis
PSD Major Source Threshold	250	250	250	250	250	250	NA	NA	100,000	250
PSD SER Threshold	40	100	40	15	10[4]	40	NA	NA	75,000	NA
Title V Major Source Threshold	100	100	100	100	100	100	25	10	100,000	100

1 Volatile organic compounds
2 Includes fugitive emissions from tanks, valves, pumps, flanges, etc. Fugitive emissions are not counted for PSD applicability because LNG terminals are not one of 28 named source categories, but are counted for Title V applicability.
3 Includes NO_X emissions increase related to increasing limit from 20 to 25 ppm on existing Trains 1-4 turbines. Also includes flaring emissions from continuous purges and flaring during periodic maintenance, start-up/shutdown, and turnaround activities related to Trains 1 through 4.
4 Also, 40 tpy SO_2, or 40 tpy NO_x (unless demonstrated not to be a $PM_{2.5}$ precursor)

The PSD air permit application submitted to the LDEQ will include the following:

- A control technology analysis to show that the SPLNG Terminal Trains 5 and 6 will employ Best Available Control Technology ("BACT") for NO_x, CO, VOC, GHG, PM_{10}, and $PM_{2.5}$ emissions.
- An air quality analysis showing that proposed emissions will not significantly cause or contribute to a violation of any NAAQS or PSD increment.
- An additional impacts analysis that assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Mamou Compressor Station

PSD review also considers the potential impacts on Class I areas located within 300 kilometers of a proposed major source or major modification. The closest Class I area to the Mamou Compressor Station is the Breton National Wildlife Refuge, located approximately 450 kilometers from the SPLNG Terminal. Therefore, an analysis of Class I area impacts is not necessary.

Table 9.2-11 summarizes the potential emissions from the Mamou Compressor Station, along with the applicable PSD thresholds. The Mamou Compressor Station's potential GHG emissions exceed 250 tpy on a mass basis and 100,000 tpy on a CO_2e basis, and the CO emissions exceed 250 tpy. Therefore, the Mamou Compressor Station is a PSD major source for CO and GHGs. Note that the Mamou Compressor Station has no Pb emissions.

TABLE 9.2-11
Mamou Compressor Station Potential Emissions and PSD and Title V Thresholds

Source	Potential Emissions (tpy)									
	NO_x	CO	VOC[1,2]	PM_{10}	$PM_{2.5}$	SO_2	Total HAPS	Single HAP	GHG as CO_2e	GHG Mass Basis
Total Facility Emissions	170.5	251.9	17.69	35.10	35.10	22.9	6.95	5.24	199,984	197,000
PSD Major Source Threshold	250	250	250	250	250	250	NA	NA	100,000	250
PSD SER Threshold	40	100	40	15	10[3]	40	NA	NA	75,000	NA
Title V Major Source Threshold	100	100	100	100	100	100	25	10	100,000	100

1. Volatile organic compounds
2. Includes fugitive emissions from tanks, valves, pumps, flanges, etc. Fugitive emissions are not counted for PSD applicability because compressor stations are not one of 28 named source categories, but are counted for Title V applicability. Also includes MSS and Louisiana GCXVII activities.
3. Also, 40 tpy SO_2, or 40 tpy NO_x (unless demonstrated not to be a $PM_{2.5}$ precursor)

The PSD air permit application submitted to the LDEQ will include:

- The control technology analysis to show that the Mamou Compressor Station will employ BACT for NO_x, CO, PM_{10}, $PM_{2.5}$, and GHG emissions.
- Air Quality Analysis showing that proposed emissions will not cause or contribute to a violation of any NAAQS or PSD increment.
- Additional impacts analysis that assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

PSD review also considers the potential impacts on Class I areas located within 300 kilometers of a proposed major source or major modification. The closest Class I area to the Mamou Compressor Station is the Breton National Wildlife Refuge, located approximately 340 kilometers from the proposed Mamou Compressor Station site. Therefore an analysis of Class I area impacts is not necessary.

9.2.3.2 Nonattainment New Source Review

Since the Project is not located in a nonattainment area for any regulated pollutants, NNSR does not apply.

9.2.3.3 Title V Operating Permit

Title V requires that a major stationary source of air emissions apply for an operating permit within one year of its initial operation. The USEPA has delegated the authority to issue the Title V permits to the

LDEQ in accordance with LAC 33.III.507. A Title V permit is required if a source has potential or actual emissions equal to or exceeding 100 tpy for any criteria pollutant, 10 tpy for a single hazardous air pollutant ("HAP"), or 25 tpy for total HAPs. Additionally, stationary sources that have potential or actual GHG emissions equal to or greater than 100,000 tpy CO_2e will be subject to Title V permitting.

SPLNG Terminal

Table 9.2-10 summarizes the potential emissions from the existing SPLNG Terminal, potential emissions resulting from proposed operating modifications at the existing SPLNG Terminal, and SPLNG Terminal Trains 5 and 6, along with the applicable Title V thresholds. The SPLNG Terminal is a Title V major source. The PSD permit application will serve as the permit application to modify the current Title V Operating permit**.**

Mamou Compressor Station

Table 9.2-11 summarizes the potential emissions from the Mamou Compressor Station, along with the applicable Title V thresholds, and shows that a Title V operating permit will be required. The Mamou Compressor Station will be a Title V major source. The PSD permit application will serve as the permit application to obtain the initial Title V Operating permit**.**

9.2.3.4 New Source Performance Standards

SPLNG Terminal

The following NSPS requirements have been identified as potentially applicable to the specified sources at the SPLNG Terminal:

40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

Subpart Kb lists applies to storage vessels with a capacity greater than or equal to 75 cubic meters ("m^3") that is used to store VOCs. Construction of SPLNG Terminal Trains 5 and 6 will not involve any additional storage vessels with a capacity greater than 75 m^3. Therefore, Subpart Kb does not apply.

40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

Subpart GG applies to all stationary gas turbines with a heat input at peak load equal or greater than 10.7 gigajoules per hour ("GJ/hr") (10 MMBtu/hr) which commence construction, modification, or reconstruction after October 3, 1997. Therefore, Subpart GG could potentially be applicable. However, 40 CFR §60.4305(b) states that stationary gas turbines regulated under Subpart KKKK are exempt from the requirements of Subpart GG. The combustion turbines associated with SPLNG Terminal Trains 5 and 6 are subject to Subpart KKKK (discussed below) and are therefore exempt from regulation under Subpart GG.

40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII applies to owners and operators of certain stationary compression ignition ("CI") internal combustion engines ("ICE"). The SPLNG Terminal Trains 5 and 6 will include two standby generator diesel engines. The standby generator diesel engines will be subject to Subpart IIII and must meet the applicable emission standards in effect for the model year and type of engine installed. Sabine Pass will comply with the emission and monitoring limitations of Subpart IIII by installing manufacturer-certified engines and maintaining those engines according to the manufacturer's specifications. Additionally, Subpart IIII limits operation of emergency stationary ICE for the purpose of maintenance checks and readiness testing to 100 hours per year unless operation beyond 100 hours per year is required by other federal, state, or local standards.

40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

Subpart KKKK applies to owners and operators of stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ/hr (10 MMBtu/hr) per hour which commence construction, modification, or reconstruction after February 18, 2005. The 12 refrigeration compressor combustion turbines and the two natural gas-fired generator combustion turbines associated with SPLNG Terminal Trains 5 and 6 will be subject to the regulations of Subpart KKKK. Subpart KKKK regulates emissions of NO_x and SO_2.

A new combustion turbine with heat input at peak load greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr must satisfy a NO_x emission rate limit of 25 parts per million by volume corrected to 15% oxygen at dry conditions (ppmvd @ 15% O_2). Based on the size of the combustion turbines, NO_x emissions must be maintained at less than or equal to 25 ppmvd @ 15% O_2. Compliance with the NO_x emission rate will be demonstrated by a continuous monitoring system.

Additionally, Subpart KKKK requires that the combustion turbines not burn any fuel which contains total potential sulfur emissions of greater than 0.060 pound per million British thermal units ("lb/MMBtu") of SO_2. The combustion turbines will only combust pipeline quality natural gas which meets the requirements of Subpart KKKK.

Mamou Compressor Station

40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels for Which construction, Reconstruction, or Modification Commenced after July 23, 1984

Subpart Kb applies to storage vessels with a capacity greater than or equal to 75 m^3 used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. The condensate tank is exempt from this subpart because the storage capacity is only 15.9 m^3.

40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

Subpart GG applies to stationary gas turbines with a heat input at peak load equal or greater than 10.7 GJ/hr (10 MMBtu/hr) which commences construction, modification, or reconstruction after October 3, 1997. Stationary gas turbines regulated under 40 CFR 60 Subpart KKKK are exempt from the requirements of Subpart GG. The Mamou Compressor Station's combustion turbines are subject to Subpart KKKK (discussed below) and are therefore exempt from regulation under Subpart GG.

<u>40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition ("SI") Internal Combustion Engines ("ICE")</u>
Subpart JJJJ applies to owners and operators of certain SI ICE. The Mamou Compressor Station will include two standby natural gas-fueled SI ICE generators. The standby natural gas-fueled SI ICE generators will be subject to Subpart JJJJ and must meet the applicable emission standards for the model year and type of engine installed. Sabine Pass must also comply with the monitoring requirements of 40 CFR 60.4237 and compliance requirements of 40 CFR 60.4243(d). Sabine Pass will comply with emission ring limitations of Subpart JJJJ by installing manufacturer-certified engines and maintaining those engines according to the manufacturer's specifications. Additionally, Subpart JJJJ limits operation of emergency stationary SI ICE for the purpose of maintenance checks and readiness testing to 100 hours per year unless operation beyond 100 hours per year is required by other federal, state, or local standards.

<u>40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines</u>
Subpart KKKK applies to owners and operators of stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ/hr which commenced construction, modification, or reconstruction after February 18, 2005. A new combustion turbine with heat input at peak load greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr must satisfy a NO_x emission rate limit of 25 ppmvd @ 15% O_2. The Mamou Compressor Station's combustion turbines will meet this limit.

Subpart KKKK requires that the combustion turbines burn fuel which contains total potential sulfur emissions less than or equal to 0.060 lb of SO_2 per MMBtu of heat input. The Mamou Compressor Station's combustion turbines will only combust pipeline quality natural gas which meets this limit.

9.2.3.5 National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants ("NESHAP") are set by the USEPA and contained in 40 CFR Parts 61 and 63. NESHAP establish technology-based Maximum Achievable Control Technology ("MACT") emissions standards for specified source categories. Sources with potential emissions equal to or greater than 10 tpy of any single HAP or 25 tpy total HAPs are major HAP sources. Sources with potential emissions less than the major source thresholds are area sources of HAPs. NESHAP requirements are incorporated by reference in LAC 33:III.5116 and 33:III.5122.

<u>SPLNG Terminal</u>

The SPLNG Terminal is a major source of HAPs. Four NESHAPs are potentially applicable to the SPLNG Terminal.

<u>40 CFR 63 Subpart Y - National Emission Standards for Marine Tank Vessel Loading Operations</u>
Subpart Y applies to marine vessel loading operations at facilities that are major sources of HAPs. This regulation is potentially applicable to the SPLNG Terminal. However, this subpart does not apply to

emissions resulting from marine tank vessel loading operations of commodities with vapor pressures less than 10.3 kilopascals (1.5 pounds per square inch absolute ("psia")) at standard conditions (40 CFR §63.560(d)(1)), therefore, Subpart Y does not apply to SPLNG Terminal Trains 5 and 6.

40 CFR 63 Subpart EEEE – National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

Subpart EEEE applies to organic liquids distribution facilities that are major sources of HAPs. This subpart is applicable to the existing condensate liquid storage tanks, truck loading operations, pipelines and components that are in service of the condensate liquid. SPLNG Terminal complies with the emission limits, operating limits and work practice standards of the subpart for the liquid storage tanks and truck loading operations.

40 CFR 63 Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart YYYY applies to owners and operators of certain stationary combustion turbines located at a major source of HAP emissions. The SPLNG Terminal is a major source of HAPs. However, 40 CFR 63.6095(d) stays the standards for new or reconstructed stationary lean premix gas-fired combustion turbines (such as the SPLNG Terminal LM 2500 turbines) and diffusion flame gas-fired stationary combustion. Sabine Pass will comply with the initial notification requirements, but need not comply with any other requirement of Subpart YYYY until USEPA takes final action to require compliance and publishes a document in the Federal Register.

40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines ("RICE")

Subpart ZZZZ applies to RICE located at major and area sources of HAP. The two standby generator diesel engines would potentially be subject to this Subpart. However, these engines qualify as new stationary RICE with a rating of more than 500 hp subject to 40 CFR 60 Subpart IIII. Per 40 CFR 63.6590(c)(7), since these engines will be subject to the requirements of 40 CFR 60 Subpart IIII, they are not subject to any additional standards under 40 CFR 63 Subpart ZZZZ.

Mamou Compressor Station

The Mamou Compressor Station is an area source of HAPs. NESHAP requirements are incorporated by reference in LAC 33:III.5116 and 33:III.5122. Three NESHAPs are potentially applicable to the Mamou Compressor Station.

40 CFR 63 Subpart HHH, NESHAP from Natural Gas Transmission and Storage Facilities

Subpart HHH applies to owners and operators of natural gas transmission facilities that are a major source of HAPs. The Mamou compressor station will not be a major source of HAP emissions. Therefore, none of the requirements of Subpart HHH apply to the Mamou Compressor Station.

<u>40 CFR 63 Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines</u>
Subpart YYYY applies to owners and operators of certain stationary combustion turbines located at major sources of HAP emissions. The Mamou Compressor Station will not be a major source of HAPs, and not subject to this subpart.

<u>40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</u>
Subpart ZZZZ applies to RICE located at major and area sources of HAP. The two standby generator engines would potentially be subject to this Subpart, however, these engines qualify as new stationary RICE with a rating of more than 500 hp subject to 40 CFR 60 Subpart JJJJ. Per 40 CFR 63.6590(c)(7), since these engines will be subject to the requirements of 40 CFR 60 Subpart JJJJ, the proposed engines are not subject to any additional standards under 40 CFR 63 Subpart ZZZZ.

9.2.3.6 Greenhouse Gas Reporting

Federal GHG reporting requirements are codified at 40 CFR Part 98. Subpart W of 40 CFR Part 98 requires petroleum and natural gas facilities with annual GHG emissions equal to or greater than 25,000 metric tons of CO_2e to report GHG from various processes within the facility. Sabine Pass will report the SPLNG Terminal’s and the Mamou Compressor Station’s GHG emissions as required.

9.2.3.7 Chemical Accident Prevention Provisions

40 CFR Part 68 is a federal regulation designed to prevent the accidental release of hazardous substances and minimize the impacts if releases occur. The regulation contains a list of substances and threshold quantities. If a facility stores, handles, or processes a listed substance in an amount equal to or greater than its threshold quantity, the facility must prepare and submit a risk management plan (“RMP”). If a facility does not have a listed substance onsite, or the quantity of a listed substance is below the applicability threshold, the facility is not required to prepare an RMP. However, it must still comply with requirements of the general duty clause if it has any regulated substance or other extremely hazardous substance onsite. The general duty clause is as follows:

> “The owners and operators of stationary sources producing, processing, handling and storing such substances have a general duty … to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.”

Regulations for the Louisiana RMP program are codified in LAC 33:III.5901.

<u>SPLNG Terminal</u>

Methane, ethylene, and propane will be stored or handled in quantities greater than the applicability threshold. These constituents are used as refrigerants in the process for liquefying the natural gas. The SPLNG Terminal and its use of these refrigerants are regulated under 49 CFR Part 193, 33 CFR Part 127 and National Fire Protection Association ("NFPA") 59A. These regulations effectively duplicate the requirements in 40 CFR Part 68, including hazard analysis, equipment spacing, siting requirements, training, spill and leak control, and implementation of emergency response plans. No other regulated substances would be handled or stored in quantities greater than the applicability threshold.

A liquefied natural gas pipeline facility (i.e., a gas pipeline facility used for transporting or storing LNG, or for LNG conversion, in interstate or foreign commerce) is not required to have a risk management plan if it is regulated by the U.S. Department of Transportation ("USDOT") or an equivalent state natural gas program certified by USDOT in accordance with Title 49 of the United States Code ("49 U.S.C.") Section 60105 or is subject to 49 CFR Part 193.

The Sabine Pass LNG Terminal is regulated under 49 CFR Part 193, and is not required to have a RMP under 40 CFR Part 98. It will meet the general duty provision of 40 CFR Part 98 by complying with USDOT regulations under 49 CFR Part 193, 33 CFR Part 127, and NFPA 59A.

<u>CCTPL Pipeline Expansion</u>

With the exception of natural gas constituents, no regulated substance would be handled or stored in quantities greater than the applicable threshold quantity. Furthermore, a natural gas pipeline is not required to have an RMP if it is regulated by the USDOT or an equivalent state natural gas program certified by USDOT in accordance with 49 U.S.C. Section 60105. The CCTPL pipeline expansion is regulated by the USDOT Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Consequently, an RMP is not required. CCTPL will comply with the general duty clause as it pertains to the CCTPL pipeline expansion.

<u>Mamou Compressor Station</u>

With the exception of natural gas constituents, no regulated substance would be handled or stored in quantities greater than the applicable threshold quantity. A gas pipeline facility (including a pipeline, right-of-way, facility, building, or equipment used in transporting gas or treating gas during its transportation) is not required to have an RMP if it is regulated by the USDOT or an equivalent state natural gas program certified by USDOT in accordance with 49 U.S.C. Section 60105. The Mamou Compressor Station is regulated by the USDOT PHMSA. Consequently, an RMP is not required. CCTPL will comply with the general duty clause as it pertains to the Mamou Compressor Station.

9.2.3.8 General Conformity

Section 176(c) of the CAA prohibits federal agencies from taking actions in nonattainment or maintenance areas which do not conform to the State Implementation Plan ("SIP") for the attainment and maintenance of the NAAQS. The purposes of conformity are to (1) ensure federal activities do not interfere with the budgets in the SIPs, (2) ensure actions do not cause or contribute to new violations, and (3) ensure attainment and maintenance of the NAAQS. General Conformity applies only in areas that are designated as NAAQS nonattainment areas or maintenance areas. A conformity review is required only for those pollutants designated as nonattainment or maintenance pollutants. General conformity analysis must consider both direct and indirect emissions. Direct emissions are those that occur as a direct result of the action, and occur at the same time and place as the action. Indirect emissions are those that occur at a later time or distance from the place where the action takes place, but may be reasonably anticipated as a consequence of the proposed action.

Some emissions are excluded from conformity determination, such as those already subject to federal nonattainment new source review, those covered by Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") or compliance with other environmental laws, actions not reasonable foreseeable, and those for which the Agency has no continuing program responsibility.

SPLNG Terminal

SPLNG Terminal Trains 5 and 6 will be located in Cameron Parish, which is an attainment area or the equivalent for all criteria pollutants. Barges transporting construction materials and equipment to the site may emit NO_x and VOC as they travel through the Houston-Galveston-Brazoria or Beaumont-Port Arthur, ozone nonattainment areas. However, these emission will be less than the *de minimis* rates specified in 40 CFR 89.153(b)(1). Consequently, General Conformity does not apply to construction of SPLNG Terminal Trains 5 and 6.

CCTPL Pipeline Expansion

The CCTPL pipeline expansion will be located in Allen, Beauregard, Calcasieu, Cameron, and Evangeline Parishes. With the exception of Beauregard Parish, which is a maintenance area for the 1-hour NAAQS for the purposes of 40 CFR 51 Subpart X (Provisions for Implementation of 8-hour Ozone NAAQS), all of these Parishes are maintenance areas or the equivalent for all criteria pollutants. The NO_x and VOC emission that occur in Beauregard Parish due to the CCTPL pipeline expansion are well below the *de minimis* rate of 100 tpy specified in 40 CFR 89.153(b)(2). Consequently, General Conformity does not apply to construction of the CCTPL pipeline expansion.

Mamou Compressor Station

The Mamou Compressor Station will be located in Evangeline Parish, which is an attainment area or the equivalent for all criteria pollutants. Consequently, General Conformity does not apply to construction of the Mamou Compressor Station.

9.2.3.9 Louisiana Air Quality Regulations

SPLNG Terminal

LAC 33:III Chapter 9 - General Regulations

This section contains general requirements applicable to SPLNG Terminal. Sabine Pass will submit an air emissions inventory as required by LAC 33:III.919. Unauthorized discharges will be reported in accordance with LAC 33:III.927 and LAC 33:I Chapter 39.

LAC 33:III Chapter 11 - Control of Air Pollution from Smoke

Chapter 11 establishes opacity limits for combustion units and prohibits open burning and the impairment of visibility on public roads (LAC 33:III.1103). Sabine Pass will comply with the provisions for impairment of visibility on public roads. However, per LAC 33:III.1107, combustion units that combust only natural gas are not subject to the opacity standards of LAC:III.1101. With the exception of two diesel-fueled emergency generators, all combustion sources at SPLNG Terminal Trains 5 and 6 will combust natural gas only and are therefore not subject to the opacity standard. The emergency generators will operate infrequently, and will not emit smoke which passes onto or across a public road and creates or intensifies a traffic hazard by impairment of visibility.

LAC 33:III Chapter 13 - Emission Standards for Particulate Matter

Chapter 13 applies to any operation, process, or activity from which PM is emitted, and requires that all reasonable precautions be taken to minimize PM emissions from fugitive sources. Additionally, fuel burning equipment is limited to 0.6 lb/MMBtu of PM emissions. Sabine Pass will comply with these requirements.

LAC 33:III Chapter 15 - Emission Standards for Sulfur Dioxide

Chapter 15 pertains to new or existing sulfuric acid production plants, new or existing sulfur recovery plants, and all other single point sources that emit or have the potential SO_2 emission equal to or greater than 5 tpy. SPLNG does not operate a sulfur recovery plant and all other single point sources are less than 5 tpy each. Therefore, SPLNG is not subject to Chapter 15.

LAC 33:III.2103 - Storage of Volatile Organic Compounds

The existing condensate tanks are exempt from the requirements of this section because it has a storage capacity less than 420,000 gallons and stores only condensate (LAC 33:III.2103.G.1).

LAC 33:III.2104 - Crude Oil and Condensate

The SPLNG Terminal is exempt from the requirements of this section because it is a natural gas transmission facility and its potential flash gas emissions are less than 100 tpy.

LAC 33:III.2107 - Volatile Organic Compounds - Loading

The SPLNG Terminal is exempt from the requirements of this section because loading operations will involve condensate only. (LAC 33:III.2107.F).

LAC 33:III.2111 - Pumps and Compressors

This section requires that pumps and compressors handling VOCs with a true vapor pressure greater than 1.5 psia at handling conditions to be equipped with mechanical seals or other equivalent equipment approved by the administrative authority. Sabine Pass will comply with this regulation as it applies to pumps and compressors at the SPLNG Terminal.

LAC 33:III.2113 - Housekeeping

Best practices housekeeping and maintenance procedures will be followed to minimize the quantity of organic compound emissions.

LAC 33:III Chapter 29 - Odor Regulations

Sabine Pass will operate the SPLNG Terminal such that off-site odors do not cause a nuisance.

LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant ("TAP") Emission Control Program

This Chapter 51 applies to major sources of TAPs. The condensate tanks and truck loading operations are subject to 40 CFR 63 Subpart EEEE (see Section 9.2.3.5). Per LAC 33:III.5101.D, this chapter does not apply to the condensate tanks and truck loading operations as they are subject to a MACT standard. The other components and emissions at the SPLNG Terminal are subject to the chapter. SPLNG Terminal will comply with the required emission and operation limits, and will submit the required reports.

CCTPL Pipeline Expansion

LAC 33:III Chapter 9 - General Regulations

This section contains general requirements applicable to the CCTPL pipeline expansion. Unauthorized discharges will be reported in accordance with LAC 33:III.927 and LAC 33:I Chapter 39.

LAC 33:III.2113 - Housekeeping

Best practices housekeeping and maintenance procedures will be followed to minimize the quantity of organic compound emissions.

LAC 33:III.2121 - Fugitive Emission Control

The Mamou Compressor Station is not one of the affected industries listed in LAC 33:III.2121.A. Therefore, this regulation does not apply.

LAC 33:III Chapter 29 - Odor Regulations

Sabine Pass will operate the Mamou Compressor Station such that off-site odors do not cause a nuisance.

Mamou Compressor Station

LAC 33:III Chapter 9 - General Regulations

This section contains general requirements applicable to the Mamou Compressor Station. CCTPL will submit an air emissions inventory as required by LAC 33:III.919. Unauthorized discharges will be reported in accordance with LAC 33:III.927 and LAC 33:I Chapter 39.

LAC 33:III Chapter 11 - Control of Air Pollution from Smoke

Chapter 11 establishes opacity limits for combustion units and prohibits open burning and the impairment of visibility on public roads (LAC 33:III.1103). CCTPL will comply with the provisions for impairment of visibility on public roads. However, per LAC 33:III.1107, combustion units that combust only natural gas are not subject to the opacity standards of LAC:III.1101. All combustion sources at the Mamou Compressor Station will combust natural gas only and are therefore not subject to the opacity standard.

LAC 33:III Chapter 13 - Emission Standards for Particulate Matter

Chapter 13 applies to any operation, process, or activity from which PM is emitted, and requires that all reasonable precautions be taken to minimize PM emissions from fugitive sources. Additionally, fuel burning equipment is limited to 0.6 lb/MMBtu of PM emissions. CCTPL will comply with these requirements.

LAC 33:III Chapter 15 - Emission Standards for Sulfur Dioxide

Chapter 15 pertains to new or existing sulfuric acid production plants, new or existing sulfur recovery plants, and all other single point sources that emit or have the potential SO_2 emission equal to or greater than 5 tpy. With the exception of Turbine D, the potential SO_2 emissions of all the Mamou Compressor Station's sources are less than 5 tpy each. Turbine D is required to meet an SO_2 emissions limitation of 2,000 ppm, or any applicable NESHAP or NSPS that is more stringent. Various methods are listed to demonstrate compliance. Turbine D will satisfy the more stringent SO_2 emission limitation of 40 CFR 60 Subpart KKKK (discussed in Section 9.2.2.4).

LAC 33:III.2103 - Storage of Volatile Organic Compounds

The Mamou Compressor Station's condensate tank is exempt from the requirements of this section because it has a storage capacity less than 420,000 gallons and stores only condensate (LAC 33:III.2103.G.1).

LAC 33:III.2104 - Crude Oil and Condensate

The Mamou Compressor Station is exempt from the requirements of this section because it is a natural gas transmission facility and its potential flash gas emissions are less than 100 tpy.

LAC 33:III.2107 - Volatile Organic Compounds - Loading

The Mamou Compressor Station is exempt from the requirements of this section because its loading operations will involve condensate only. (LAC 33:III.2107.F)

LAC 33:III.2111 - Pumps and Compressors

This section requires that pumps and compressors handling VOCs with a true vapor pressure greater than 1.5 psia at handling conditions to be equipped with mechanical seals or other equivalent equipment approved by the administrative authority. CCTPL will comply with this regulation as it applies to pumps and compressors at the Mamou Compressor Station.

LAC 33:III.2113 - Housekeeping
Best practices housekeeping and maintenance procedures will be followed to minimize the quantity of organic compound emissions.

LAC 33:III.2121 - Fugitive Emission Control
The Mamou Compressor Station is not one of the affected industries listed in LAC 33:III.2121.A. Therefore, this regulation does not apply.

LAC 33:III Chapter 29 - Odor Regulations
CCTPL will operate the Mamou Compressor Station such that off-site odors do not cause a nuisance.

LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program
Chapter 51 does not apply to the Mamou Compressor Station because it is not a major source of TAP emissions.

9.2.4 Air Quality Impacts

9.2.4.1 Construction

Air quality impacts associated with construction of the Project will include engine emissions from construction equipment, engine emissions from workers commuting to the construction site, engine emissions from vehicles delivering and removing materials, and fugitive dust generated by construction activities or resulting from wind erosion of disturbed areas. In addition, emissions will result from open burning in certain upland forest areas during construction of the CCTPL pipeline expansion. Detailed emission calculations are provided in Appendix 9A.

Emission estimates for construction equipment engines are based on the equipment that is expected to be used (number, type, capacity, and level of activity).

Emission factors in grams per horsepower hour ("g/hp-hr") for NO_x, CO, PM, SO_2, VOC[1], and CO_2 for nonroad equipment engines were obtained using the most recent version of the USEPA's NONROAD model (NONROAD2008a). NONROAD was run to obtain annual average emission factors for 2015 through 2019. Emission factors in grams per gallon of fuel for CH_4 and N_2O were obtained from the "2013 Climate Registry Default Emission Factors", and apportioned based on CO_2 emissions.

Emissions factors in grams per vehicle mile traveled ("g/VMT") for on-road vehicles were obtained from the USEPA Mobile Vehicle Emissions Simulator ("MOVES") version MOVES2010b. Emission factors were obtained for NO_x, CO, PM_{10}, $PM_{2.5}$[2], SO_2, VOC, and CO_2, and CO_2e for road types in Louisiana for 2015 through 2019.

[1] NONROAD does not provide emissions factors for VOC. The emission factor for total hydrocarbons is used as a conservative estimate of VOC.
[2] $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Fugitive dust emissions were estimated using the methodology described in Section 3.4 of the Western Regional Air Partnership ("WRAP") Fugitive Dust Handbook[3]. Use of this methodology is conservative, as the climates typical of many Western states are more arid than in the Project area.

SPLNG Terminal

Table 9.2-12 summarizes the construction emissions for Trains 5 and 6. Emissions from construction are not expected to cause, or significantly contribute, to a violation of any applicable ambient air quality standard. The emissions will be limited to the immediate vicinity of the SPLNG Terminal area and will be short-term.

TABLE 9.2-12
SPLNG Terminal Trains 5 and 6 Estimated Construction Emissions (tons)

Source	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e
2015										
Non-Road Engines	18.82	42.69	0.10	4.06	2.84	2.84	10,955	0.64	0.28	11,159
On-Road Vehicle Engines	3.62	1.87	0.01	0.20	0.06	0.06	802	----	----	803
Barge Tugs	8.24	43.04	4.35	0.90	1.02	1.02	2,308	0.07	0.30	2,335
Fugitive Dust	----	----	----	----	104.21	10.42	----	----	----	----
2015 Total	30.68	87.60	4.46	5.16	108.13	14.34	14,065	0.71	0.58	14,297
2016										
Non-Road Engines	163.12	67.58	0.18	9.69	4.86	4.86	15,709	0.93	0.40	16,005
On-Road Vehicle Engines	13.63	7.02	0.04	0.74	0.24	0.23	3,278	----	----	3,282
Barge Tugs	19.25	100.50	10.15	2.11	2.38	2.38	5,389	0.16	0.70	5,452
Fugitive Dust	----	----	----	----	104.21	10.42	----	----	----	----
2016 Total	196.00	175.10	10.37	12.54	111.69	17.89	24,376	1.08	1.10	24,739
2017										
Non-Road Engines	301.59	93.84	0.20	14.88	6.71	6.71	20,289	1.18	0.52	20,666
On-Road Vehicle Engines	14.02	8.65	0.04	0.84	0.31	0.30	3,949	----	----	3,954
Barge Tugs	0.50	2.63	0.27	0.06	0.06	0.06	142	0.004	0.02	143
Fugitive Dust	----	----	----	----	104.21	10.42	----	----	----	----
2017 Total	316.11	105.12	0.51	15.77	111.30	17.50	24,379	1.19	0.53	24,763
2018										
Non-Road Engines	296.15	84.23	0.16	14.29	6.29	6.29	19,677	1.13	0.50	20,038
On-Road Vehicle Engines	21.32	7.18	0.05	0.92	0.23	0.22	4,320	----	----	4,326
Barge Tugs	----	----	----	----	----	----	----	----	----	----
Fugitive Dust	----	----	----	----	104.21	10.42	----	----	----	----
2018 Total	317.47	91.40	0.21	15.22	110.73	16.93	23,997	1.13	0.50	24,364

[3] WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1.

TABLE 9.2-12 SPLNG Terminal Trains 5 and 6 Estimated Construction Emissions (tons)										
Source	**CO**	**NO_x**	**SO_2**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
2019										
Non-Road Engines	75.16	18.97	0.03	3.56	1.48	1.48	5,327	0.30	0.13	5,423
On-Road Vehicle Engines	11.83	2.14	0.03	0.39	0.05	0.05	1,884	----	----	1,887
Barge Tugs	----	----	----	----	----	----	----	----	----	----
Fugitive Dust	----	----	----	----	104.21	10.42	----	----	----	----
2019 Total	86.99	21.12	0.06	3.95	105.74	11.95	7,210	0.30	0.13	7,310

Although most of the emissions summarized in Table 9.2-12 occur in attainment areas, a small fraction of these result from tugs pushing barges which transport construction materials and equipment through the Houston-Galveston-Brazoria or Beaumont-Port Arthur ozone nonattainment areas. Table 9.2-13 summarizes the emissions by attainment and non-attainment areas. As can be seen, the emissions of ozone precursors (NO_x and VOC) in nonattainment areas are much less than the *de minimis* thresholds for general conformity listed in 40 CFR 93.153(b).

TABLE 9.2-13 Criteria Pollutant and Greenhouse Gas Emissions (tons) from Material and Equipment Delivery Barges							
Year	**NO_x**	**VOC**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**CO_2e**
Houston-Galveston-Brazoria 1-Hour Ozone Severe-17 and 8-Hour Ozone Severe-15 Nonattainment [1]							
2015	0.04	0.23	0.02	0.005	0.005	0.005	12
2016	0.22	1.13	0.11	0.024	0.027	0.027	61
2017	0.22	1.13	0.11	0.024	0.027	0.027	61
2018	----	----	----	----	----	----	----
2019	----	----	----	----	----	----	----
Beaumont-Port Arthur 1-Hour Ozone Serious Nonattainment Nonattainment[2]							
2015	0.02	0.13	0.013	0.003	0.003	0.003	7
2016	0.12	0.63	0.063	0.013	0.015	0.015	33
2017	0.12	0.63	0.063	0.013	0.015	0.015	33
2018	----	----	----	----	----	----	----
2019	----	----	----	----	----	----	----
Louisiana Unclassifiable or Attainment Areas[3]							
2015	8.18	42.69	4.31	0.90	1.01	1.01	2,289
2016	18.91	98.74	9.98	2.07	2.34	2.34	5,295
2017	0.17	0.87	0.09	0.02	0.02	0.02	47
2018	----	----	----	----	----	----	----
2019	----	----	----	----	----	----	----

TABLE 9.2-13
Criteria Pollutant and Greenhouse Gas Emissions (tons) from Material and Equipment Delivery Barges

Year	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2e
Totals all Gulf Ports							
2015	8.24	43.04	4.35	0.90	1.02	1.02	2,308
2016	19.25	100.50	10.15	2.11	2.38	2.38	5,389
2017	0.50	2.63	0.27	0.06	0.06	0.06	142
2018	----	----	----	----	----	----	----
2019	----	----	----	----	----	----	----

1 Includes barges originating at the Port of Houston.
2 Includes all barges for some duration, depending on originating port.
3 Includes barges from Louisiana ports (Port of Westlake/Lake Charles and Port of New Orleans).

CCTPL Pipeline Expansion

Table 9.2-14 summarizes the construction emissions. Emissions from construction are not expected to cause, or significantly contribute, to a violation of any applicable ambient air quality standard. The emissions will be limited to the immediate vicinity of the CCTPL Pipeline Expansion area and will be short-term.

TABLE 9.2-14
CCTPL Pipeline Expansion Estimated Construction Emissions (tons)

Source	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e
2015										
Non-Road Engines	4.64	10.43	0.01	1.06	0.79	0.79	3,965	0.10	0.23	4,001
On-Road Vehicle Engines	2.78	2.33	0.01	0.30	0.10	0.10	811	----	----	812
Fugitive Dust	----	----	----	----	61.87	7.12	----	----	----	----
Open Burning	71.06	2.02	----	12.20	8.67	8.67	1,603	0.09	0.02	1,611
2015 Total	78.48	14.78	0.02	13.56	71.43	16.68	6,379	0.19	0.25	6,425
2016										
Non-Road Engines	13.50	32.24	0.04	3.34	2.24	2.24	11,163	0.28	0.63	11,265
On-Road Vehicle Engines	15.11	9.57	0.04	1.39	0.41	0.40	3,868	----	----	3,874
Fugitive Dust	----	----	----	----	185.60	21.36	----	----	----	----
Open Burning	213.19	6.05	----	36.59	26.01	26.01	4,809	0.27	0.06	4,833
2016 Total	241.80	47.85	0.08	41.31	214.26	50.00	19,840	0.56	0.69	19,972

Mamou Compressor Station

Table 9.2-15 summarizes the construction emissions. Emissions from construction are not expected to cause, or significantly contribute, to a violation of any applicable ambient air quality standard. The emissions will be limited to the immediate vicinity of the Mamou Compressor Station area and will be short-term.

TABLE 9.2-15 Mamou Compressor Station Estimated Construction Emissions (tons)										
Source	**CO**	**NO_x**	**SO_2**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
2015										
Non-Road Engines	0.95	2.16	<0.01	0.19	0.16	0.16	438	0.01	0.02	442
On-Road Vehicle Engines	0.60	0.52	<0.01	0.05	0.02	0.02	189	----	----	190
Fugitive Dust	----	----	----	----	4.40	0.44	----	----	----	----
2015 Total	1.55	2.69	<0.01	0.24	4.58	0.62	627	0.01	0.02	632
2016										
Non-Road Engines	9.90	3.57	0.01	0.51	0.20	0.20	775	0.02	0.04	782
On-Road Vehicle Engines	0.56	0.46	<0.01	0.04	0.02	0.02	188	----	----	188
Fugitive Dust	----	----	----	----	6.30	0.73	----	----	----	----
2016 Total	10.46	4.03	0.01	0.56	6.52	0.94	964	0.02	0.04	971

Air Impacts Mitigation Measures

The construction equipment will be operated on an as-needed basis, primarily during daylight hours. Reasonable measures will be taken to limit emissions of fugitive dust. Sabine Pass will maintain all construction equipment in accordance with manufacturers' recommendations and minimize engine idling time. CCTPL will employ proven construction practices, such as water sprays, to control fugitive dust emissions during construction. Additionally, all areas disturbed by construction will be stabilized in accordance with the Federal Energy Regulatory Commission ("FERC or Commission") *Upland Erosion Control, Revegetation, and Maintenance Plan*, May 2013 ("Plan"). Due to these factors, the intermittent and short-term characteristic of the emissions, construction is not expected to cause, or significantly contribute, to a violation of any applicable ambient air quality standard or degradation of air quality.

9.2.4.2 Operations

SPLNG Terminal Trains 1 through 4 Emissions Estimates

Table 9.2-16 provides updated emission estimates for the flares. It also provides the estimated increase which result from increasing the compressor turbines emissions from 20 to 25 ppmvd @ 15% O_2. Detailed emission calculations are provided in Appendix 9B.

TABLE 9.2-16 SPLNG Terminal Trains 1-4 Increases in Potential to Emit (tpy)									
Emissions Unit	**NO_x**	**CO**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAP**	**Single HAP[1]**	**GHG as CO_2e**
Wet Gas Flare No. 1 Dry Gas Flare No. 1	32.00	274.36	47.42	<0.1	<0.1	0.35	0.54	0.35	69,817
Wet Gas Flare No. 2 Dry Gas Flare No. 2	32.00	274.36	47.42	<0.1	<0.1	0.35	0.54	0.35	69,817

TABLE 9.2-16 SPLNG Terminal Trains 1-4 Increases in Potential to Emit (tpy)									
Emissions Unit	**NO_x**	**CO**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAP**	**Single HAP[1]**	**GHG as CO_2e**
Compressor Turbines Nos. 1- 24 (20 – 25 ppm NO_x)	602.86	---	---	---	---	---	---	---	---
Total	**666.86**	**548.72**	**94.84**	**0.2**	**0.2**	**0.7**	**1.08**	**0.7**	**139,634**

SPLNG Terminal Trains 5 and 6 Emissions Estimates

Emissions will result from the operation of stationary equipment. There will be no additional LNG carrier calls associated with operation of SPLNG Terminal Trains 5 and 6, and hence no additional ship or tug emissions.

Detailed emission calculations are provided in Appendix 9B. Table 9.2-17 summarizes the potential annual air emissions of criteria pollutants, GHG, total HAP, and the single HAP with the highest potential to emit. Table 9.2-17 includes the equipment listed in Section 9.2.1, as well as fugitive emissions.

TABLE 9.2-17 SPLNG Terminal Trains 5 and 6 Potential to Emit (tpy)									
Emissions Unit or Type	**NO_x**	**CO**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAP**	**Single HAP[1]**	**GHG as CO_2e**
Thermal Oxidizer 5	9.38	37.4	0.56	0.76	0.76	2.95	0.20	0.18	197,823
Thermal Oxidizer 6	9.38	37.4	0.56	0.76	0.76	2.95	0.20	0.18	197,823
Wet Gas Flare No. 3 Dry Gas Flare No. 3	32.00	274.36	47.42	<0.1	<0.1	0.28	0.54	0.35	69,816
Compressor Turbine 25	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 26	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 27	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 28	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 29	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 30	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 31	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 32	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 33	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 34	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 35	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Compressor Turbine 36	125.6	191	2.63	8.28	8.28	---	1.30	0.89	146,744
Generator Turbine 7	125.6	76.5	2.63	8.28	8.28	---	1.30	0.89	146,744
Generator Turbine 8	125.6	76.5	2.63	8.28	8.28	---	1.30	0.89	146,744
Standby Generator 7	5.84	3.2	0.36	0.18	0.18	0.01	<0.01	<0.01	231

TABLE 9.2-17
SPLNG Terminal Trains 5 and 6 Potential to Emit (tpy)

Emissions Unit or Type	NO_x	CO	VOC	PM_{10}	$PM_{2.5}$	SO_2	Total HAP	Single HAP[1]	GHG as CO_2e
Standby Generator 8	5.84	3.2	0.36	0.18	0.18	0.01	<0.01	<0.01	231
Fugitive	----	----	4.33	----	---	----	---	----	22,575
Total	**1,820.8**	**2,800.6**	**90.4**	**117.8**	**117.8**	**6.2**	**19.1**	**13.2**	**2,542,915**

FERC staff requested that Sabine Pass conduct NAAQS modeling to include marine vessel emissions for activities within the US Coast Guard (USGC) security zone. The proposed modeling protocol to include emission from LNGCs and support vessels is included as Appendix 9C.

CCTPL Pipeline Expansion Emissions Estimates

Other than small quantities of fugitive VOC emissions from valve or fitting leaks, no air emissions will occur as a result of CCTPL Pipeline Expansion operation.

Mamou Compressor Station Emissions Estimates

Detailed emission calculations are provided in Appendix 9B. Table 9.2-18 summarizes the potential annual air emissions of criteria pollutants, GHG, total HAP, and the single HAP with the highest potential to emit. Table 9.2-18 includes the equipment listed in Section 9.2.1, fugitive emissions, MSS emissions, unit and station blow down ("BD") emissions, and truck loading emissions.

TABLE 9.2-18
Mamou Compressor Station Potential to Emit (tpy)

Emissions Unit or Type	NO_x	CO	VOC	PM_{10}	$PM_{2.5}$	SO_2	Total HAP	Single HAP[1]	GHG as CO_2e
Turbine A	34.82	42.90	2.40	7.24	7.24	4.72	1.22	1.05	40,352
Turbine B	34.82	42.90	2.40	7.24	7.24	4.72	1.22	1.05	40,352
Turbine C	34.82	42.90	2.40	7.24	7.24	4.72	1.22	1.05	40,352
Turbine D	64.30	78.24	4.43	13.37	13.37	8.71	2.19	1.99	74,494
Generator A[2]	0.60	0.39	0.11	<0.01	<0.01	0.01	0.05	0.05	109
Generator B[2]	0.60	0.39	0.11	<0.01	<0.01	0.01	0.05	0.05	109
Tank[3]	----	----	0.26	----	----	----	----	----	----
Fugitive[4]	----	----	0.25	----	----	----	0.06	----	----
MSS[5]	0.50	44.20	0.51	----	----	----	----	----	286
Unit BD[6]	----	----	2.21	----	----	----	0.44	----	1,838
Station BD[7]	----	----	2.52	----	----	----	0.50	----	2,092
Truck loading	----	----	0.09	----	----	----	----	----	----
Total	**170.5**	**251.9**	**17.7**	**35.1**	**35.1**	**22.9**	**6.95**	**5.24**	**199,984**

TABLE 9.2-18
Mamou Compressor Station Potential to Emit (tpy)

Emissions Unit or Type	NO_x	CO	VOC	PM_{10}	$PM_{2.5}$	SO_2	Total HAP	Single HAP[1]	GHG as CO_2e

1. Formaldehyde
2. Emergency generators
3. 100 barrel condensate tank
4. Fugitive emissions from valves, pumps, flanges, etc.
5. Maintenance, startup, and shutdown emissions
6. 12 BD events per compressor unit per year
7. 4 Station BD events (suction and discharge) per year
8. Condensate loading

Air Impacts Mitigation Measures

The Project will use new, state-of-the-art equipment to minimize emissions. SPLNG Terminal Trains 5 and 6 and the Mamou Compressor Station will employ BACT for NO_x, CO, PM_{10}, $PM_{2.5}$, and GHG emissions. In additions, SPLNG Terminal Trains 5 and 6 will employ BACT for VOC.

The two emergency diesel engines will fire only ultra-low sulfur diesel. The remaining combustion equipment will fire clean-burning natural gas. The reciprocating internal combustion engines and combustion turbines will utilize computer controls for air, fuel, and timing.

Anticipated Air Quality Impacts

As part of the air permitting process, air quality analyses will be performed to show that proposed emissions will not significantly cause or contribute to a violation of any NAAQS or PSD increment. Also as part of the air permitting process, analyses will be performed to assess the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

9.3 NOISE

Construction of the Project facilities will involve general construction equipment and noise will occur during the installation of the Project components. Operation of liquefaction Trains 5 and 6 at the SPLNG Terminal and the new Mamou Compressor Station may result in long-term increases in noise levels in the vicinity of each facility.

The unit of noise measurement is the decibel (“dB”), which measures the energy of the noise. Because the human ear is not uniformly sensitive to all noise frequencies, the "A" weighting frequency scale (“dBA”) was devised to correspond with the ear’s sensitivity. The L_{dn} is a 24-hour average equivalent sound level (“L_{eq}”) of the measured daytime (“L_d”) dB and measured nighttime (“L_n”) dB with 10 dB added to the sound levels occurring during the nighttime hours of 10 p.m. to 7 a.m. to compensate for enhanced receptor sensitivity during the nighttime. Rather than being a true measure of the sound level, the L_{dn} represents a skewed average that correlates generally with the results of studies relating environmental sound levels to physiological reaction and effects. For a source that operates at a continuous sound level over a 24-hour period, the L_{dn} is approximately 6.4 dBA above the measured L_{eq}. Consequently, an L_{dn} of 55 dBA corresponds to a steady state A-weighted L_{eq} ("L_{Aeq}") of 48.6 dBA.

FERC guidelines require that the sound attributable to a new aboveground facility (not the total sound level in the area) not exceed an L_{dn} of 55 dBA at any nearby NSA (e.g., residences, schools, hospitals, etc.) unless such NSAs are established after facility construction. No state or local noise regulations or ordinances were identified that are applicable to the SPLNG Terminal or Mamou Compressor Station.

The following sections summarize noise analyses conducted to date.

9.3.1 Construction Noise

Construction noise is highly variable, as the types of equipment in use at a construction site change with the construction phase and the type of activities. Generally, construction activities will occur during daylight (e.g., 7 a.m. to 7 p.m.) hours and will include the following major phases: site preparation, excavation, installation of pipeline and/or aboveground facilities, and site cleanup and restoration. The construction equipment that will be utilized will differ from phase to phase, but will include dozers, cranes, cement mixers, dump trucks, and loaders. Noise generated during construction is primarily from diesel engines which power the equipment. Exhaust noise usually is the predominant source of diesel engine noise. Equipment used is not generally operated continuously, nor is the equipment always operated simultaneously. Typically, the highest site average sound levels (89 dBA at 50 feet) are associated with excavation and finishing activities.

Noise actually transmitted from the construction site will be attenuated by a variety of mechanisms. The most significant of these is the diversion of the sound waves with distance (attenuation by divergence). In general, this mechanism will result in a 6 dBA decrease in the sound level with every doubling of distance from the source. Additional reductions in noise are achieved through absorption by the atmosphere.

Noise from construction activities may be noticeable at nearby residences. However, the construction noise levels provided above are those which would be experienced by people outdoors. A building (residence) provides significant attenuation for those who are indoors and sound levels can be expected to be up to 27 dBA lower indoors with the windows closed. Even in homes with the windows open, indoor sound levels can be reduced by up to 17 dBA (USEPA, 1978).

The short-term nature and small expected magnitude of the potential construction noise impacts do not warrant any mitigation measures. The continuous manner in which construction work must be done makes complete control of construction noise infeasible. Measures to mitigate construction noise will include compliance with federal regulations limiting noise from trucks, and ensuring that equipment and sound muffling devices provided by the manufacturer are kept in good working condition. In addition, construction activity will generally not occur during the nighttime hours when people are sleeping.

9.3.1.1 SPLNG Terminal

The nearest NSAs to the SPLNG Terminal are located across the Sabine Pass Channel in Texas and include a marina (4,900 feet) and the Sabine Pass Battleground State Park (4,750 feet). There are no residences within 0.5 mile.

Construction at the SPLNG Terminal will include pile driving that will result in greater noise level impacts. Pre-cast concrete piles will be utilized and installed using a combination of boring and impact pile driving. The sound power level of a typical pre-cast pile driver installing piles at approximately 50 blows per minute was calculated from sound level measurements of pile driving at a similar LNG project. The calculated sound power level was 123 dBA per pile driver operation. Assuming two simultaneous pile driving operations at the closest edge of the Trains 5 and 6 construction area, the predicted sound level due to pile driving operations is about 38 dBA at the nearest NSA. The temporary pile driving noise impact is anticipated to be minimal, even if it occurs at night. Further, the nearest NSAs do not have overnight sleeping facilities.

9.3.1.2 CCTPL Pipelines

CCTPL will use a horizontal direction drill (“HDD”) construction technique to install the pipeline at twelve locations along the pipeline route. HDD utilizes a number of pieces of equipment that include power generation, drill pile storage, control rooms, an excavator, and storage trailers. Of these sources, the diesel engine power generation units are the most significant noise generating sources. Noise level data measured at a typical HDD site, where a 600 horsepower drive drill engine is in use, indicate that at the HDD entry site, the HDD generates a sound level, with equipment at full load, of approximately 85 dBA at 50 feet. Noise levels on the HDD exit site, where fewer equipment are in use, are approximately 79 dBA at 50 feet.

Table 9.3-1 identifies the nearest NSA within 0.5 mile of the entry and exit locations for each HDD. No HDDs are planned on Loop 1, or the ANR and TGT Laterals. Assuming that HDDs are conducted during the daytime only using standard drilling equipment, noise levels at residences located at a conservative distance of 1,200 feet from the entry/exit sites will not experience noise levels above the 55 dBA threshold. CCTPL will conduct noise analyses for those residences that are located less than 1,200 feet from the HDD entry/exit sites and will provide those analyses in September 2013.

TABLE 9.3-1
Nearest NSAs Within 0.5 Mile of CCTPL HDD Entry and Exit Locations

Facility / Feature	Entry and Exit Site			
	Approx. MP	NSA (Distance (ft) / Direction)	Approx. MP	NSA (Distance (ft) / Direction)
Loop 2				
Houston River Canal	71.0	1,772 / NE[1]	71.3	670 / E[1]
Houston River	73.4	460 / W	73.9	2,249 / SW

TABLE 9.3-1
Nearest NSAs Within 0.5 Mile of CCTPL HDD Entry and Exit Locations

Facility / Feature	Entry and Exit Site			
	Approx. MP	NSA (Distance (ft) / Direction)	Approx. MP	NSA (Distance (ft) / Direction)
U.S. 27/Bankens Road/Railroad	76.3	94 / N	76.5	933 / W
Little River	77.3	1,448 / S[1]	77.7	2,226 / SW[1]
West Fork Calcasieu River	81.0	523 / S	81.6	None
Indian Bayou/Camp Edgewood Road	86.8	1,407 / E[1]	87.0	309 / S
Marsh Bayou	90.2	302 / W[1]	90.5	1,990 / SW[1]
Extension				
Whiskey Chitto Creek	109	924 / E	109.6	None
Calcasieu River	112.2	1,856 / N	112.7	None
Caney Creek	130.2	2,695 / N[1]	130.5	2,310 / N[1]

TABLE 9.3-1
Nearest NSAs Within 0.5 Mile of CCTPL HDD Entry and Exit Locations

Facility / Feature	Entry and Exit Site			
	Approx. MP	NSA (Distance (ft) / Direction)	Approx. MP	NSA (Distance (ft) / Direction)
CGT Lateral				
WCGTLTA016 Wetland	10.8	929 / S[1]	11.1	1,530 / SW[1]
PPEC Lateral				
East Fork Bayou Nezpique	1.6	2,179 / SE	2.2	None
1 Same residence at both locations.				

9.3.2 Operational Noise

9.3.2.1 SPLNG Terminal

The major noise generating sources at the SPLNG Terminal include:

- Two ConocoPhillips Optimized Cascade LNG Trains, each consisting of:
  - Six LM2500+G4 gas turbine-driven refrigerant compressors;
  - Gas treatment facilities;
  - Waste heat recovery systems;
  - Induced draft air coolers;
  - Associated Piping;
- Two LM2500+ gas turbine generators;
- Recycle boil-off gas (BOG) compressors;
- Instrument air compressor packages; and
- Liquefaction Flares.

Existing Noise Levels

The SPLNG Terminal in Cameron Parish, Louisiana is bounded by the Sabine Pass Channel on the west and south and open land (primarily wetlands) to the north, and east. The nearest NSAs to the site are a marina and the Sabine Pass Battleground State Park, both located across the Sabine River in Texas. These NSAs, which were identified during licensing of the original Sabine Pass LNG receiving terminal in 2005, do not have overnight sleeping facilities and are shown on Figure 1 in Appendix 9D.

Ambient noise monitoring was conducted during June 17-18, 2013 at these NSA locations in order to quantify the existing noise levels. Measurements were limited to daytime only at NSA 1 (the marina), and were judged to be representative of noise conditions at both NSA sites. No construction or operational noise was audible during the measurement period. Meteorological conditions during the daytime measurements included clear to partly cloudy skies, south-southwest winds of 7 to 15 miles per hour and a temperature of 82 degrees F. Table 9.3-2 lists the NSAs, their distance and direction to the site, the measured short-term ambient noise levels, and the calculated L_{dn} levels.

TABLE 9.3-2
SPLNG Terminal NSA Locations and Measured Ambient Noise Levels (dBA)

NSA	Distance (ft) / Direction	Daytime L_{eq}[1]	L_{dn}[2]
1 – Marina	4,900	47.1	53.5
2 – Sabine Pass Battleground State Park	4,750	47.1	53.5

[1] Only daytime noise levels were measured at NSA 1, and assumed to exist for NSA 2.
[2] L_{dn} based on assuming L_{day} and L_{night} are the same.

Noise Mitigation Measures

Noise mitigation measures were incorporated in the modeling analysis for the SPLNG Terminal and included:

- Acoustically treated buildings for the BOG compressors;
- Liquefaction train combustion turbine exhaust stack silencers;
- Power generator combustion turbine exhaust stack silencers;
- Pipe lagging around above-ground pipes; and
- Low noise gas coolers and lube oil coolers.

It may be possible to achieve compliance through use of alternative noise control measures other than those used in the analyses, provided that the final design achieves the same level of compliance.

Predicted Noise Levels During Operation

Manufacturer's data (as available) and measurements of similar units at other LNG facilities were used to develop noise model input data for the SPLNG Terminal. The results of the noise modeling analysis are provided in Table 9.3-3 and indicate that the calculated levels at the nearest NSAs are all below the L_{dn} of 55 dBA. The highest calculated L_{dn} is 54.7 dBA at NSA (Marina), located about 4,900 feet southwest of the approximate center of the SPLNG Terminal site. The expected increases in noise levels at the two NSAs range from 3.4 dBA to 3.7 dBA.

TABLE 9.3-3
SPLNG Terminal Operational Noise Impact at the Nearest NSAs (dBA)

NSA	Distance (ft) / Direction	L_{dn} for Station Only [1] (dBA)	Existing L_{dn} without Station (dBA)	Combined L_{dn} (Station plus Existing) (dBA)	Expected Increase (dBA)
1 – Marina	4,900 / SW	54.7	53.5	57.2	3.7
2 - Sabine Pass Battleground State Park	4,750 / SW	54.2	53.5	56.9	3.4

1 Includes existing LNG vaporization equipment and the approved liquefaction Trains 1 through 4, and equipment.

Within 60 days of placing the SPLNG Terminal into service, a post-construction sound survey will be performed to ensure that the sound level attributable to the station, at full load operation, does not exceed the criterion of 55 dBA L_{dn} at the nearby NSAs. The results of the post-construction sound survey will be filed with the FERC.

9.3.2.2 Mamou Compressor Station

The preliminary design includes four Dresser Rand compressors driven by Solar Taurus 70 and Solar Titan 130 combustion turbines. Three of the compressors/turbines will be located within one building, and the fourth compressor/turbine in a separate building. Listed below is the major equipment proposed for the station:

- Three (3) Dresser Rand C40-5M compressors;
- One (1) Dresser Rand C51-4 compressor;
- Three (3) Solar Taurus 70 combustion turbines;
- One (1) Solar Titan 130 combustion turbines;
- Four (4) Lube Oil Cooler fan bays (8 fans in total); and
- Eight (8) Gas Cooler fan bays (21 fans in total).

Measurements of existing noise levels were made at nearby NSAs to each Project site to provide a comparison of calculated future noise levels. Calculated Project noise levels were also evaluated against the FERC noise criterion.

Existing Noise Levels

The Mamou Compressor Station site in Evangeline Parish is surrounded by undeveloped, agricultural land, and low density residential use. Nearby NSAs to the Mamou Compressor Station site (all residences) were identified through the use of topographic maps and site reconnaissance. The NSAs are listed in Table 9.3-4 and their location in relation to the Mamou Compressor Station is shown in Figure 2 in Appendix 9D.

TABLE 9.3-4 Mamou Compressor Station NSA Locations and Measured Ambient Noise Levels (dBA)						
NSA	Distance (ft) / Direction	Daytime L_{eq}	Nighttime L_{eq} with insects	L_{dn} with Insects	Nighttime L_{eq} without insects	L_{dn} Without Insects
1 – 1298 Lariat Lane	1,800 / N	37.4	56.1	61.9	43.4	49.3
2 – 1926 Rocky Lane	2,000 / SE	38.8	53.7	59.5	51.3	57.1
3 – 1176 Joe Lane	3,200 / W	40.5	53.0	58.5	35.4	43.0

Ambient noise monitoring was conducted in the vicinity of the Mamou Compressor Station site on June 12 and 13, 2013. Short-term (10 minutes per location) noise level measurements were conducted at the nearest NSAs during the daytime hours and late at night to calculate existing L_{dn} levels. Noise levels typically are lowest during the late night hours, when human activity and traffic are at a minimum.

The primary sources of noise in the area included occasional cars on local roads, as well as natural sounds such as insects, birds and farm animals. Insect noise was more pronounced at night, resulting in higher ambient sound levels during the nighttime hours at all locations. Meteorological conditions during the daytime measurement program included partly cloudy skies, winds of 10 mph or less and temperatures ranging from 85 degrees Fahrenheit to 92 degrees Fahrenheit. At night, skies were clear and winds were near calm. The temperature was approximately 80 degrees Fahrenheit.

The measured nighttime noise levels were further analyzed to estimate the amount of insect noise present. Insect noise is typically present in the higher frequency ranges, generally 4,000 to 8,000 hertz. When the one-third octave data are plotted, insect noise is revealed as spikes at these frequencies. In most outdoor environments without insect sound, the one-third octave data will show higher sound levels in the lower frequencies and the sound level will gradually taper off into the higher frequencies. It is therefore possible to remove the insect sound by eliminating the spikes at the higher frequencies such that the plot gradually tapers off instead of spiking, then recombining the data into a single dBA level. This methodology was used to remove insect noise from the measured levels.

Ambient L_{dn} levels from the short term measurements ranged from 58.8 dBA to 61.9 dBA with insect noise, but were found to be lower at 43.0 dBA to 57.1 dBA with insect noise removed. Table 9.3-4 provides the measured short-term ambient noise levels with and without insect noise, and the calculated L_{dn} levels at the nearest NSAs.

<u>Noise Mitigation Measures</u>

Noise mitigation measures were incorporated in the modeling analysis for the Mamou Compressor Station and included:

- Acoustically treated compressor building;
- Exhaust stack silencers;

- Engine combustion air intake silencers;
- Pipe lagging around above-ground pipes; and
- Low noise gas coolers and lube oil coolers.

It may be possible to achieve compliance through use of alternative noise control measures other than those used in the analyses, provided that the final design achieves the same level of compliance.

Predicted Noise Levels During Operation

Noise will generally be produced on a continuous basis at the Mamou Compressor Station by the turbines/compressors and associated auxiliary equipment. CCTPL will enclose the turbines and compressors in acoustically designed buildings and silencers will be fitted to the turbine air intakes and exhausts, which will extend outside the buildings.

Estimated noise level data for the Solar turbines and lube oil coolers were obtained from Solar. Data for the compressors, gas coolers, and above ground piping were estimated from similar projects. The results of the noise modeling analysis for noise impacts with and without insect noise are provided in Tables 9.3-5 and 9.3-6, respectively. The analysis indicates that the calculated levels at the NSAs are all below the L_{dn} of 55 dBA with the highest calculated L_{dn} of 52.8 dBA at the nearest NSA (NSA 1). The expected increases in noise levels at the NSAs around the Mamou Compressor Station site range from 0.2 dBA to 0.7 dBA with existing insect noise and 1.1 dBA to 5.1 dBA with insect noise removed.

TABLE 9.3-5
Mamou Compressor Station Operational Noise Impact Results With Insect Noise in Ambient (dBA)

NSA	Distance (ft) / Direction	L_{dn} for Station Only (dBA)	Existing L_{dn} without Station (dBA)	Combined L_{dn} (with Station) (dBA)	Expected Increase (dBA)
1 – 1298 Lariat Lane	1,800 / N	52.8	61.9	62.4	0.5
2 – 1926 Rocky Lane	2,000 / SE	51.7	59.5	60.2	0.7
3 – 1176 Joe Lane	3,200 / W	46.2	58.8	59.0	0.2
All distances calculated from the center of the site.					

TABLE 9.3-6
Mamou Compressor Station Operational Noise Impact Results Without Insect Noise in Ambient (dBA)

NSA	Distance (ft) / Direction	L_{dn} for Station Only (dBA)	Existing L_{dn} without Station (dBA)	Combined L_{dn} (with Station) (dBA)	Expected Increase (dBA)
1 – 1298 Lariat Lane	1,800 / N	52.8	49.3	54.4	5.1
2 – 1926 Rocky Lane	2,000 / SEt	51.7	57.1	58.2	1.1
3 – 1176 Joe Lane	3,200 / W	46.2	43.0	47.9	4.9
All distances calculated from the center of the site.					

Within 60 days of placing the SPLNG Terminal and the Mamou Compressor Station into service, a post-construction sound survey will be performed to ensure that the sound level attributable to the station, at full load operation, does not exceed the criterion of 55 dBA L_{dn} at the nearby NSAs. The results of the post-construction sound survey will be filed with the FERC.

9.3.2.3 CCTPL Pipelines

There are no anticipated operational noise effects associated with the operation of the pipeline.

9.4 REFERENCES

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APPENDIX 9A

Construction Emissions Calculations

Table 9.A.1.1 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 06 PERSONNEL CARRIERS																
All terrain vehicle	Diesel	2270001060	22	21%	7.66	6.41	4.7E-03	1.89	1.09	225	40	0.35	0.29	2.1E-04	0.09	0.05
CLASS 11 EARTHMOVING																
Dozer	Diesel	2270002069	159	59%	0.87	2.02	3.1E-03	0.18	0.21	-	40	-	-	-	-	-
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	0.74	3.58	3.2E-03	0.18	0.11	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	250	59%	0.55	1.66	3.0E-03	0.16	0.10	-	40	-	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	0.89	2.22	3.1E-03	0.16	0.13	-	40	-	-	-	-	-
Motor graders	Diesel	2270002048	183	59%	0.62	1.82	3.0E-03	0.17	0.12	-	40	-	-	-	-	-
Loader backhoe	Diesel	2270002066	101	21%	2.60	4.37	3.9E-03	0.66	0.50	-	40	-	-	-	-	-
Loader tool carrier	Diesel	2270002066	134	21%	2.60	4.37	3.9E-03	0.66	0.50	-	40	-	-	-	-	-
Skidsteer loader	Diesel	2270002072	68	21%	5.94	5.51	4.5E-03	1.16	0.90	-	40	-	-	-	-	-
Rubber tire loader	Diesel	2270002060	249	59%	0.72	2.17	3.1E-03	0.19	0.14	-	40	-	-	-	-	-
Tractor	Diesel	2270005015	115	59%	1.34	3.40	3.3E-03	0.29	0.28	-	40	-	-	-	-	-
CLASS 12 PIPELAYING / TRENCHING EQUIPMENT																
Trencher	Diesel	2270002030	51	59%	2.69	3.89	3.7E-03	0.31	0.33	-	40	-	-	-	-	-
CLASS 13 COMPACTION																
Soil compactor	Diesel	2270002009	339	43%	2.52	4.73	4.0E-03	0.53	0.37	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.52	4.73	4.0E-03	0.53	0.37	-	40	-	-	-	-	-
CLASS 14 CRANES																
Crane crawler	Diesel	2270002045	285	43%	0.49	2.27	3.1E-03	0.19	0.10	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	300	43%	0.82	3.21	3.2E-03	0.19	0.12	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	340	43%	0.82	3.21	3.2E-03	0.19	0.12	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	600	43%	1.09	3.22	3.2E-03	0.18	0.13	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	500	43%	0.82	3.21	3.2E-03	0.19	0.12	-	40	-	-	-	-	-
Crane carrydeck	Diesel	2270003010	200	21%	3.13	5.31	4.0E-03	0.82	0.54	-	40	-	-	-	-	-
Crane carrydeck	Diesel	2270003010	300	21%	3.13	5.31	4.0E-03	0.82	0.54	-	40	-	-	-	-	-
RT crane - 35 ton	Diesel	2270002045	140	43%	0.65	2.48	3.2E-03	0.21	0.16	4	40	0.01	0.03	3.4E-05	2.2E-03	1.7E-03
RT crane - 50 ton	Diesel	2270002045	180	43%	0.49	2.27	3.1E-03	0.19	0.10	-	40	-	-	-	-	-
RT crane - 66 ton	Diesel	2270002045	220	43%	0.49	2.27	3.1E-03	0.19	0.10	4	40	0.01	0.04	5.2E-05	3.1E-03	1.6E-03
RT crane - 75 ton	Diesel	2270002045	220	43%	0.49	2.27	3.1E-03	0.19	0.10	-	40	-	-	-	-	-
RT crane - 80 ton	Diesel	2270002045	260	43%	0.49	2.27	3.1E-03	0.19	0.10	-	40	-	-	-	-	-

Table 9.A.1.1 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
RT crane - 110 ton	Diesel	2270002045	300	43%	0.82	3.21	3.2E-03	0.19	0.12	-	40	-	-	-	-	-
CLASS 15 FORKLIFT																
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	0.50	1.28	2.9E-03	0.15	0.11	4	40	0.01	0.02	4.5E-05	2.3E-03	1.8E-03
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	9.04	1.44	0.01	0.28	0.06	4	40	0.05	0.01	5.7E-05	1.5E-03	3.0E-04
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	1.04	2.62	3.3E-03	0.23	0.23	4	40	0.01	0.03	3.4E-05	2.4E-03	2.4E-03
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	0.50	1.28	2.9E-03	0.15	0.11	4	40	0.01	0.02	3.6E-05	1.9E-03	1.4E-03
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	0.50	1.28	2.9E-03	0.15	0.11	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	0.50	1.28	2.9E-03	0.15	0.11	4	40	0.01	0.01	3.0E-05	1.5E-03	1.2E-03
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	0.50	1.28	2.9E-03	0.15	0.11	-	40	-	-	-	-	-
CLASS 16 CONCRETE / AGGREGATE																
Concrete pump	Diesel	2270002042	350	43%	1.31	4.48	3.3E-03	0.30	0.18	-	40	-	-	-	-	-
CLASS 17 AIR COMPRESSORS																
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.86	3.32	3.6E-03	0.30	0.29	-	40	-	-	-	-	-
Air compressor 250 cfm	Diesel	2270006015	80	43%	1.86	3.32	3.6E-03	0.30	0.29	-	40	-	-	-	-	-
Air compressor 375 cfm	Diesel	2270006015	115	43%	0.72	2.88	3.2E-03	0.23	0.17	-	40	-	-	-	-	-
Air compressor 600 cfm	Diesel	2270006015	250	43%	0.57	2.68	3.2E-03	0.21	0.11	-	40	-	-	-	-	-
Air compressor 750 cfm	Diesel	2270006015	275	43%	0.57	2.68	3.2E-03	0.21	0.11	-	40	-	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	310	43%	1.01	3.61	3.3E-03	0.23	0.15	-	40	-	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	-	-	40	-	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	1.01	3.61	3.3E-03	0.23	0.15	-	40	-	-	-	-	-
CLASS 25 CABLE LAYING / PULLING EQUIPMENT																
Cable winch	Diesel	2270002081	26	59%	1.19	4.02	3.5E-03	0.23	0.19	-	40	-	-	-	-	-
CLASS 52 WELDING EQUIPMENT																
Welder 400A trailer mount	Diesel	2270006025	32	21%	4.62	5.12	4.4E-03	1.08	0.72	-	40	-	-	-	-	-
Welder 500A trailer mount	Diesel	2270006025	40	21%	4.62	5.12	4.4E-03	1.08	0.72	-	40	-	-	-	-	-
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	6.08	5.68	4.7E-03	1.38	0.84	-	40	-	-	-	-	-
CLASS 53 GENERATION EQUIPMENT																
Generator set 150 kW	Diesel	2270006005	221	43%	1.18	4.21	3.3E-03	0.34	0.22	4	40	0.02	0.07	5.6E-05	0.01	3.7E-03
Generator set 800 kW	Diesel	2270006005	1,125	0%	-	-	-	-	-	4	40	-	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1,425	0%	-	-	-	-	-	9	40	-	-	-	-	-
Light plant	Diesel	2270002027	14	43%	2.46	4.64	4.0E-03	0.50	0.36	9	40	0.01	0.01	9.5E-06	1.2E-03	8.5E-04

Table 9.A.1.1 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 54 MANLIFTS / SCISSORLIFTS																
Manlift - 40 ft	Diesel	2270003010	28	21%	6.32	5.59	4.5E-03	1.64	0.91	-	40	-	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	5.38	5.68	4.5E-03	1.08	0.77	-	40	-	-	-	-	-
Manlift - 80 ft	Diesel	2270003010	65	21%	5.38	5.68	4.5E-03	1.08	0.77	-	40	-	-	-	-	-
Manlift - 125 ft	Diesel	2270003010	75	21%	5.94	5.38	4.4E-03	1.12	0.86	-	40	-	-	-	-	-
Scissor lift - 60 ft	Diesel	2270003010	31	21%	6.32	5.59	4.5E-03	1.64	0.91	-	40	-	-	-	-	-
CLASS 55,56 SMALL CAPITAL EQUIPMENT																
Compactor - 29'' manual	Diesel	2270002003	15	59%	2.40	4.46	4.0E-03	0.45	0.35	-	40	-	-	-	-	-
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	289.04	2.03	0.02	5.15	0.11	-	40	-	-	-	-	-
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	2.50	4.52	3.7E-03	0.50	0.45	-	40	-	-	-	-	-
Water pump trash 316 gpm	Diesel	2270006010	7	43%	4.51	5.08	4.0E-03	0.70	0.50	-	40	-	-	-	-	-
Water pump trash 611 gpm	Diesel	2270006010	15	43%	2.65	4.90	4.0E-03	0.58	0.39	-	40	-	-	-	-	-
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.64	4.54	3.7E-03	0.38	0.31	-	40	-	-	-	-	-
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	4.51	5.08	4.0E-03	0.70	0.50	-	40	-	-	-	-	-
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	289.04	2.03	0.02	5.15	0.11	-	40	-	-	-	-	-
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	2.65	4.90	4.0E-03	0.58	0.39	-	40	-	-	-	-	-
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	2.65	4.90	4.0E-03	0.58	0.39	-	40	-	-	-	-	-
Compactor - 16" in manual	Diesel	2270002003	5	59%	2.40	4.46	4.0E-03	0.45	0.35	-	40	-	-	-	-	-
Compactor - 26" in manual	Diesel	2270002003	9	59%	2.40	4.46	4.0E-03	0.45	0.35	-	40	-	-	-	-	-
Tamper rammer	Diesel	2270002003	9	59%	2.40	4.46	4.0E-03	0.45	0.35	-	40	-	-	-	-	-
Mortar mixer	Diesel	2270002042	5	43%	4.73	6.17	4.0E-03	0.88	0.66	-	40	-	-	-	-	-
Concrete mixer	Gas	2265002042	5	59%	221.18	2.35	0.02	8.86	0.34	-	40	-	-	-	-	-
Generator set 6 kW	Gas	2265006005	9	68%	291.40	2.23	0.02	5.39	0.11	9	40	0.71	0.01	4.6E-05	0.01	2.7E-04
Generator set 10 kW	Gas	2265006005	15	68%	291.40	2.23	0.02	5.39	0.11	9	40	1.18	0.01	7.7E-05	0.02	4.6E-04
Concrete trowel 36"	Gas	2265002021	5	59%	212.62	2.12	0.02	6.43	0.32	-	40	-	-	-	-	-
SOIL STABLIZATION & SITE PREP																
CAT D6M dozer	Diesel	2270002069	140	59%	0.87	2.02	3.1E-03	0.18	0.21	43	40	0.14	0.32	4.9E-04	0.03	0.03
Soil compactor	Diesel	2270002009	153	43%	2.52	4.73	4.0E-03	0.53	0.37	43	40	0.31	0.59	5.0E-04	0.07	0.05
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.55	1.66	3.0E-03	0.16	0.10	1,040	40	3.54	10.57	0.02	1.04	0.67
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.50	1.28	2.9E-03	0.15	0.11	87	40	0.12	0.32	7.1E-04	0.04	0.03
Generator set 150 kW	Diesel	2270006005	221	43%	1.18	4.21	3.3E-03	0.34	0.22	87	40	0.43	1.54	1.2E-03	0.12	0.08

Table 9.A.1.1 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	$NO_x{}^2$	$SO_2{}^2$	VOC^2	$PM_{10}/PM_{2.5}{}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.64	4.54	3.7E-03	0.38	0.31	87	40	0.09	0.26	2.1E-04	0.02	0.02
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.64	1.63	3.0E-03	0.15	0.10	433	40	3.06	7.83	0.01	0.71	0.49
Light plant	Diesel	2270002027	15	43%	2.46	4.64	4.0E-03	0.50	0.36	867	40	0.61	1.15	9.8E-04	0.12	0.09
Water truck	Diesel	2270002051	427	59%	0.64	1.63	3.0E-03	0.15	0.10	43	40	0.30	0.78	1.4E-03	0.07	0.05
Excavator CAT 345B	Diesel	2270002036	345	59%	0.89	2.22	3.1E-03	0.16	0.13	208	40	1.65	4.14	0.01	0.30	0.24
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.55	1.66	3.0E-03	0.16	0.10	52	40	0.18	0.53	9.5E-04	0.05	0.03
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.64	1.63	3.0E-03	0.15	0.10	208	40	1.47	3.76	0.01	0.34	0.23
CAT D6M dozer	Diesel	2270002069	140	59%	0.87	2.02	3.1E-03	0.18	0.21	156	40	0.49	1.15	1.8E-03	0.11	0.12
Motor graders	Diesel	2270002048	185	59%	0.62	1.82	3.0E-03	0.17	0.12	104	40	0.31	0.91	1.5E-03	0.08	0.06
Soil compactor	Diesel	2270002009	228	43%	2.52	4.73	4.0E-03	0.53	0.37	26	40	0.28	0.53	4.5E-04	0.06	0.04
Soil compactor	Diesel	2270002009	153	43%	2.52	4.73	4.0E-03	0.53	0.37	52	40	0.38	0.71	6.0E-04	0.08	0.06
Loader tool carrier	Diesel	2270001060	125	21%	3.49	5.01	4.0E-03	0.84	0.56	26	40	0.10	0.15	1.2E-04	0.03	0.02
PILE DRIVING																
American 9310	Diesel	2270001060	285	21%	3.07	4.76	3.9E-03	0.76	0.48	82	40	0.66	1.03	8.5E-04	0.17	0.10
American 9260	Diesel	2270001060	275	21%	3.07	4.76	3.9E-03	0.76	0.48	104	40	0.81	1.26	1.0E-03	0.20	0.13
Pile hammer	Diesel	2270001060	60	21%	5.76	5.37	4.5E-03	1.10	0.80	82	40	0.26	0.24	2.0E-04	0.05	0.04
Manlift - 60 ft	Diesel	2270003010	65	21%	5.38	5.68	4.5E-03	1.08	0.77	61	40	0.20	0.21	1.6E-04	0.04	0.03
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.50	1.28	2.9E-03	0.15	0.11	61	40	0.09	0.22	5.0E-04	0.03	0.02
Welder	Diesel	2270001060	50	21%	5.76	5.37	4.5E-03	1.10	0.80	82	40	0.22	0.20	1.7E-04	0.04	0.03
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.86	3.32	3.6E-03	0.30	0.29	82	40	0.23	0.41	4.5E-04	0.04	0.04
MISCELLANEOUS																
Tugs Twin Screw[4,5]	Diesel		350	31%	2.01	13.41	0.17	0.36	0.35	52	40	0.50	3.34	0.04	0.09	0.09
Total												**18.8**	**42.7**	**0.10**	**4.1**	**2.8**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2015, Cameron Parish, LA, except as noted
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.
4. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
5. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Comments - Exhibit 5

Table 9.A.1.2 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 06 PERSONNEL CARRIERS														
All terrain vehicle	Diesel	2270001060	22	21%	690	0.039	0.018	696	225	40	32	1.8E-03	8.1E-04	32
CLASS 11 EARTHMOVING														
Dozer	Diesel	2270002069	159	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	596	0.034	0.015	601	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	250	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	0	40	-	-	-	-
Motor graders	Diesel	2270002048	183	59%	536	0.030	0.014	541	0	40	-	-	-	-
Loader backhoe	Diesel	2270002066	101	21%	624	0.035	0.016	630	0	40	-	-	-	-
Loader tool carrier	Diesel	2270002066	134	21%	624	0.035	0.016	630	0	40	-	-	-	-
Skidsteer loader	Diesel	2270002072	68	21%	692	0.039	0.018	699	0	40	-	-	-	-
Rubber tire loader	Diesel	2270002060	249	59%	536	0.030	0.014	541	0	40	-	-	-	-
Tractor	Diesel	2270005015	115	59%	536	0.030	0.014	541	0	40	-	-	-	-
CLASS 12 PIPELAYING / TRENCHING EQUI														
Trencher	Diesel	2270002030	51	59%	595	0.034	0.015	601	0	40	-	-	-	-
CLASS 13 COMPACTION														
Soil compactor	Diesel	2270002009	339	43%	589	0.033	0.015	594	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
CLASS 14 CRANES														
Crane crawler	Diesel	2270002045	285	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	300	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	340	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	600	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	500	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane carrydeck	Diesel	2270003010	200	21%	624	0.035	0.016	630	0	40	-	-	-	-
Crane carrydeck	Diesel	2270003010	300	21%	624	0.035	0.016	630	0	40	-	-	-	-
RT crane - 35 ton	Diesel	2270002045	140	43%	530	0.030	0.014	535	4	40	6	3.2E-04	1.4E-04	6
RT crane - 50 ton	Diesel	2270002045	180	43%	530	0.030	0.014	535	0	40	-	-	-	-
RT crane - 66 ton	Diesel	2270002045	220	43%	530	0.030	0.014	535	4	40	9	5.0E-04	2.3E-04	9
RT crane - 75 ton	Diesel	2270002045	220	43%	530	0.030	0.014	535	0	40	-	-	-	-
RT crane - 80 ton	Diesel	2270002045	260	43%	530	0.030	0.014	535	0	40	-	-	-	-

Table 9.A.1.2 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
RT crane - 110 ton	Diesel	2270002045	300	43%	530	0.030	0.014	535	0	40	-	-	-	-
CLASS 15 FORKLIFT														
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	4	40	8	4.8E-04	2.1E-04	9
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	555	0.032	0.013	560	4	40	3	1.7E-04	6.7E-05	3
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	536	0.030	0.014	541	4	40	6	3.2E-04	1.4E-04	6
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	536	0.030	0.014	541	4	40	7	3.8E-04	1.7E-04	7
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	4	40	6	3.2E-04	1.4E-04	6
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	0	40	-	-	-	-
CLASS 16 CONCRETE / AGGREGATE														
Concrete pump	Diesel	2270002042	350	43%	530	0.030	0.013	535	0	40	-	-	-	-
CLASS 17 AIR COMPRESSORS														
Air compressor 185 cfm	Diesel	2270006015	80	43%	589	0.033	0.015	595	0	40	-	-	-	-
Air compressor 250 cfm	Diesel	2270006015	80	43%	589	0.033	0.015	595	0	40	-	-	-	-
Air compressor 375 cfm	Diesel	2270006015	115	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 600 cfm	Diesel	2270006015	250	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 750 cfm	Diesel	2270006015	275	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	310	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	0	40	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	530	0.030	0.014	535	0	40	-	-	-	-
CLASS 25 CABLE LAYING / PULLING EQUIF														
Cable winch	Diesel	2270002081	26	59%	595	0.034	0.015	601	0	40	-	-	-	-
CLASS 52 WELDING EQUIPMENT														
Welder 400A trailer mount	Diesel	2270006025	32	21%	693	0.039	0.018	699	0	40	-	-	-	-
Welder 500A trailer mount	Diesel	2270006025	40	21%	693	0.039	0.018	699	0	40	-	-	-	-
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	692	0.039	0.018	698	0	40	-	-	-	-
CLASS 53 GENERATION EQUIPMENT														
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	4	40	9	5.0E-04	2.3E-04	9
Generator set 800 kW	Diesel	2270006005	1125	0%	-	-	-	-	4	40	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1425	0%	-	-	-	-	9	40	-	-	-	-
Light plant	Diesel	2270002027	14	43%	589	0.033	0.015	594	9	40	1	8.0E-05	3.6E-05	1

Table 9.A.1.2 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 54 MANLIFTS / SCISSORLIFTS														
Manlift - 40 ft	Diesel	2270003010	28	21%	691	0.039	0.018	697	0	40	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	0	40	-	-	-	-
Manlift - 80 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	0	40	-	-	-	-
Manlift - 125 ft	Diesel	2270003010	75	21%	692	0.039	0.018	699	0	40	-	-	-	-
Scissor lift - 60 ft	Diesel	2270003010	31	21%	691	0.039	0.018	697	0	40	-	-	-	-
CLASS 55,56 SMALL CAPITAL EQUIPMENT														
Compactor - 29'' manual	Diesel	2270002003	15	59%	595	0.034	0.015	600	0	40	-	-	-	-
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	1,046	0.060	0.024	1,055	0	40	-	-	-	-
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	589	0.033	0.015	594	0	40	-	-	-	-
Water pump trash 316 gpm	Diesel	2270006010	6.5	43%	588	0.033	0.015	593	0	40	-	-	-	-
Water pump trash 611 gpm	Diesel	2270006010	15	43%	589	0.033	0.015	594	0	40	-	-	-	-
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	0	40	-	-	-	-
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	588	0.033	0.015	593	0	40	-	-	-	-
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	1,046	0.059	0.027	1,056	0	40	-	-	-	-
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	589	0.033	0.015	594	0	40	-	-	-	-
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	589	0.033	0.015	594	0	40	-	-	-	-
Compactor - 16" in manual	Diesel	2270002003	5	59%	595	0.034	0.015	600	0	40	-	-	-	-
Compactor - 26" in manual	Diesel	2270002003	9	59%	595	0.034	0.015	600	0	40	-	-	-	-
Tamper rammer	Diesel	2270002003	9	59%	595	0.034	0.015	600	0	40	-	-	-	-
Mortar mixer	Diesel	2270002042	5	43%	588	0.033	0.015	593	0	40	-	-	-	-
Concrete mixer	Gas	2265002042	5	59%	1,220	0.069	0.028	1,230	0	40	-	-	-	-
Generator set 6 kW	Gas	2265006005	9	68%	1,046	0.060	0.024	1,055	9	40	3	1.4E-04	5.8E-05	3
Generator set 10 kW	Gas	2265006005	15	68%	1,046	0.060	0.024	1,055	9	40	4	2.4E-04	9.6E-05	4
Concrete trowel 36"	Gas	2265002021	5	59%	1,229	0.070	0.028	1,239	0	40	-	-	-	-
SOIL STABLIZATION & SITE PREP														
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	43	40	84	4.8E-03	2.1E-03	86
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	43	40	73	4.2E-03	1.9E-03	75
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	1040	40	3,424	0.19	0.09	3,487
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	87	40	134	0.01	3.4E-03	136
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	87	40	193	0.01	4.9E-03	197

Table 9.A.1.2 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	87	40	34	1.9E-03	8.7E-04	35
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	433	40	2,580	0.15	0.07	2,627
Light plant	Diesel	2270002027	15	43%	589	0.033	0.015	594	867	40	145	0.01	3.7E-03	148
Water truck	Diesel	2270002051	427	59%	536	0.030	0.014	541	43	40	256	0.01	0.01	261
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	208	40	1,001	0.06	0.03	1,019
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	52	40	171	0.01	4.4E-03	174
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	208	40	1,239	0.07	0.03	1,262
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	156	40	305	0.02	0.01	310
Motor graders	Diesel	2270002048	185	59%	536	0.030	0.014	541	104	40	268	0.02	0.01	273
Soil compactor	Diesel	2270002009	228	43%	589	0.033	0.015	594	26	40	66	3.8E-03	1.7E-03	67
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	52	40	89	0.01	2.3E-03	90
Loader tool carrier	Diesel	2270001060	125	21%	624	0.035	0.016	630	26	40	19	1.1E-03	4.8E-04	19
PILE DRIVING														
American 9310	Diesel	2270001060	285	21%	624	0.035	0.016	630	82	40	135	0.01	3.4E-03	138
American 9260	Diesel	2270001060	275	21%	624	0.035	0.016	630	104	40	165	0.01	4.2E-03	168
Pile hammer	Diesel	2270001060	60	21%	692	0.039	0.018	699	82	40	32	1.8E-03	8.0E-04	32
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	61	40	25	1.4E-03	6.5E-04	26
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	61	40	94	0.01	2.4E-03	95
Welder	Diesel	2270001060	50	21%	692	0.039	0.018	699	82	40	26	1.5E-03	6.7E-04	27
Air compressor 185 cfm	Diesel	2270006015	80	43%	589	0.033	0.015	595	82	40	73	4.2E-03	1.9E-03	75
MISCELLANEOUS														
Tugs Twin Screw[4,5]	Diesel		350	31%	925	0.121	0.027	936	52	40	230	0.03	0.01	240
Total											**10,955**	**0.64**	**0.28**	**11,159**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2015, Cameron Parish, LA, except as noted
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.
5. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
6. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.3 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 06 PERSONNEL CARRIERS																
All terrain vehicle	Diesel	2270001060	22	21%	7.26	6.24	4.7E-03	1.77	1.03	1,105	40	1.63	1.41	1.0E-03	0.40	0.23
CLASS 11 EARTHMOVING																
Dozer	Diesel	2270002069	159	59%	0.74	1.70	3.0E-03	0.17	0.18	56	40	0.17	0.39	7.0E-04	0.04	0.04
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	0.47	3.26	3.0E-03	0.15	0.06	104	40	0.03	0.24	2.2E-04	0.01	4.3E-03
Excavator CAT 330BL	Diesel	2270002036	250	59%	0.44	1.34	2.9E-03	0.15	0.08	95	40	0.27	0.83	1.8E-03	0.09	0.05
Excavator CAT 345B	Diesel	2270002036	345	59%	0.77	1.90	3.1E-03	0.15	0.12	43	40	0.30	0.73	1.2E-03	0.06	0.04
Motor graders	Diesel	2270002048	183	59%	0.51	1.52	2.9E-03	0.16	0.10	43	40	0.10	0.31	6.0E-04	0.03	0.02
Loader backhoe	Diesel	2270002066	101	21%	2.33	3.99	3.9E-03	0.61	0.46	113	40	0.25	0.42	4.1E-04	0.06	0.05
Loader tool carrier	Diesel	2270002066	134	21%	2.33	3.99	3.9E-03	0.61	0.46	104	40	0.30	0.52	5.0E-04	0.08	0.06
Skidsteer loader	Diesel	2270002072	68	21%	5.58	5.33	4.4E-03	1.08	0.84	104	40	0.37	0.35	2.9E-04	0.07	0.05
Rubber tire loader	Diesel	2270002060	249	59%	0.63	1.86	3.0E-03	0.18	0.12	104	40	0.42	1.25	2.1E-03	0.12	0.08
Tractor	Diesel	2270005015	115	59%	1.22	3.08	3.3E-03	0.27	0.25	117	40	0.43	1.08	1.1E-03	0.09	0.09
CLASS 12 PIPELAYING / TRENCHING EQUIPMENT																
Trencher	Diesel	2270002030	51	59%	2.44	3.75	3.7E-03	0.29	0.29	35	40	0.11	0.17	1.7E-04	0.01	0.01
CLASS 13 COMPACTION																
Soil compactor	Diesel	2270002009	339	43%	2.48	4.66	4.0E-03	0.51	0.36	69	40	1.10	2.07	1.8E-03	0.23	0.16
Soil compactor	Diesel	2270002009	153	43%	2.48	4.66	4.0E-03	0.51	0.36	69	40	0.50	0.93	7.9E-04	0.10	0.07
CLASS 14 CRANES																
Crane crawler	Diesel	2270002045	285	43%	0.43	1.95	3.0E-03	0.17	0.09	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	300	43%	0.74	2.89	3.2E-03	0.18	0.11	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	340	43%	0.74	2.89	3.2E-03	0.18	0.11	43	40	0.21	0.80	8.8E-04	0.05	0.03
Crane crawler	Diesel	2270002045	600	43%	1.00	2.90	3.2E-03	0.18	0.12	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	500	43%	0.74	2.89	3.2E-03	0.18	0.11	-	40	-	-	-	-	-
Crane carrydeck	Diesel	2270003010	200	21%	2.90	4.95	3.9E-03	0.76	0.50	9	40	0.05	0.08	6.5E-05	0.01	0.01
Crane carrydeck	Diesel	2270003010	300	21%	2.90	4.95	3.9E-03	0.76	0.50	9	40	0.07	0.12	9.8E-05	0.02	0.01
RT crane - 35 ton	Diesel	2270002045	140	43%	0.57	2.14	3.1E-03	0.19	0.14	221	40	0.34	1.25	1.8E-03	0.11	0.08
RT crane - 50 ton	Diesel	2270002045	180	43%	0.43	1.95	3.0E-03	0.17	0.09	225	40	0.33	1.49	2.3E-03	0.13	0.07
RT crane - 66 ton	Diesel	2270002045	220	43%	0.43	1.95	3.0E-03	0.17	0.09	230	40	0.41	1.87	2.9E-03	0.17	0.08
RT crane - 75 ton	Diesel	2270002045	220	43%	0.43	1.95	3.0E-03	0.17	0.09	-	40	-	-	-	-	-
RT crane - 80 ton	Diesel	2270002045	260	43%	0.43	1.95	3.0E-03	0.17	0.09	4	40	0.01	0.04	6.0E-05	3.5E-03	1.7E-03

Table 9.A.1.3 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
RT crane - 110 ton	Diesel	2270002045	300	43%	0.74	2.89	3.2E-03	0.18	0.11	9	40	0.04	0.15	1.6E-04	0.01	0.01
CLASS 15 FORKLIFT																
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	0.30	0.90	2.7E-03	0.14	0.06	169	40	0.20	0.59	1.8E-03	0.09	0.04
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	7.74	1.27	0.01	0.24	0.06	82	40	0.84	0.14	1.2E-03	0.03	0.01
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	0.93	2.30	3.2E-03	0.21	0.21	100	40	0.24	0.60	8.3E-04	0.05	0.05
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	0.30	0.90	2.7E-03	0.14	0.06	69	40	0.06	0.19	5.8E-04	0.03	0.01
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	0.30	0.90	2.7E-03	0.14	0.06	43	40	0.05	0.15	4.5E-04	0.02	0.01
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	0.30	0.90	2.7E-03	0.14	0.06	212	40	0.17	0.49	1.5E-03	0.08	0.03
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	0.30	0.90	2.7E-03	0.14	0.06	191	40	0.15	0.45	1.3E-03	0.07	0.03
CLASS 16 CONCRETE / AGGREGATE																
Concrete pump	Diesel	2270002042	350	43%	1.21	4.17	3.3E-03	0.28	0.17	52	40	0.42	1.44	1.1E-03	0.10	0.06
CLASS 17 AIR COMPRESSORS																
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.69	2.95	3.5E-03	0.27	0.26	182	40	0.47	0.81	9.7E-04	0.07	0.07
Air compressor 250 cfm	Diesel	2270006015	80	43%	1.69	2.95	3.5E-03	0.27	0.26	-	40	-	-	-	-	-
Air compressor 375 cfm	Diesel	2270006015	115	43%	0.65	2.53	3.2E-03	0.22	0.15	-	40	-	-	-	-	-
Air compressor 600 cfm	Diesel	2270006015	250	43%	0.50	2.34	3.1E-03	0.20	0.10	-	40	-	-	-	-	-
Air compressor 750 cfm	Diesel	2270006015	275	43%	0.50	2.34	3.1E-03	0.20	0.10	-	40	-	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	310	43%	0.92	3.30	3.2E-03	0.21	0.14	-	40	-	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	-	-	40	-	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	0.92	3.30	3.2E-03	0.21	0.14	-	40	-	-	-	-	-
CLASS 25 CABLE LAYING / PULLING EQUIPMENT																
Cable winch	Diesel	2270002081	26	59%	0.98	3.81	3.4E-03	0.21	0.15	-	40	-	-	-	-	-
CLASS 52 WELDING EQUIPMENT																
Welder 400A trailer mount	Diesel	2270006025	32	21%	4.09	4.92	4.3E-03	0.93	0.65	381	40	0.46	0.55	4.9E-04	0.11	0.07
Welder 500A trailer mount	Diesel	2270006025	40	21%	4.09	4.92	4.3E-03	0.93	0.65	191	40	0.29	0.35	3.1E-04	0.07	0.05
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	5.60	5.50	4.7E-03	1.25	0.77	87	40	0.06	0.06	4.9E-05	0.01	0.01
CLASS 53 GENERATION EQUIPMENT																
Generator set 150 kW	Diesel	2270006005	221	43%	1.08	3.93	3.3E-03	0.32	0.21	91	40	0.41	1.50	1.2E-03	0.12	0.08
Generator set 800 kW	Diesel	2270006005	1,125	0%	-	-	-	-	-	130	40	-	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1,425	0%	-	-	-	-	-	104	40	-	-	-	-	-
Light plant	Diesel	2270002027	14	43%	2.42	4.59	4.0E-03	0.49	0.35	875	40	0.56	1.07	9.2E-04	0.11	0.08

Table 9.A.1.3 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6
(Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 54 MANLIFTS / SCISSORLIFTS																
Manlift - 40 ft	Diesel	2270003010	28	21%	5.87	5.42	4.4E-03	1.52	0.85	165	40	0.25	0.23	1.9E-04	0.06	0.04
Manlift - 60 ft	Diesel	2270003010	65	21%	5.07	5.47	4.4E-03	1.00	0.72	139	40	0.42	0.46	3.7E-04	0.08	0.06
Manlift - 80 ft	Diesel	2270003010	65	21%	5.07	5.47	4.4E-03	1.00	0.72	191	40	0.58	0.63	5.1E-04	0.12	0.08
Manlift - 125 ft	Diesel	2270003010	75	21%	5.61	5.04	4.3E-03	1.04	0.80	17	40	0.07	0.06	5.1E-05	0.01	0.01
Scissor lift - 60 ft	Diesel	2270003010	31	21%	5.87	5.42	4.4E-03	1.52	0.85	74	40	0.12	0.12	9.3E-05	0.03	0.02
CLASS 55,56 SMALL CAPITAL EQUIPMENT																
Compactor - 29'' manual	Diesel	2270002003	15	59%	2.38	4.46	4.0E-03	0.45	0.36	173	40	0.16	0.30	2.7E-04	0.03	0.02
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	287.26	1.90	0.02	4.98	0.11	173	40	24.21	0.16	1.6E-03	0.42	0.01
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	2.36	4.25	3.7E-03	0.47	0.43	208	40	0.74	1.34	1.2E-03	0.15	0.13
Water pump trash 316 gpm	Diesel	2270006010	7	43%	4.49	4.94	4.0E-03	0.67	0.48	312	40	0.17	0.19	1.5E-04	0.03	0.02
Water pump trash 611 gpm	Diesel	2270006010	15	43%	2.59	4.81	4.0E-03	0.55	0.38	156	40	0.11	0.21	1.8E-04	0.02	0.02
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.47	4.38	3.6E-03	0.34	0.28	312	40	0.31	0.91	7.5E-04	0.07	0.06
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	4.49	4.94	4.0E-03	0.67	0.48	208	40	0.09	0.10	7.8E-05	0.01	0.01
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	287.26	1.90	0.02	4.98	0.11	95	40	11.25	0.07	7.5E-04	0.19	4.5E-03
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	2.59	4.81	4.0E-03	0.55	0.38	312	40	0.24	0.46	3.8E-04	0.05	0.04
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	2.59	4.81	4.0E-03	0.55	0.38	312	40	0.35	0.65	5.4E-04	0.08	0.05
Compactor - 16" in manual	Diesel	2270002003	5	59%	2.38	4.46	4.0E-03	0.45	0.36	173	40	0.05	0.10	9.0E-05	0.01	0.01
Compactor - 26" in manual	Diesel	2270002003	9	59%	2.38	4.46	4.0E-03	0.45	0.36	173	40	0.10	0.18	1.6E-04	0.02	0.01
Tamper rammer	Diesel	2270002003	9	59%	2.38	4.46	4.0E-03	0.45	0.36	139	40	0.08	0.15	1.3E-04	0.01	0.01
Mortar mixer	Diesel	2270002042	5	43%	4.69	5.96	4.0E-03	0.85	0.63	121	40	0.05	0.07	4.5E-05	0.01	0.01
Concrete mixer	Gas	2265002042	5	59%	214.92	2.18	0.02	7.23	0.32	173	40	4.84	0.05	5.0E-04	0.16	0.01
Generator set 6 kW	Gas	2265006005	9	68%	288.22	2.00	0.02	5.07	0.11	355	40	27.61	0.19	1.8E-03	0.49	0.01
Generator set 10 kW	Gas	2265006005	15	68%	288.22	2.00	0.02	5.07	0.11	477	40	61.83	0.43	4.1E-03	1.09	0.02
Concrete trowel 36"	Gas	2265002021	5	59%	212.29	2.11	0.02	6.33	0.32	113	40	3.12	0.03	3.3E-04	0.09	4.8E-03
SOIL STABLIZATION & SITE PREP																
CAT D6M dozer	Diesel	2270002069	140	59%	0.74	1.70	3.0E-03	0.17	0.18	17	40	0.05	0.11	1.9E-04	0.01	0.01
Soil compactor	Diesel	2270002009	153	43%	2.48	4.66	4.0E-03	0.51	0.36	17	40	0.12	0.23	2.0E-04	0.03	0.02
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.44	1.34	2.9E-03	0.15	0.08	416	40	1.11	3.43	0.01	0.39	0.20
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.30	0.90	2.7E-03	0.14	0.06	35	40	0.03	0.09	2.7E-04	0.01	0.01
Generator set 150 kW	Diesel	2270006005	221	43%	1.08	3.93	3.3E-03	0.32	0.21	35	40	0.16	0.58	4.8E-04	0.05	0.03

Table 9.A.1.3 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.47	4.38	3.6E-03	0.34	0.28	35	40	0.03	0.10	8.4E-05	0.01	0.01
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.50	1.33	2.9E-03	0.14	0.08	173	40	0.96	2.56	0.01	0.28	0.15
Light plant	Diesel	2270002027	15	43%	2.42	4.59	4.0E-03	0.49	0.35	347	40	0.24	0.45	3.9E-04	0.05	0.03
Water truck	Diesel	2270002051	427	59%	0.50	1.33	2.9E-03	0.14	0.08	17	40	0.09	0.25	5.4E-04	0.03	0.01
Excavator CAT 345B	Diesel	2270002036	345	59%	0.77	1.90	3.1E-03	0.15	0.12	277	40	1.91	4.72	0.01	0.38	0.29
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.44	1.34	2.9E-03	0.15	0.08	69	40	0.18	0.57	1.2E-03	0.06	0.03
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.50	1.33	2.9E-03	0.14	0.08	277	40	1.54	4.09	0.01	0.44	0.24
CAT D6M dozer	Diesel	2270002069	140	59%	0.74	1.70	3.0E-03	0.17	0.18	208	40	0.56	1.29	2.3E-03	0.13	0.13
Motor graders	Diesel	2270002048	185	59%	0.51	1.52	2.9E-03	0.16	0.10	139	40	0.34	1.02	2.0E-03	0.11	0.06
Soil compactor	Diesel	2270002009	228	43%	2.48	4.66	4.0E-03	0.51	0.36	35	40	0.37	0.71	6.0E-04	0.08	0.05
Soil compactor	Diesel	2270002009	153	43%	2.48	4.66	4.0E-03	0.51	0.36	69	40	0.50	0.93	7.9E-04	0.10	0.07
Loader tool carrier	Diesel	2270001060	125	21%	3.22	4.68	3.9E-03	0.78	0.52	35	40	0.13	0.19	1.6E-04	0.03	0.02
PILE DRIVING																
American 9310	Diesel	2270001060	285	21%	2.81	4.44	3.9E-03	0.71	0.44	191	40	1.42	2.24	1.9E-03	0.36	0.22
American 9260	Diesel	2270001060	275	21%	2.81	4.44	3.9E-03	0.71	0.44	234	40	1.67	2.65	2.3E-03	0.42	0.26
Pile hammer	Diesel	2270001060	60	21%	5.40	5.20	4.4E-03	1.03	0.75	191	40	0.57	0.55	4.7E-04	0.11	0.08
Manlift - 60 ft	Diesel	2270003010	65	21%	5.07	5.47	4.4E-03	1.00	0.72	147	40	0.45	0.48	3.9E-04	0.09	0.06
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.30	0.90	2.7E-03	0.14	0.06	147	40	0.13	0.38	1.1E-03	0.06	0.02
Welder	Diesel	2270001060	50	21%	5.40	5.20	4.4E-03	1.03	0.75	191	40	0.48	0.46	3.9E-04	0.09	0.07
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.69	2.95	3.5E-03	0.27	0.26	191	40	0.49	0.85	1.0E-03	0.08	0.07
MISCELLANEOUS																
Tugs Twin Screw[4,5]	Diesel		350	31%	2.01	13.41	0.17	0.36	0.35	104	40	1.00	6.67	0.09	0.18	0.17
Total												**163.1**	**67.6**	**0.18**	**9.7**	**4.9**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2016, Cameron Parish, LA, except as noted
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.
4. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
5. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.4 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 06 PERSONNEL CARRIERS														
All terrain vehicle	Diesel	2270001060	22	21%	690	0.039	0.018	697	1105	40	155	0.01	4.0E-03	158
CLASS 11 EARTHMOVING														
Dozer	Diesel	2270002069	159	59%	536	0.030	0.014	541	56	40	124	0.01	3.2E-03	126
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	596	0.034	0.015	601	104	40	44	2.5E-03	1.1E-03	44
Excavator CAT 330BL	Diesel	2270002036	250	59%	536	0.030	0.014	541	95	40	331	0.02	0.01	337
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	43	40	207	0.01	0.01	211
Motor graders	Diesel	2270002048	183	59%	536	0.030	0.014	541	43	40	110	0.01	2.8E-03	112
Loader backhoe	Diesel	2270002066	101	21%	625	0.035	0.016	630	113	40	66	3.7E-03	1.7E-03	67
Loader tool carrier	Diesel	2270002066	134	21%	625	0.035	0.016	630	104	40	81	4.6E-03	2.1E-03	82
Skidsteer loader	Diesel	2270002072	68	21%	693	0.039	0.018	699	104	40	45	2.6E-03	1.2E-03	46
Rubber tire loader	Diesel	2270002060	249	59%	536	0.030	0.014	541	104	40	361	0.02	0.01	368
Tractor	Diesel	2270005015	115	59%	536	0.030	0.014	541	117	40	188	0.01	4.8E-03	191
CLASS 12 PIPELAYING / TRENCHING EQUI														
Trencher	Diesel	2270002030	51	59%	595	0.034	0.015	601	35	40	28	1.6E-03	7.0E-04	28
CLASS 13 COMPACTION														
Soil compactor	Diesel	2270002009	339	43%	589	0.033	0.015	594	69	40	261	0.01	0.01	266
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	69	40	118	0.01	3.0E-03	120
CLASS 14 CRANES														
Crane crawler	Diesel	2270002045	285	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	300	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	340	43%	530	0.030	0.014	535	43	40	147	0.01	3.7E-03	150
Crane crawler	Diesel	2270002045	600	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	500	43%	530	0.030	0.014	535	0	40	-	-	-	-
Crane carrydeck	Diesel	2270003010	200	21%	624	0.035	0.016	630	9	40	10	5.9E-04	2.6E-04	11
Crane carrydeck	Diesel	2270003010	300	21%	624	0.035	0.016	630	9	40	16	8.9E-04	4.0E-04	16
RT crane - 35 ton	Diesel	2270002045	140	43%	530	0.030	0.014	535	221	40	311	0.02	0.01	317
RT crane - 50 ton	Diesel	2270002045	180	43%	530	0.030	0.014	535	225	40	407	0.02	0.01	415
RT crane - 66 ton	Diesel	2270002045	220	43%	530	0.030	0.014	535	230	40	509	0.03	0.01	518
RT crane - 75 ton	Diesel	2270002045	220	43%	530	0.030	0.014	535	0	40	-	-	-	-
RT crane - 80 ton	Diesel	2270002045	260	43%	530	0.030	0.014	535	4	40	10	5.9E-04	2.7E-04	11

Table 9.A.1.4 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
RT crane - 110 ton	Diesel	2270002045	300	43%	530	0.030	0.014	535	9	40	27	1.5E-03	6.9E-04	28
CLASS 15 FORKLIFT														
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	169	40	354	0.02	0.01	360
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	554	0.032	0.013	558	82	40	60	3.4E-03	1.4E-03	61
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	536	0.030	0.014	541	100	40	139	0.01	3.6E-03	142
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	536	0.030	0.014	541	69	40	116	0.01	2.9E-03	118
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	43	40	90	0.01	2.3E-03	92
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	212	40	296	0.02	0.01	301
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	191	40	267	0.02	0.01	271
CLASS 16 CONCRETE / AGGREGATE														
Concrete pump	Diesel	2270002042	350	43%	530	0.030	0.014	535	52	40	183	0.01	4.7E-03	186
CLASS 17 AIR COMPRESSORS														
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	182	40	163	0.01	4.1E-03	166
Air compressor 250 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	0	40	-	-	-	-
Air compressor 375 cfm	Diesel	2270006015	115	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 600 cfm	Diesel	2270006015	250	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 750 cfm	Diesel	2270006015	275	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	310	43%	530	0.030	0.014	535	0	40	-	-	-	-
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	0	40	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	530	0.030	0.014	535	0	40	-	-	-	-
CLASS 25 CABLE LAYING / PULLING EQUIP														
Cable winch	Diesel	2270002081	26	59%	595	0.034	0.015	601	0	40	-	-	-	-
CLASS 52 WELDING EQUIPMENT														
Welder 400A trailer mount	Diesel	2270006025	32	21%	693	0.039	0.018	699	381	40	78	4.4E-03	2.0E-03	80
Welder 500A trailer mount	Diesel	2270006025	40	21%	693	0.039	0.018	699	191	40	49	2.8E-03	1.2E-03	50
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	692	0.039	0.018	698	87	40	7	4.1E-04	1.8E-04	7
CLASS 53 GENERATION EQUIPMENT														
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	91	40	202	0.01	0.01	206
Generator set 800 kW	Diesel	2270006005	1125	0%	-	-	-	-	130	40	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1425	0%	-	-	-	-	104	40	-	-	-	-
Light plant	Diesel	2270002027	14	43%	589	0.033	0.015	594	875	40	137	0.01	3.5E-03	139

Table 9.A.1.4 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 54 MANLIFTS / SCISSORLIFTS														
Manlift - 40 ft	Diesel	2270003010	28	21%	691	0.039	0.018	697	165	40	30	1.7E-03	7.5E-04	30
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	139	40	58	3.3E-03	1.5E-03	59
Manlift - 80 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	191	40	80	4.5E-03	2.0E-03	81
Manlift - 125 ft	Diesel	2270003010	75	21%	693	0.039	0.018	699	17	40	8	4.6E-04	2.1E-04	8
Scissor lift - 60 ft	Diesel	2270003010	31	21%	691	0.039	0.018	697	74	40	15	8.3E-04	3.7E-04	15
CLASS 55,56 SMALL CAPITAL EQUIPMENT														
Compactor - 29'' manual	Diesel	2270002003	15	59%	595	0.034	0.015	600	173	40	40	2.3E-03	1.0E-03	41
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	1,046	0.060	0.024	1,055	173	40	88	0.01	2.0E-03	90
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	589	0.033	0.015	594	208	40	186	0.01	4.7E-03	189
Water pump trash 316 gpm	Diesel	2270006010	6.5	43%	588	0.033	0.015	594	312	40	23	1.3E-03	5.8E-04	23
Water pump trash 611 gpm	Diesel	2270006010	15	43%	589	0.033	0.015	594	156	40	26	1.5E-03	6.6E-04	27
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	312	40	122	0.01	3.1E-03	124
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	588	0.033	0.015	594	208	40	12	6.6E-04	3.0E-04	12
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	1,046	0.059	0.027	1,056	95	40	41	2.3E-03	1.0E-03	42
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	589	0.033	0.015	594	312	40	56	3.2E-03	1.4E-03	57
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	589	0.033	0.015	594	312	40	80	4.5E-03	2.0E-03	82
Compactor - 16" in manual	Diesel	2270002003	5	59%	595	0.034	0.015	600	173	40	13	7.6E-04	3.4E-04	14
Compactor - 26" in manual	Diesel	2270002003	9	59%	595	0.034	0.015	600	173	40	24	1.4E-03	6.1E-04	25
Tamper rammer	Diesel	2270002003	9	59%	595	0.034	0.015	600	139	40	19	1.1E-03	4.9E-04	20
Mortar mixer	Diesel	2270002042	5	43%	588	0.033	0.015	593	121	40	7	3.8E-04	1.7E-04	7
Concrete mixer	Gas	2265002042	5	59%	1,226	0.070	0.028	1,236	173	40	28	1.6E-03	6.3E-04	28
Generator set 6 kW	Gas	2265006005	9	68%	1,046	0.060	0.024	1,055	355	40	100	0.01	2.3E-03	102
Generator set 10 kW	Gas	2265006005	15	68%	1,046	0.060	0.024	1,055	477	40	225	0.01	0.01	229
Concrete trowel 36"	Gas	2265002021	5	59%	1,229	0.070	0.028	1,239	113	40	18	1.0E-03	4.1E-04	18
SOIL STABLIZATION & SITE PREP														
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	17	40	33	1.9E-03	8.5E-04	34
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	17	40	29	1.6E-03	7.4E-04	30
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	416	40	1,370	0.08	0.03	1,395
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	35	40	54	3.1E-03	1.4E-03	55
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	35	40	78	4.4E-03	2.0E-03	79

Table 9.A.1.4 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	35	40	14	7.8E-04	3.5E-04	14
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	173	40	1,031	0.06	0.03	1,049
Light plant	Diesel	2270002027	15	43%	589	0.033	0.015	594	347	40	58	3.3E-03	1.5E-03	59
Water truck	Diesel	2270002051	427	59%	536	0.030	0.014	541	17	40	101	0.01	2.6E-03	103
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	277	40	1,333	0.08	0.03	1,358
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	69	40	227	0.01	0.01	231
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	277	40	1,650	0.09	0.04	1,680
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	208	40	406	0.02	0.01	414
Motor graders	Diesel	2270002048	185	59%	536	0.030	0.014	541	139	40	359	0.02	0.01	365
Soil compactor	Diesel	2270002009	228	43%	589	0.033	0.015	594	35	40	89	0.01	2.3E-03	91
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	69	40	118	0.01	3.0E-03	120
Loader tool carrier	Diesel	2270001060	125	21%	624	0.035	0.016	630	35	40	25	1.4E-03	6.4E-04	26
PILE DRIVING														
American 9310	Diesel	2270001060	285	21%	624	0.035	0.016	630	191	40	315	0.02	0.01	320
American 9260	Diesel	2270001060	275	21%	624	0.035	0.016	630	234	40	372	0.02	0.01	379
Pile hammer	Diesel	2270001060	60	21%	693	0.039	0.018	699	191	40	74	4.2E-03	1.9E-03	75
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	147	40	61	3.5E-03	1.6E-03	62
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	147	40	226	0.01	0.01	230
Welder	Diesel	2270001060	50	21%	693	0.039	0.018	699	191	40	61	3.5E-03	1.6E-03	62
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	191	40	171	0.01	4.3E-03	174
MISCELLANEOUS														
Tugs Twin Screw[4,5]	Diesel		350	31%	925	0.121	0.027	936	104	40	460	0.06	0.01	479
Total											**15,709**	**0.93**	**0.40**	**16,005**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2016, Cameron Parish, LA, except as noted
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.
5. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
6. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.5 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x[2]	SO_2[2]	VOC[2]	$PM_{10}/PM_{2.5}$[2,3]	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 06 PERSONNEL CARRIERS																
All terrain vehicle	Diesel	2270001060	22	21%	6.87	6.09	4.7E-03	1.66	0.98	1,564	40	2.19	1.94	1.5E-03	0.53	0.31
CLASS 11 EARTHMOVING																
Dozer	Diesel	2270002069	159	59%	0.61	1.41	2.9E-03	0.16	0.14	104	40	0.26	0.61	1.3E-03	0.07	0.06
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	0.35	3.13	3.0E-03	0.14	0.04	208	40	0.05	0.46	4.3E-04	0.02	0.01
Excavator CAT 330BL	Diesel	2270002036	250	59%	0.32	1.07	2.8E-03	0.15	0.05	156	40	0.33	1.09	2.8E-03	0.15	0.06
Excavator CAT 345B	Diesel	2270002036	345	59%	0.66	1.63	3.0E-03	0.15	0.10	52	40	0.31	0.76	1.4E-03	0.07	0.05
Motor graders	Diesel	2270002048	183	59%	0.41	1.25	2.8E-03	0.15	0.07	104	40	0.20	0.62	1.4E-03	0.08	0.04
Loader backhoe	Diesel	2270002066	101	21%	2.13	3.66	3.8E-03	0.56	0.43	208	40	0.42	0.71	7.4E-04	0.11	0.08
Loader tool carrier	Diesel	2270002066	134	21%	2.13	3.66	3.8E-03	0.56	0.43	208	40	0.55	0.94	9.8E-04	0.14	0.11
Skidsteer loader	Diesel	2270002072	68	21%	5.24	5.15	4.4E-03	1.00	0.78	208	40	0.69	0.67	5.7E-04	0.13	0.10
Rubber tire loader	Diesel	2270002060	249	59%	0.54	1.60	3.0E-03	0.17	0.10	208	40	0.73	2.16	4.0E-03	0.22	0.14
Tractor	Diesel	2270005015	115	59%	1.11	2.79	3.2E-03	0.25	0.23	208	40	0.69	1.73	2.0E-03	0.16	0.14
CLASS 12 PIPELAYING / TRENCHING EQUIPMENT																
Trencher	Diesel	2270002030	51	59%	2.20	3.61	3.6E-03	0.26	0.25	35	40	0.10	0.17	1.7E-04	0.01	0.01
CLASS 13 COMPACTION																
Soil compactor	Diesel	2270002009	339	43%	2.44	4.61	4.0E-03	0.49	0.36	104	40	1.63	3.08	2.7E-03	0.33	0.24
Soil compactor	Diesel	2270002009	153	43%	2.44	4.61	4.0E-03	0.49	0.36	104	40	0.74	1.39	1.2E-03	0.15	0.11
CLASS 14 CRANES																
Crane crawler	Diesel	2270002045	285	43%	0.37	1.67	3.0E-03	0.17	0.07	69	40	0.14	0.62	1.1E-03	0.06	0.03
Crane crawler	Diesel	2270002045	300	43%	0.67	2.58	3.1E-03	0.18	0.10	69	40	0.26	1.01	1.2E-03	0.07	0.04
Crane crawler	Diesel	2270002045	340	43%	0.67	2.58	3.1E-03	0.18	0.10	312	40	1.34	5.20	0.01	0.35	0.20
Crane crawler	Diesel	2270002045	600	43%	0.92	2.60	3.1E-03	0.17	0.11	43	40	0.45	1.27	1.5E-03	0.08	0.05
Crane crawler	Diesel	2270002045	500	43%	0.67	2.58	3.1E-03	0.18	0.10	87	40	0.55	2.13	2.6E-03	0.15	0.08
Crane carrydeck	Diesel	2270003010	200	21%	2.68	4.60	3.9E-03	0.71	0.47	165	40	0.82	1.41	1.2E-03	0.22	0.14
Crane carrydeck	Diesel	2270003010	300	21%	2.68	4.60	3.9E-03	0.71	0.47	165	40	1.23	2.11	1.8E-03	0.33	0.22
RT crane - 35 ton	Diesel	2270002045	140	43%	0.50	1.82	3.0E-03	0.18	0.12	390	40	0.52	1.88	3.1E-03	0.18	0.13
RT crane - 50 ton	Diesel	2270002045	180	43%	0.37	1.67	3.0E-03	0.17	0.07	572	40	0.72	3.26	0.01	0.32	0.14
RT crane - 66 ton	Diesel	2270002045	220	43%	0.37	1.67	3.0E-03	0.17	0.07	572	40	0.88	3.99	0.01	0.40	0.18
RT crane - 75 ton	Diesel	2270002045	220	43%	0.37	1.67	3.0E-03	0.17	0.07	329	40	0.51	2.29	4.1E-03	0.23	0.10
RT crane - 80 ton	Diesel	2270002045	260	43%	0.37	1.67	3.0E-03	0.17	0.07	100	40	0.18	0.82	1.5E-03	0.08	0.04

Table 9.A.1.5 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
RT crane - 110 ton	Diesel	2270002045	300	43%	0.67	2.58	3.1E-03	0.18	0.10	52	40	0.20	0.76	9.2E-04	0.05	0.03
CLASS 15 FORKLIFT																
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	0.23	0.65	2.7E-03	0.14	0.04	312	40	0.28	0.79	3.2E-03	0.17	0.04
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	6.80	1.14	0.01	0.20	0.06	104	40	0.94	0.16	1.5E-03	0.03	0.01
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	0.82	1.99	3.1E-03	0.19	0.19	156	40	0.33	0.81	1.3E-03	0.08	0.08
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	0.23	0.65	2.7E-03	0.14	0.04	104	40	0.07	0.21	8.6E-04	0.04	0.01
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	0.23	0.65	2.7E-03	0.14	0.04	104	40	0.09	0.26	1.1E-03	0.06	0.01
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	0.23	0.65	2.7E-03	0.14	0.04	312	40	0.18	0.52	2.2E-03	0.11	0.03
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	0.23	0.65	2.7E-03	0.14	0.04	416	40	0.25	0.70	2.9E-03	0.15	0.04
CLASS 16 CONCRETE / AGGREGATE																
Concrete pump	Diesel	2270002042	350	43%	1.11	3.88	3.2E-03	0.26	0.15	152	40	1.12	3.91	3.3E-03	0.26	0.16
CLASS 17 AIR COMPRESSORS																
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.53	2.60	3.4E-03	0.25	0.22	407	40	0.95	1.61	2.1E-03	0.15	0.14
Air compressor 250 cfm	Diesel	2270006015	80	43%	1.53	2.60	3.4E-03	0.25	0.22	312	40	0.72	1.23	1.6E-03	0.12	0.11
Air compressor 375 cfm	Diesel	2270006015	115	43%	0.58	2.23	3.1E-03	0.20	0.14	312	40	0.40	1.52	2.1E-03	0.14	0.09
Air compressor 600 cfm	Diesel	2270006015	250	43%	0.45	2.05	3.0E-03	0.19	0.09	104	40	0.22	1.01	1.5E-03	0.09	0.04
Air compressor 750 cfm	Diesel	2270006015	275	43%	0.45	2.05	3.0E-03	0.19	0.09	104	40	0.24	1.11	1.6E-03	0.10	0.05
Air compressor 900 cfm	Diesel	2270006015	310	43%	0.83	3.02	3.2E-03	0.20	0.13	104	40	0.51	1.85	1.9E-03	0.12	0.08
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	-	52	40	-	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	0.83	3.02	3.2E-03	0.20	0.13	69	40	0.55	1.98	2.1E-03	0.13	0.08
CLASS 25 CABLE LAYING / PULLING EQUIPMENT																
Cable winch	Diesel	2270002081	26	59%	0.80	3.61	3.3E-03	0.19	0.12	234	40	0.13	0.57	5.2E-04	0.03	0.02
CLASS 52 WELDING EQUIPMENT																
Welder 400A trailer mount	Diesel	2270006025	32	21%	3.59	4.72	4.3E-03	0.80	0.57	2,288	40	2.43	3.20	2.9E-03	0.54	0.39
Welder 500A trailer mount	Diesel	2270006025	40	21%	3.59	4.72	4.3E-03	0.80	0.57	1,144	40	1.52	2.00	1.8E-03	0.34	0.24
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	5.15	5.33	4.7E-03	1.12	0.71	52	40	0.03	0.03	2.9E-05	0.01	4.4E-03
CLASS 53 GENERATION EQUIPMENT																
Generator set 150 kW	Diesel	2270006005	221	43%	0.98	3.65	3.2E-03	0.30	0.19	104	40	0.43	1.59	1.4E-03	0.13	0.08
Generator set 800 kW	Diesel	2270006005	1,125	0%	-	-	-	-	-	156	40	-	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1,425	0%	-	-	-	-	-	104	40	-	-	-	-	-
Light plant	Diesel	2270002027	14	43%	2.40	4.55	4.0E-03	0.47	0.35	2,513	40	1.60	3.03	2.6E-03	0.32	0.23

Table 9.A.1.5 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 54 MANLIFTS / SCISSORLIFTS																
Manlift - 40 ft	Diesel	2270003010	28	21%	5.44	5.26	4.3E-03	1.39	0.79	849	40	1.20	1.16	9.6E-04	0.31	0.17
Manlift - 60 ft	Diesel	2270003010	65	21%	4.77	5.27	4.4E-03	0.93	0.67	685	40	1.97	2.17	1.8E-03	0.38	0.28
Manlift - 80 ft	Diesel	2270003010	65	21%	4.77	5.27	4.4E-03	0.93	0.67	1,014	40	2.91	3.22	2.7E-03	0.57	0.41
Manlift - 125 ft	Diesel	2270003010	75	21%	5.30	4.72	4.3E-03	0.97	0.75	243	40	0.89	0.80	7.2E-04	0.16	0.13
Scissor lift - 60 ft	Diesel	2270003010	31	21%	5.44	5.26	4.3E-03	1.39	0.79	273	40	0.43	0.41	3.4E-04	0.11	0.06
CLASS 55,56 SMALL CAPITAL EQUIPMENT																
Compactor - 29'' manual	Diesel	2270002003	15	59%	2.37	4.46	4.0E-03	0.45	0.36	416	40	0.38	0.72	6.5E-04	0.07	0.06
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	286.01	1.81	0.02	4.85	0.11	312	40	43.48	0.28	2.9E-03	0.74	0.02
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	2.21	3.98	3.6E-03	0.44	0.40	416	40	1.40	2.51	2.3E-03	0.28	0.25
Water pump trash 316 gpm	Diesel	2270006010	7	43%	4.47	4.82	4.0E-03	0.65	0.46	416	40	0.23	0.25	2.0E-04	0.03	0.02
Water pump trash 611 gpm	Diesel	2270006010	15	43%	2.54	4.74	4.0E-03	0.53	0.37	208	40	0.15	0.28	2.3E-04	0.03	0.02
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.32	4.23	3.6E-03	0.31	0.25	416	40	0.36	1.17	9.8E-04	0.09	0.07
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	4.47	4.82	4.0E-03	0.65	0.46	416	40	0.18	0.19	1.6E-04	0.03	0.02
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	286.01	1.81	0.02	4.85	0.11	104	40	12.26	0.08	8.2E-04	0.21	4.9E-03
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	2.54	4.74	4.0E-03	0.53	0.37	416	40	0.32	0.60	5.0E-04	0.07	0.05
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	2.54	4.74	4.0E-03	0.53	0.37	416	40	0.46	0.86	7.2E-04	0.10	0.07
Compactor - 16" in manual	Diesel	2270002003	5	59%	2.37	4.46	4.0E-03	0.45	0.36	416	40	0.13	0.24	2.2E-04	0.02	0.02
Compactor - 26" in manual	Diesel	2270002003	9	59%	2.37	4.46	4.0E-03	0.45	0.36	416	40	0.23	0.43	3.9E-04	0.04	0.03
Tamper rammer	Diesel	2270002003	9	59%	2.37	4.46	4.0E-03	0.45	0.36	208	40	0.12	0.22	2.0E-04	0.02	0.02
Mortar mixer	Diesel	2270002042	5	43%	4.65	5.76	4.0E-03	0.81	0.60	208	40	0.09	0.11	7.8E-05	0.02	0.01
Concrete mixer	Gas	2265002042	5	59%	212.79	2.12	0.02	6.62	0.31	208	40	5.76	0.06	6.1E-04	0.18	0.01
Generator set 6 kW	Gas	2265006005	9	68%	286.71	1.89	0.02	4.92	0.11	416	40	32.18	0.21	2.1E-03	0.55	0.01
Generator set 10 kW	Gas	2265006005	15	68%	286.71	1.89	0.02	4.92	0.11	1,248	40	160.92	1.06	0.01	2.76	0.06
Concrete trowel 36"	Gas	2265002021	5	59%	212.19	2.11	0.02	6.30	0.32	182	40	5.02	0.05	5.3E-04	0.15	0.01
SOIL STABLIZATION & SITE PREP																
CAT D6M dozer	Diesel	2270002069	140	59%	0.61	1.41	2.9E-03	0.16	0.14	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.44	4.61	4.0E-03	0.49	0.36	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.32	1.07	2.8E-03	0.15	0.05	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.23	0.65	2.7E-03	0.14	0.04	-	40	-	-	-	-	-
Generator set 150 kW	Diesel	2270006005	221	43%	0.98	3.65	3.2E-03	0.30	0.19	-	40	-	-	-	-	-

Table 9.A.1.5 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	PM_{10}/ $PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	PM_{10}/ $PM_{2.5}$
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.32	4.23	3.6E-03	0.31	0.25	-	40	-	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.37	1.06	2.8E-03	0.14	0.05	-	40	-	-	-	-	-
Light plant	Diesel	2270002027	15	43%	2.40	4.55	4.0E-03	0.47	0.35	-	40	-	-	-	-	-
Water truck	Diesel	2270002051	427	59%	0.37	1.06	2.8E-03	0.14	0.05	-	40	-	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	0.66	1.63	3.0E-03	0.15	0.10	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.32	1.07	2.8E-03	0.15	0.05	-	40	-	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.37	1.06	2.8E-03	0.14	0.05	-	40	-	-	-	-	-
CAT D6M dozer	Diesel	2270002069	140	59%	0.61	1.41	2.9E-03	0.16	0.14	-	40	-	-	-	-	-
Motor graders	Diesel	2270002048	185	59%	0.41	1.25	2.8E-03	0.15	0.07	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	228	43%	2.44	4.61	4.0E-03	0.49	0.36	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.44	4.61	4.0E-03	0.49	0.36	-	40	-	-	-	-	-
Loader tool carrier	Diesel	2270001060	125	21%	2.96	4.37	3.9E-03	0.73	0.49	-	40	-	-	-	-	-
PILE DRIVING																
American 9310	Diesel	2270001060	285	21%	2.56	4.14	3.8E-03	0.66	0.41	-	40	-	-	-	-	-
American 9260	Diesel	2270001060	275	21%	2.56	4.14	3.8E-03	0.66	0.41	-	40	-	-	-	-	-
Pile hammer	Diesel	2270001060	60	21%	5.06	5.03	4.4E-03	0.95	0.69	-	40	-	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	4.77	5.27	4.4E-03	0.93	0.67	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.23	0.65	2.7E-03	0.14	0.04	-	40	-	-	-	-	-
Welder	Diesel	2270001060	50	21%	5.06	5.03	4.4E-03	0.95	0.69	-	40	-	-	-	-	-
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.53	2.60	3.4E-03	0.25	0.22	-	40	-	-	-	-	-
MISCELLANEOUS																
Tugs Twin Screw[4,5]	Diesel		350	31%	2.01	13.41	0.17	0.36	0.35	87	40	0.84	5.58	0.07	0.15	0.15
Total												**301.6**	**93.8**	**0.20**	**14.9**	**6.7**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2017, Cameron Parish, LA, except as noted
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.
4. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
5. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.6 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 06 PERSONNEL CARRIERS														
All terrain vehicle	Diesel	2270001060	22	21%	691	0.039	0.018	697	1564	40	220	0.01	0.01	224
CLASS 11 EARTHMOVING														
Dozer	Diesel	2270002069	159	59%	536	0.030	0.014	541	104	40	231	0.01	0.01	235
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	596	0.034	0.015	601	208	40	87	4.9E-03	2.2E-03	89
Excavator CAT 330BL	Diesel	2270002036	250	59%	536	0.030	0.014	541	156	40	544	0.03	0.01	554
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	52	40	250	0.01	0.01	255
Motor graders	Diesel	2270002048	183	59%	536	0.030	0.014	541	104	40	266	0.02	0.01	270
Loader backhoe	Diesel	2270002066	101	21%	625	0.035	0.016	630	208	40	122	0.01	3.1E-03	124
Loader tool carrier	Diesel	2270002066	134	21%	625	0.035	0.016	630	208	40	161	0.01	4.1E-03	164
Skidsteer loader	Diesel	2270002072	68	21%	693	0.039	0.018	699	208	40	91	0.01	2.3E-03	92
Rubber tire loader	Diesel	2270002060	249	59%	536	0.030	0.014	541	208	40	723	0.04	0.02	736
Tractor	Diesel	2270005015	115	59%	536	0.030	0.014	541	208	40	334	0.02	0.01	340
CLASS 12 PIPELAYING / TRENCHING EQUI														
Trencher	Diesel	2270002030	51	59%	595	0.034	0.015	601	35	40	28	1.6E-03	7.0E-04	28
CLASS 13 COMPACTION														
Soil compactor	Diesel	2270002009	339	43%	589	0.033	0.015	594	104	40	394	0.02	0.01	401
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	104	40	178	0.01	4.5E-03	181
CLASS 14 CRANES														
Crane crawler	Diesel	2270002045	285	43%	531	0.030	0.014	535	69	40	198	0.01	0.01	201
Crane crawler	Diesel	2270002045	300	43%	530	0.030	0.014	535	69	40	208	0.01	0.01	212
Crane crawler	Diesel	2270002045	340	43%	530	0.030	0.014	535	312	40	1,067	0.06	0.03	1,086
Crane crawler	Diesel	2270002045	600	43%	530	0.030	0.014	535	43	40	259	0.01	0.01	264
Crane crawler	Diesel	2270002045	500	43%	530	0.030	0.014	535	87	40	438	0.02	0.01	445
Crane carrydeck	Diesel	2270003010	200	21%	624	0.035	0.016	630	165	40	191	0.01	4.9E-03	194
Crane carrydeck	Diesel	2270003010	300	21%	624	0.035	0.016	630	165	40	286	0.02	0.01	291
RT crane - 35 ton	Diesel	2270002045	140	43%	530	0.030	0.014	535	390	40	549	0.03	0.01	559
RT crane - 50 ton	Diesel	2270002045	180	43%	531	0.030	0.014	535	572	40	1,036	0.06	0.03	1,054
RT crane - 66 ton	Diesel	2270002045	220	43%	531	0.030	0.014	535	572	40	1,266	0.07	0.03	1,289
RT crane - 75 ton	Diesel	2270002045	220	43%	531	0.030	0.014	535	329	40	728	0.04	0.02	741
RT crane - 80 ton	Diesel	2270002045	260	43%	531	0.030	0.014	535	100	40	262	0.01	0.01	266

Table 9.A.1.6 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
RT crane - 110 ton	Diesel	2270002045	300	43%	530	0.030	0.014	535	52	40	157	0.01	4.0E-03	160
CLASS 15 FORKLIFT														
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	312	40	653	0.04	0.02	665
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	553	0.031	0.013	557	104	40	76	4.3E-03	1.7E-03	77
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	536	0.030	0.014	541	156	40	218	0.01	0.01	222
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	536	0.030	0.014	541	104	40	174	0.01	4.4E-03	177
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	104	40	218	0.01	0.01	222
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	312	40	435	0.02	0.01	443
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	416	40	580	0.03	0.01	591
CLASS 16 CONCRETE / AGGREGATE														
Concrete pump	Diesel	2270002042	350	43%	530	0.030	0.014	535	152	40	535	0.03	0.01	545
CLASS 17 AIR COMPRESSORS														
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	407	40	364	0.02	0.01	371
Air compressor 250 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	312	40	279	0.02	0.01	284
Air compressor 375 cfm	Diesel	2270006015	115	43%	530	0.030	0.014	535	312	40	361	0.02	0.01	367
Air compressor 600 cfm	Diesel	2270006015	250	43%	530	0.030	0.014	535	104	40	261	0.01	0.01	266
Air compressor 750 cfm	Diesel	2270006015	275	43%	530	0.030	0.014	535	104	40	288	0.02	0.01	293
Air compressor 900 cfm	Diesel	2270006015	310	43%	530	0.030	0.014	535	104	40	324	0.02	0.01	330
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	52	40	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	530	0.030	0.014	535	69	40	347	0.02	0.01	353
CLASS 25 CABLE LAYING / PULLING EQUIP														
Cable winch	Diesel	2270002081	26	59%	596	0.034	0.015	601	234	40	94	0.01	2.4E-03	96
CLASS 52 WELDING EQUIPMENT														
Welder 400A trailer mount	Diesel	2270006025	32	21%	693	0.039	0.018	700	2288	40	470	0.03	0.01	479
Welder 500A trailer mount	Diesel	2270006025	40	21%	693	0.039	0.018	700	1144	40	294	0.02	0.01	299
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	692	0.039	0.018	699	52	40	4	2.5E-04	1.1E-04	4
CLASS 53 GENERATION EQUIPMENT														
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	104	40	231	0.01	0.01	235
Generator set 800 kW	Diesel	2270006005	1125	0%	-	-	-	-	156	40	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1425	0%	-	-	-	-	104	40	-	-	-	-
Light plant	Diesel	2270002027	14	43%	589	0.033	0.015	594	2513	40	393	0.02	0.01	400

Table 9.A.1.6 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6
(Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
			(hp)		CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 54 MANLIFTS / SCISSORLIFTS														
Manlift - 40 ft	Diesel	2270003010	28	21%	692	0.039	0.018	698	849	40	152	0.01	3.9E-03	155
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	685	40	286	0.02	0.01	291
Manlift - 80 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	1014	40	423	0.02	0.01	431
Manlift - 125 ft	Diesel	2270003010	75	21%	693	0.039	0.018	699	243	40	117	0.01	3.0E-03	119
Scissor lift - 60 ft	Diesel	2270003010	31	21%	692	0.039	0.018	698	273	40	54	3.1E-03	1.4E-03	55
CLASS 55,56 SMALL CAPITAL EQUIPMENT														
Compactor - 29'' manual	Diesel	2270002003	15	59%	595	0.034	0.015	600	416	40	97	0.01	2.5E-03	98
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	1,047	0.060	0.024	1,055	312	40	159	0.01	3.6E-03	162
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	589	0.033	0.015	594	416	40	372	0.02	0.01	378
Water pump trash 316 gpm	Diesel	2270006010	6.5	43%	588	0.033	0.015	594	416	40	30	1.7E-03	7.7E-04	31
Water pump trash 611 gpm	Diesel	2270006010	15	43%	589	0.033	0.015	594	208	40	35	2.0E-03	8.9E-04	35
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	416	40	163	0.01	4.1E-03	166
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	588	0.033	0.015	594	416	40	23	1.3E-03	5.9E-04	24
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	1,047	0.059	0.027	1,056	104	40	45	2.5E-03	1.1E-03	46
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	589	0.033	0.015	594	416	40	74	4.2E-03	1.9E-03	76
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	589	0.033	0.015	594	416	40	107	0.01	2.7E-03	109
Compactor - 16" in manual	Diesel	2270002003	5	59%	595	0.034	0.015	600	416	40	32	1.8E-03	8.2E-04	33
Compactor - 26" in manual	Diesel	2270002003	9	59%	595	0.034	0.015	600	416	40	58	3.3E-03	1.5E-03	59
Tamper rammer	Diesel	2270002003	9	59%	595	0.034	0.015	600	208	40	29	1.6E-03	7.4E-04	29
Mortar mixer	Diesel	2270002042	5	43%	588	0.033	0.015	593	208	40	12	6.6E-04	3.0E-04	12
Concrete mixer	Gas	2265002042	5	59%	1,228	0.070	0.028	1,238	208	40	33	1.9E-03	7.6E-04	34
Generator set 6 kW	Gas	2265006005	9	68%	1,047	0.060	0.024	1,055	416	40	117	0.01	2.7E-03	120
Generator set 10 kW	Gas	2265006005	15	68%	1,047	0.060	0.024	1,055	1248	40	587	0.03	0.01	598
Concrete trowel 36"	Gas	2265002021	5	59%	1,229	0.070	0.028	1,239	182	40	29	1.7E-03	6.6E-04	30
SOIL STABLIZATION & SITE PREP														
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	0	40	-	-	-	-
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	0	40	-	-	-	-

Table 9.A.1.6 - Liquefaction and CCTPL Expansion Project
2017 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	0	40	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
Light plant	Diesel	2270002027	15	43%	589	0.033	0.015	594	0	40	-	-	-	-
Water truck	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	0	40	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	0	40	-	-	-	-
Motor graders	Diesel	2270002048	185	59%	536	0.030	0.014	541	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	228	43%	589	0.033	0.015	594	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
Loader tool carrier	Diesel	2270001060	125	21%	624	0.035	0.016	630	0	40	-	-	-	-
PILE DRIVING														
American 9310	Diesel	2270001060	285	21%	624	0.035	0.016	630	0	40	-	-	-	-
American 9260	Diesel	2270001060	275	21%	624	0.035	0.016	630	0	40	-	-	-	-
Pile hammer	Diesel	2270001060	60	21%	693	0.039	0.018	699	0	40	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	699	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	0	40	-	-	-	-
Welder	Diesel	2270001060	50	21%	693	0.039	0.018	699	0	40	-	-	-	-
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	0	40	-	-	-	-
MISCELLANEOUS														
Tugs Twin Screw[4,5]	Diesel		350	31%	925	0.121	0.027	936	87	40	385	0.05	0.01	401
Total											**20,289**	**1.18**	**0.52**	**20,666**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2017, Cameron Parish, LA, except as noted
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.
5. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
6. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.7 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
			(hp)		CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 06 PERSONNEL CARRIERS																
All terrain vehicle	Diesel	2270001060	22	21%	6.49	5.94	4.7E-03	1.55	0.92	1,504	40	1.99	1.82	1.4E-03	0.47	0.28
CLASS 11 EARTHMOVING																
Dozer	Diesel	2270002069	159	59%	0.49	1.16	2.9E-03	0.15	0.11	91	40	0.19	0.43	1.1E-03	0.06	0.04
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	0.30	3.07	2.9E-03	0.14	0.03	182	40	0.04	0.39	3.7E-04	0.02	3.8E-03
Excavator CAT 330BL	Diesel	2270002036	250	59%	0.23	0.83	2.7E-03	0.14	0.03	113	40	0.17	0.61	2.0E-03	0.10	0.03
Excavator CAT 345B	Diesel	2270002036	345	59%	0.56	1.40	2.9E-03	0.15	0.08	4	40	0.02	0.05	1.0E-04	0.01	3.0E-03
Motor graders	Diesel	2270002048	183	59%	0.31	1.01	2.8E-03	0.15	0.05	91	40	0.13	0.44	1.2E-03	0.06	0.02
Loader backhoe	Diesel	2270002066	101	21%	1.96	3.34	3.7E-03	0.52	0.40	208	40	0.38	0.65	7.3E-04	0.10	0.08
Loader tool carrier	Diesel	2270002066	134	21%	1.96	3.34	3.7E-03	0.52	0.40	208	40	0.51	0.86	9.7E-04	0.13	0.10
Skidsteer loader	Diesel	2270002072	68	21%	4.90	4.98	4.3E-03	0.93	0.72	208	40	0.64	0.65	5.6E-04	0.12	0.09
Rubber tire loader	Diesel	2270002060	249	59%	0.46	1.36	2.9E-03	0.16	0.09	208	40	0.62	1.83	3.9E-03	0.21	0.11
Tractor	Diesel	2270005015	115	59%	1.01	2.50	3.2E-03	0.23	0.21	208	40	0.63	1.56	2.0E-03	0.15	0.13
CLASS 12 PIPELAYING / TRENCHING EQUIPMENT																
Trencher	Diesel	2270002030	51	59%	1.96	3.50	3.5E-03	0.24	0.22	-	40	-	-	-	-	-
CLASS 13 COMPACTION																
Soil compactor	Diesel	2270002009	339	43%	2.41	4.56	4.0E-03	0.48	0.35	91	40	1.41	2.67	2.3E-03	0.28	0.21
Soil compactor	Diesel	2270002009	153	43%	2.41	4.56	4.0E-03	0.48	0.35	91	40	0.64	1.20	1.0E-03	0.13	0.09
CLASS 14 CRANES																
Crane crawler	Diesel	2270002045	285	43%	0.32	1.43	2.9E-03	0.16	0.06	91	40	0.16	0.70	1.4E-03	0.08	0.03
Crane crawler	Diesel	2270002045	300	43%	0.60	2.31	3.1E-03	0.17	0.09	91	40	0.31	1.20	1.6E-03	0.09	0.05
Crane crawler	Diesel	2270002045	340	43%	0.60	2.31	3.1E-03	0.17	0.09	295	40	1.15	4.40	0.01	0.32	0.17
Crane crawler	Diesel	2270002045	600	43%	0.84	2.31	3.1E-03	0.17	0.09	87	40	0.83	2.29	3.0E-03	0.16	0.09
Crane crawler	Diesel	2270002045	500	43%	0.60	2.31	3.1E-03	0.17	0.09	87	40	0.50	1.91	2.5E-03	0.14	0.07
Crane carrydeck	Diesel	2270003010	200	21%	2.46	4.27	3.8E-03	0.66	0.44	173	40	0.79	1.37	1.2E-03	0.21	0.14
Crane carrydeck	Diesel	2270003010	300	21%	2.46	4.27	3.8E-03	0.66	0.44	173	40	1.18	2.05	1.8E-03	0.32	0.21
RT crane - 35 ton	Diesel	2270002045	140	43%	0.44	1.55	3.0E-03	0.17	0.11	347	40	0.40	1.43	2.7E-03	0.15	0.10
RT crane - 50 ton	Diesel	2270002045	180	43%	0.32	1.43	2.9E-03	0.16	0.06	451	40	0.49	2.20	4.4E-03	0.24	0.10
RT crane - 66 ton	Diesel	2270002045	220	43%	0.32	1.43	2.9E-03	0.16	0.06	451	40	0.60	2.69	0.01	0.30	0.12
RT crane - 75 ton	Diesel	2270002045	220	43%	0.32	1.43	2.9E-03	0.16	0.06	260	40	0.34	1.55	3.1E-03	0.17	0.07
RT crane - 80 ton	Diesel	2270002045	260	43%	0.32	1.43	2.9E-03	0.16	0.06	82	40	0.13	0.58	1.2E-03	0.06	0.03

Table 9.A.1.7 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
			(hp)		CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
RT crane - 110 ton	Diesel	2270002045	300	43%	0.60	2.31	3.1E-03	0.17	0.09	52	40	0.18	0.68	9.1E-04	0.05	0.03
CLASS 15 FORKLIFT																
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	0.18	0.45	2.6E-03	0.13	0.02	312	40	0.23	0.55	3.2E-03	0.16	0.03
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	6.10	1.05	0.01	0.18	0.06	104	40	0.84	0.14	1.5E-03	0.02	0.01
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	0.72	1.72	3.0E-03	0.18	0.17	156	40	0.29	0.70	1.2E-03	0.07	0.07
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	0.18	0.45	2.6E-03	0.13	0.02	104	40	0.06	0.15	8.5E-04	0.04	0.01
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	0.18	0.45	2.6E-03	0.13	0.02	104	40	0.08	0.18	1.1E-03	0.05	0.01
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	0.18	0.45	2.6E-03	0.13	0.02	312	40	0.15	0.36	2.1E-03	0.11	0.02
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	0.18	0.45	2.6E-03	0.13	0.02	416	40	0.20	0.48	2.8E-03	0.15	0.02
CLASS 16 CONCRETE / AGGREGATE																
Concrete pump	Diesel	2270002042	350	43%	1.02	3.59	3.2E-03	0.24	0.14	104	40	0.70	2.48	2.2E-03	0.17	0.10
CLASS 17 AIR COMPRESSORS																
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.38	2.28	3.4E-03	0.23	0.20	416	40	0.87	1.44	2.1E-03	0.14	0.13
Air compressor 250 cfm	Diesel	2270006015	80	43%	1.38	2.28	3.4E-03	0.23	0.20	312	40	0.65	1.08	1.6E-03	0.11	0.09
Air compressor 375 cfm	Diesel	2270006015	115	43%	0.52	1.95	3.0E-03	0.19	0.12	312	40	0.35	1.32	2.1E-03	0.13	0.08
Air compressor 600 cfm	Diesel	2270006015	250	43%	0.40	1.78	3.0E-03	0.17	0.08	104	40	0.19	0.88	1.5E-03	0.09	0.04
Air compressor 750 cfm	Diesel	2270006015	275	43%	0.40	1.78	3.0E-03	0.17	0.08	104	40	0.21	0.97	1.6E-03	0.09	0.04
Air compressor 900 cfm	Diesel	2270006015	310	43%	0.76	2.76	3.1E-03	0.19	0.12	104	40	0.46	1.69	1.9E-03	0.12	0.07
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	-	52	40	-	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	0.76	2.76	3.1E-03	0.19	0.12	104	40	0.75	2.72	3.1E-03	0.19	0.11
CLASS 25 CABLE LAYING / PULLING EQUIPMENT																
Cable winch	Diesel	2270002081	26	59%	0.62	3.43	3.1E-03	0.17	0.09	312	40	0.13	0.72	6.6E-04	0.04	0.02
CLASS 52 WELDING EQUIPMENT																
Welder 400A trailer mount	Diesel	2270006025	32	21%	3.21	4.56	4.2E-03	0.71	0.52	2,912	40	2.77	3.93	3.6E-03	0.61	0.44
Welder 500A trailer mount	Diesel	2270006025	40	21%	3.21	4.56	4.2E-03	0.71	0.52	1,456	40	1.73	2.46	2.3E-03	0.38	0.28
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	4.73	5.17	4.7E-03	1.01	0.64	-	40	-	-	-	-	-
CLASS 53 GENERATION EQUIPMENT																
Generator set 150 kW	Diesel	2270006005	221	43%	0.89	3.39	3.2E-03	0.29	0.17	104	40	0.39	1.48	1.4E-03	0.12	0.08
Generator set 800 kW	Diesel	2270006005	1,125	0%	-	-	-	-	-	204	40	-	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1,425	0%	-	-	-	-	-	104	40	-	-	-	-	-
Light plant	Diesel	2270002027	14	43%	2.38	4.52	4.0E-03	0.46	0.35	3,120	40	1.97	3.74	3.3E-03	0.38	0.29

Table 9.A.1.7 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6
(Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
			(hp)		CO[2]	NO_x[2]	SO_2[2]	VOC[2]	PM_{10}/ $PM_{2.5}$[2,3]	weeks	hrs/week	CO	NO_x	SO_2	VOC	PM_{10}/ $PM_{2.5}$
CLASS 54 MANLIFTS / SCISSORLIFTS																
Manlift - 40 ft	Diesel	2270003010	28	21%	5.02	5.10	4.3E-03	1.27	0.73	1,040	40	1.35	1.37	1.2E-03	0.34	0.20
Manlift - 60 ft	Diesel	2270003010	65	21%	4.48	5.08	4.3E-03	0.87	0.62	832	40	2.24	2.54	2.2E-03	0.43	0.31
Manlift - 80 ft	Diesel	2270003010	65	21%	4.48	5.08	4.3E-03	0.87	0.62	1,248	40	3.36	3.82	3.2E-03	0.65	0.47
Manlift - 125 ft	Diesel	2270003010	75	21%	4.99	4.41	4.2E-03	0.90	0.70	277	40	0.96	0.85	8.1E-04	0.17	0.13
Scissor lift - 60 ft	Diesel	2270003010	31	21%	5.02	5.10	4.3E-03	1.27	0.73	312	40	0.45	0.46	3.8E-04	0.11	0.07
CLASS 55,56 SMALL CAPITAL EQUIPMENT																
Compactor - 29'' manual	Diesel	2270002003	15	59%	2.37	4.46	4.0E-03	0.45	0.36	416	40	0.38	0.72	6.5E-04	0.07	0.06
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	285.33	1.77	0.02	4.77	0.11	312	40	43.37	0.27	2.9E-03	0.73	0.02
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	2.08	3.73	3.6E-03	0.42	0.37	416	40	1.31	2.35	2.3E-03	0.26	0.23
Water pump trash 316 gpm	Diesel	2270006010	7	43%	4.46	4.71	4.0E-03	0.63	0.44	416	40	0.23	0.24	2.0E-04	0.03	0.02
Water pump trash 611 gpm	Diesel	2270006010	15	43%	2.49	4.68	4.0E-03	0.52	0.37	208	40	0.15	0.28	2.3E-04	0.03	0.02
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.18	4.09	3.5E-03	0.28	0.22	416	40	0.33	1.13	9.6E-04	0.08	0.06
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	4.46	4.71	4.0E-03	0.63	0.44	416	40	0.18	0.19	1.6E-04	0.02	0.02
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	285.33	1.77	0.02	4.77	0.11	104	40	12.23	0.08	8.2E-04	0.20	4.9E-03
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	2.49	4.68	4.0E-03	0.52	0.37	416	40	0.31	0.59	5.0E-04	0.07	0.05
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	2.49	4.68	4.0E-03	0.52	0.37	416	40	0.45	0.85	7.2E-04	0.09	0.07
Compactor - 16" in manual	Diesel	2270002003	5	59%	2.37	4.46	4.0E-03	0.45	0.36	416	40	0.13	0.24	2.2E-04	0.02	0.02
Compactor - 26" in manual	Diesel	2270002003	9	59%	2.37	4.46	4.0E-03	0.45	0.36	416	40	0.23	0.43	3.9E-04	0.04	0.03
Tamper rammer	Diesel	2270002003	9	59%	2.37	4.46	4.0E-03	0.45	0.36	208	40	0.12	0.22	2.0E-04	0.02	0.02
Mortar mixer	Diesel	2270002042	5	43%	4.62	5.58	4.0E-03	0.78	0.57	199	40	0.09	0.11	7.5E-05	0.01	0.01
Concrete mixer	Gas	2265002042	5	59%	211.48	2.08	0.02	6.23	0.30	199	40	5.47	0.05	5.8E-04	0.16	0.01
Generator set 6 kW	Gas	2265006005	9	68%	285.60	1.81	0.02	4.80	0.11	416	40	32.06	0.20	2.1E-03	0.54	0.01
Generator set 10 kW	Gas	2265006005	15	68%	285.60	1.81	0.02	4.80	0.11	1,248	40	160.30	1.02	0.01	2.70	0.06
Concrete trowel 36"	Gas	2265002021	5	59%	212.19	2.11	0.02	6.30	0.32	95	40	2.62	0.03	2.8E-04	0.08	4.0E-03
SOIL STABLIZATION & SITE PREP																
CAT D6M dozer	Diesel	2270002069	140	59%	0.49	1.16	2.9E-03	0.15	0.11	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.41	4.56	4.0E-03	0.48	0.35	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.23	0.83	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.18	0.45	2.6E-03	0.13	0.02	-	40	-	-	-	-	-
Generator set 150 kW	Diesel	2270006005	221	43%	0.89	3.39	3.2E-03	0.29	0.17	-	40	-	-	-	-	-

Table 9.A.1.7 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.18	4.09	3.5E-03	0.28	0.22	-	40	-	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.27	0.82	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Light plant	Diesel	2270002027	15	43%	2.38	4.52	4.0E-03	0.46	0.35	-	40	-	-	-	-	-
Water truck	Diesel	2270002051	427	59%	0.27	0.82	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	0.56	1.40	2.9E-03	0.15	0.08	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.23	0.83	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.27	0.82	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
CAT D6M dozer	Diesel	2270002069	140	59%	0.49	1.16	2.9E-03	0.15	0.11	-	40	-	-	-	-	-
Motor graders	Diesel	2270002048	185	59%	0.31	1.01	2.8E-03	0.15	0.05	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	228	43%	2.41	4.56	4.0E-03	0.48	0.35	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.41	4.56	4.0E-03	0.48	0.35	-	40	-	-	-	-	-
Loader tool carrier	Diesel	2270001060	125	21%	2.71	4.07	3.8E-03	0.68	0.45	-	40	-	-	-	-	-
PILE DRIVING																
American 9310	Diesel	2270001060	285	21%	2.33	3.84	3.8E-03	0.61	0.37	-	40	-	-	-	-	-
American 9260	Diesel	2270001060	275	21%	2.33	3.84	3.8E-03	0.61	0.37	-	40	-	-	-	-	-
Pile hammer	Diesel	2270001060	60	21%	4.74	4.87	4.3E-03	0.88	0.64	-	40	-	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	4.48	5.08	4.3E-03	0.87	0.62	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.18	0.45	2.6E-03	0.13	0.02	-	40	-	-	-	-	-
Welder	Diesel	2270001060	50	21%	4.74	4.87	4.3E-03	0.88	0.64	-	40	-	-	-	-	-
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.38	2.28	3.4E-03	0.23	0.20	-	40	-	-	-	-	-
MISCELLANEOUS																
Tugs Twin Screw[4,5]	Diesel		350	31%	2.01	13.41	0.17	0.36	0.35	39	40	0.38	2.50	0.03	0.07	0.07
Total												**296.2**	**84.2**	**0.16**	**14.3**	**6.3**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2018, Cameron Parish, LA, except as noted
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.
4. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
5. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.8 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
			(hp)		CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 06 PERSONNEL CARRIERS														
All terrain vehicle	Diesel	2270001060	22	21%	691	0.039	0.018	697	1504	40	212	0.01	0.01	216
CLASS 11 EARTHMOVING														
Dozer	Diesel	2270002069	159	59%	536	0.030	0.014	541	91	40	202	0.01	0.01	206
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	596	0.034	0.015	601	182	40	76	4.3E-03	1.9E-03	78
Excavator CAT 330BL	Diesel	2270002036	250	59%	536	0.030	0.014	541	113	40	394	0.02	0.01	401
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	4	40	19	1.1E-03	4.9E-04	20
Motor graders	Diesel	2270002048	183	59%	536	0.030	0.014	541	91	40	232	0.01	0.01	237
Loader backhoe	Diesel	2270002066	101	21%	625	0.035	0.016	631	208	40	122	0.01	3.1E-03	124
Loader tool carrier	Diesel	2270002066	134	21%	625	0.035	0.016	631	208	40	161	0.01	4.1E-03	164
Skidsteer loader	Diesel	2270002072	68	21%	693	0.039	0.018	699	208	40	91	0.01	2.3E-03	92
Rubber tire loader	Diesel	2270002060	249	59%	536	0.030	0.014	541	208	40	723	0.04	0.02	736
Tractor	Diesel	2270005015	115	59%	536	0.030	0.014	541	208	40	334	0.02	0.01	340
CLASS 12 PIPELAYING / TRENCHING EQUI														
Trencher	Diesel	2270002030	51	59%	595	0.034	0.015	601	0	40	-	-	-	-
CLASS 13 COMPACTION														
Soil compactor	Diesel	2270002009	339	43%	589	0.033	0.015	594	91	40	344	0.02	0.01	351
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	91	40	155	0.01	4.0E-03	158
CLASS 14 CRANES														
Crane crawler	Diesel	2270002045	285	43%	531	0.030	0.014	535	91	40	261	0.01	0.01	266
Crane crawler	Diesel	2270002045	300	43%	530	0.030	0.014	535	91	40	275	0.02	0.01	280
Crane crawler	Diesel	2270002045	340	43%	530	0.030	0.014	535	295	40	1,009	0.06	0.03	1,027
Crane crawler	Diesel	2270002045	600	43%	531	0.030	0.014	535	87	40	525	0.03	0.01	535
Crane crawler	Diesel	2270002045	500	43%	530	0.030	0.014	535	87	40	438	0.02	0.01	445
Crane carrydeck	Diesel	2270003010	200	21%	624	0.035	0.016	630	173	40	200	0.01	0.01	204
Crane carrydeck	Diesel	2270003010	300	21%	624	0.035	0.016	630	173	40	300	0.02	0.01	306
RT crane - 35 ton	Diesel	2270002045	140	43%	531	0.030	0.014	535	347	40	489	0.03	0.01	497
RT crane - 50 ton	Diesel	2270002045	180	43%	531	0.030	0.014	535	451	40	817	0.05	0.02	831
RT crane - 66 ton	Diesel	2270002045	220	43%	531	0.030	0.014	535	451	40	998	0.06	0.03	1,016
RT crane - 75 ton	Diesel	2270002045	220	43%	531	0.030	0.014	535	260	40	575	0.03	0.01	586
RT crane - 80 ton	Diesel	2270002045	260	43%	531	0.030	0.014	535	82	40	214	0.01	0.01	218

Comments - Exhibit 5

Table 9.A.1.8 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
RT crane - 110 ton	Diesel	2270002045	300	43%	530	0.030	0.014	535	52	40	157	0.01	4.0E-03	160
CLASS 15 FORKLIFT														
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	312	40	653	0.04	0.02	665
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	552	0.031	0.013	556	104	40	76	4.3E-03	1.7E-03	77
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	536	0.030	0.014	541	156	40	218	0.01	0.01	222
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	536	0.030	0.014	541	104	40	174	0.01	4.4E-03	177
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	104	40	218	0.01	0.01	222
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	312	40	435	0.02	0.01	443
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	416	40	580	0.03	0.01	591
CLASS 16 CONCRETE / AGGREGATE														
Concrete pump	Diesel	2270002042	350	43%	530	0.030	0.014	535	104	40	366	0.02	0.01	373
CLASS 17 AIR COMPRESSORS														
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	416	40	372	0.02	0.01	379
Air compressor 250 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	312	40	279	0.02	0.01	284
Air compressor 375 cfm	Diesel	2270006015	115	43%	530	0.030	0.014	535	312	40	361	0.02	0.01	367
Air compressor 600 cfm	Diesel	2270006015	250	43%	530	0.030	0.014	535	104	40	262	0.01	0.01	266
Air compressor 750 cfm	Diesel	2270006015	275	43%	530	0.030	0.014	535	104	40	288	0.02	0.01	293
Air compressor 900 cfm	Diesel	2270006015	310	43%	530	0.030	0.014	535	104	40	324	0.02	0.01	330
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	52	40	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	530	0.030	0.014	535	104	40	523	0.03	0.01	532
CLASS 25 CABLE LAYING / PULLING EQUIP														
Cable winch	Diesel	2270002081	26	59%	596	0.034	0.015	601	312	40	126	0.01	3.2E-03	128
CLASS 52 WELDING EQUIPMENT														
Welder 400A trailer mount	Diesel	2270006025	32	21%	694	0.039	0.018	700	2912	40	599	0.03	0.02	609
Welder 500A trailer mount	Diesel	2270006025	40	21%	694	0.039	0.018	700	1456	40	374	0.02	0.01	381
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	693	0.039	0.018	699	0	40	-	-	-	-
CLASS 53 GENERATION EQUIPMENT														
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	104	40	231	0.01	0.01	235
Generator set 800 kW	Diesel	2270006005	1125	0%	-	-	-	-	204	40	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1425	0%	-	-	-	-	104	40	-	-	-	-
Light plant	Diesel	2270002027	14	43%	589	0.033	0.015	594	3120	40	488	0.03	0.01	497

Table 9.A.1.8 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 54 MANLIFTS / SCISSORLIFTS														
Manlift - 40 ft	Diesel	2270003010	28	21%	692	0.039	0.018	698	1040	40	187	0.01	4.8E-03	190
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	700	832	40	347	0.02	0.01	353
Manlift - 80 ft	Diesel	2270003010	65	21%	693	0.039	0.018	700	1248	40	521	0.03	0.01	530
Manlift - 125 ft	Diesel	2270003010	75	21%	693	0.039	0.018	699	277	40	133	0.01	3.4E-03	136
Scissor lift - 60 ft	Diesel	2270003010	31	21%	692	0.039	0.018	698	312	40	62	3.5E-03	1.6E-03	63
CLASS 55,56 SMALL CAPITAL EQUIPMENT														
Compactor - 29" manual	Diesel	2270002003	15	59%	595	0.034	0.015	600	416	40	97	0.01	2.5E-03	98
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	1,047	0.060	0.024	1,055	312	40	159	0.01	3.6E-03	162
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	589	0.033	0.015	594	416	40	372	0.02	0.01	378
Water pump trash 316 gpm	Diesel	2270006010	6.5	43%	588	0.033	0.015	594	416	40	30	1.7E-03	7.7E-04	31
Water pump trash 611 gpm	Diesel	2270006010	15	43%	589	0.033	0.015	594	208	40	35	2.0E-03	8.9E-04	35
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	416	40	163	0.01	4.1E-03	166
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	588	0.033	0.015	594	416	40	23	1.3E-03	5.9E-04	24
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	1,047	0.059	0.027	1,056	104	40	45	2.5E-03	1.1E-03	46
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	589	0.033	0.015	594	416	40	74	4.2E-03	1.9E-03	76
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	589	0.033	0.015	594	416	40	107	0.01	2.7E-03	109
Compactor - 16" in manual	Diesel	2270002003	5	59%	595	0.034	0.015	600	416	40	32	1.8E-03	8.2E-04	33
Compactor - 26" in manual	Diesel	2270002003	9	59%	595	0.034	0.015	600	416	40	58	3.3E-03	1.5E-03	59
Tamper rammer	Diesel	2270002003	9	59%	595	0.034	0.015	600	208	40	29	1.6E-03	7.4E-04	29
Mortar mixer	Diesel	2270002042	5	43%	588	0.033	0.015	593	199	40	11	6.3E-04	2.8E-04	11
Concrete mixer	Gas	2265002042	5	59%	1,229	0.070	0.028	1,240	199	40	32	1.8E-03	7.2E-04	32
Generator set 6 kW	Gas	2265006005	9	68%	1,047	0.060	0.024	1,055	416	40	118	0.01	2.7E-03	120
Generator set 10 kW	Gas	2265006005	15	68%	1,047	0.060	0.024	1,055	1248	40	588	0.03	0.01	598
Concrete trowel 36"	Gas	2265002021	5	59%	1,229	0.070	0.028	1,239	95	40	15	8.6E-04	3.5E-04	15
SOIL STABLIZATION & SITE PREP														
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	0	40	-	-	-	-
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.013	535	0	40	-	-	-	-

Table 9.A.1.8 - Liquefaction and CCTPL Expansion Project
2018 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	589	0.033	0.015	595	0	40	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
Light plant	Diesel	2270002027	15	43%	589	0.033	0.015	594	0	40	-	-	-	-
Water truck	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	0	40	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	0	40	-	-	-	-
Motor graders	Diesel	2270002048	185	59%	536	0.030	0.014	541	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	228	43%	589	0.033	0.015	594	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
Loader tool carrier	Diesel	2270001060	125	21%	624	0.035	0.016	630	0	40	-	-	-	-
PILE DRIVING														
American 9310	Diesel	2270001060	285	21%	625	0.035	0.016	630	0	40	-	-	-	-
American 9260	Diesel	2270001060	275	21%	625	0.035	0.016	630	0	40	-	-	-	-
Pile hammer	Diesel	2270001060	60	21%	693	0.039	0.018	699	0	40	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	700	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	0	40	-	-	-	-
Welder	Diesel	2270001060	50	21%	693	0.039	0.018	699	0	40	-	-	-	-
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	0	40	-	-	-	-
MISCELLANEOUS														
Tugs Twin Screw[4,5]	Diesel		350	31%	925	0.121	0.027	936	39	40	173	0.02	0.01	180
Total											**19,677**	**1.13**	**0.50**	**20,038**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2018, Cameron Parish, LA, except as noted
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.
5. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
6. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.9 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 06 PERSONNEL CARRIERS																
All terrain vehicle	Diesel	2270001060	22	21%	6.12	5.79	4.7E-03	1.44	0.87	542	40	0.68	0.64	5.1E-04	0.16	0.10
CLASS 11 EARTHMOVING																
Dozer	Diesel	2270002069	159	59%	0.38	0.92	2.8E-03	0.15	0.08	26	40	0.04	0.10	3.0E-04	0.02	0.01
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	0.27	3.03	2.9E-03	0.13	0.02	35	40	0.01	0.07	7.1E-05	3.3E-03	6.1E-04
Excavator CAT 330BL	Diesel	2270002036	250	59%	0.19	0.67	2.7E-03	0.14	0.03	26	40	0.03	0.11	4.5E-04	0.02	4.5E-03
Excavator CAT 345B	Diesel	2270002036	345	59%	0.47	1.19	2.8E-03	0.14	0.07	-	40	-	-	-	-	-
Motor graders	Diesel	2270002048	183	59%	0.23	0.80	2.7E-03	0.14	0.03	26	40	0.03	0.10	3.3E-04	0.02	4.2E-03
Loader backhoe	Diesel	2270002066	101	21%	1.80	3.05	3.7E-03	0.48	0.36	78	40	0.13	0.22	2.7E-04	0.03	0.03
Loader tool carrier	Diesel	2270002066	134	21%	1.80	3.05	3.7E-03	0.48	0.36	78	40	0.17	0.29	3.6E-04	0.05	0.04
Skidsteer loader	Diesel	2270002072	68	21%	4.58	4.81	4.2E-03	0.85	0.67	78	40	0.22	0.24	2.1E-04	0.04	0.03
Rubber tire loader	Diesel	2270002060	249	59%	0.38	1.14	2.8E-03	0.15	0.07	78	40	0.19	0.58	1.4E-03	0.08	0.03
Tractor	Diesel	2270005015	115	59%	0.91	2.23	3.1E-03	0.22	0.19	78	40	0.21	0.52	7.3E-04	0.05	0.04
CLASS 12 PIPELAYING / TRENCHING EQUIPMENT																
Trencher	Diesel	2270002030	51	59%	1.74	3.39	3.4E-03	0.22	0.19	-	40	-	-	-	-	-
CLASS 13 COMPACTION																
Soil compactor	Diesel	2270002009	339	43%	2.39	4.53	4.0E-03	0.47	0.35	4	40	0.06	0.12	1.0E-04	0.01	0.01
Soil compactor	Diesel	2270002009	153	43%	2.39	4.53	4.0E-03	0.47	0.35	4	40	0.03	0.05	4.6E-05	0.01	4.1E-03
CLASS 14 CRANES																
Crane crawler	Diesel	2270002045	285	43%	0.26	1.21	2.8E-03	0.15	0.05	26	40	0.04	0.17	3.9E-04	0.02	0.01
Crane crawler	Diesel	2270002045	300	43%	0.54	2.06	3.0E-03	0.16	0.08	26	40	0.08	0.30	4.5E-04	0.02	0.01
Crane crawler	Diesel	2270002045	340	43%	0.54	2.06	3.0E-03	0.16	0.08	52	40	0.18	0.69	1.0E-03	0.05	0.03
Crane crawler	Diesel	2270002045	600	43%	0.77	2.06	3.0E-03	0.16	0.09	-	40	-	-	-	-	-
Crane crawler	Diesel	2270002045	500	43%	0.54	2.06	3.0E-03	0.16	0.08	-	40	-	-	-	-	-
Crane carrydeck	Diesel	2270003010	200	21%	2.26	3.95	3.8E-03	0.62	0.41	-	40	-	-	-	-	-
Crane carrydeck	Diesel	2270003010	300	21%	2.26	3.95	3.8E-03	0.62	0.41	-	40	-	-	-	-	-
RT crane - 35 ton	Diesel	2270002045	140	43%	0.37	1.32	2.9E-03	0.16	0.09	113	40	0.11	0.40	8.6E-04	0.05	0.03
RT crane - 50 ton	Diesel	2270002045	180	43%	0.26	1.21	2.8E-03	0.15	0.05	87	40	0.08	0.36	8.3E-04	0.05	0.02
RT crane - 66 ton	Diesel	2270002045	220	43%	0.26	1.21	2.8E-03	0.15	0.05	113	40	0.12	0.57	1.3E-03	0.07	0.02
RT crane - 75 ton	Diesel	2270002045	220	43%	0.26	1.21	2.8E-03	0.15	0.05	26	40	0.03	0.13	3.0E-04	0.02	0.01
RT crane - 80 ton	Diesel	2270002045	260	43%	0.26	1.21	2.8E-03	0.15	0.05	22	40	0.03	0.13	3.0E-04	0.02	0.01

Table 9.A.1.9 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6
(Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
RT crane - 110 ton	Diesel	2270002045	300	43%	0.54	2.06	3.0E-03	0.16	0.08	22	40	0.07	0.26	3.8E-04	0.02	0.01
CLASS 15 FORKLIFT																
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	0.16	0.37	2.6E-03	0.13	0.02	152	40	0.09	0.22	1.5E-03	0.08	0.01
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	5.59	0.99	0.01	0.16	0.06	65	40	0.48	0.08	9.2E-04	0.01	5.0E-03
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	0.63	1.48	3.0E-03	0.17	0.14	91	40	0.15	0.35	7.0E-04	0.04	0.03
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	0.16	0.37	2.6E-03	0.13	0.02	39	40	0.02	0.04	3.2E-04	0.02	1.9E-03
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	0.16	0.37	2.6E-03	0.13	0.02	69	40	0.04	0.10	7.0E-04	0.04	4.2E-03
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	0.16	0.37	2.6E-03	0.13	0.02	113	40	0.05	0.11	7.6E-04	0.04	4.6E-03
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	0.16	0.37	2.6E-03	0.13	0.02	139	40	0.06	0.13	9.4E-04	0.05	0.01
CLASS 16 CONCRETE / AGGREGATE																
Concrete pump	Diesel	2270002042	350	43%	0.93	3.32	3.2E-03	0.23	0.13	17	40	0.10	0.37	3.6E-04	0.03	0.01
CLASS 17 AIR COMPRESSORS																
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.23	1.99	3.3E-03	0.21	0.17	156	40	0.29	0.47	7.8E-04	0.05	0.04
Air compressor 250 cfm	Diesel	2270006015	80	43%	1.23	1.99	3.3E-03	0.21	0.17	139	40	0.26	0.42	7.0E-04	0.04	0.04
Air compressor 375 cfm	Diesel	2270006015	115	43%	0.46	1.68	3.0E-03	0.18	0.11	121	40	0.12	0.44	7.8E-04	0.05	0.03
Air compressor 600 cfm	Diesel	2270006015	250	43%	0.35	1.54	2.9E-03	0.16	0.07	35	40	0.06	0.26	4.8E-04	0.03	0.01
Air compressor 750 cfm	Diesel	2270006015	275	43%	0.35	1.54	2.9E-03	0.16	0.07	35	40	0.06	0.28	5.3E-04	0.03	0.01
Air compressor 900 cfm	Diesel	2270006015	310	43%	0.69	2.50	3.1E-03	0.18	0.10	52	40	0.21	0.77	9.4E-04	0.06	0.03
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	-	17	40	-	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	0.69	2.50	3.1E-03	0.18	0.10	17	40	0.11	0.40	5.0E-04	0.03	0.02
CLASS 25 CABLE LAYING / PULLING EQUIPMENT																
Cable winch	Diesel	2270002081	26	59%	0.47	3.26	3.0E-03	0.15	0.06	91	40	0.03	0.20	1.9E-04	0.01	3.8E-03
CLASS 52 WELDING EQUIPMENT																
Welder 400A trailer mount	Diesel	2270006025	32	21%	2.88	4.41	4.1E-03	0.63	0.46	693	40	0.59	0.90	8.5E-04	0.13	0.09
Welder 500A trailer mount	Diesel	2270006025	40	21%	2.88	4.41	4.1E-03	0.63	0.46	312	40	0.33	0.51	4.8E-04	0.07	0.05
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	4.41	5.06	4.7E-03	0.93	0.60	-	40	-	-	-	-	-
CLASS 53 GENERATION EQUIPMENT																
Generator set 150 kW	Diesel	2270006005	221	43%	0.81	3.13	3.1E-03	0.27	0.16	61	40	0.21	0.80	8.0E-04	0.07	0.04
Generator set 800 kW	Diesel	2270006005	1,125	0%	-	-	-	-	-	121	40	-	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1,425	0%	-	-	-	-	-	82	40	-	-	-	-	-
Light plant	Diesel	2270002027	14	43%	2.36	4.50	4.0E-03	0.46	0.35	832	40	0.52	0.99	8.8E-04	0.10	0.08

Table 9.A.1.9 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
			(hp)		CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
CLASS 54 MANLIFTS / SCISSORLIFTS																
Manlift - 40 ft	Diesel	2270003010	28	21%	4.61	4.94	4.2E-03	1.16	0.68	329	40	0.39	0.42	3.6E-04	0.10	0.06
Manlift - 60 ft	Diesel	2270003010	65	21%	4.19	4.90	4.2E-03	0.80	0.57	269	40	0.68	0.79	6.9E-04	0.13	0.09
Manlift - 80 ft	Diesel	2270003010	65	21%	4.19	4.90	4.2E-03	0.80	0.57	390	40	0.98	1.15	1.0E-03	0.19	0.13
Manlift - 125 ft	Diesel	2270003010	75	21%	4.69	4.11	4.2E-03	0.83	0.64	52	40	0.17	0.15	1.5E-04	0.03	0.02
Scissor lift - 60 ft	Diesel	2270003010	31	21%	4.61	4.94	4.2E-03	1.16	0.68	117	40	0.15	0.17	1.4E-04	0.04	0.02
CLASS 55,56 SMALL CAPITAL EQUIPMENT																
Compactor - 29'' manual	Diesel	2270002003	15	59%	2.37	4.46	4.0E-03	0.45	0.36	87	40	0.08	0.15	1.4E-04	0.02	0.01
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	284.98	1.74	0.02	4.73	0.11	104	40	14.44	0.09	9.7E-04	0.24	0.01
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	1.95	3.48	3.5E-03	0.39	0.34	104	40	0.31	0.55	5.6E-04	0.06	0.05
Water pump trash 316 gpm	Diesel	2270006010	7	43%	4.46	4.61	4.0E-03	0.61	0.42	139	40	0.08	0.08	6.8E-05	0.01	0.01
Water pump trash 611 gpm	Diesel	2270006010	15	43%	2.46	4.63	4.0E-03	0.50	0.36	69	40	0.05	0.09	7.8E-05	0.01	0.01
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.05	3.96	3.4E-03	0.26	0.19	139	40	0.10	0.37	3.1E-04	0.02	0.02
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	4.46	4.61	4.0E-03	0.61	0.42	104	40	0.04	0.05	3.9E-05	0.01	4.2E-03
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	284.98	1.74	0.02	4.73	0.11	35	40	4.11	0.03	2.8E-04	0.07	1.7E-03
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	2.46	4.63	4.0E-03	0.50	0.36	139	40	0.10	0.20	1.7E-04	0.02	0.02
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	2.46	4.63	4.0E-03	0.50	0.36	139	40	0.15	0.28	2.4E-04	0.03	0.02
Compactor - 16" in manual	Diesel	2270002003	5	59%	2.37	4.46	4.0E-03	0.45	0.36	87	40	0.03	0.05	4.5E-05	0.01	4.1E-03
Compactor - 26" in manual	Diesel	2270002003	9	59%	2.37	4.46	4.0E-03	0.45	0.36	87	40	0.05	0.09	8.2E-05	0.01	0.01
Tamper rammer	Diesel	2270002003	9	59%	2.37	4.46	4.0E-03	0.45	0.36	52	40	0.03	0.05	4.9E-05	0.01	4.4E-03
Mortar mixer	Diesel	2270002042	5	43%	4.58	5.40	4.0E-03	0.75	0.54	39	40	0.02	0.02	1.5E-05	2.8E-03	2.0E-03
Concrete mixer	Gas	2265002042	5	59%	210.93	2.06	0.02	6.05	0.30	39	40	1.07	0.01	1.1E-04	0.03	1.5E-03
Generator set 6 kW	Gas	2265006005	9	68%	284.91	1.76	0.02	4.73	0.11	104	40	8.00	0.05	5.4E-04	0.13	3.2E-03
Generator set 10 kW	Gas	2265006005	15	68%	284.91	1.76	0.02	4.73	0.11	295	40	37.80	0.23	2.5E-03	0.63	0.01
Concrete trowel 36"	Gas	2265002021	5	59%	212.19	2.11	0.02	6.30	0.32	-	40	-	-	-	-	-
SOIL STABLIZATION & SITE PREP																
CAT D6M dozer	Diesel	2270002069	140	59%	0.38	0.92	2.8E-03	0.15	0.08	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.39	4.53	4.0E-03	0.47	0.35	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.19	0.67	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.16	0.37	2.6E-03	0.13	0.02	-	40	-	-	-	-	-
Generator set 150 kW	Diesel	2270006005	221	43%	0.81	3.13	3.1E-03	0.27	0.16	-	40	-	-	-	-	-

Table 9.A.1.9 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration		Pollutant Emissions (tons)				
					CO^2	$NO_x{}^2$	$SO_2{}^2$	VOC^2	$PM_{10}/PM_{2.5}{}^{2,3}$	weeks	hrs/week	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	1.05	3.96	3.4E-03	0.26	0.19	-	40	-	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.22	0.66	2.7E-03	0.13	0.03	-	40	-	-	-	-	-
Light plant	Diesel	2270002027	15	43%	2.36	4.50	4.0E-03	0.46	0.35	-	40	-	-	-	-	-
Water truck	Diesel	2270002051	427	59%	0.22	0.66	2.7E-03	0.13	0.03	-	40	-	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	0.47	1.19	2.8E-03	0.14	0.07	-	40	-	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	0.19	0.67	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	0.22	0.66	2.7E-03	0.13	0.03	-	40	-	-	-	-	-
CAT D6M dozer	Diesel	2270002069	140	59%	0.38	0.92	2.8E-03	0.15	0.08	-	40	-	-	-	-	-
Motor graders	Diesel	2270002048	185	59%	0.23	0.80	2.7E-03	0.14	0.03	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	228	43%	2.39	4.53	4.0E-03	0.47	0.35	-	40	-	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	2.39	4.53	4.0E-03	0.47	0.35	-	40	-	-	-	-	-
Loader tool carrier	Diesel	2270001060	125	21%	2.48	3.77	3.8E-03	0.63	0.42	-	40	-	-	-	-	-
PILE DRIVING																
American 9310	Diesel	2270001060	285	21%	2.11	3.56	3.7E-03	0.56	0.34	-	40	-	-	-	-	-
American 9260	Diesel	2270001060	275	21%	2.11	3.56	3.7E-03	0.56	0.34	-	40	-	-	-	-	-
Pile hammer	Diesel	2270001060	60	21%	4.42	4.72	4.2E-03	0.81	0.59	-	40	-	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	4.19	4.90	4.2E-03	0.80	0.57	-	40	-	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	0.16	0.37	2.6E-03	0.13	0.02	-	40	-	-	-	-	-
Welder	Diesel	2270001060	50	21%	4.42	4.72	4.2E-03	0.81	0.59	-	40	-	-	-	-	-
Air compressor 185 cfm	Diesel	2270006015	80	43%	1.23	1.99	3.3E-03	0.21	0.17	-	40	-	-	-	-	-
MISCELLANEOUS																
Tugs Twin Screw[4,5]	Diesel		350	31%	2.01	13.41	0.17	0.36	0.35	-	40	-	-	-	-	-
Total												**75.2**	**19.0**	**3.3E-02**	**3.6**	**1.5**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2019, Cameron Parish, LA, except as noted
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.
4. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
5. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.10 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 06 PERSONNEL CARRIERS														
All terrain vehicle	Diesel	2270001060	22	21%	691	0.039	0.018	698	542	40	76	4.3E-03	1.9E-03	78
CLASS 11 EARTHMOVING														
Dozer	Diesel	2270002069	159	59%	536	0.030	0.014	541	26	40	58	3.3E-03	1.5E-03	59
Excavator CAT 303.5CR	Diesel	2270002036	27	59%	596	0.034	0.015	601	35	40	15	8.3E-04	3.7E-04	15
Excavator CAT 330BL	Diesel	2270002036	250	59%	536	0.030	0.014	541	26	40	91	0.01	2.3E-03	92
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	0	40	-	-	-	-
Motor graders	Diesel	2270002048	183	59%	536	0.030	0.014	541	26	40	66	3.8E-03	1.7E-03	68
Loader backhoe	Diesel	2270002066	101	21%	625	0.036	0.016	631	78	40	46	2.6E-03	1.2E-03	46
Loader tool carrier	Diesel	2270002066	134	21%	625	0.036	0.016	631	78	40	60	3.4E-03	1.5E-03	62
Skidsteer loader	Diesel	2270002072	68	21%	693	0.039	0.018	700	78	40	34	1.9E-03	8.7E-04	35
Rubber tire loader	Diesel	2270002060	249	59%	536	0.030	0.014	541	78	40	271	0.02	0.01	276
Tractor	Diesel	2270005015	115	59%	536	0.030	0.014	541	78	40	125	0.01	3.2E-03	127
CLASS 12 PIPELAYING / TRENCHING EQUI														
Trencher	Diesel	2270002030	51	59%	595	0.034	0.015	601	0	40	-	-	-	-
CLASS 13 COMPACTION														
Soil compactor	Diesel	2270002009	339	43%	589	0.033	0.015	594	4	40	15	8.6E-04	3.9E-04	15
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	4	40	7	3.9E-04	1.7E-04	7
CLASS 14 CRANES														
Crane crawler	Diesel	2270002045	285	43%	531	0.030	0.014	535	26	40	75	4.2E-03	1.9E-03	76
Crane crawler	Diesel	2270002045	300	43%	531	0.030	0.014	535	26	40	78	4.5E-03	2.0E-03	80
Crane crawler	Diesel	2270002045	340	43%	531	0.030	0.014	535	52	40	178	0.01	4.5E-03	181
Crane crawler	Diesel	2270002045	600	43%	531	0.030	0.014	535	0	40	-	-	-	-
Crane crawler	Diesel	2270002045	500	43%	531	0.030	0.014	535	0	40	-	-	-	-
Crane carrydeck	Diesel	2270003010	200	21%	625	0.035	0.016	630	0	40	-	-	-	-
Crane carrydeck	Diesel	2270003010	300	21%	625	0.035	0.016	630	0	40	-	-	-	-
RT crane - 35 ton	Diesel	2270002045	140	43%	531	0.030	0.014	535	113	40	159	0.01	4.1E-03	162
RT crane - 50 ton	Diesel	2270002045	180	43%	531	0.030	0.014	535	87	40	158	0.01	4.0E-03	160
RT crane - 66 ton	Diesel	2270002045	220	43%	531	0.030	0.014	535	113	40	250	0.01	0.01	255
RT crane - 75 ton	Diesel	2270002045	220	43%	531	0.030	0.014	535	26	40	58	3.3E-03	1.5E-03	59
RT crane - 80 ton	Diesel	2270002045	260	43%	531	0.030	0.014	535	22	40	58	3.3E-03	1.5E-03	59

Table 9.A.1.10 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
			(hp)		CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
RT crane - 110 ton	Diesel	2270002045	300	43%	531	0.030	0.014	535	22	40	66	3.8E-03	1.7E-03	68
CLASS 15 FORKLIFT														
Forklift, yard 36,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	152	40	318	0.02	0.01	324
Forklift, wharehouse 6,000 lb	LPG	2267003020	100	30%	551	0.031	0.013	556	65	40	47	2.7E-03	1.1E-03	48
Forklift, RT 6,000 lb	Diesel	2270002057	100	59%	536	0.030	0.014	541	91	40	127	0.01	3.2E-03	129
Forklift, yard 11,000 lb	Diesel	2270003020	120	59%	536	0.030	0.014	541	39	40	65	3.7E-03	1.7E-03	66
Forklift, yard 20,000 lb	Diesel	2270003020	150	59%	536	0.030	0.014	541	69	40	144	0.01	3.7E-03	147
Forklift, tele-boom 8,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	113	40	158	0.01	4.0E-03	161
Forklift, tele-boom 9,000 lb	Diesel	2270003020	100	59%	536	0.030	0.014	541	139	40	194	0.01	4.9E-03	197
CLASS 16 CONCRETE / AGGREGATE														
Concrete pump	Diesel	2270002042	350	43%	530	0.030	0.014	535	17	40	60	3.4E-03	1.5E-03	61
CLASS 17 AIR COMPRESSORS														
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	156	40	140	0.01	3.6E-03	142
Air compressor 250 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	139	40	124	0.01	3.2E-03	127
Air compressor 375 cfm	Diesel	2270006015	115	43%	530	0.030	0.014	535	121	40	140	0.01	3.6E-03	142
Air compressor 600 cfm	Diesel	2270006015	250	43%	531	0.030	0.014	535	35	40	88	5.0E-03	2.2E-03	90
Air compressor 750 cfm	Diesel	2270006015	275	43%	531	0.030	0.014	535	35	40	97	0.01	2.5E-03	99
Air compressor 900 cfm	Diesel	2270006015	310	43%	530	0.030	0.014	535	52	40	162	0.01	4.1E-03	165
Air compressor 900 cfm	Diesel	2270006015	700	0%	-	-	-	-	17	40	-	-	-	-
Air compressor 1500 cfm	Diesel	2270006015	500	43%	530	0.030	0.014	535	17	40	85	4.9E-03	2.2E-03	87
CLASS 25 CABLE LAYING / PULLING EQUIP														
Cable winch	Diesel	2270002081	26	59%	596	0.034	0.015	601	91	40	37	2.1E-03	9.3E-04	37
CLASS 52 WELDING EQUIPMENT														
Welder 400A trailer mount	Diesel	2270006025	32	21%	694	0.039	0.018	700	693	40	143	0.01	3.6E-03	145
Welder 500A trailer mount	Diesel	2270006025	40	21%	694	0.039	0.018	700	312	40	80	4.6E-03	2.0E-03	82
Welder fusion Tracstart 28	Diesel	2270006025	13	21%	693	0.039	0.018	699	0	40	-	-	-	-
CLASS 53 GENERATION EQUIPMENT														
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.014	535	61	40	136	0.01	3.5E-03	138
Generator set 800 kW	Diesel	2270006005	1125	0%	-	-	-	-	121	40	-	-	-	-
Generator set 1000 kW	Diesel	2270006005	1425	0%	-	-	-	-	82	40	-	-	-	-
Light plant	Diesel	2270002027	14	43%	589	0.033	0.015	594	832	40	130	0.01	3.3E-03	132

Table 9.A.1.10 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
CLASS 54 MANLIFTS / SCISSORLIFTS														
Manlift - 40 ft	Diesel	2270003010	28	21%	692	0.039	0.018	699	329	40	59	3.4E-03	1.5E-03	60
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	700	269	40	112	0.01	2.9E-03	114
Manlift - 80 ft	Diesel	2270003010	65	21%	693	0.039	0.018	700	390	40	163	0.01	4.1E-03	166
Manlift - 125 ft	Diesel	2270003010	75	21%	693	0.039	0.018	700	52	40	25	1.4E-03	6.4E-04	25
Scissor lift - 60 ft	Diesel	2270003010	31	21%	692	0.039	0.018	699	117	40	23	1.3E-03	5.9E-04	24
CLASS 55,56 SMALL CAPITAL EQUIPMENT														
Compactor - 29" manual	Diesel	2270002003	15	59%	595	0.034	0.015	600	87	40	20	1.1E-03	5.1E-04	21
Pressure washer 3500 psi 4 gpm	Gas	2265006030	13	85%	1,047	0.060	0.024	1,055	104	40	53	3.0E-03	1.2E-03	54
Water pump centrifugal 1600 gpm	Diesel	2270006010	80	43%	589	0.033	0.015	594	104	40	93	0.01	2.4E-03	95
Water pump trash 316 gpm	Diesel	2270006010	6.5	43%	588	0.033	0.015	594	139	40	10	5.7E-04	2.6E-04	10
Water pump trash 611 gpm	Diesel	2270006010	15	43%	589	0.033	0.015	594	69	40	12	6.6E-04	2.9E-04	12
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	590	0.033	0.015	595	139	40	54	3.1E-03	1.4E-03	55
Water pump centrifugal 10,000 gph	Diesel	2270006010	5	43%	588	0.033	0.015	594	104	40	6	3.3E-04	1.5E-04	6
Pressure washer 3000 psi 3.5 gpm	Gas	2265006030	11	85%	1,047	0.059	0.027	1,056	35	40	15	8.6E-04	3.8E-04	15
Water pump submersible 420 gpm	Diesel	2270006010	16	43%	589	0.033	0.015	594	139	40	25	1.4E-03	6.3E-04	25
Water pump submersible 800 gpm	Diesel	2270006010	23	43%	589	0.033	0.015	594	139	40	36	2.0E-03	9.1E-04	36
Compactor - 16" in manual	Diesel	2270002003	5	59%	595	0.034	0.015	600	87	40	7	3.8E-04	1.7E-04	7
Compactor - 26" in manual	Diesel	2270002003	9	59%	595	0.034	0.015	600	87	40	12	6.9E-04	3.1E-04	12
Tamper rammer	Diesel	2270002003	9	59%	595	0.034	0.015	600	52	40	7	4.1E-04	1.8E-04	7
Mortar mixer	Diesel	2270002042	5	43%	588	0.033	0.015	593	39	40	2	1.2E-04	5.5E-05	2
Concrete mixer	Gas	2265002042	5	59%	1,230	0.070	0.028	1,240	39	40	6	3.6E-04	1.4E-04	6
Generator set 6 kW	Gas	2265006005	9	68%	1,047	0.060	0.024	1,055	104	40	29	1.7E-03	6.7E-04	30
Generator set 10 kW	Gas	2265006005	15	68%	1,047	0.060	0.024	1,055	295	40	139	0.01	3.2E-03	141
Concrete trowel 36"	Gas	2265002021	5	59%	1,229	0.070	0.028	1,239	0	40	-	-	-	-
SOIL STABLIZATION & SITE PREP														
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	0	40	-	-	-	-
Generator set 150 kW	Diesel	2270006005	221	43%	530	0.030	0.014	535	0	40	-	-	-	-

Table 9.A.1.10 - Liquefaction and CCTPL Expansion Project
2019 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - SPLNG Terminal Trains 5 & 6 (Continued)

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration		Pollutant Emissions (tons)			
					CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	hours/day	CO_2	N_2O	CH_4	CO_2e
Water pump trash 1083 gpm	Diesel	2270006010	35	43%	590	0.033	0.015	595	0	40	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
Light plant	Diesel	2270002027	15	43%	589	0.033	0.015	594	0	40	-	-	-	-
Water truck	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 345B	Diesel	2270002036	345	59%	536	0.030	0.014	541	0	40	-	-	-	-
Excavator CAT 330BL	Diesel	2270002036	236	59%	536	0.030	0.014	541	0	40	-	-	-	-
Articulated truck, CAT D400	Diesel	2270002051	427	59%	536	0.030	0.014	541	0	40	-	-	-	-
CAT D6M dozer	Diesel	2270002069	140	59%	536	0.030	0.014	541	0	40	-	-	-	-
Motor graders	Diesel	2270002048	185	59%	536	0.030	0.014	541	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	228	43%	589	0.033	0.015	594	0	40	-	-	-	-
Soil compactor	Diesel	2270002009	153	43%	589	0.033	0.015	594	0	40	-	-	-	-
Loader tool carrier	Diesel	2270001060	125	21%	625	0.035	0.016	630	0	40	-	-	-	-
PILE DRIVING														
American 9310	Diesel	2270001060	285	21%	625	0.035	0.016	630	0	40	-	-	-	-
American 9260	Diesel	2270001060	275	21%	625	0.035	0.016	630	0	40	-	-	-	-
Pile hammer	Diesel	2270001060	60	21%	693	0.039	0.018	700	0	40	-	-	-	-
Manlift - 60 ft	Diesel	2270003010	65	21%	693	0.039	0.018	700	0	40	-	-	-	-
Forklift, tele-boom 8,000 lb	Diesel	2270003020	110	59%	536	0.030	0.014	541	0	40	-	-	-	-
Welder	Diesel	2270001060	50	21%	693	0.039	0.018	700	0	40	-	-	-	-
Air compressor 185 cfm	Diesel	2270006015	80	43%	590	0.033	0.015	595	0	40	-	-	-	-
MISCELLANEOUS														
Tugs Twin Screw[4,5]	Diesel		350	31%	925	0.121	0.027	936	0	40	-	-	-	-
Total											**5,327**	**0.30**	**0.13**	**5,423**

1. User's Guide for the Final NONROAD2005, except as noted Model, EPA420-R-05-013, US EPA, December 2005, except as noted
2. EPA NONROAD2008 run for calendar year 2019, Cameron Parish, LA, except as noted
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD.
   http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.
5. Load factor from Table 3-4 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.
6. Tier 0 emission factors from Tables 3-8 and 3-9 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories, ICF International, April 2009.

Table 9.A.1.11 - Liquefaction and CCTPL Expansion Project
On-Road On-Site Construction VehicleTailpipe Emission Factors - SPLNG Terminal Trains 5 & 6

Vehicle	Emission Factor (g/VMT)[1]								Onsite Travel (mile/ vehicle-day)	Vehicle-months	Vehicle Usage (vehicle-days/year)
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e			
2015											
Diesel Heavy Trucks	1.59	6.13	0.014	0.333	0.246	0.239	1,897	1,898	50	-	-
Diesel Buses	2.25	6.13	0.009	0.420	0.283	0.274	1,211	1,212	50	-	-
Diesel Light Trucks	1.54	2.10	0.005	0.302	0.109	0.105	631	631	50		-
Gasoline Passenger Cars	1.91	0.22	0.005	0.053	0.004	0.004	313	314	50		-
Gasoline Passenger Trucks	4.36	0.69	0.007	0.185	0.007	0.007	430	432	50	128	2,781
2016											
Diesel Heavy Trucks	1.39	5.35	0.014	0.294	0.210	0.204	1,897	1,898	50	222	4,836
Diesel Buses	2.00	5.41	0.009	0.378	0.247	0.239	1,211	1,212	50	13	283
Diesel Light Trucks	1.43	1.92	0.005	0.270	0.096	0.093	628	629	50		-
Gasoline Passenger Cars	1.79	0.18	0.005	0.045	0.004	0.004	307	307	50		-
Gasoline Passenger Trucks	4.10	0.63	0.007	0.164	0.007	0.006	421	422	50	68	1,481
2017											
Diesel Heavy Trucks	1.21	4.65	0.014	0.261	0.178	0.173	1,897	1,898	50	391	8,495
Diesel Buses	1.77	4.76	0.009	0.337	0.213	0.207	1,211	1,212	50	24	521
Diesel Light Trucks	1.33	1.76	0.005	0.240	0.085	0.082	625	626	50		-
Gasoline Passenger Cars	1.70	0.16	0.005	0.039	0.004	0.003	301	301	50		-
Gasoline Passenger Trucks	3.92	0.58	0.006	0.147	0.007	0.006	413	414	50	239	5,193
2018											
Diesel Heavy Trucks	1.06	4.04	0.014	0.230	0.150	0.145	1,897	1,898	50	373	8,104
Diesel Buses	1.55	4.19	0.009	0.299	0.181	0.176	1,211	1,212	50	24	521
Diesel Light Trucks	1.24	1.61	0.005	0.213	0.075	0.073	622	623	50		-
Gasoline Passenger Cars	1.64	0.13	0.005	0.034	0.004	0.003	295	296	50		-
Gasoline Passenger Trucks	3.75	0.53	0.006	0.133	0.007	0.006	405	406	50	496	10,776
Total											
2019											
Diesel Heavy Trucks	0.92	3.53	0.013	0.204	0.127	0.124	1,897	1,898	50	144	3,129
Diesel Buses	1.36	3.68	0.009	0.266	0.158	0.154	1,211	1,212	50	11	239
Diesel Light Trucks	1.17	1.47	0.005	0.189	0.066	0.064	620	620	50		-
Gasoline Passenger Cars	1.59	0.12	0.004	0.031	0.004	0.003	290	290	50		-
Gasoline Passenger Trucks	3.60	0.49	0.006	0.121	0.007	0.006	397	398	50	460	9,994

1. EPA MOVES2010b

Table 9.A.1.12 - Liquefaction and CCTPL Expansion Project
On-Road On-Site Construction VehicleTailpipe Emissions - SPLNG Terminal Trains 5 & 6

Vehicle	Vehicle Miles Traveled (VMT)	Emissions (ton/yr)							
		CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e
2015									
Diesel Heavy Trucks	-	-	-	-	-	-	-	-	-
Diesel Buses	-	-	-	-	-	-	-	-	-
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	139,050	0.67	0.11	1.0E-03	0.03	1.1E-03	1.0E-03	66	66
Total		**0.67**	**0.11**	**1.0E-03**	**0.03**	**1.1E-03**	**1.0E-03**	**66**	**66**
2016									
Diesel Heavy Trucks	241,800	0.37	1.43	3.7E-03	0.08	0.06	0.05	506	506
Diesel Buses	14,150	0.03	0.08	1.4E-04	0.01	3.8E-03	3.7E-03	19	19
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	74,050	0.33	0.05	5.3E-04	0.01	5.7E-04	5.3E-04	34	34
Total		**0.74**	**1.56**	**4.3E-03**	**0.10**	**0.06**	**0.06**	**559**	**559**
2017									
Diesel Heavy Trucks	424,750	0.57	2.18	0.01	0.12	0.08	0.08	888	889
Diesel Buses	26,050	0.05	0.14	2.5E-04	0.01	0.01	0.01	35	35
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	259,650	1.12	0.17	1.8E-03	0.04	2.0E-03	1.8E-03	118	118
Total		**1.74**	**2.48**	**0.01**	**0.17**	**0.09**	**0.09**	**1,041**	**1,042**
2018									
Diesel Heavy Trucks	405,200	0.47	1.81	0.01	0.10	0.07	0.06	847	848
Diesel Buses	26,050	0.04	0.12	2.5E-04	0.01	0.01	0.01	35	35
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	538,800	2.23	0.32	3.7E-03	0.08	4.0E-03	3.7E-03	240	241
Total		**2.75**	**2.24**	**0.01**	**0.19**	**0.08**	**0.07**	**1,122**	**1,124**
2019									
Diesel Heavy Trucks	156,450	0.16	0.61	2.3E-03	0.04	0.02	0.02	327	327
Diesel Buses	11,950	0.02	0.05	1.1E-04	3.5E-03	2.1E-03	2.0E-03	16	16
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	499,700	1.99	0.27	3.4E-03	0.07	3.7E-03	3.4E-03	219	219
Total		**2.16**	**0.93**	**0.01**	**0.11**	**0.03**	**0.03**	**562**	**563**

Table 9.A.1.13 - Liquefaction and CCTPL Expansion Project
On-Road Material Delivery, and Worker Commuting Emission Factors - SPLNG Terminal Trains 5 & 6

Vehicle	Emission Factor (g/VMT)[1]								Trip Distance (2-way) (miles)	Vehicle-months	Vehicle Usage (vehicle-days/year)
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e			
2015											
Diesel Heavy Trucks	1.59	6.13	0.014	0.333	0.246	0.239	1,897	1,898	100	94	2,042
Diesel Buses	2.25	6.13	0.009	0.420	0.283	0.274	1,211	1,212	50	1	22
Diesel Light Trucks	1.54	2.10	0.005	0.302	0.109	0.105	631	631	50		-
Gasoline Passenger Cars	1.91	0.22	0.005	0.053	0.004	0.004	313	314	50	345	7,499
Gasoline Passenger Trucks	4.36	0.69	0.007	0.185	0.007	0.007	430	432	50	345	7,499
2016											
Diesel Heavy Trucks	1.39	5.35	0.014	0.294	0.210	0.204	1,897	1,898	100	240	5,214
Diesel Buses	2.00	5.41	0.009	0.378	0.247	0.239	1,211	1,212	50	116	2,520
Diesel Light Trucks	1.43	1.92	0.005	0.270	0.096	0.093	628	629	50		-
Gasoline Passenger Cars	1.79	0.18	0.005	0.045	0.004	0.004	307	307	50	1,675	36,390
Gasoline Passenger Trucks	4.10	0.63	0.007	0.164	0.007	0.006	421	422	50	1,675	36,390
2017											
Diesel Heavy Trucks	1.21	4.65	0.014	0.261	0.178	0.173	1,897	1,898	100	193	4,193
Diesel Buses	1.77	4.76	0.009	0.337	0.213	0.207	1,211	1,212	50	460	9,994
Diesel Light Trucks	1.33	1.76	0.005	0.240	0.085	0.082	625	626	50		-
Gasoline Passenger Cars	1.70	0.16	0.005	0.039	0.004	0.003	301	301	50	1,596	34,683
Gasoline Passenger Trucks	3.92	0.58	0.006	0.147	0.007	0.006	413	414	50	1,596	34,683
2018											
Diesel Heavy Trucks	1.06	4.04	0.014	0.230	0.150	0.145	1,897	1,898	100	65	1,412
Diesel Buses	1.55	4.19	0.009	0.299	0.181	0.176	1,211	1,212	50	424	9,212
Diesel Light Trucks	1.24	1.61	0.005	0.213	0.075	0.073	622	623	50		-
Gasoline Passenger Cars	1.64	0.13	0.005	0.034	0.004	0.003	295	296	50	2,729	59,295
Gasoline Passenger Trucks	3.75	0.53	0.006	0.133	0.007	0.006	405	406	50	2,729	59,295
2019											
Diesel Heavy Trucks	0.92	3.53	0.013	0.204	0.127	0.124	1,897	1,898	100	10	217
Diesel Buses	1.36	3.68	0.009	0.266	0.158	0.154	1,211	1,212	50	-	-
Diesel Light Trucks	1.17	1.47	0.005	0.189	0.066	0.064	620	620	50		-
Gasoline Passenger Cars	1.59	0.12	0.004	0.031	0.004	0.003	290	290	50	1,551	33,697
Gasoline Passenger Trucks	3.60	0.49	0.006	0.121	0.007	0.006	397	398	50	1,551	33,697

1. EPA MOVES2010b

Table 9.A.1.14 - Liquefaction and CCTPL Expansion Project
On-Road Material Delivery, and Worker Commuting Emissions - SPLNG Terminal Trains 5 & 6

Vehicle	Vehicle Miles Traveled (VMT)	Emissions (ton/yr)							
		CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e
2015									
Diesel Heavy Trucks	204,200	0.36	1.38	3.1E-03	0.07	0.06	0.05	427	427
Diesel Buses	1,100	2.7E-03	0.01	1.1E-05	5.1E-04	3.4E-04	3.3E-04	1	1
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	374,950	0.79	0.09	2.0E-03	0.02	1.7E-03	1.5E-03	130	130
Gasoline Passenger Trucks	374,950	1.80	0.29	2.8E-03	0.08	3.0E-03	2.7E-03	178	178
Total		**2.95**	**1.77**	**0.01**	**0.17**	**0.06**	**0.06**	**736**	**737**
2016									
Diesel Heavy Trucks	521,400	0.80	3.07	0.01	0.17	0.12	0.12	1,090	1,091
Diesel Buses	126,000	0.28	0.75	1.2E-03	0.05	0.03	0.03	168	168
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	1,819,500	3.59	0.37	0.01	0.09	0.01	0.01	616	616
Gasoline Passenger Trucks	1,819,500	8.23	1.26	0.01	0.33	0.01	0.01	845	847
Total		**12.89**	**5.46**	**0.03**	**0.64**	**0.18**	**0.17**	**2,719**	**2,723**
2017									
Diesel Heavy Trucks	419,300	0.56	2.15	0.01	0.12	0.08	0.08	877	877
Diesel Buses	499,700	0.97	2.62	4.9E-03	0.19	0.12	0.11	667	668
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	1,734,150	3.25	0.30	0.01	0.07	0.01	0.01	575	576
Gasoline Passenger Trucks	1,734,150	7.49	1.11	0.01	0.28	0.01	0.01	789	791
Total		**12.28**	**6.17**	**0.03**	**0.66**	**0.22**	**0.21**	**2,908**	**2,912**
2018									
Diesel Heavy Trucks	141,200	0.16	0.63	2.1E-03	0.04	0.02	0.02	295	295
Diesel Buses	460,600	0.79	2.13	4.4E-03	0.15	0.09	0.09	615	615
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	2,964,750	5.35	0.44	0.01	0.11	0.01	0.01	965	966
Gasoline Passenger Trucks	2,964,750	12.27	1.74	0.02	0.43	0.02	0.02	1,323	1,326
Total		**18.57**	**4.93**	**0.04**	**0.73**	**0.15**	**0.14**	**3,198**	**3,203**
2019									
Diesel Heavy Trucks	21,700	0.02	0.08	3.2E-04	4.9E-03	3.0E-03	3.0E-03	45	45
Diesel Buses	-	-	-	-	-	-	-	-	-
Diesel Light Trucks	-	-	-	-	-	-	-	-	-
Gasoline Passenger Cars	1,684,850	2.95	0.22	0.01	0.06	0.01	0.01	539	540
Gasoline Passenger Trucks	1,684,850	6.69	0.91	0.01	0.22	0.01	0.01	738	739
Total		**9.67**	**1.21**	**0.02**	**0.29**	**0.02**	**0.02**	**1,322**	**1,324**

Table 9.A.1.15 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - New Orleans to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6

	Emission Factors (g/kw-hr)[1]								
	NO_x	VOC	CO	PM_{10}	$PM_{2.5}$	SO_2	CO_2	N_2O	CH_4
Main Engine	13	0.27	2.5	0.3	0.3	1.3	690	0.02	0.09
Auxiliary Engines	10	0.27	1.7	0.4	0.4	1.3	690	0.02	0.09

Assist Tug Engine Data[2]	
Main Engine Power (kW)	1540
Main Engines per Vessel	2
Auxiliary Engine Power (kW)	100
Auxiliary Engines per Vessel	1.9

Year	Calls	Comments
2015	46	Pile deliveries
2016	106	Pile deliveries
2017	-	
2018	-	
2019	-	
Total	152	

Travel Segment	Distances (nautical miles)			
	Severe Non-attainment	Serious Non-attainment	Attainment	Total
New Orleans to Sabine Pass[3]				254.0
Reduced Speed Zone[4]				
New Orleans	-	-	104.2	104.2
Port Arthur	-	-	-	-
Intracostal Waterway			149.8	149.8
Total RSZ	-	-	254.0	254.0
Cruise Zone Distance	-	-	-	-

Houston-Galveston-Brazoria 1-Hour Ozone Standard Severe 17 Nonattainment / 8-Hour Ozone Standard Severe 15 Nonattainment (40 CFR 81.344)

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	0.00	0.00	0.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	-	-	-	-	-	-	-	-	-
Maneuver (g/call)	-	-	-	-	-	-	-	-	-
Hotel (g/call)	-	-	-	-	-	-	-	-	-
Total (g/call)	-	-	-	-	-	-	-	-	-
Total (tons/call)	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Year	Annual Emissions (tons)								
	CO	NO_x	VOC	SO_2	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-

Beaumont - Port Arthur, TX 1-Hour Ozone Standard Serious Nonattainment (40 CFR 81.344)

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	0.00	0.00	0.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	-	-	-	-	-	-	-	-	-
Maneuver (g/call)	-	-	-	-	-	-	-	-	-
Hotel (g/call)	-	-	-	-	-	-	-	-	-
Total (g/call)	-	-	-	-	-	-	-	-	-
Total (tons/call)	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Table 9.A.1.15 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - New Orleans to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6
(Continued)

Year	Annual Emissions (tons)								
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-

1-Hour Ozone Standard Attainment or Unclassifiable / 8-Hour Ozone Standard Attainment or Unclassifiable

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	42.33	2.00	12.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	157,152	819,711	82,623	17,160	19,284	19,284	43,853,559	1,271	5,720
Maneuver (g/call)	2,439	12,881	1,339	278	326	326	710,887	21	93
Hotel (g/call)	853	5,016	652	135	201	201	346,104	10	45
Total (g/call)	160,444	837,608	84,614	17,574	19,811	19,811	44,910,550	1,302	5,858
Total (tons/call)	0.177	0.923	0.093	0.019	0.022	0.022	49.51	1.4E-03	6.5E-03

Year	Annual Emissions (tons)								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	8.14	42.47	4.29	0.89	1.00	1.00	2,277	0.066	0.297
2016	18.75	97.87	9.89	2.05	2.31	2.31	5,248	0.152	0.684
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	26.88	140.34	14.18	2.94	3.32	3.32	7,525	0.218	0.982

1. Tier 0 emission factors from Table 3-8 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
2. Tug engine data is taken from Table 3-10 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
3. From Distances Between United States Ports (12th Edition) , NOAA, 2012. Port Arthur used as location of Sabine Pass.
4. From Table 2-18 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
   The barges do not enter open ocean
5. See Section 2-7.3 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
   Calculated using Propeller Law:
   $LF = (AS/MS)^3$
   Where;
   LF = Load Factor
   AS = Actual Speed (knots)
   MS = Maximum Speed (knots)
6. From Table 2-7 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
7. Emission rates were calculated using the following equation:
   $E\ (g/call) = P_{Main} * LF_{Main} * A * EF_{Main} + P_{Aux} * LF_{Aux} * A * EF_{Aux}$
   Where
   P = Engine Power Rating (kW)
   LF = Load Factor
   A = Activity (hours)
   EF = Emission Factor

Table 9.A.1.16 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - Houston to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6

	Emission Factors (g/kw-hr)[1]								
	NO_x	VOC	CO	PM_{10}	$PM_{2.5}$	SO_2	CO_2	N_2O	CH_4
Main Engine	13	0.27	2.5	0.3	0.3	1.3	690	0.02	0.09
Auxiliary Engines	10	0.27	1.7	0.4	0.4	1.3	690	0.02	0.09

Assist Tug Engine Data[2]	
Main Engine Power (kW)	1540
Main Engines per Vessel	2
Auxiliary Engine Power (kW)	100
Auxiliary Engines per Vessel	1.9

Year	Calls	Comments
2015	1	Equipment / Materials
2016	5	Equipment / Materials
2017	5	Equipment / Materials
2018	-	
2019	-	
Total	11	

Travel Segment	Distances (nautical miles)			
	Severe Non-attainment	Serious Non-attainment	Attainment	Total
Houston to Sabine Pass[3]				97.0
Reduced Speed Zone[4]				
Houston	49.6	-	-	49.6
Port Arthur	-	-	-	-
Intracostal Waterway	12.2	35.2	-	47.4
Total RSZ	61.8	35.2	-	97.0
Cruise Zone Distance	-	-	-	-

Houston-Galveston-Brazoria 1-Hour Ozone Standard Severe 17 Nonattainment / 8-Hour Ozone Standard Severe 15 Nonattainment (40 CFR 81.344)

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	10.30	1.00	0.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	38,236	199,442	20,103	4,175	4,692	4,692	10,669,882	309	1,392
Maneuver (g/call)	1,219	6,440	670	139	163	163	355,444	10	46
Hotel (g/call)	-	-	-	-	-	-	-	-	-
Total (g/call)	39,456	205,882	20,772	4,314	4,855	4,855	11,025,325	320	1,438
Total (tons/call)	4.3E-02	2.3E-01	2.3E-02	4.8E-03	5.4E-03	5.4E-03	1.2E+01	3.5E-04	1.6E-03

Year	Annual Emissions (tons)								
	CO	NO_x	VOC	SO_2	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	0.04	0.23	0.00	0.02	0.01	0.01	12.15	0.000	0.002
2016	0.22	1.13	0.02	0.11	0.03	0.03	60.77	0.002	0.008
2017	0.22	1.13	0.02	0.11	0.03	0.03	60.77	0.002	0.008
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	0.48	2.50	0.05	0.25	0.06	0.06	133.69	0.004	0.017

Beaumont - Port Arthur, TX 1-Hour Ozone Standard Serious Nonattainment (40 CFR 81.344)

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	5.87	0.00	0.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	21,779	113,598	11,450	2,378	2,672	2,672	6,077,344	176	793
Maneuver (g/call)	-	-	-	-	-	-	-	-	-
Hotel (g/call)	-	-	-	-	-	-	-	-	-
Total (g/call)	21,779	113,598	11,450	2,378	2,672	2,672	6,077,344	176	793
Total (tons/call)	2.4E-02	1.3E-01	1.3E-02	2.6E-03	2.9E-03	2.9E-03	6.7E+00	1.9E-04	8.7E-04

Table 9.A.1.16 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - Houston to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6
(Continued)

Year	Annual Emissions (tons)								
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	0.02	0.13	0.01	0.00	0.00	0.00	6.70	0.000	0.001
2016	0.12	0.63	0.06	0.01	0.01	0.01	33.50	0.001	0.004
2017	0.12	0.63	0.06	0.01	0.01	0.01	33.50	0.001	0.004
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	0.26	1.38	0.14	0.03	0.03	0.03	73.69	0.002	0.010

1-Hour Ozone Standard Attainment or Unclassifiable / 8-Hour Ozone Standard Attainment or Unclassifiable

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	0.00	1.00	12.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	-	-	-	-	-	-	-	-	-
Maneuver (g/call)	1,219	6,440	670	139	163	163	355,444	10	46
Hotel (g/call)	853	5,016	652	135	201	201	346,104	10	45
Total (g/call)	2,072	11,456	1,322	275	364	364	701,548	20	92
Total (tons/call)	0.002	0.013	0.001	0.000	0.000	0.000	0.77	2.2E-05	1.0E-04

Year	Annual Emissions (tons)								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	0.00	0.01	0.00	0.00	0.00	0.00	1	0.000	0.000
2016	0.01	0.06	0.01	0.00	0.00	0.00	4	0.000	0.001
2017	0.01	0.06	0.01	0.00	0.00	0.00	4	0.000	0.001
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	0.03	0.14	0.02	0.00	0.00	0.00	9	0.000	0.001

1. Tier 0 emission factors from Table 3-8 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
2. Tug engine data is taken from Table 3-10 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
3. From Distances Between United States Ports (12th Edition) , NOAA, 2012. Port Arthur used as location of Sabine Pass.
4. From Table 2-18 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
   The barges do not enter open ocean
5. See Section 2-7.3 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
   Calculated using Propeller Law:
   $LF = (AS/MS)^3$
   Where;
   LF = Load Factor
   AS = Actual Speed (knots)
   MS = Maximum Speed (knots)
6. From Table 2-7 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
7. Emission rates were calculated using the following equation:
   $E\ (g/call) = P_{Main} * LF_{Main} * A * EF_{Main} + P_{Aux} * LF_{Aux} * A * EF_{Aux}$
   Where
   P = Engine Power Rating (kW)
   LF = Load Factor
   A = Activity (hours)
   EF = Emission Factor

Table 9.A.1.17 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - Lake Charles to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6

	Emission Factors (g/kw-hr)[1]								
	NO_x	VOC	CO	PM_{10}	$PM_{2.5}$	SO_2	CO_2	N_2O	CH_4
Main Engine	13	0.27	2.5	0.3	0.3	1.3	690	0.02	0.09
Auxiliary Engines	10	0.27	1.7	0.4	0.4	1.3	690	0.02	0.09

Assist Tug Engine Data[2]	
Main Engine Power (kW)	1540
Main Engines per Vessel	2
Auxiliary Engine Power (kW)	100
Auxiliary Engines per Vessel	1.9

Year	Calls	Comments
2015	1	Equipment / Materials
2016	4	Equipment / Materials
2017	4	Equipment / Materials
2018	-	
2019	-	
Total	9	

Travel Segment	Distances (nautical miles)			
	Severe Non-attainment	Serious Non-attainment	Attainment	Total
Lake Charles to Sabine Pass[3]				51.0
Reduced Speed Zone[4]				
Port Arthur	-	-	-	-
Lake Charles	-	-	38.0	38.0
Intracostal Waterway			13.0	13.0
Total RSZ	-	-	51.0	51.0
Cruise Zone Distance	-	-	-	-

Houston-Galveston-Brazoria 1-Hour Ozone Standard Severe 17 Nonattainment / 8-Hour Ozone Standard Severe 15 Nonattainment (40 CFR 81.344)

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	0.00	0.00	0.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	-	-	-	-	-	-	-	-	-
Maneuver (g/call)	-	-	-	-	-	-	-	-	-
Hotel (g/call)	-	-	-	-	-	-	-	-	-
Total (g/call)	-	-	-	-	-	-	-	-	-
Total (tons/call)	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Year	Annual Emissions (tons)								
	CO	NO_x	VOC	SO_2	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-

Beaumont - Port Arthur, TX 1-Hour Ozone Standard Serious Nonattainment (40 CFR 81.344)

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	0.00	0.00	0.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	-	-	-	-	-	-	-	-	-
Maneuver (g/call)	-	-	-	-	-	-	-	-	-
Hotel (g/call)	-	-	-	-	-	-	-	-	-
Total (g/call)	-	-	-	-	-	-	-	-	-
Total (tons/call)	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Table 9.A.1.17 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - Lake Charles to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6
(Continued)

Year	Annual Emissions (tons)								
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-

1-Hour Ozone Standard Attainment or Unclassifiable / 8-Hour Ozone Standard Attainment or Unclassifiable

Mode	Cruise	RSZ	Maneuver	Hotel
Time (per call)	0.00	8.50	2.00	12.00
Speed (knots)	14.5	12.0	8.0	0.0
Load Factors				
Main Engine[5]	0.83	0.47	0.14	0.00
Auxiliary Engine[6]	0.17	0.27	0.45	0.22

Mode	Emission Rates[7]								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
Cruise (g/call)	-	-	-	-	-	-	-	-	-
RSZ (g/call)	31,554	164,588	16,590	3,446	3,872	3,872	8,805,242	255	1,149
Maneuver (g/call)	2,439	12,881	1,339	278	326	326	710,887	21	93
Hotel (g/call)	853	5,016	652	135	201	201	346,104	10	45
Total (g/call)	34,846	182,484	18,581	3,859	4,399	4,399	9,862,233	286	1,286
Total (tons/call)	0.038	0.201	0.020	0.004	0.005	0.005	10.87	3.2E-04	1.4E-03

Year	Annual Emissions (tons)								
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
2015	0.04	0.20	0.02	0.00	0.00	0.00	11	0.000	0.001
2016	0.15	0.80	0.08	0.02	0.02	0.02	43	0.001	0.006
2017	0.15	0.80	0.08	0.02	0.02	0.02	43	0.001	0.006
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
Total	0.35	1.81	0.18	0.04	0.04	0.04	98	0.003	0.013

1. Tier 0 emission factors from Table 3-8 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
2. Tug engine data is taken from Table 3-10 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
3. From Distances Between United States Ports (12th Edition) , NOAA, 2012. Port Arthur used as location of Sabine Pass.
4. From Table 2-18 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
   The barges do not enter open ocean
5. See Section 2-7.3 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
   Calculated using Propeller Law:
   $LF = (AS/MS)^3$
   Where;
   LF = Load Factor
   AS = Actual Speed (knots)
   MS = Maximum Speed (knots)
6. From Table 2-7 of Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories , ICF International, April 2009.
7. Emission rates were calculated using the following equation:
   $E\ (g/call) = P_{Main} * LF_{Main} * A * EF_{Main} + P_{Aux} * LF_{Aux} * A * EF_{Aux}$
   Where
   P = Engine Power Rating (kW)
   LF = Load Factor
   A = Activity (hours)
   EF = Emission Factor

Table 9.A.1.18 - Liquefaction and CCTPL Expansion Project
Tug Transport Emissions - Total All Ports to Sabine Pass LNG - SPLNG Terminal Trains 5 & 6

Houston-Galveston-Brazoria, TX 1-Hour Ozone Standard Severe 17 Nonattainment / 8-Hour Ozone Standard Severe 15 Nonattainment (40 CFR 81.344)										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	0.04	0.23	0.02	4.8E-03	0.01	0.01	12	3.5E-04	1.6E-03	12
2016	0.22	1.13	0.11	0.02	0.03	0.03	61	1.8E-03	0.01	61
2017	0.22	1.13	0.11	0.02	0.03	0.03	61	1.8E-03	0.01	61
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
Total	0.48	2.50	0.25	0.05	0.06	0.06	134	3.9E-03	0.02	135

Beaumont - Port Arthur, TX 1-Hour Ozone Standard Serious Nonattainment (40 CFR 81.344)										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	0.02	0.13	0.01	2.6E-03	2.9E-03	2.9E-03	7	1.9E-04	8.7E-04	7
2016	0.12	0.63	0.06	0.01	0.01	0.01	33	9.7E-04	4.4E-03	34
2017	0.12	0.63	0.06	0.01	0.01	0.01	33	9.7E-04	4.4E-03	34
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
Total	0.26	1.38	0.14	0.03	0.03	0.03	74	2.1E-03	0.01	75

1-Hour Ozone Standard Attainment or Unclassifiable / 8-Hour Ozone Standard Attainment or Unclassifiable										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	8.18	42.69	4.31	0.90	1.01	1.01	2,289	0.07	0.30	2,316
2016	18.91	98.74	9.98	2.07	2.34	2.34	5,295	0.15	0.69	5,357
2017	0.17	0.87	0.09	0.02	0.02	0.02	47	1.4E-03	0.01	48
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
Total	27.25	142.29	14.38	2.99	3.37	3.37	7,631	0.22	1.00	7,721

Total Attainment and Non-attainment Areas										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	8.24	43.04	4.35	0.90	1.02	1.02	2,308	0.07	0.30	2,335
2016	19.25	100.50	10.15	2.11	2.38	2.38	5,389	0.16	0.70	5,452
2017	0.50	2.63	0.27	0.06	0.06	0.06	142	4.1E-03	0.02	143
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
Total	28.00	146.17	14.77	3.07	3.46	3.46	7,839	0.23	1.02	7,930

Table 9.A.1.19 - Liquefaction and CCTPL Expansion Project
Fugitive Dust - SPLNG Terminal Trains 5 & 6

Year	Construction Area (acres)		Emission Factor (ton/acre-month)		Duration (months)	Uncontrolled Emissions (tons)		Controlled Emissions[3] (tons)	
	Laydown Areas	Trains 5 & 6 Facilities	PM_{10}[1]	$PM_{2.5}$[2]		PM_{10}	$PM_{2.5}$	PM_{10}	$PM_{2.5}$
2015	103.9	54.0	1.1E-01	1.1E-02	12	208.4	20.84	104.2	10.42
2016	103.9	54.0	1.1E-01	1.1E-02	12	208.4	20.84	104.2	10.42
2017	103.9	54.0	1.1E-01	1.1E-02	12	208.4	20.84	104.2	10.42
2018	103.9	54.0	1.1E-01	1.1E-02	12	208.4	20.84	104.2	10.42
2019	103.9	54.0	1.1E-01	1.1E-02	12	208.4	20.84	104.2	10.42

1. WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Table 3-2, level 1, average conditions.
2. $PM_{2.5}/PM_{10}$ = 0.10 (WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1)
3. Assume 50% control from water and other approved dust suppressants. (WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1)

Comments - Exhibit 5

Table 9.A.1.20 - Liquefaction and CCTPL Expansion Project Construction Emissions Totals - SPLNG Terminal Trains 5 & 6

Nonroad Tailpipe Emissions										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	18.82	42.69	0.10	4.06	2.84	2.84	10,955	0.64	0.28	11,159
2016	163.12	67.58	0.18	9.69	4.86	4.86	15,709	0.93	0.40	16,005
2017	301.59	93.84	0.20	14.88	6.71	6.71	20,289	1.18	0.52	20,666
2018	296.15	84.23	0.16	14.29	6.29	6.29	19,677	1.13	0.50	20,038
2019	75.16	18.97	0.03	3.56	1.48	1.48	5,327	0.30	0.13	5,423
Total	854.84	307.31	0.68	46.47	22.17	22.17	71,957	4.18	1.83	73,291

On-Road Tailpipe Emissions										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	3.62	1.87	0.009	0.20	0.06	0.06	802			803
2016	13.63	7.02	0.036	0.74	0.24	0.23	3,278			3,282
2017	14.02	8.65	0.041	0.84	0.31	0.30	3,949			3,954
2018	21.32	7.18	0.052	0.92	0.23	0.22	4,320			4,326
2019	11.83	2.14	0.026	0.39	0.05	0.05	1,884			1,887
Total	64.42	26.87	0.164	3.09	0.89	0.85	14,232	-	-	14,252

Tugs - Total Attainment and Non-attainment Areas										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	8.24	43.04	4.35	0.90	1.02	1.02	2,308	0.07	0.30	2,335
2016	19.25	100.50	10.15	2.11	2.38	2.38	5,389	0.16	0.70	5,452
2017	0.50	2.63	0.27	0.06	0.06	0.06	142	0.00	0.02	143
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
Total	28.00	146.17	14.77	3.07	3.46	3.46	7,839	0.227	1.022	7,930

Table 9.A.1.20 - Liquefaction and CCTPL Expansion Project Construction Emissions Totals - SPLNG Terminal Trains 5 & 6 (Continued)

Fugitive Dust										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	-	-	-	-	104.21	10.42	-	-	-	-
2016	-	-	-	-	104.21	10.42	-	-	-	-
2017	-	-	-	-	104.21	10.42	-	-	-	-
2018	-	-	-	-	104.21	10.42	-	-	-	-
2019	-	-	-	-	104.21	10.42	-	-	-	-
Total	-	-	-	-	521.07	52.11	-	-	-	-

Totals										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	30.68	87.60	4.46	5.16	108.13	14.34	14,065	0.71	0.58	14,297
2016	196.00	175.10	10.37	12.54	111.69	17.89	24,376	1.08	1.10	24,739
2017	316.11	105.12	0.51	15.77	111.30	17.50	24,379	1.19	0.53	24,763
2018	317.47	91.40	0.21	15.22	110.73	16.93	23,997	1.13	0.50	24,364
2019	86.99	21.12	0.06	3.95	105.74	11.95	7,210	0.30	0.13	7,310
Total	947.26	480.34	15.61	52.63	547.59	78.59	94,028	4.41	2.85	95,473

Comments - Exhibit 5

Table 9.A.2.1 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - CCTPL Pipeline Expansion

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration			Pollutant Emissions (tons)				
						CO^2	NO_x^2	SO_2^2	VOC^2	$PM_{10}/PM_{2.5}^{2,3}$	weeks	days/ week	hours/ day	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
Lowboy Truck	Diesel	2270002051	400	9	59%	0.64	1.63	3.0E-03	0.15	0.10	13	6	5	0.58	1.49	2.7E-03	0.13	0.09
Flatbed Truck	Diesel	2270002051	125	16	59%	0.52	1.32	2.9E-03	0.15	0.12	13	6	5	0.26	0.67	1.5E-03	0.08	0.06
Dozer	Diesel	2270002069	250	12	59%	0.63	1.85	3.0E-03	0.17	0.12	13	6	5	0.48	1.41	2.3E-03	0.13	0.09
Backhoe/Excavator	Diesel	2270002066	300	12	21%	2.12	4.10	3.9E-03	0.58	0.40	13	6	5	0.69	1.33	1.3E-03	0.19	0.13
Backhoe	Diesel	2270002066	80	6	21%	5.70	4.65	4.4E-03	0.92	0.84	13	6	5	0.25	0.20	1.9E-04	0.04	0.04
Side booms	Diesel	2270002069	260	8	59%	0.63	1.85	3.0E-03	0.17	0.12	13	6	5	0.33	0.98	1.6E-03	0.09	0.06
Crane	Diesel	2270002045	250	3	43%	0.49	2.27	3.1E-03	0.19	0.10	13	6	5	0.07	0.31	4.3E-04	0.03	0.01
Crane	Diesel	2270002045	680	3	43%	1.09	3.22	3.2E-03	0.18	0.14	13	6	5	0.41	1.21	1.2E-03	0.07	0.05
Loaders/Graders/Special	Diesel	2270002048	250	2	59%	0.62	1.82	3.0E-03	0.17	0.12	13	6	5	0.08	0.23	3.8E-04	0.02	0.02
Farm Tractors	Diesel	2270002066	175	1	21%	2.12	4.10	3.9E-03	0.58	0.40	13	6	5	0.03	0.06	6.1E-05	0.01	0.01
Forklift / manlift	Diesel	2270002057	60	3	59%	2.54	3.73	3.7E-03	0.28	0.30	13	6	5	0.12	0.17	1.7E-04	0.01	0.01
Bending Machine	Diesel	2270002081	85	1	59%	2.86	3.24	3.6E-03	0.31	0.40	13	6	5	0.06	0.07	7.9E-05	0.01	0.01
Road Boring machine	Diesel	2270002033	90	1	43%	2.47	4.62	3.7E-03	0.49	0.46	13	6	5	0.04	0.08	6.2E-05	0.01	0.01
Fill / Test pumps	Diesel	2270006010	40	2	43%	1.64	4.54	3.7E-03	0.38	0.32	4	6	5	0.01	0.02	1.7E-05	1.7E-03	1.4E-03
185 acfm compressor	Diesel	2270006015	60	2	43%	2.03	3.98	3.7E-03	0.30	0.28	13	6	5	0.05	0.09	8.2E-05	0.01	0.01
375 acfm compressor	Diesel	2270006015	100	2	43%	0.72	2.88	3.2E-03	0.23	0.18	13	6	5	0.03	0.11	1.2E-04	0.01	0.01
1200 acfm compressor	Diesel	2270006015	350	2	43%	1.01	3.61	3.3E-03	0.23	0.16	13	6	5	0.13	0.47	4.2E-04	0.03	0.02
Welding machine	Diesel	2270006025	40	16	21%	4.62	5.12	4.4E-03	1.08	0.73	13	6	5	0.27	0.30	2.5E-04	0.06	0.04
Generator	Diesel	2270006005	50	14	43%	2.58	4.93	3.8E-03	0.50	0.44	13	6	5	0.33	0.64	4.9E-04	0.07	0.06
Misc saws, trowel machine, compactor plate, etc.	Diesel	2270002008	50	6	43%	4.48	4.88	4.0E-03	0.66	0.49	13	6	5	0.25	0.27	2.2E-04	0.04	0.03
6" Water Pump	Diesel	2270006010	60	6	43%	2.61	4.94	3.8E-03	0.51	0.45	13	6	5	0.17	0.33	2.5E-04	0.03	0.03
3" Water Pump	Diesel	2270006010	40	6	43%	1.64	4.54	3.7E-03	0.38	0.32	0	6	5	-	-	0.0E+00	-	-
Total														**4.6**	**10.4**	**1.4E-02**	**1.06**	**0.79**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2015, all Parishes in Louisiana
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.

Table 9.A.2.2 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - CCTPL Pipeline Expansion

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration			Pollutant Emissions (tons)			
						CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	days/ week	hours/ day	CO_2	N_2O	CH_4	CO_2e
Lowboy Truck	Diesel	2270002051	400	9	59%	536	0.030	0.014	541	13	5	10	816	0.02	0.05	824
Flatbed Truck	Diesel	2270002051	125	16	59%	536	0.030	0.014	541	13	5	10	453	0.01	0.03	458
Dozer	Diesel	2270002069	250	12	59%	536	0.030	0.014	541	13	5	10	680	0.02	0.04	686
Backhoe/Excavator	Diesel	2270002066	300	12	21%	625	0.035	0.016	630	13	5	10	338	0.01	0.02	341
Backhoe	Diesel	2270002066	80	6	21%	693	0.039	0.018	699	13	5	10	50	1.3E-03	2.8E-03	51
Side booms	Diesel	2270002069	260	8	59%	536	0.030	0.014	541	13	5	10	472	0.01	0.03	476
Crane	Diesel	2270002045	250	3	43%	530	0.030	0.014	535	13	5	10	123	3.1E-03	0.01	124
Crane	Diesel	2270002045	680	3	43%	530	0.030	0.014	535	13	5	10	333	0.01	0.02	336
Loaders/Graders/Special	Diesel	2270002048	250	2	59%	536	0.030	0.014	541	13	5	10	113	2.9E-03	0.01	114
Farm Tractors	Diesel	2270002066	175	1	21%	625	0.035	0.016	630	13	5	10	16	4.2E-04	9.3E-04	17
Forklift / manlift	Diesel	2270002057	60	3	59%	595	0.034	0.015	601	13	5	10	45	1.2E-03	2.6E-03	46
Bending Machine	Diesel	2270002081	85	1	59%	595	0.034	0.015	601	13	5	10	21	5.4E-04	1.2E-03	22
Road Boring machine	Diesel	2270002033	90	1	43%	589	0.033	0.015	594	13	5	10	16	4.2E-04	9.3E-04	16
Fill / Test pumps	Diesel	2270006010	40	2	43%	589	0.033	0.015	595	4	5	10	4	1.1E-04	2.5E-04	5
185 acfm compressor	Diesel	2270006015	60	2	43%	589	0.033	0.015	595	13	5	10	22	5.5E-04	1.2E-03	22
375 acfm compressor	Diesel	2270006015	100	2	43%	530	0.030	0.014	535	13	5	10	33	8.3E-04	1.9E-03	33
1200 acfm compressor	Diesel	2270006015	350	2	43%	530	0.030	0.014	535	13	5	10	114	2.9E-03	0.01	115
Welding machine	Diesel	2270006025	40	16	21%	693	0.039	0.018	699	13	5	10	67	1.7E-03	3.8E-03	67
Generator	Diesel	2270006005	50	14	43%	589	0.033	0.015	594	13	5	10	127	3.2E-03	0.01	128
Misc saws, trowel machine, compactor plate, etc.	Diesel	2270002008	50	6	43%	588	0.033	0.015	594	13	5	10	54	1.4E-03	3.1E-03	55
6" Water Pump	Diesel	2270006010	60	6	43%	589	0.033	0.015	594	13	5	10	65	1.7E-03	3.7E-03	66
3" Water Pump	Diesel	2270006010	40	6	43%	589	0.033	0.015	595	0	5	10	-	-	-	-
Total													**3,965**	**1.0E-01**	**2.3E-01**	**4,001**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2015, all Parishes in Louisiana
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.

Comments - Exhibit 5

Table 9.A.2.3 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - CCTPL Pipeline Expansion

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration			Pollutant Emissions (tons)				
						CO[2]	NO_x[2]	SO_2[2]	VOC[2]	PM_{10}/ $PM_{2.5}$[2,3]	weeks	days/ week	hours/ day	CO	NO_x	SO_2	VOC	PM_{10}/ $PM_{2.5}$
Lowboy Truck	Diesel	2270002051	400	12	59%	0.50	1.33	2.9E-03	0.14	0.08	26	6	5	1.22	3.24	0.01	0.35	0.19
Flatbed Truck	Diesel	2270002051	125	23	59%	0.32	0.93	2.7E-03	0.14	0.06	26	6	5	0.47	1.36	4.0E-03	0.20	0.09
Dozer	Diesel	2270002069	250	18	59%	0.52	1.55	2.9E-03	0.16	0.10	24	6	5	1.10	3.27	0.01	0.34	0.21
Backhoe/Excavator	Diesel	2270002066	300	23	21%	1.93	3.76	3.8E-03	0.54	0.37	24	6	5	2.22	4.33	4.4E-03	0.62	0.42
Backhoe	Diesel	2270002066	80	8	21%	5.29	4.28	4.3E-03	0.84	0.77	26	6	5	0.61	0.50	5.0E-04	0.10	0.09
Side booms	Diesel	2270002069	260	10	59%	0.52	1.55	2.9E-03	0.16	0.10	22	6	5	0.58	1.73	3.3E-03	0.18	0.11
Crane	Diesel	2270002045	250	2	43%	0.43	1.95	3.0E-03	0.17	0.09	26	6	5	0.08	0.36	5.6E-04	0.03	0.02
Crane	Diesel	2270002045	680	3	43%	1.00	2.90	3.2E-03	0.18	0.13	26	6	5	0.76	2.19	2.4E-03	0.13	0.09
Loaders/Graders/Special	Diesel	2270002048	250	2	59%	0.51	1.52	2.9E-03	0.16	0.10	22	6	5	0.11	0.33	6.3E-04	0.03	0.02
Farm Tractors	Diesel	2270002066	175	4	21%	1.93	3.76	3.8E-03	0.54	0.37	26	6	5	0.24	0.48	4.8E-04	0.07	0.05
Forklift / manlift	Diesel	2270002057	60	3	59%	2.26	3.59	3.6E-03	0.26	0.26	26	6	5	0.21	0.33	3.3E-04	0.02	0.02
Bending Machine	Diesel	2270002081	85	1	59%	2.60	2.89	3.6E-03	0.28	0.35	26	6	5	0.11	0.12	1.5E-04	0.01	0.02
Road Boring machine	Diesel	2270002033	90	2	43%	2.32	4.32	3.7E-03	0.46	0.43	26	6	5	0.15	0.29	2.5E-04	0.03	0.03
Fill / Test pumps	Diesel	2270006010	40	4	43%	1.47	4.38	3.6E-03	0.34	0.29	13	6	5	0.04	0.13	1.1E-04	0.01	0.01
185 acfm compressor	Diesel	2270006015	60	2	43%	1.86	3.82	3.6E-03	0.28	0.25	26	6	5	0.08	0.17	1.6E-04	0.01	0.01
375 acfm compressor	Diesel	2270006015	100	2	43%	0.65	2.53	3.2E-03	0.22	0.16	26	6	5	0.05	0.19	2.3E-04	0.02	0.01
1200 acfm compressor	Diesel	2270006015	350	2	43%	0.92	3.30	3.2E-03	0.21	0.15	26	6	5	0.24	0.86	8.3E-04	0.05	0.04
Welding machine	Diesel	2270006025	40	26	21%	4.09	4.92	4.3E-03	0.93	0.66	26	6	5	0.77	0.92	8.1E-04	0.18	0.12
Generator	Diesel	2270006005	50	20	43%	2.43	4.78	3.7E-03	0.47	0.41	26	6	5	0.90	1.77	1.4E-03	0.18	0.15
Misc saws, trowel machine, compactor plate, etc.	Diesel	2270002008	50	10	43%	4.47	4.75	4.0E-03	0.64	0.46	26	6	5	0.83	0.88	7.3E-04	0.12	0.09
6" Water Pump	Diesel	2270006010	60	10	43%	2.46	4.79	3.7E-03	0.48	0.42	22	6	5	0.46	0.90	7.0E-04	0.09	0.08
3" Water Pump	Diesel	2270006010	40	10	43%	1.47	4.38	3.6E-03	0.34	0.29	22	6	5	0.18	0.55	4.5E-04	0.043	0.036
HDD Rig	Diesel	2270002033	800	2	43%	1.50	5.59	3.3E-03	0.39	0.24	17	6	10	1.16	4.32	2.5E-03	0.305	0.187
Mud pump	Diesel	2270006010	400	4	43%	1.20	3.92	3.3E-03	0.28	0.18	17	6	10	0.93	3.04	2.5E-03	0.214	0.142
Total														**13.5**	**32.2**	**4.1E-02**	**3.34**	**2.24**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2016, all Parishes in Louisiana
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.

Table 9.A.2.4 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - CCTPL Pipeline Expansion

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration			Pollutant Emissions (tons)			
						CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	days/ week	hours/ day	CO_2	N_2O	CH_4	CO_2e
Lowboy Truck	Diesel	2270002051	400	12	59%	536	0.030	0.014	541	26	5	10	2,177	0.06	0.12	2,197
Flatbed Truck	Diesel	2270002051	125	23	59%	536	0.030	0.014	541	26	5	10	1,304	0.03	0.07	1,316
Dozer	Diesel	2270002069	250	18	59%	536	0.030	0.014	541	24	5	10	1,884	0.05	0.11	1,901
Backhoe/Excavator	Diesel	2270002066	300	23	21%	625	0.035	0.016	631	24	5	10	1,198	0.03	0.07	1,208
Backhoe	Diesel	2270002066	80	8	21%	693	0.039	0.018	700	26	5	10	134	3.4E-03	0.01	135
Side booms	Diesel	2270002069	260	10	59%	536	0.030	0.014	541	22	5	10	998	0.03	0.06	1,007
Crane	Diesel	2270002045	250	2	43%	530	0.030	0.014	535	26	5	10	163	4.2E-03	0.01	165
Crane	Diesel	2270002045	680	3	43%	530	0.030	0.014	535	26	5	10	667	0.02	0.04	673
Loaders/Graders/Special	Diesel	2270002048	250	2	59%	536	0.030	0.014	541	22	5	10	192	4.9E-03	0.01	194
Farm Tractors	Diesel	2270002066	175	4	21%	625	0.035	0.016	631	26	5	10	132	3.4E-03	0.01	133
Forklift / manlift	Diesel	2270002057	60	3	59%	595	0.034	0.015	601	26	5	10	91	2.3E-03	0.01	91
Bending Machine	Diesel	2270002081	85	1	59%	595	0.034	0.015	601	26	5	10	43	1.1E-03	2.4E-03	43
Road Boring machine	Diesel	2270002033	90	2	43%	589	0.033	0.015	594	26	5	10	65	1.7E-03	3.7E-03	66
Fill / Test pumps	Diesel	2270006010	40	4	43%	589	0.033	0.015	595	13	5	10	29	7.4E-04	1.7E-03	29
185 acfm compressor	Diesel	2270006015	60	2	43%	589	0.033	0.015	595	26	5	10	44	1.1E-03	2.5E-03	44
375 acfm compressor	Diesel	2270006015	100	2	43%	530	0.030	0.014	535	26	5	10	65	1.7E-03	3.7E-03	66
1200 acfm compressor	Diesel	2270006015	350	2	43%	530	0.030	0.014	535	26	5	10	229	0.01	0.01	231
Welding machine	Diesel	2270006025	40	26	21%	693	0.039	0.018	699	26	5	10	217	0.01	0.01	219
Generator	Diesel	2270006005	50	20	43%	589	0.033	0.015	594	26	5	10	363	0.01	0.02	366
Misc saws, trowel machine, compactor plate, etc.	Diesel	2270002008	50	10	43%	588	0.033	0.015	594	26	5	10	181	4.6E-03	0.01	183
6" Water Pump	Diesel	2270006010	60	10	43%	589	0.033	0.015	594	22	5	10	184	4.7E-03	0.01	186
3" Water Pump	Diesel	2270006010	40	10	43%	589	0.033	0.015	595	22	5	10	123	3.1E-03	0.01	124
HDD Rig	Diesel	2270002033	800	2	43%	530	0.030	0.013	535	17	5	10	342	8.7E-03	1.9E-02	345
Mud pump	Diesel	2270006010	400	4	43%	530	0.030	0.014	535	17	5	10	342	8.7E-03	1.9E-02	345
Total													**11,163**	**2.8E-01**	**6.3E-01**	**11,265**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2016, all Parishes in Louisiana
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.

Table 9.A.2.5 - Liquefaction and CCTPL Expansion Project
On-Road Material Delivery, and Worker Commuting Emission Factors - CCTPL Pipeline Expansion

Vehicle	Emission Factor (g/VMT)[1]								Trip Distance (2-way) (miles)	Vehicle-months	Vehicle Usage (vehicle-days/yr)
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e			
2015											
Diesel Heavy Trucks	1.59	6.13	0.014	0.333	0.246	0.239	1,897	1,898	100	36	939
Diesel Buses	2.25	6.13	0.009	0.420	0.283	0.274	1,211	1,212	100	3	78
Diesel Light Trucks	1.54	2.10	0.005	0.302	0.109	0.105	631	631	100	18	469
Gasoline Passenger Cars	1.91	0.22	0.005	0.053	0.004	0.004	313	314	100	74	1,929
Gasoline Passenger Trucks	4.36	0.69	0.007	0.185	0.007	0.007	430	432	100	92	2,399
2016											
Diesel Heavy Trucks	1.39	5.35	0.014	0.294	0.210	0.204	1,897	1,898	160	60	1,304
Diesel Buses	2.00	5.41	0.009	0.378	0.247	0.239	1,211	1,212	160	5	109
Diesel Light Trucks	1.43	1.92	0.005	0.270	0.096	0.093	628	629	160	91	1,977
Gasoline Passenger Cars	1.79	0.18	0.005	0.045	0.004	0.004	307	307	160	363	7,887
Gasoline Passenger Trucks	4.10	0.63	0.007	0.164	0.007	0.006	421	422	160	454	9,864

1. EPA MOVES2010b

Table 9.A.2.6 - Liquefaction and CCTPL Expansion Project
On-Road Material Delivery, and Worker Commuting Emissions - CCTPL Pipeline Expansion

Vehicle	Vehicle Miles Traveled (VMT)	Emissions (ton/yr)							
		CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e
2015									
Diesel Heavy Trucks	93,900	0.16	0.63	1.4E-03	0.03	0.03	0.02	196	196
Diesel Buses	7,800	0.02	0.05	7.7E-05	3.6E-03	2.4E-03	2.4E-03	10	10
Diesel Light Trucks	46,900	0.08	0.11	2.5E-04	0.02	0.01	0.01	33	33
Gasoline Passenger Cars	192,900	0.41	0.05	1.0E-03	0.01	8.6E-04	7.9E-04	67	67
Gasoline Passenger Trucks	239,900	1.15	0.18	1.8E-03	0.05	1.9E-03	1.7E-03	114	114
Total		**1.82**	**1.03**	**4.6E-03**	**1.1E-01**	**3.6E-02**	**3.5E-02**	**420**	**420**
2016									
Diesel Heavy Trucks	208,640	0.32	1.23	3.2E-03	0.07	0.05	0.05	436	436
Diesel Buses	17,440	0.04	0.10	1.7E-04	0.01	4.7E-03	4.6E-03	23	23
Diesel Light Trucks	316,320	0.50	0.67	1.6E-03	0.09	0.03	0.03	219	219
Gasoline Passenger Cars	1,261,920	2.49	0.26	0.01	0.06	0.01	5.0E-03	427	427
Gasoline Passenger Trucks	1,578,240	7.14	1.10	0.01	0.28	0.01	0.01	733	735
Total		**10.48**	**3.36**	**2.3E-02**	**5.2E-01**	**1.0E-01**	**1.0E-01**	**1,838**	**1,841**

Table 9.A.2.7 - Liquefaction and CCTPL Expansion Project
On-Road On-Site Construction Vehicle Tailpipe Emission Factors - CCTPL Pipeline Expansion

Vehicle	Emission Factor (g/VMT)[1]								Onsite Travel (mile/ vehicle-day)	Vehicle-months	Vehicle Usage (vehicle-days/yr)
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e			
2015											
Diesel Heavy Trucks	1.59	6.13	0.014	0.333	0.246	0.239	1,897	1,898	-	-	-
Diesel Buses	2.25	6.13	0.009	0.420	0.283	0.274	1,211	1,212	-	-	-
Diesel Light Trucks	1.54	2.10	0.005	0.302	0.109	0.105	631	631	150	144	3,754
Gasoline Passenger Cars	1.91	0.22	0.005	0.053	0.004	0.004	313	314	-	-	-
Gasoline Passenger Trucks	4.36	0.69	0.007	0.185	0.007	0.007	430	432	-	-	-
2016											
Diesel Heavy Trucks	1.39	5.35	0.014	0.294	0.210	0.204	1,897	1,898	-	-	-
Diesel Buses	2.00	5.41	0.009	0.378	0.247	0.239	1,211	1,212	-	-	-
Diesel Light Trucks	1.43	1.92	0.005	0.270	0.096	0.093	628	629	150	750	19,554
Gasoline Passenger Cars	1.79	0.18	0.005	0.045	0.004	0.004	307	307	-	-	-
Gasoline Passenger Trucks	4.10	0.63	0.007	0.164	0.007	0.006	421	422	-	-	-

1. EPA MOVES2010b

Table 9.A.2.8 - Liquefaction and CCTPL Expansion Project
On-Road On-Site Construction Vehicle Tailpipe Emissions - CCTPL Pipeline Expansion

Vehicle	Vehicle Miles Traveled (VMT)	Emissions (ton/yr)							
		CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e
2015									
Diesel Heavy Trucks	-	-	-	-	-	-	-	-	-
Diesel Buses	-	-	-	-	-	-	-	-	-
Diesel Light Trucks	563,100	0.96	1.30	2.9E-03	0.19	0.07	0.07	391	392
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	-	-	-	-	-	-	-	-	-
Total		**0.96**	**1.30**	**2.9E-03**	**1.9E-01**	**6.7E-02**	**6.5E-02**	**391**	**392**
2016									
Diesel Heavy Trucks	-	-	-	-	-	-	-	-	-
Diesel Buses	-	-	-	-	-	-	-	-	-
Diesel Light Trucks	2,933,100	4.62	6.21	0.02	0.87	0.31	0.30	2,030	2,032
Gasoline Passenger Cars	-	-	-	-	-	-	-	-	-
Gasoline Passenger Trucks	-	-	-	-	-	-	-	-	-
Total		**4.62**	**6.21**	**1.5E-02**	**8.7E-01**	**3.1E-01**	**3.0E-01**	**2,030**	**2,032**

Table 9.A.2.9 - Liquefaction and CCTPL Expansion Project
2015 Fugitive Dust - CCTPL Pipeline Expansion

Acres Disturbed 392.8
Dust Control Efficiency 50%

Activity	Emission Factor (ton/acre-month)		Reference	Duration (months)[7,8]	Uncontrolled Emissions (tons)		Controlled Emissions (tons)	
	PM_{10}	$PM_{2.5}$			PM_{10}	$PM_{2.5}$	PM_{10}	$PM_{2.5}$
Construction	1.10E-01	1.10E-02	2, 3	2	86.42	8.64	43.21	4.32
Wind erosion	1.58E-02	2.38E-03	4, 5, 6	6	37.32	5.60	18.66	2.80
Total Emissions					123.73	14.24	61.87	7.12

1. Assume 50% control from water and other approved dust suppressants. (WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1.
2. WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Table 3-2, level 1, average conditions
3. $PM_{2.5}/PM_{10}$ = 0.10 (WRAP Fugitive Dust Handbook, Section 3.4.1)
4. Wind erosion of exposed areas (seeded land, stripped or graded overburden) = 0.38 ton TSP/acre/yr (WRAP Fugitive Dust Handbook, Table 11-6)
5. PM_{10}/TSP = 0.5, $PM_{2.5}/PM_{10}$ = 0.15, (WRAP Fugitive Dust Handbook, Section 7-2)
6. Emission factor converted from ton/acre-year to ton/acre-month by dividing by 12
7. It is assumed that constructionof a given pipeline segment will entail 2 months of continuous activity.
8. It is assumed that, on average, it will require 6 months to fully revegetate disturbed areas.

Table 9.A.2.10 - Liquefaction and CCTPL Expansion Project
2016 Fugitive Dust - CCTPL Pipeline Expansion

Acres Disturbed	1,178							
Dust Control Efficiency[1]	50%							
Activity	**Emission Factor (ton/acre-month)**		**Reference**	**Duration (months)**[7,8]	**Uncontrolled Emissions (tons)**		**Controlled Emissions (tons)**	
	PM_{10}	**$PM_{2.5}$**			**PM_{10}**	**$PM_{2.5}$**	**PM_{10}**	**$PM_{2.5}$**
Construction	1.10E-01	1.10E-02	2, 3	2	259.25	25.93	129.63	12.96
Wind erosion	1.58E-02	2.38E-03	4, 5, 6	6	111.95	16.79	55.97	8.40
Total Emissions					371.20	42.72	185.60	21.36

1. Assume 50% control from water and other approved dust suppressants. (WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1.
2. WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Table 3-2, level 1, average conditions
3. $PM_{2.5}/PM_{10}$ = 0.10 (WRAP Fugitive Dust Handbook, Section 3.4.1)
4. Wind erosion of exposed areas (seeded land, stripped or graded overburden) = 0.38 ton TSP/acre/yr (WRAP Fugitive Dust Handbook, Table 11-6)
5. PM_{10}/TSP = 0.5, $PM_{2.5}/PM_{10}$ = 0.15, (WRAP Fugitive Dust Handbook, Section 7-2)
6. Emission factor converted from ton/acre-year to ton/acre-month by dividing by 12
7. It is assumed that constructionof a given pipeline segment will entail 2 months of continuous activity.
8. It is assumed that, on average, it will require 6 months to fully revegetate disturbed areas.

Table 9.A.2.11 - Liquefaction and CCTPL Expansion Project
Open Burning - CCTPL Pipeline Expansion

Fuel Loading (tons/acre)	9.0(a)
Upland Forest Total (acres)	560
Percent Burned in 2015	20%
Percent Burned in 2016	60%

Pollutant	Emission Factor		Emission (tons)	
	(lb/ton)	(lb/acre)	2015	2016
CO	141.0(b)	1,269	71.06	213.19
NO_x	4.0(b)	36	2.02	6.05
VOC	24.2(b)	218	12.20	36.59
PM	17.2(b)	155	8.67	26.01
CO_2	3,180.5(c)	28,624	1,602.97	4,808.91
CH_4	0.18(d)	1.62	0.09	0.27
N_2O	0.04(d)	0.36	0.02	0.06
CO_2e	3,196.7(e)	28,770	1,611.12	4,833.37

References
(a) AP42 Table 13.1-1 (10/96) (Region 8: Southern)
(b) AP42 page 13.1-2, Southern Region
(c) 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Table 12.1.
(d) 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Table 12.4.
(e) The global warming potentials of CO_2, CH_4, and N_2O are 1, 21, and 310, respectively.

Table 9.A.2.12 - Liquefaction and CCTPL Expansion Project
Construction Emissions Totals - CCTPL Pipeline Expansion

Nonroad Tailpipe Emissions: Pipeline Construction										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	4.64	10.43	1.4E-02	1.06	0.79	0.79	3,965	1.0E-01	0.23	4,001
2016	13.50	32.24	4.1E-02	3.34	2.24	2.24	11,163	2.8E-01	0.63	11,265
Total	18.14	42.67	0.05	4.40	3.03	3.03	15,129	0.39	0.86	15,266

On-Road Emissions: Pipeline Material Deliveries and Commuting										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	1.82	1.03	4.6E-03	0.11	0.04	0.04	420	-	-	420
2016	10.48	3.36	2.3E-02	0.52	0.10	0.10	1,838	-	-	1,841
Total	12.30	4.38	0.03	0.63	0.14	0.14	2,258	-	-	2,262

On-Road Emissions: Pipeline On-site Construction Vehicles										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	0.96	1.30	2.9E-03	0.19	0.07	0.07	391	-	-	392
2016	4.62	6.21	1.5E-02	0.87	0.31	0.30	2,030	-	-	2,032
Total	5.58	7.51	0.02	1.06	0.38	0.37	2,421	-	-	2,424

Fugitive Dust Emissions: Pipeline Construction										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	-	-	-	-	61.87	7.12	-	-	-	-
2016	-	-	-	-	185.60	21.36	-	-	-	-
Total	-	-	-	-	247.47	28.48	-	-	-	-

Total: Open Burning										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10} [1]	$PM_{2.5}$ [1]	CO_2	N_2O	CH_4	CO_2e
2015	71.06	2.02	-	12.20	8.67	8.67	1,603	0.09	0.02	1,611
2016	213.19	6.05	-	36.59	26.01	26.01	4,809	0.27	0.06	4,833
Total	284.26	8.06	-	48.79	34.68	34.68	6,412	0.36	0.08	6,444

1. Total PM is conservatively reported as PM_{10} and $PM_{2.5}$.

Table 9.A.2.12 - Liquefaction and CCTPL Expansion Project Construction Emissions Totals - CCTPL Pipeline Expansion (Continued)

Total: Pipeline Construction										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	78.48	14.78	0.02	13.56	71.43	16.68	6,379	0.19	0.25	6,425
2016	241.80	47.85	0.08	41.31	214.26	50.00	19,840	0.56	0.69	19,972
Total	314.70	55.12	0.08	53.81	285.31	66.31	23,799	0.75	0.94	23,972

Table 9.A.3.1 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - Mamou Compressor Station

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration			Pollutant Emissions (tons)				
						CO^2	$NO_x{}^2$	$SO_2{}^2$	VOC^2	$PM_{10}/PM_{2.5}{}^{2,3}$	weeks	days/ week	hours/day	CO	NO_x	SO_2	VOC	$PM_{10}/PM_{2.5}$
D-6 Dozer	Diesel	2270002069	140	1	59%	0.87	2.02	3.1E-03	0.18	0.21	12	5	10	0.05	0.11	1.7E-04	0.01	0.01
D-8 Dozer	Diesel	2270002069	305	1	59%	1.00	2.53	3.2E-03	0.17	0.15	12	5	10	0.12	0.30	3.8E-04	0.02	0.02
Caterpillar 385C	Diesel	2270002036	520	1	59%	0.89	2.22	3.1E-03	0.16	0.14	12	5	10	0.18	0.45	6.4E-04	0.03	0.03
Weld Machine	Gas	2265006025	80	1	68%	31.28	2.26	0.04	0.91	0.07	0	5	10	-	-	-	-	-
Backhoe	Diesel	2270002036	125	2	59%	0.80	1.82	3.1E-03	0.17	0.19	12	5	10	0.08	0.18	3.0E-04	0.02	0.02
Air Compressor	Diesel	2270006015	50	2	43%	2.03	3.98	3.7E-03	0.30	0.28	12	5	10	0.06	0.11	1.1E-04	0.01	0.01
50 T Link Belt Crane	Diesel	2270002045	330	1	43%	0.82	3.21	3.2E-03	0.19	0.13	0	5	10	-	-	-	-	-
Crawler Crane	Diesel	2270002045	500	1	43%	0.82	3.21	3.2E-03	0.19	0.13	0	5	10	-	-	-	-	-
Generators	Diesel	2270006005	30	2	43%	1.92	4.73	3.7E-03	0.48	0.37	12	5	10	0.03	0.08	6.4E-05	0.01	0.01
Pumps	Diesel	2270006010	75	4	43%	2.50	4.52	3.7E-03	0.50	0.46	12	5	10	0.21	0.39	3.2E-04	0.04	0.04
Aerial Lifts	Gas	2265003010	80	1	46%	143.13	10.07	0.05	4.63	0.07	0	5	10	-	-	-	-	-
9000 # Fork Lifts	Diesel	2270003020	90	1	59%	1.36	1.52	3.2E-03	0.15	0.17	12	5	10	0.05	0.05	1.1E-04	0.01	0.01
Trenchers	Diesel	2270002030	185	1	59%	0.88	2.67	3.2E-03	0.22	0.17	8	5	10	0.04	0.13	1.5E-04	0.01	0.01
Graders	Diesel	2270002048	185	1	59%	0.62	1.82	3.0E-03	0.17	0.12	8	5	10	0.03	0.09	1.5E-04	0.01	0.01
Concrete Saws	Gas	2265002039	15	1	78%	291.25	1.91	0.06	5.49	0.14	0	5	10	-	-	-	-	-
Off Highway trucks	Diesel	2270002051	303	2	59%	0.64	1.63	3.0E-03	0.15	0.10	12	5	10	0.15	0.38	7.0E-04	0.03	0.02
Roller Compacter	Diesel	2270002015	50	1	59%	2.36	3.58	3.7E-03	0.25	0.27	0	5	10	-	-	-	-	-
Total														**0.95**	**2.16**	**2.9E-03**	**0.19**	**0.16**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2015, all Parishes in Louisiana
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.

Table 9.A.3.2 - Liquefaction and CCTPL Expansion Project
2015 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - Mamou Compressor Station

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration			Pollutant Emissions (tons)			
						CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	days/week	hours/day	CO_2	N_2O	CH_4	CO_2e
D-6 Dozer	Diesel	2270002069	140	1	59%	536	0.030	0.014	541	12	5	10	29	7.5E-04	1.7E-03	30
D-8 Dozer	Diesel	2270002069	305	1	59%	536	0.030	0.014	541	12	5	10	64	1.6E-03	3.6E-03	64
Caterpillar 385C	Diesel	2270002036	520	1	59%	536	0.030	0.014	541	12	5	10	109	2.8E-03	0.01	110
Weld Machine	Gas	2265006025	80	1	68%	711	0.040	0.016	717	0	5	10	-	-	-	-
Backhoe	Diesel	2270002036	125	2	59%	536	0.030	0.014	541	12	5	10	52	1.3E-03	3.0E-03	53
Air Compressor	Diesel	2270006015	50	2	43%	589	0.033	0.015	595	12	5	10	17	4.3E-04	9.5E-04	17
50 T Link Belt Crane	Diesel	2270002045	330	1	43%	530	0.030	0.014	535	0	5	10	-	-	-	-
Crawler Crane	Diesel	2270002045	500	1	43%	530	0.030	0.014	535	0	5	10	-	-	-	-
Generators	Diesel	2270006005	30	2	43%	589	0.033	0.015	594	12	5	10	10	2.6E-04	5.7E-04	10
Pumps	Diesel	2270006010	75	4	43%	589	0.033	0.015	594	12	5	10	50	1.3E-03	2.9E-03	51
Aerial Lifts	Gas	2265003010	80	1	46%	823	0.047	0.019	830	0	5	10	-	-	-	-
9000 # Fork Lifts	Diesel	2270003020	90	1	59%	596	0.034	0.015	601	12	5	10	21	5.3E-04	1.2E-03	21
Trenchers	Diesel	2270002030	185	1	59%	536	0.030	0.014	541	8	5	10	26	6.6E-04	1.5E-03	26
Graders	Diesel	2270002048	185	1	59%	536	0.030	0.014	541	8	5	10	26	6.6E-04	1.5E-03	26
Concrete Saws	Gas	2265002039	15	1	78%	1,044	0.059	0.024	1,053	0	5	10	-	-	-	-
Off Highway trucks	Diesel	2270002051	303	1	59%	536	0.030	0.014	541	12	5	10	63	1.6E-03	3.6E-03	64
Roller Compacter	Diesel	2270002015	50	1	59%	595	0.034	0.015	601	0	5	10	-	-	-	-
Total													**438**	**0.01**	**0.02**	**442**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2015, all Parishes in Louisiana
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
4. The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.

Table 9.A.3.3 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Criteria Pollutant Tailpipe Emissions - Mamou Compressor Station

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)					Equipment Operating Duration			Pollutant Emissions (tons)				
						CO^2	$NO_x{}^2$	$SO_2{}^2$	VOC^2	PM_{10}/ $PM_{2.5}{}^{2,3}$	weeks	days/ week	hours/day	CO	NO_x	SO_2	VOC	PM_{10}/ $PM_{2.5}$
D-6 Dozer	Diesel	2270002069	140	1	59%	0.74	1.70	3.0E-03	0.17	0.18	4	5	10	0.01	0.03	5.5E-05	3.1E-03	3.2E-03
D-8 Dozer	Diesel	2270002069	305	1	59%	0.89	2.22	3.1E-03	0.16	0.13	4	5	10	0.04	0.09	1.2E-04	0.01	0.01
Caterpillar 385C	Diesel	2270002036	520	1	59%	0.77	1.90	3.1E-03	0.15	0.12	18	5	10	0.23	0.58	9.3E-04	0.05	0.04
Weld Machine	Gas	2265006025	80	2	68%	26.25	1.95	0.04	0.76	0.07	18	5	10	2.83	0.21	4.4E-03	0.08	0.01
Backhoe	Diesel	2270002036	125	2	59%	0.65	1.49	3.0E-03	0.16	0.16	4	5	10	0.02	0.05	9.7E-05	0.01	0.01
Air Compressor	Diesel	2270006015	50	2	43%	1.86	3.82	3.6E-03	0.28	0.25	18	5	10	0.08	0.16	1.5E-04	0.01	0.01
50 T Link Belt Crane	Diesel	2270002045	330	1	43%	0.74	2.89	3.2E-03	0.18	0.12	18	5	10	0.10	0.41	4.5E-04	0.03	0.02
Crawler Crane	Diesel	2270002045	500	1	43%	0.74	2.89	3.2E-03	0.18	0.12	18	5	10	0.16	0.62	6.8E-04	0.04	0.03
Generators	Diesel	2270006005	30	2	43%	1.71	4.55	3.7E-03	0.42	0.33	18	5	10	0.04	0.12	9.4E-05	0.01	0.01
Pumps	Diesel	2270006010	75	4	43%	2.36	4.25	3.7E-03	0.47	0.43	18	5	10	0.30	0.54	4.7E-04	0.06	0.06
Aerial Lifts	Gas	2265003010	80	1	46%	141.04	9.87	0.05	4.55	0.07	18	5	10	5.15	0.36	1.7E-03	0.17	2.7E-03
9000 # Fork Lifts	Diesel	2270003020	90	1	59%	0.82	1.04	3.0E-03	0.14	0.08	18	5	10	0.04	0.05	1.6E-04	0.01	4.3E-03
Trenchers	Diesel	2270002030	185	1	59%	0.78	2.35	3.1E-03	0.21	0.15	4	5	10	0.02	0.06	7.6E-05	4.9E-03	3.7E-03
Graders	Diesel	2270002048	185	1	59%	0.51	1.52	2.9E-03	0.16	0.10	4	5	10	0.01	0.04	7.1E-05	3.9E-03	2.3E-03
Concrete Saws	Gas	2265002039	15	1	78%	290.90	1.89	0.06	5.45	0.14	4	5	10	0.75	4.9E-03	1.6E-04	0.01	3.5E-04
Off Highway trucks	Diesel	2270002051	303	1	59%	0.50	1.33	2.9E-03	0.14	0.08	18	5	10	0.09	0.24	5.1E-04	0.03	0.01
Roller Compacter	Diesel	2270002015	50	1	59%	2.07	3.44	3.6E-03	0.23	0.23	9	5	10	0.03	0.05	5.2E-05	3.3E-03	3.4E-03
Total														**9.90**	**3.57**	**0.01**	**0.51**	**0.20**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2016, all Parishes in Louisiana
3. $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions for combustion sources.

Comments - Exhibit 5

Table 9.A.3.4 - Liquefaction and CCTPL Expansion Project
2016 Non-Road Construction Equipment Greenhouse Gas Tailpipe Emissions - Mamou Compressor Station

Equipment Type	Fuel	Source Category[1]	Engine Rating (hp)	No.	Load Factor	Pollutant Emission Factor (g/hp-hr)				Equipment Operating Duration			Pollutant Emissions (tons)			
						CO_2[2]	CH_4[3]	N_2O[3]	CO_2e[4]	weeks	days/ week	hours/d ay	CO_2	N_2O	CH_4	CO_2e
D-6 Dozer	Diesel	2270002069	140	1	59%	536	0.030	0.014	541	4	5	10	10	2.5E-04	5.5E-04	10
D-8 Dozer	Diesel	2270002069	305	1	59%	536	0.030	0.014	541	4	5	10	21	5.4E-04	1.2E-03	21
Caterpillar 385C	Diesel	2270002036	520	1	59%	536	0.030	0.014	541	18	5	10	163	4.2E-03	0.01	165
Weld Machine	Gas	2265006025	80	2	68%	708	0.040	0.018	715	18	5	10	76	1.9E-03	4.3E-03	77
Backhoe	Diesel	2270002036	125	2	59%	536	0.030	0.014	541	4	5	10	17	4.4E-04	9.9E-04	18
Air Compressor	Diesel	2270006015	50	2	43%	589	0.033	0.015	595	18	5	10	25	6.4E-04	1.4E-03	25
50 T Link Belt Crane	Diesel	2270002045	330	1	43%	530	0.030	0.014	535	18	5	10	75	1.9E-03	4.2E-03	75
Crawler Crane	Diesel	2270002045	500	1	43%	530	0.030	0.014	535	18	5	10	113	2.9E-03	0.01	114
Generators	Diesel	2270006005	30	2	43%	589	0.033	0.015	594	18	5	10	15	3.8E-04	8.6E-04	15
Pumps	Diesel	2270006010	75	4	43%	589	0.033	0.015	594	18	5	10	75	1.9E-03	4.3E-03	76
Aerial Lifts	Gas	2265003010	80	1	46%	819	0.047	0.021	827	18	5	10	30	7.6E-04	1.7E-03	30
9000 # Fork Lifts	Diesel	2270003020	90	1	59%	596	0.034	0.015	601	18	5	10	31	8.0E-04	1.8E-03	32
Trenchers	Diesel	2270002030	185	1	59%	536	0.030	0.014	541	4	5	10	13	3.3E-04	7.3E-04	13
Graders	Diesel	2270002048	185	1	59%	536	0.030	0.014	541	4	5	10	13	3.3E-04	7.3E-04	13
Concrete Saws	Gas	2265002039	15	1	78%	1,044	0.059	0.027	1,054	4	5	10	3	6.9E-05	1.5E-04	3
Off Highway trucks	Diesel	2270002051	303	1	59%	536	0.030	0.014	541	18	5	10	95	2.4E-03	0.01	96
Roller Compacter	Diesel	2270002015	50	1	59%	595	0.034	0.015	601	9	5	10	9	2.2E-04	4.9E-04	9
Total													**775**	**0.02**	**0.04**	**782**

1. User's Guide for the Final NONROAD2005 Model, EPA420-R-05-013, US EPA, December 2005
2. EPA NONROAD2008 run for calendar year 2016, all Parishes in Louisiana
3. 2013 Climate Registry Default Emission Factors, Released: April 2, 2013, Tables 13.1 and 13.7., ratioed based on CO_2 emission factor from NONROAD. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/

4 The global warming potentials of CO_2, CH_4, and N_2O are assumed to be 1, 21, and 310, respectively.

Table 9.A.3.5 - Liquefaction and CCTPL Expansion Project
On-Road Material Delivery, and Worker Commuting Emission Factors - Mamou Compressor Station

Vehicle	Emission Factor (g/VMT)[1]								Trip Distance (2-way) (miles)	Vehicle-months	Vehicle Usage (vehicle-days/yea
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e			
2015											
Diesel Heavy Trucks	1.59	6.13	0.014	0.333	0.246	0.239	1,897	1,898	150	16	348
Diesel Buses	2.25	6.13	0.009	0.420	0.283	0.274	1,211	1,212	75	4	87
Diesel Light Trucks	1.54	2.10	0.005	0.302	0.109	0.105	631	631	75	16	348
Gasoline Passenger Cars	1.91	0.22	0.005	0.053	0.004	0.004	313	314	75	40	869
Gasoline Passenger Trucks	4.36	0.69	0.007	0.185	0.007	0.007	430	432	75	40	869
2016											
Diesel Heavy Trucks	1.39	5.35	0.014	0.294	0.210	0.204	1,897	1,898	150	16	348
Diesel Buses	2.00	5.41	0.009	0.378	0.247	0.239	1,211	1,212	75	4	87
Diesel Light Trucks	1.43	1.92	0.005	0.270	0.096	0.093	628	629	75	16	348
Gasoline Passenger Cars	1.79	0.18	0.005	0.045	0.004	0.004	307	307	75	40	869
Gasoline Passenger Trucks	4.10	0.63	0.007	0.164	0.007	0.006	421	422	75	40	869

1. EPA MOVES2010b

Table 9.A.3.6 - Liquefaction and CCTPL Expansion Project
On-Road Material Delivery, and Worker Commuting Emissions - Mamou Compressor Station

Vehicle	Vehicle Miles Traveled (VMT)	Emissions (ton/yr)							
		CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	CO_2e
2015									
Diesel Heavy Trucks	52,200	0.09	0.35	8.0E-04	0.02	0.01	0.01	109.1	109.2
Diesel Buses	6,525	0.02	0.04	6.5E-05	3.0E-03	2.0E-03	2.0E-03	8.7	8.7
Diesel Light Trucks	26,100	0.04	0.06	1.4E-04	0.01	3.1E-03	3.0E-03	18.1	18.2
Gasoline Passenger Cars	65,175	0.14	0.02	3.5E-04	3.8E-03	2.9E-04	2.7E-04	22.5	22.6
Gasoline Passenger Trucks	65,175	0.31	0.05	4.8E-04	0.01	5.2E-04	4.7E-04	30.9	31.0
Total		**0.60**	**0.52**	**1.8E-03**	**4.8E-02**	**2.0E-02**	**1.9E-02**	**189**	**190**
2016									
Diesel Heavy Trucks	52,200	0.08	0.31	7.9E-04	0.02	0.01	0.01	109.1	109.2
Diesel Buses	6,525	0.01	0.04	6.4E-05	2.7E-03	1.8E-03	1.7E-03	8.7	8.7
Diesel Light Trucks	26,100	0.04	0.06	1.3E-04	0.01	2.8E-03	2.7E-03	18.1	18.1
Gasoline Passenger Cars	65,175	0.13	0.01	3.4E-04	3.2E-03	2.8E-04	2.6E-04	22.0	22.1
Gasoline Passenger Trucks	65,175	0.29	0.05	4.7E-04	0.01	5.0E-04	4.6E-04	30.3	30.4
Total		**0.56**	**0.46**	**1.8E-03**	**4.2E-02**	**1.7E-02**	**1.7E-02**	**188**	**188**

Table 9.A.3.7 - Liquefaction and CCTPL Expansion Project
2015 Fugitive Dust - Mamou Compressor Station

Acres Disturbed 40.0
Dust Control Efficiency[1] 50%

Activity	Emission Factor (ton/acre-month)		Reference	Duration (months)[7]	Uncontrolled Emissions (tons)		Controlled Emissions (tons)	
	PM_{10}	$PM_{2.5}$			PM_{10}	$PM_{2.5}$	PM_{10}	$PM_{2.5}$
Construction	1.10E-01	1.10E-02	2, 3	2	8.80	0.88	4.40	0.44
Wind erosion	1.58E-02	2.38E-03	4, 5, 6	0	0.00	0.00	0.00	0.00
Total Emissions					8.80	0.88	4.40	0.44

1. Assume 50% control from water and other approved dust suppressants. (WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1.
2. WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Table 3-2, level 1, average conditions
3. $PM_{2.5}/PM_{10}$ = 0.10 (WRAP Fugitive Dust Handbook, Section 3.4.1)
4. Wind erosion of exposed areas (seeded land, stripped or graded overburden) = 0.38 ton TSP/acre/yr (WRAP Fugitive Dust Handbook, Table 11-6)
5. PM_{10}/TSP = 0.5, $PM_{2.5}/PM_{10}$ = 0.15, (WRAP Fugitive Dust Handbook, Section 7-2)
6. Emission factor converted from ton/acre-year to ton/acre-month by dividing by 12
7. It is assumed that, on average, it will require 6 months to fully revegetate disturbed areas.

Table 9.A.3.8 - Liquefaction and CCTPL Expansion Project
2016 Fugitive Dust - Mamou Compressor Station

Acres Disturbed 40
Dust Control Efficiency[1] 50%

Activity	Emission Factor (ton/acre-month)		Reference	Duration (months)[7]	Uncontrolled Emissions (tons)		Controlled Emissions (tons)	
	PM_{10}	$PM_{2.5}$			PM_{10}	$PM_{2.5}$	PM_{10}	$PM_{2.5}$
Construction	1.10E-01	1.10E-02	2, 3	2	8.80	0.88	4.40	0.44
Wind erosion	1.58E-02	2.38E-03	4, 5, 6	6	3.80	0.57	1.90	0.29
Total Emissions					12.60	1.45	6.30	0.73

1. Assume 50% control from water and other approved dust suppressants. (WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Section 3.4.1.
2. WRAP Fugitive Dust Handbook, Countess Environmental, September 2006, Table 3-2, level 1, average conditions
3. $PM_{2.5}/PM_{10}$ = 0.10 (WRAP Fugitive Dust Handbook, Section 3.4.1)
4. Wind erosion of exposed areas (seeded land, stripped or graded overburden) = 0.38 ton TSP/acre/yr (WRAP Fugitive Dust Handbook, Table 11-6)
5. PM_{10}/TSP = 0.5, $PM_{2.5}/PM_{10}$ = 0.15, (WRAP Fugitive Dust Handbook, Section 7-2)
6. Emission factor converted from ton/acre-year to ton/acre-month by dividing by 12
7. It is assumed that, on average, it will require 6 months to fully revegetate disturbed areas.

Table 9.A.3.9 - Liquefaction and CCTPL Expansion Project
Construction Emissions Totals - Mamou Compressor Station

Nonroad Tailpipe Emissions - Mamou Compressor Station Construction										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	0.95	2.16	2.9E-03	0.19	0.16	0.16	438	1.1E-02	0.02	442
2016	9.90	3.57	1.0E-02	0.51	0.20	0.20	775	2.0E-02	0.04	782
Total	10.86	5.73	1.3E-02	0.70	0.36	0.36	1,213	0.03	0.07	1,224

On-Road Emissions - Mamou Compressor Station Material Deliveries and Commuting										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	0.60	0.52	1.8E-03	0.05	0.02	0.02	189	-	-	190
2016	0.56	0.46	1.8E-03	0.04	0.02	0.02	188	-	-	188
Total	1.16	0.98	3.6E-03	0.09	0.04	0.04	378	-	-	378

Fugitive Dust Emissions - Mamou Compressor Station Construction										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	-	-	-	-	4.40	0.44	-	-	-	-
2016	-	-	-	-	6.30	0.73	-	-	-	-
Total	-	-	-	-	10.70	1.17	-	-	-	-

Total - Mamou Compressor Station Construction										
Year	Annual Emissions (tons)									
	CO	NOx	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4	CO_2e
2015	1.55	2.69	4.7E-03	0.24	4.58	0.62	627	1.1E-02	0.02	632
2016	10.46	4.03	1.2E-02	0.56	6.52	0.94	964	2.0E-02	0.04	971
Total	12.02	6.72	1.7E-02	0.79	11.10	1.57	1,591	0.03	0.07	1,603

APPENDIX 9B

Operating Emissions Calculations

Mamou Compressor Station
Evangeline Parish, Louisiana

EMERGENCY GENERATOR EMISSION CALCULATIONS

Company	Facility	
Cheniere Energy, Inc.	Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Emergency Generator	N/A	G-0223

Operating Data[1]		
Manufacturer	Dresser Waukesha	
Model	VGF24GL/GLD	
Rating	543	hp
	6,846	Btu/hp-hr
	3.72	MMBtu/hr
Fuel Type	Natural Gas	
Hours of Operations	500	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
$PM_{10}/PM_{2.5}$	7.71E-05	lb/MMBtu	AP-42 Table 3.2-2	0.00	0.00	0.00
SO_2	1.33E-02	lb/MMBtu	Fuel Gas Composition (5 grains sulfur/100 SCF)	0.05	0.05	0.01
NO_X	2.00	g/bhp-hr	Manufacturer Spec.	2.39	2.39	0.60
CO	1.30	g/bhp-hr	Manufacturer Spec.	1.56	1.56	0.39
VOC Total	0.37	g/bhp-hr	Manufacturer Spec.	0.45	0.45	0.11
Formaldehyde	5.28E-02	lb/MMBtu	AP-42 Table 3.2-2	0.20	0.20	0.05
CO_2-e	53.02	kg/MMBtu	EPA Factor[2]	434.52	434.52	108.63

(1) Provided by Cheniere Energy, Inc.

(2) Table NN-1 to Subpart NN of Part 98 - Default Factors for Calculation Methodology 1 of this subpart (40 CFR 98, October 30, 2009)

(3) Emission rates calculated as follows:

Example 1: *Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) X Emission Factor (lb/MMBtu)*

Example 2: *Emiision rate (lb/hr) = Operating Rate (bhp) X Emission Factor (g/bhp-hr) / (453.6 g/lb)*

Company	Facility	
Cheniere Energy, Inc.	Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Emergency Generator	N/A	G-0224

Operating Data[1]		
Manufacturer	Dresser Waukesha	
Model	VGF24GL/GLD	
Rating	543	hp
	6,846	Btu/hp-hr
	3.72	MMBtu/hr
Fuel Type	Natural Gas	
Hours of Operations	500	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
$PM_{10}/PM_{2.5}$	7.71E-05	lb/MMBtu	AP-42 Table 3.2-2	0.00	0.00	0.00
SO_2	1.33E-02	lb/MMBtu	Fuel Gas Composition (5 grains sulfur/100 SCF)	0.05	0.05	0.01
NO_X	2.00	g/bhp-hr	Manufacturer Spec.	2.39	2.39	0.60
CO	1.30	g/bhp-hr	Manufacturer Spec.	1.56	1.56	0.39
VOC Total	0.37	g/bhp-hr	Manufacturer Spec.	0.45	0.45	0.11
Formaldehyde	5.28E-02	lb/MMBtu	AP-42 Table 3.2-2	0.20	0.20	0.05
CO_2-e	53.02	kg/MMBtu	EPA Factor[2]	434.52	434.52	108.63

(1) Provided by Cheniere Energy, Inc.

(2) Table NN-1 to Subpart NN of Part 98 - Default Factors for Calculation Methodology 1 of this subpart (40 CFR 98, October 30, 2009)

(3) Emission rates calculated as follows:

Example 1: *Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) X Emission Factor (lb/MMBtu)*

Example 2: *Emiision rate (lb/hr) = Operating Rate (bhp) X Emission Factor (g/bhp-hr) / (453.6 g/lb)*

NATURAL GAS-FIRED TURBINE EMISSION CALCULATIONS

Company Cheniere Energy, Inc.	Facility Compressor Station	
Descriptive Name of Emission Point Gas Turbine Driven Compressor Unit A - Taurus 70	TEMP Subject Item ID N/A	Emission Point ID No. Z-0101

Operating Data[1]		
Manufacturer	Solar	
Model	Taurus 70-1080S	
Rating	10,836	hp
	7,267	Btu/hp-hr
	78.74	MMBtu/hr
Fuel Type	Natural Gas	
Hours of Operations	8,760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
$PM_{10}/PM_{2.5}$	0.02	lb/MMBtu	Manufacturer Spec.	1.65	1.65	7.24
SO_2	0.01	lb/MMBtu	Fuel Gas Composition (5 grains sulfur/100 SCF)	1.08	1.08	4.72
NO_X	0.33	g/bhp-hr	Manufacturer Spec.	7.95	7.95	34.82
CO	0.41	g/bhp-hr	Manufacturer Spec.	9.68	9.68	42.40
VOC Total	0.02	g/bhp-hr	Manufacturer Spec.	0.55	0.55	2.40
Formaldehyde	0.01	g/bhp-hr	Manufacturer Spec.	0.23	0.23	0.99
CO_2-e	53.02	kg/MMBtu	EPA Factor[2]	9,203.84	9,203.84	40,312.82

(1) Provided by Cheniere Energy, Inc.

(2) Table NN-1 to Subpart NN of Part 98 - Default Factors for Calculation Methodology 1 of this subpart (40 CFR 98, October 30, 2009)

(3) Emission rates calculated as follows:

Example 1: *Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) X Emission Factor (lb/MMBtu)*

Example 2: *Emiision rate (lb/hr) = Operating Rate (bhp) X Emission Factor (g/bhp-hr) / (453.6 g/lb)*

Company Cheniere Energy, Inc.	Facility Compressor Station	
Descriptive Name of Emission Point Gas Turbine Driven Compressor Unit B - Taurus 70	TEMP Subject Item ID N/A	Emission Point ID No. Z-0102

Operating Data[1]		
Manufacturer	Solar	
Model	Taurus 70-1080S	
Rating	10,836	hp
	7,267	Btu/hp-hr
	78.74	MMBtu/hr
Fuel Type	Natural Gas	
Hours of Operations	8,760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
$PM_{10}/PM_{2.5}$	0.02	lb/MMBtu	Manufacturer Spec.	1.65	1.65	7.24
SO_2	0.01	lb/MMBtu	Fuel Gas Composition (5 grains sulfur/100 SCF)	1.08	1.08	4.72
NO_X	0.33	g/bhp-hr	Manufacturer Spec.	7.95	7.95	34.82
CO	0.41	g/bhp-hr	Manufacturer Spec.	9.68	9.68	42.40
VOC Total	0.02	g/bhp-hr	Manufacturer Spec.	0.55	0.55	2.40
Formaldehyde	0.01	g/bhp-hr	Manufacturer Spec.	0.23	0.23	0.99
CO_2-e	53.02	kg/MMBtu	EPA Factor[2]	9,203.84	9,203.84	40,312.82

(1) Provided by Cheniere Energy, Inc.

(2) Table NN-1 to Subpart NN of Part 98 - Default Factors for Calculation Methodology 1 of this subpart (40 CFR 98, October 30, 2009)

(3) Emission rates calculated as follows:

Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) X Emission Factor (lb/MMBtu)

Example 2: Emiision rate (lb/hr) = Operating Rate (bhp) X Emission Factor (g/bhp-hr) / (453.6 g/lb)

Company Cheniere Energy, Inc.	Facility Compressor Station	
Descriptive Name of Emission Point Gas Turbine Driven Compressor Unit C - Taurus 70	TEMP Subject Item ID N/A	Emission Point ID No. Z-0103

Operating Data[1]		
Manufacturer	Solar	
Model	Taurus 70-1080S	
Rating	10,836	hp
	7,267	Btu/hp-hr
	78.74	MMBtu/hr
Fuel Type	Natural Gas	
Hours of Operations	8,760	hrs/year

Pollutant	Emission Factor	Reference	Emission Rates		
			Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
$PM_{10}/PM_{2.5}$	0.02 lb/MMBtu	Manufacturer Spec.	1.65	1.65	7.24
SO_2	0.01 lb/MMBtu	Fuel Gas Composition (5 grains sulfur/100 SCF)	1.08	1.08	4.72
NO_X	0.33 g/bhp-hr	Manufacturer Spec.	7.95	7.95	34.82
CO	0.41 g/bhp-hr	Manufacturer Spec.	9.68	9.68	42.40
VOC Total	0.02 g/bhp-hr	Manufacturer Spec.	0.55	0.55	2.40
Formaldehyde	0.01 g/bhp-hr	Manufacturer Spec.	0.23	0.23	0.99
CO_2-e	53.02 kg/MMBtu	EPA Factor[2]	9,203.84	9,203.84	40,312.82

(1) Provided by Cheniere Energy, Inc.

(2) Table NN-1 to Subpart NN of Part 98 - Default Factors for Calculation Methodology 1 of this subpart (40 CFR 98, October 30, 2009)

(3) Emission rates calculated as follows:

Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) X Emission Factor (lb/MMBtu)

Example 2: Emiision rate (lb/hr) = Operating Rate (bhp) X Emission Factor (g/bhp-hr) / (453.6 g/lb)

Company Cheniere Energy, Inc.	Facility Compressor Station	
Descriptive Name of Emission Point Gas Turbine Driven Compressor Unit D - Titan 130	TEMP Subject Item ID N/A	Emission Point ID No. Z-0104

Operating Data[1]		
Manufacturer	Solar	
Model	Titan 130-20502S	
Rating	20,617	hp
	7,050	Btu/hp-hr
	145.36	MMBtu/hr
Fuel Type	Natural Gas	
Hours of Operations	8,760	hrs/year

Pollutant	Emission Factor	Reference	Emission Rates		
			Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
$PM_{10}/PM_{2.5}$	0.02 lb/MMBtu	Manufacturer Spec.	3.053	3.053	13.37
SO_2	0.01 lb/MMBtu	Fuel Gas Composition (5 grains sulfur/100 SCF)	1.989	1.989	8.71
NO_X	0.32 g/bhp-hr	Manufacturer Spec.	14.681	14.681	64.30
CO	0.39 g/bhp-hr	Manufacturer Spec.	17.863	17.863	78.24
VOC Total	0.02 g/bhp-hr	Manufacturer Spec.	1.011	1.011	4.43
Formaldehyde	0.01 g/bhp-hr	Manufacturer Spec.	0.418	0.418	1.83
CO_2-e	53.02 kg/MMBtu	EPA Factor[2]	16,990.986	16,990.986	74,420.52

(1) Provided by Cheniere Energy, Inc.

(2) Table NN-1 to Subpart NN of Part 98 - Default Factors for Calculation Methodology 1 of this subpart (40 CFR 98, October 30, 2009)

(3) Emission rates calculated as follows:

Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) X Emission Factor (lb/MMBtu)

Example 2: Emiision rate (lb/hr) = Operating Rate (bhp) X Emission Factor (g/bhp-hr) / (453.6 g/lb)

CONDENSATE TANK EMISSION CALCULATIONS

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	TK-0101	
City:	Lake Charles	
State:	Louisiana	
Company:	Cheniere	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	Condensate Storage Tank	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		8.00
Liquid Height (ft) :		11.50
Avg. Liquid Height (ft):		10.00
Volume (gallons):		4,324.15
Turnovers:		12.00
Net Throughput(gal/yr):		51,889.82
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	White/White	
Shell Condition	Good	
Roof Color/Shade:	White/White	
Roof Condition:	Good	
Roof Characteristics		
Type:	Cone	
Height (ft)		1.00
Slope (ft/ft) (Cone Roof)		0.25
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Baton Rouge, Louisiana (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-101 - Vertical Fixed Roof Tank
Lake Charles, Louisiana

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Gasoline (RVP 7)	All	69.60	64.20	74.99	67.70	4.2222	3.7936	4.6890	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-101 - Vertical Fixed Roof Tank
Lake Charles, Louisiana

Annual Emission Calcaulations	
Standing Losses (lb):	171.1491
Vapor Space Volume (cu ft):	117.2861
Vapor Density (lb/cu ft):	0.0506
Vapor Space Expansion Factor:	0.1204
Vented Vapor Saturation Factor:	0.6570
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	117.2861
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	2.3333
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	10.0000
Roof Outage (ft):	0.3333
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.3333
Roof Height (ft):	1.0000
Roof Slope (ft/ft):	0.2500
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0506

Vapor Molecular Weight (lb/lb-mole):	68.0000
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	4.2222
Daily Avg. Liquid Surface Temp. (deg. R):	529.2692
Daily Average Ambient Temp. (deg. F):	67.6833
Ideal Gas Constant R	
(psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	527.3733
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation	
Factor (Btu/sqft day):	1,418.1969
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1204
Daily Vapor Temperature Range (deg. R):	21.5826
Daily Vapor Pressure Range (psia):	0.8955
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	4.2222
Vapor Pressure at Daily Minimum Liquid	
Surface Temperature (psia):	3.7936
Vapor Pressure at Daily Maximum Liquid	
Surface Temperature (psia):	4.6890
Daily Avg. Liquid Surface Temp. (deg R):	529.2692
Daily Min. Liquid Surface Temp. (deg R):	523.8735
Daily Max. Liquid Surface Temp. (deg R):	534.6648
Daily Ambient Temp. Range (deg. R):	20.6000
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.6570
Vapor Pressure at Daily Average Liquid:	
Surface Temperature (psia):	4.2222
Vapor Space Outage (ft):	2.3333
Working Losses (lb):	354.7121
Vapor Molecular Weight (lb/lb-mole):	68.0000
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	4.2222
Annual Net Throughput (gal/yr.):	51,889.8169
Annual Turnovers:	12.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,324.1514
Maximum Liquid Height (ft):	11.5000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	525.8612

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-101 - Vertical Fixed Roof Tank
Lake Charles, Louisiana

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Gasoline (RVP 7)	354.71	171.15	525.86

FUGITIVE EMISSION CALCULATIONS

Component Name	Stream Type	Number of Components	Emission Factor	Uncontrolled Emissions Rates	
			lb/hr	lb/hr	Ton/year
Valves	Gas	**100**	9.92E-03	0.99	4.34
Pumps	Gas	**0**	5.29E-03	0.00	0.00
Flanges/Connectors	Gas	**200**	8.60E-04	0.17	0.75
Compressors	Gas	**3**	1.94E-02	0.06	0.25
Relief Valves	Gas	**15**	1.94E-02	0.29	1.27
Open-ended Lines	Gas	**10**	4.41E-03	0.04	0.19
Connectors	Gas	**0**	4.40E-04	0.00	0.00
Others	Gas	**0**	1.94E-02	0.00	0.00
Process Drains	Gas	**10**	1.94E-02	0.19	0.85
Valves	Water / Light Oil	**20**	2.16E-04	0.00	0.02
Pumps	Water / Light Oil	**1**	5.20E-05	0.00	0.00
Flanges/Connectors	Water / Light Oil	**40**	6.00E-06	0.00	0.00
Compressors	Water / Light Oil	**0**	3.09E-02	0.00	0.00
Relief Valves	Water / Light Oil	**2**	3.09E-02	0.06	0.27
Open-ended Lines	Water / Light Oil	**10**	5.50E-04	0.01	0.02
Connectors	Water / Light Oil	**10**	2.43E-04	0.00	0.01
Others	Water / Light Oil	**0**	3.09E-02	0.00	0.00
Process Drains	Water / Light Oil	**10**	3.09E-02	0.31	1.35
Valves	Light Oil	**20**	5.50E-03	0.11	0.48
Pumps	Light Oil	**1**	2.87E-02	0.03	0.13
Flanges/Connectors	Light Oil	**40**	2.43E-04	0.01	0.04
Compressors	Light Oil	**0**	1.65E-02	0.00	0.00
Relief Valves	Light Oil	**2**	1.65E-02	0.03	0.14
Open-ended Lines	Light Oil	**10**	3.09E-03	0.03	0.14
Connectors	Light Oil	**10**	4.63E-04	0.00	0.02
Others	Light Oil	**0**	1.65E-02	0.00	0.00
Process Drains	Light Oil	**10**	1.65E-02	0.17	0.72
		THC	96.92	2.44	10.68
		NMHCs	7.34	0.18	0.81
		NMNEHCs(VOCs)	2.22	0.06	0.25
		HEXANE	0.51	0.01	0.06

MAINTENANCE STARTUP AND SHUTDOWN EMISSION CALCULATIONS

Company	Facility	
Cheniere Energy, Inc.	Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item	Emission Point ID No.
Maintenance Startup and Shutdown	N/A	MSS

Start up Emissions - 10 Minute Startup[1]

Description	Events per Year	NO_X			CO			VOC			CO_2		
		Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY
Gas Turbine Driven Compressor Unit A - Taurus 70	100	0.80	4.80	0.04	73.10	438.60	3.66	0.84	5.04	0.04	519.00	3,114.00	25.95
Gas Turbine Driven Compressor Unit B - Taurus 70	100	0.80	4.80	0.04	73.10	438.60	3.66	0.84	5.04	0.04	519.00	3,114.00	25.95
Gas Turbine Driven Compressor Unit C - Taurus 70	100	0.80	4.80	0.04	73.10	438.60	3.66	0.84	5.04	0.04	519.00	3,114.00	25.95
Gas Turbine Driven Compressor Unit D - Titan 130	100	1.90	11.40	0.10	176.90	1,061.40	8.85	2.02	12.12	0.10	1,161.00	6,966.00	58.05
Total Startup Emissions				**0.22**			**19.81**			**0.23**			**135.90**

Shutdown Emissions - 10 Minute Shutdown[1]

Description	Events per Year	NO_X			CO			VOC			CO_2		
		Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY
Gas Turbine Driven Compressor Unit A - Taurus 70	100	1.10	6.60	0.06	93.40	560.40	4.67	1.06	6.36	0.05	575.00	3,450.00	28.75
Gas Turbine Driven Compressor Unit B - Taurus 70	100	1.10	6.60	0.06	93.40	560.40	4.67	1.06	6.36	0.05	575.00	3,450.00	28.75
Gas Turbine Driven Compressor Unit C - Taurus 70	100	1.10	6.60	0.06	93.40	560.40	4.67	1.06	6.36	0.05	575.00	3,450.00	28.75
Gas Turbine Driven Compressor Unit D - Titan 130	100	2.40	14.40	0.12	207.60	1,245.60	10.38	2.38	14.28	0.12	1,272.00	7,632.00	63.60
Total Shutdown Emissions				**0.29**			**24.39**			**0.28**			**149.85**
Total MSS Emissions				**0.50**			**44.20**			**0.51**			**285.75**

(1) Emissions data and maintenance sheduling provided by Manufacturing Specifications.

BLOWN STACK EMISSION CALCULATIONS

BLOW DOWN SYSTEM CALCULATIONS

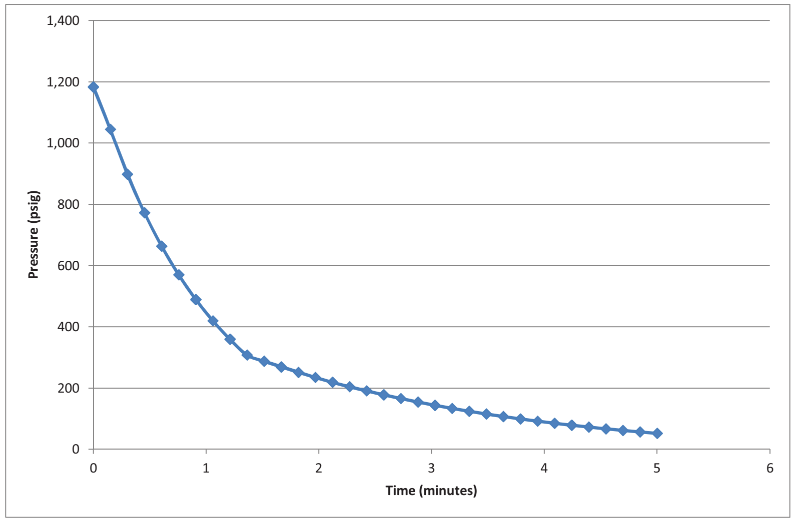
PIPE VOLUME CALCULATIONS

SECTION:	COMPRESSOR UNIT: Taurus 70 Units	BDV TAG:	

Section	Description	Line Number	NPS (in)	Piping Class	Sch / BWG	OD(in)	ID(in)	WT(in)	Length (ft)	Transv Sect Area (ft2)	Cylinder Volume (ft3)	Heads Volume (ft3)	Volume (ft3)	Normal Volume (ft3)	Press (psig)	Temp (°F)	Pseudo-reduced Press	Pseudo-reduced Temp	Z Factor	Moles (lbmol)	Temp x Moles
Comp Suction	Piping		20"	D	XS	20.000	19.000	0.500	100	1.969	196.895		197	10651	850	75	1.277	1.519	0.887	33	17879
Comp Discharge	Piping		16"	D	XS	16.000	15.000	0.500	200	1.227	245.437		245	18348	1370	160	2.044	1.761	0.907	56	34937
Cooler Inlet	Piping		12"	D	STD	12.750	12.000	0.375	20	0.785	15.708		16	1174	1370	160	2.044	1.761	0.907	4	2236
Cooler Inlet	Piping		12"	D	STD	12.750	12.000	0.375	20	0.785	15.708		16	1174	1370	160	2.044	1.761	0.907	4	2236
Cooler Outlet	Piping		12"	D	STD	12.750	12.000	0.375	20	0.785	15.708		16	1251	1365	120	2.037	1.647	0.875	4	2307
Cooler Outlet	Piping		12"	D	STD	12.750	12.000	0.375	20	0.785	15.708		16	1251	1365	120	2.037	1.647	0.875	4	2307
Cooler Discharge	Piping		16"	D	XS	16.000	15.000	0.500	50	1.227	61.359		61	4885	1365	120	2.037	1.647	0.875	16	9013
Compressor Bypass	Piping		12"	D	STD	12.750	12.000	0.375	125	0.785	98.175		98	7817	1365	120	2.037	1.647	0.875	25	14421
Compressor Bypass	Piping		12"	D	STD	12.750	12.000	0.375	125	0.785	98.175		98	5311	850	75	1.277	1.519	0.887	17	8915
Cooler	Tubing	Tubes	1"		14	1.000	0.834	0.083	9000	0.004	34.143		34	2552	1370	160	2.044	1.761	0.907	8	4860
Cooler	Tubing	Tubes	1"		14	1.000	0.834	0.083	9000	0.004	34.143		34	2552	1370	160	2.044	1.761	0.907	8	4860
													831	56967			**Total**			178	103972
																	T Average			°F	125.16
																	P Average			psig	1,183.53
																	Std Vol			SCF	67,413.40
																	Molecular Weight			lb/lbmol	17.03
																	Pseudo Critical Pressure			psia	677.4

BLOWDOWN CALCULATIONS

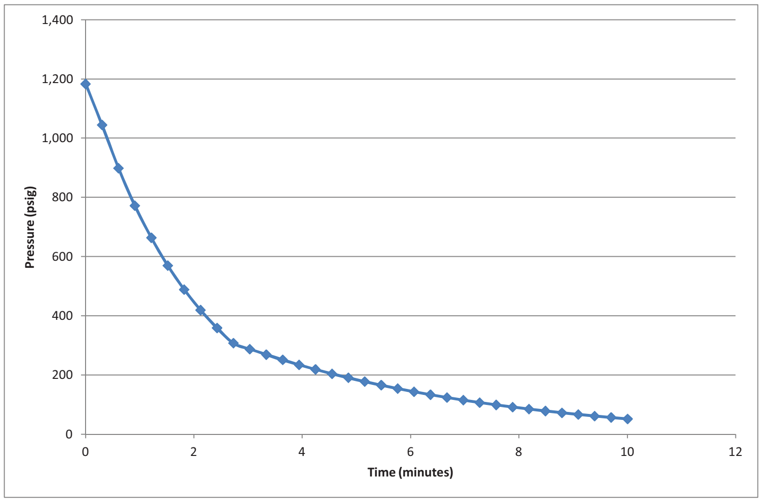
Reference Data		Initial	Change
Orifice Diameter, Inches		1.307	1.307
Choke Area	in2	1.341	
Inlet Pipe OD	in	6"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	6.065	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.215	
Settleout Z		0.914	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		42.147	
Time Increment, seconds		9.091	
Critical Ratio, Pcrt		0.043	
Expansion Factor, Fcr		1.357	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		831.159	
Mole to Blowdown, LB-Moles		177.637	
Settleout Pressure, psig		1,183.525	
Ave. Settleout Temp., deg R/deg F		585.305	°R / 125°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1183.53	1183.5	0.012	3605388	177.637	-	
0.15	9	1045.23	1045.2	0.014	3189275	153.647	24.0	24.0
0.30	18	898.83	898.8	0.016	2748767	132.425	21.2	45.2
0.45	27	772.65	772.7	0.019	2369102	114.134	18.3	63.5
0.61	36	663.90	663.9	0.022	2041878	98.370	15.8	79.3
0.76	45	570.17	570.2	0.025	1759850	84.783	13.6	92.9
0.91	55	489.39	489.4	0.029	1516776	73.072	11.7	104.6
1.06	64	419.76	419.8	0.034	1307277	62.979	10.1	114.7
1.21	73	359.76	359.8	0.039	1126713	54.281	8.7	123.4
1.36	82	308.03	308.0	0.046	435349	46.783	7.5	130.9
1.52	91	288.05	288.1	0.049	409000	43.886	2.9	133.8
1.67	100	269.28	269.3	0.052	384237	41.165	2.7	136.5
1.82	109	251.64	251.6	0.055	360963	38.608	2.6	139.0
1.97	118	235.07	235.1	0.059	339089	36.206	2.4	141.4
2.12	127	219.50	219.5	0.063	318529	33.950	2.3	143.7
2.27	136	204.88	204.9	0.067	299204	31.830	2.1	145.8
2.42	145	191.15	191.1	0.071	281039	29.839	2.0	147.8
2.58	155	178.25	178.2	0.076	263964	27.969	1.9	149.7
2.73	164	166.13	166.1	0.081	247912	26.213	1.8	151.4
2.88	173	154.75	154.7	0.087	232821	24.563	1.6	153.1
3.03	182	144.06	144.1	0.093	218633	23.014	1.5	154.6
3.18	191	134.03	134.0	0.099	205292	21.559	1.5	156.1
3.33	200	124.60	124.6	0.106	192748	20.193	1.4	157.4
3.48	209	115.75	115.8	0.113	180950	18.910	1.3	158.7
3.64	218	107.45	107.4	0.120	169854	17.706	1.2	159.9
3.79	227	99.65	99.7	0.129	159417	16.576	1.1	161.1
3.94	236	92.33	92.3	0.137	149597	15.515	1.1	162.1
4.09	245	85.47	85.5	0.147	140358	14.520	1.0	163.1
4.24	255	79.02	79.0	0.157	131662	13.586	0.9	164.1
4.39	264	72.98	73.0	0.168	123477	12.710	0.9	164.9
4.55	273	67.31	67.3	0.179	115771	11.888	0.8	165.7
4.70	282	62.00	62.0	0.192	108513	11.118	0.8	166.5
4.85	291	57.02	57.0	0.205	101676	10.396	0.7	167.2
5.00	300	52.35	52.3	0.219	95233	9.719	0.7	167.9

BLOWDOWN CALCULATIONS

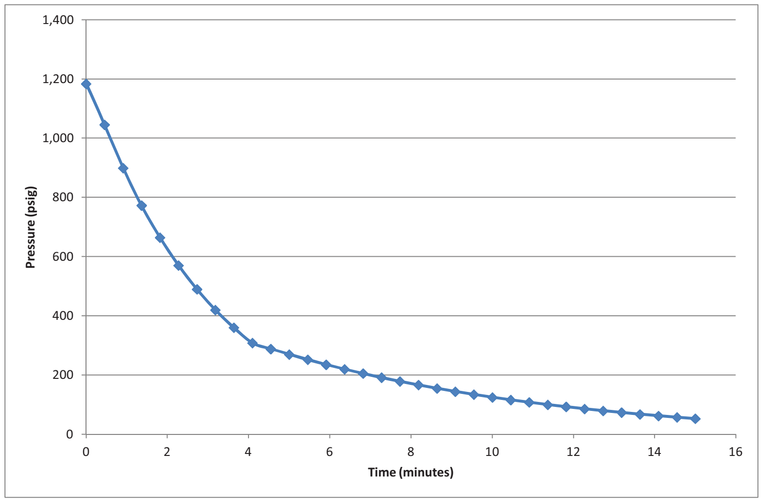
Reference Data		Initial	Change
Orifice Diameter, Inches		0.924	0.924
Choke Area	in2	0.671	
Inlet Pipe OD	in	6"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	6.065	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.152	
Settleout Z		0.914	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		42.147	
Time Increment, seconds		18.182	
Critical Ratio, Pcrt		0.043	
Expansion Factor, Fcr		1.357	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		831.159	
Mole to Blowdown, LB-Moles		177.637	
Settleout Pressure, psig		1,183.525	
Ave. Settleout Temp., deg R/deg F		585.305	°R / 125°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1183.53	1183.5	0.012	1803957	177.637	-	
0.30	18	1045.12	1045.1	0.014	1595580	153.630	24.0	24.0
0.61	36	898.63	898.6	0.016	1375041	132.395	21.2	45.2
0.91	55	772.39	772.4	0.019	1184985	114.096	18.3	63.5
1.21	73	663.60	663.6	0.022	1021198	98.326	15.8	79.3
1.52	91	569.85	569.8	0.025	880050	84.735	13.6	92.9
1.82	109	489.05	489.1	0.029	758411	73.023	11.7	104.6
2.12	127	419.42	419.4	0.034	653584	62.930	10.1	114.7
2.42	145	359.42	359.4	0.039	563247	54.232	8.7	123.4
2.73	164	307.71	307.7	0.046	217613	46.736	7.5	130.9
3.03	182	287.73	287.7	0.049	204433	43.840	2.9	133.8
3.33	200	268.96	269.0	0.052	192046	41.119	2.7	136.5
3.64	218	251.33	251.3	0.055	180405	38.564	2.6	139.1
3.94	236	234.77	234.8	0.059	169465	36.163	2.4	141.5
4.24	255	219.21	219.2	0.063	159183	33.907	2.3	143.7
4.55	273	204.60	204.6	0.067	149519	31.789	2.1	145.8
4.85	291	190.87	190.9	0.072	140435	29.799	2.0	147.8
5.15	309	177.98	178.0	0.076	131896	27.930	1.9	149.7
5.45	327	165.87	165.9	0.081	123870	26.175	1.8	151.5
5.76	345	154.50	154.5	0.087	116324	24.526	1.6	153.1
6.06	364	143.82	143.8	0.093	109230	22.978	1.5	154.7
6.36	382	133.79	133.8	0.099	102560	21.525	1.5	156.1
6.67	400	124.37	124.4	0.106	96288	20.160	1.4	157.5
6.97	418	115.53	115.5	0.113	90390	18.878	1.3	158.8
7.27	436	107.23	107.2	0.121	84843	17.675	1.2	160.0
7.58	455	99.44	99.4	0.129	79626	16.546	1.1	161.1
7.88	473	92.13	92.1	0.138	74717	15.487	1.1	162.2
8.18	491	85.27	85.3	0.147	70099	14.492	1.0	163.1
8.48	509	78.84	78.8	0.157	65753	13.559	0.9	164.1
8.79	527	72.80	72.8	0.168	61662	12.684	0.9	165.0
9.09	545	67.14	67.1	0.180	57810	11.864	0.8	165.8
9.39	564	61.83	61.8	0.192	54183	11.094	0.8	166.5
9.70	582	56.86	56.9	0.205	50766	10.373	0.7	167.3
10.00	600	52.20	52.2	0.220	47546	9.698	0.7	167.9

BLOWDOWN CALCULATIONS

Reference Data		**Initial**	**Change**
Orifice Diameter, Inches		0.754	0.754
Choke Area	in2	0.447	
Inlet Pipe OD	in	6"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	6.065	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.124	
Settleout Z		0.914	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		42.147	
Time Increment, seconds		27.273	
Critical Ratio, Pcrt		0.043	
Expansion Factor, Fcr		1.357	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		831.159	
Mole to Blowdown, LB-Moles		177.637	
Settleout Pressure, psig		1,183.525	
Ave. Settleout Temp., deg R/deg F		585.305	°R / 125°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1183.53	1183.5	0.012	1201799	177.637	-	
0.45	27	1045.23	1045.2	0.014	1063094	153.647	24.0	24.0
0.91	55	898.83	898.8	0.016	916257	132.425	21.2	45.2
1.36	82	772.65	772.7	0.019	789702	114.134	18.3	63.5
1.82	109	663.90	663.9	0.022	680627	98.369	15.8	79.3
2.27	136	570.17	570.2	0.025	586617	84.782	13.6	92.9
2.73	164	489.39	489.4	0.029	505592	73.072	11.7	104.6
3.18	191	419.76	419.8	0.034	435759	62.979	10.1	114.7
3.64	218	359.75	359.8	0.039	375571	54.280	8.7	123.4
4.09	245	308.03	308.0	0.046	145116	46.783	7.5	130.9
4.55	273	288.05	288.0	0.049	136333	43.886	2.9	133.8
5.00	300	269.27	269.3	0.052	128079	41.165	2.7	136.5
5.45	327	251.64	251.6	0.055	120321	38.608	2.6	139.0
5.91	355	235.07	235.1	0.059	113029	36.206	2.4	141.4
6.36	382	219.50	219.5	0.063	106176	33.950	2.3	143.7
6.82	409	204.88	204.9	0.067	99735	31.830	2.1	145.8
7.27	436	191.15	191.1	0.071	93680	29.839	2.0	147.8
7.73	464	178.25	178.2	0.076	87988	27.969	1.9	149.7
8.18	491	166.13	166.1	0.081	82637	26.213	1.8	151.4
8.64	518	154.75	154.7	0.087	77607	24.563	1.6	153.1
9.09	545	144.06	144.1	0.093	72877	23.014	1.5	154.6
9.55	573	134.02	134.0	0.099	68431	21.559	1.5	156.1
10.00	600	124.60	124.6	0.106	64249	20.193	1.4	157.4
10.45	627	115.75	115.8	0.113	60317	18.910	1.3	158.7
10.91	655	107.45	107.4	0.120	56618	17.706	1.2	159.9
11.36	682	99.65	99.6	0.129	53139	16.576	1.1	161.1
11.82	709	92.33	92.3	0.137	49866	15.515	1.1	162.1
12.27	736	85.47	85.5	0.147	46786	14.520	1.0	163.1
12.73	764	79.02	79.0	0.157	43887	13.586	0.9	164.1
13.18	791	72.98	73.0	0.168	41159	12.710	0.9	164.9
13.64	818	67.31	67.3	0.179	38590	11.888	0.8	165.7
14.09	845	62.00	62.0	0.192	36171	11.118	0.8	166.5
14.55	873	57.01	57.0	0.205	33892	10.396	0.7	167.2
15.00	900	52.35	52.3	0.219	31744	9.719	0.7	167.9

Case	Stack	Height Above	Stack Gas Flow				Stack Temperature		Temperature Correction Factor	Stack Pressure		Pressure Correction Factor	Corrected Stack Flow		Stack Area	Stack
	Diameter in	Ground ft	MW	lb/hr	MMSCFD	SCFS	lbmol/hr	°F	R		psig	psia		ft3/sec	ft3/min	ft2	Velocity ft/s
Emergency	54	12	17.039	655,650	350	4,051	38,478	80	540	1.174	0	14.700	1.000	4,755	285,312	15.904	298.988
5 min	54	12	17.039	162,094	87	1,001	9,513	80	540	1.174	0	14.700	1.000	1,176	70,537	15.904	73.918
10 min	54	12	17.039	81,104	43	501	4,760	80	540	1.174	0	14.700	1.000	588	35,293	15.904	36.985
15 min	54	12	17.039	54,032	29	334	3,171	80	540	1.174	0	14.700	1.000	392	23,512	15.904	24.639

	MOLECULAR WEIGHT LB/LBMOL	MOL FRACTION	MASS FRACTION	GAS VOLUME LBMOL	GAS MASS LBM
METHANE	16.042	**0.951**	0.895	168.92	2,709.74
ETHANE	30.069	**0.029**	0.051	5.15	154.90
PROPANE	44.096	**0.004**	0.011	0.75	32.90
ISO-BUTANE	58.122	**0.001**	0.003	0.18	10.32
N-BUTANE	58.122	**0.001**	0.003	0.16	9.29
ISO-PENTANE	72.149	**0.000**	0.000	0.02	1.28
N-PENTANE	72.149	**0.000**	0.000	0.02	1.28
N-HEXANE	86.175	**0.001**	0.005	0.16	13.78
CYCLOHEXANE	84.159	**0.000**	0.000	0.00	0.00
N-HEPTANE	100.202	**0.000**	0.000	0.00	0.00
BENZENE	78.112	**0.000**	0.000	0.00	0.00
TOLUENE	92.138	**0.000**	0.000	0.00	0.00
ETHYLBENZENE	106.165	**0.000**	0.000	0.00	0.00
XYLENE	106.165	**0.000**	0.000	0.00	0.00
STYRENE	104.149	**0.000**	0.000	0.00	0.00
CARBON DIOXIDE	44.100	**0.010**	0.026	1.81	79.90
WATER	18.015	**0.000**	0.000	0.00	0.00
NITROGEN	28.014	**0.003**	0.004	0.48	13.44
TOTAL	17.04	1.000	1.000	178	3,027
THC		0.987	0.969	175	2,933
NMHC		0.036	0.074	6	224
NMNEHC (VOCs)		0.007	0.023	1	69
HEXANE		0.001	0.005	0	14

Company	Facility	
Cheniere Energy, Inc.	Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Taurus 70 Unit Blowdown Stacks	N/A	NA

Emissions Per Event[1]			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
VOC	826.00	413.00	275.00
Hexane	165.00	83.00	55.00
CO_2	958.80	479.40	319.60
CH_4	32,516.88	16,258.44	10,838.96
CO_2-e	683,813.28	341,906.64	227,937.76

Emissions Per Year[1]			
Pollutant	3 Events	6 Events	12 Events
	TPY	TPY	TPY
VOC	0.10	0.21	0.41
Hexane	0.02	0.04	0.08
CO_2	0.12	0.24	0.48
CH_4	4.06	8.13	16.26
CO_2-e	85.48	170.95	341.91

(1) Emission calculation methodology provided by Engineering Firm with Site Specific Process Knowledge.

Emission calculations based upon site specific fuel analysis.

BLOW DOWN SYSTEM CALCULATIONS

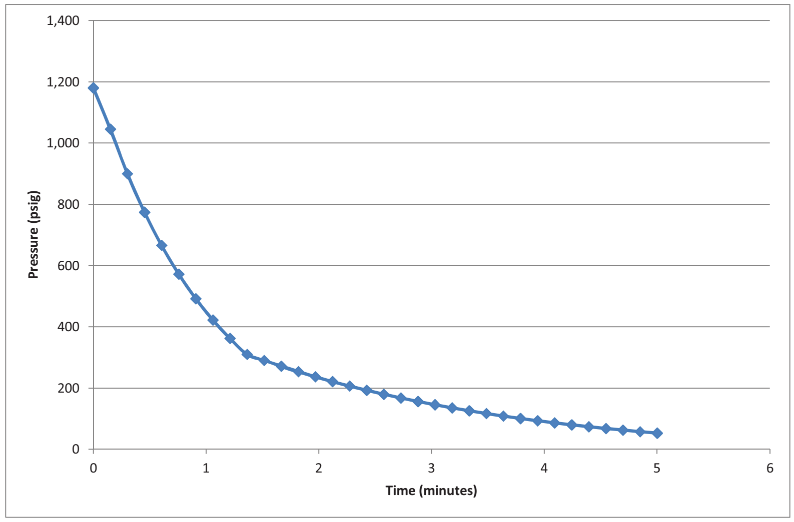
PIPE VOLUME CALCULATIONS

SECTION:	COMPRESSOR UNIT: Titan 130 Unit	BDV TAG:	

Section	Description	Line Number	NPS (in)	Piping Class	Sch / BWG	OD(in)	ID(in)	WT(in)	Length (ft)	Transv Sect Area (ft2)	Cylinder Volume (ft3)	Heads Volume (ft3)	Volume (ft3)	Normal Volume (ft3)	Press (psig)	Temp (°F)	Pseudo-reduced Press	Pseudo-reduced Temp	Z Factor	Moles (lbmol)	Temp x Moles
Comp Suction	Piping		30"	D	STD	30.000	29.250	0.375	100	4.666	466.637		467	25243	850	75	1.277	1.519	0.887	79	42374
Comp Discharge	Piping		24"	D	40	24.000	22.624	0.688	200	2.792	558.337		558	41738	1370	160	2.044	1.761	0.907	128	79477
Cooler Inlet	Piping		16"	D	XS	16.000	15.000	0.500	20	1.227	24.544		25	1835	1370	160	2.044	1.761	0.907	6	3494
Cooler Inlet	Piping		16"	D	XS	16.000	15.000	0.500	20	1.227	24.544		25	1835	1370	160	2.044	1.761	0.907	6	3494
Cooler Inlet	Piping		16"	D	XS	16.000	15.000	0.500	20	1.227	24.544		25	1835	1370	160	2.044	1.761	0.907	6	3494
Cooler Outlet	Piping		16"	D	XS	16.000	15.000	0.500	20	1.227	24.544		25	1954	1365	120	2.037	1.647	0.875	6	3605
Cooler Outlet	Piping		16"	D	XS	16.000	15.000	0.500	20	1.227	24.544		25	1954	1365	120	2.037	1.647	0.875	6	3605
Cooler Outlet	Piping		16"	D	XS	16.000	15.000	0.500	20	1.227	24.544		25	1954	1365	120	2.037	1.647	0.875	6	3605
Cooler Discharge	Piping		24"	D	40	24.000	22.624	0.688	50	2.792	139.584		140	11114	1365	120	2.037	1.647	0.875	35	20503
Compressor Bypass	Piping		20"	D	XS	20.000	19.000	0.500	125	1.969	246.119		246	19596	1365	120	2.037	1.647	0.875	62	36152
Compressor Bypass	Piping		20"	D	XS	20.000	19.000	0.500	125	1.969	246.119		246	13314	850	75	1.277	1.519	0.887	42	22349
Cooler	Tubing	Tubes	1 1/4"		14	1.250	1.084	0.083	9000	0.006	57.680		58	4312	1370	160	2.044	1.761	0.907	13	8211
Cooler	Tubing	Tubes	1 1/4"		14	1.250	1.084	0.083	9000	0.006	57.680		58	4312	1370	160	2.044	1.761	0.907	13	8211
Cooler	Tubing	Tubes	1 1/4"		14	1.250	1.084	0.083	9000	0.006	57.680		58	4312	1370	160	2.044	1.761	0.907	13	8211
													1977	135308			**Total**			422	246784
																	T Average			°F	124.62
																	P Average			psig	1,180.66
																	d Vol			SCF	160,157.15
																	Molecular Weight			lb/lbmol	17.03
																	Pseudo Critical Pressure			psia	677.4
																	Pseudo Critical Temperature			°R	352.

BLOWDOWN CALCULATIONS

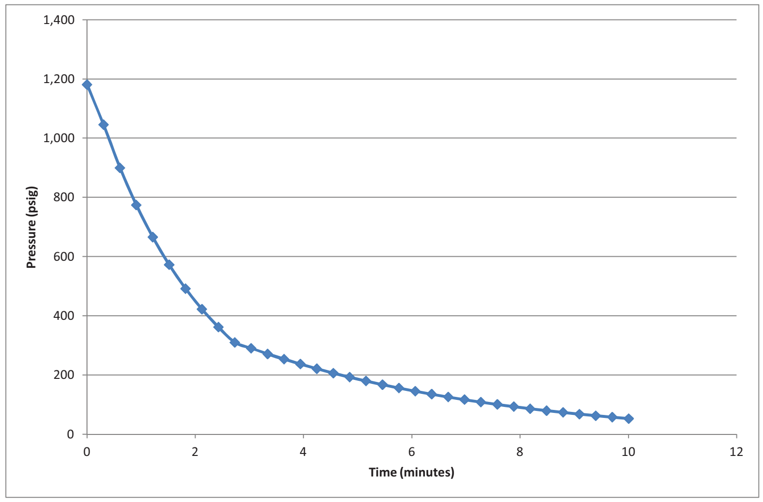
Reference Data		**Initial**	**Change**
Orifice Diameter, Inches		2.010	2.010
Choke Area	in2	3.172	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.252	
Settleout Z		0.915	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		41.852	
Time Increment, seconds		9.091	
Critical Ratio, Pcrt		0.043	
Expansion Factor, Fcr		1.355	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		1,977.099	
Mole to Blowdown, LB-Moles		422.021	
Settleout Pressure, psig		1,180.661	
Ave. Settleout Temp., deg R/deg F		584.767	°R / 125°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1180.66	1180.7	0.012	8501744	422.021	-	
0.15	9	1045.81	1045.8	0.014	7542649	365.450	56.6	56.6
0.30	18	900.16	900.2	0.016	6506759	315.260	50.2	106.8
0.45	27	774.52	774.5	0.019	5613136	271.963	43.3	150.1
0.61	36	666.13	666.1	0.022	4842242	234.612	37.4	187.4
0.76	45	572.63	572.6	0.025	4177220	202.391	32.2	219.6
0.91	55	491.96	492.0	0.029	3603530	174.595	27.8	247.4
1.06	64	422.38	422.4	0.034	3108630	150.617	24.0	271.4
1.21	73	362.35	362.4	0.039	2681698	129.931	20.7	292.1
1.36	82	310.57	310.6	0.045	1039668	112.087	17.8	309.9
1.52	91	290.49	290.5	0.048	976939	105.169	6.9	316.9
1.67	100	271.63	271.6	0.051	917973	98.668	6.5	323.4
1.82	109	253.90	253.9	0.055	862543	92.560	6.1	329.5
1.97	118	237.25	237.2	0.058	810436	86.820	5.7	335.2
2.12	127	221.60	221.6	0.062	761452	81.427	5.4	340.6
2.27	136	206.89	206.9	0.066	715401	76.361	5.1	345.7
2.42	145	193.08	193.1	0.071	672106	71.600	4.8	350.4
2.58	155	180.10	180.1	0.075	631400	67.128	4.5	354.9
2.73	164	167.91	167.9	0.081	593126	62.926	4.2	359.1
2.88	173	156.46	156.5	0.086	557138	58.980	3.9	363.0
3.03	182	145.70	145.7	0.092	523296	55.272	3.7	366.7
3.18	191	135.59	135.6	0.098	491470	51.790	3.5	370.2
3.33	200	126.10	126.1	0.104	461537	48.520	3.3	373.5
3.48	209	117.19	117.2	0.111	433382	45.449	3.1	376.6
3.64	218	108.82	108.8	0.119	406897	42.565	2.9	379.5
3.79	227	100.96	101.0	0.127	381979	39.857	2.7	382.2
3.94	236	93.59	93.6	0.136	358532	37.316	2.5	384.7
4.09	245	86.66	86.7	0.145	336467	34.930	2.4	387.1
4.24	255	80.17	80.2	0.155	315698	32.691	2.2	389.3
4.39	264	74.07	74.1	0.166	296145	30.590	2.1	391.4
4.55	273	68.35	68.4	0.177	277733	28.620	2.0	393.4
4.70	282	62.99	63.0	0.189	260391	26.772	1.8	395.2
4.85	291	57.96	58.0	0.202	244051	25.039	1.7	397.0
5.00	300	53.25	53.2	0.216	228652	23.415	1.6	398.6

BLOWDOWN CALCULATIONS

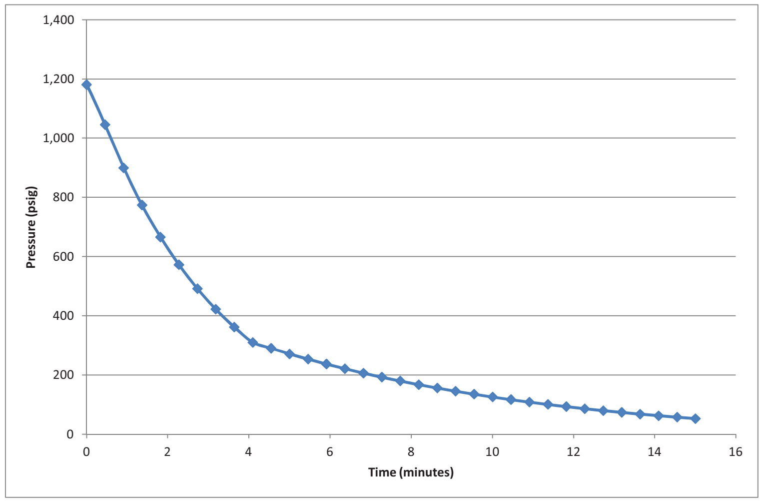
Reference Data		**Initial**	**Change**
Orifice Diameter, Inches		1.421	1.421
Choke Area	in2	1.586	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.178	
Settleout Z		0.915	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		41.852	
Time Increment, seconds		18.182	
Critical Ratio, Pcrt		0.043	
Expansion Factor, Fcr		1.355	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		1,977.099	
Mole to Blowdown, LB-Moles		422.021	
Settleout Pressure, psig		1,180.661	
Ave. Settleout Temp., deg R/deg F		584.767	°R / 125°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1180.66	1180.7	0.012	4250872	422.021	-	
0.30	18	1045.81	1045.8	0.014	3771324	365.450	56.6	56.6
0.61	36	900.16	900.2	0.016	3253380	315.260	50.2	106.8
0.91	55	774.52	774.5	0.019	2806568	271.963	43.3	150.1
1.21	73	666.13	666.1	0.022	2421121	234.612	37.4	187.4
1.52	91	572.63	572.6	0.025	2088610	202.391	32.2	219.6
1.82	109	491.96	492.0	0.029	1801765	174.595	27.8	247.4
2.12	127	422.38	422.4	0.034	1554315	150.617	24.0	271.4
2.42	145	362.35	362.4	0.039	1340849	129.931	20.7	292.1
2.73	164	310.57	310.6	0.045	519834	112.087	17.8	309.9
3.03	182	290.49	290.5	0.048	488469	105.169	6.9	316.9
3.33	200	271.63	271.6	0.051	458986	98.668	6.5	323.4
3.64	218	253.90	253.9	0.055	431272	92.560	6.1	329.5
3.94	236	237.25	237.2	0.058	405218	86.820	5.7	335.2
4.24	255	221.60	221.6	0.062	380726	81.427	5.4	340.6
4.55	273	206.89	206.9	0.066	357700	76.361	5.1	345.7
4.85	291	193.08	193.1	0.071	336053	71.600	4.8	350.4
5.15	309	180.10	180.1	0.075	315700	67.128	4.5	354.9
5.45	327	167.91	167.9	0.081	296563	62.926	4.2	359.1
5.76	345	156.46	156.5	0.086	278569	58.980	3.9	363.0
6.06	364	145.70	145.7	0.092	261648	55.272	3.7	366.7
6.36	382	135.59	135.6	0.098	245735	51.790	3.5	370.2
6.67	400	126.10	126.1	0.104	230768	48.520	3.3	373.5
6.97	418	117.19	117.2	0.111	216691	45.449	3.1	376.6
7.27	436	108.82	108.8	0.119	203448	42.565	2.9	379.5
7.58	455	100.96	101.0	0.127	190989	39.857	2.7	382.2
7.88	473	93.59	93.6	0.136	179266	37.316	2.5	384.7
8.18	491	86.66	86.7	0.145	168234	34.930	2.4	387.1
8.48	509	80.17	80.2	0.155	157849	32.691	2.2	389.3
8.79	527	74.07	74.1	0.166	148073	30.590	2.1	391.4
9.09	545	68.35	68.4	0.177	138867	28.620	2.0	393.4
9.39	564	62.99	63.0	0.189	130195	26.772	1.8	395.2
9.70	582	57.96	58.0	0.202	122026	25.039	1.7	397.0
10.00	600	53.25	53.2	0.216	114326	23.415	1.6	398.6

BLOWDOWN CALCULATIONS

Reference Data		Initial	Change
Orifice Diameter, Inches		1.160	1.160
Choke Area	in2	1.057	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.145	
Settleout Z		0.915	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		41.852	
Time Increment, seconds		27.273	
Critical Ratio, Pcrt		0.043	
Expansion Factor, Fcr		1.355	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		1,977.099	
Mole to Blowdown, LB-Moles		422.021	
Settleout Pressure, psig		1,180.661	
Ave. Settleout Temp., deg R/deg F		584.767	°R / 125°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1180.66	1180.7	0.012	2833915	422.021	-	
0.45	27	1045.81	1045.8	0.014	2514216	365.450	56.6	56.6
0.91	55	900.16	900.2	0.016	2168920	315.260	50.2	106.8
1.36	82	774.52	774.5	0.019	1871045	271.963	43.3	150.1
1.82	109	666.13	666.1	0.022	1614081	234.612	37.4	187.4
2.27	136	572.63	572.6	0.025	1392407	202.391	32.2	219.6
2.73	164	491.96	492.0	0.029	1201177	174.595	27.8	247.4
3.18	191	422.38	422.4	0.034	1036210	150.617	24.0	271.4
3.64	218	362.35	362.4	0.039	893899	129.931	20.7	292.1
4.09	245	310.57	310.6	0.045	346556	112.087	17.8	309.9
4.55	273	290.49	290.5	0.048	325646	105.169	6.9	316.9
5.00	300	271.63	271.6	0.051	305991	98.668	6.5	323.4
5.45	327	253.90	253.9	0.055	287514	92.560	6.1	329.5
5.91	355	237.25	237.2	0.058	270145	86.820	5.7	335.2
6.36	382	221.60	221.6	0.062	253817	81.427	5.4	340.6
6.82	409	206.89	206.9	0.066	238467	76.361	5.1	345.7
7.27	436	193.08	193.1	0.071	224035	71.600	4.8	350.4
7.73	464	180.10	180.1	0.075	210467	67.128	4.5	354.9
8.18	491	167.91	167.9	0.081	197709	62.926	4.2	359.1
8.64	518	156.46	156.5	0.086	185713	58.980	3.9	363.0
9.09	545	145.70	145.7	0.092	174432	55.272	3.7	366.7
9.55	573	135.59	135.6	0.098	163823	51.790	3.5	370.2
10.00	600	126.10	126.1	0.104	153846	48.520	3.3	373.5
10.45	627	117.19	117.2	0.111	144461	45.449	3.1	376.6
10.91	655	108.82	108.8	0.119	135632	42.565	2.9	379.5
11.36	682	100.96	101.0	0.127	127326	39.857	2.7	382.2
11.82	709	93.59	93.6	0.136	119511	37.316	2.5	384.7
12.27	736	86.66	86.7	0.145	112156	34.930	2.4	387.1
12.73	764	80.17	80.2	0.155	105233	32.691	2.2	389.3
13.18	791	74.07	74.1	0.166	98715	30.590	2.1	391.4
13.64	818	68.35	68.4	0.177	92578	28.620	2.0	393.4
14.09	845	62.99	63.0	0.189	86797	26.772	1.8	395.2
14.55	873	57.96	58.0	0.202	81350	25.039	1.7	397.0
15.00	900	53.25	53.2	0.216	76217	23.415	1.6	398.6

Case	Stack	Height Above	Stack Gas Flow				Stack Temperature		Temperature Correction Factor	Stack Pressure		Pressure Correction Factor	Corrected Stack Flow		Stack Area	Stack
	Diameter in	Ground ft	MW	lb/hr	MMSCFD	SCFS	lbmol/hr	°F	R		psig	psia		ft3/sec	ft3/min	ft2	Velocity ft/s
Emergency	78	12	17.039	655,650	350	4,051	38,478	80	540	1.174	0	14.700	1.000	4,755	285,312	33.183	143.302
5 min	78	12	17.039	382,229	204	2,362	22,432	80	540	1.174	0	14.700	1.000	2,772	166,330	33.183	83.542
10 min	78	12	17.039	191,114	102	1,181	11,216	80	540	1.174	0	14.700	1.000	1,386	83,165	33.183	41.771
15 min	78	12	17.039	127,410	68	787	7,477	80	540	1.174	0	14.700	1.000	924	55,443	33.183	27.847

	MOLECULAR WEIGHT LB/LBMOL	MOL FRACTION	MASS FRACTION	GAS VOLUME LBMOL	GAS MASS LBM
METHANE	16.042	0.951	0.895	401.30	6,437.66
ETHANE	30.069	0.029	0.051	12.24	368.00
PROPANE	44.096	0.004	0.011	1.77	78.16
ISO-BUTANE	58.122	0.001	0.003	0.42	24.53
N-BUTANE	58.122	0.001	0.003	0.38	22.08
ISO-PENTANE	72.149	0.000	0.000	0.04	3.04
N-PENTANE	72.149	0.000	0.000	0.04	3.04
N-HEXANE	86.175	0.001	0.005	0.38	32.73
CYCLOHEXANE	84.159	0.000	0.000	0.00	0.00
N-HEPTANE	100.202	0.000	0.000	0.00	0.00
BENZENE	78.112	0.000	0.000	0.00	0.00
TOLUENE	92.138	0.000	0.000	0.00	0.00
ETHYLBENZENE	106.165	0.000	0.000	0.00	0.00
XYLENE	106.165	0.000	0.000	0.00	0.00
STYRENE	104.149	0.000	0.000	0.00	0.00
CARBON DIOXIDE	44.100	0.010	0.026	4.30	189.83
WATER	18.015	0.000	0.000	0.00	0.00
NITROGEN	28.014	0.003	0.004	1.14	31.92
TOTAL	17.04	1.000	1.000	422	7,191
THC		0.987	0.969	417	6,969
NMHC		0.036	0.074	15	532
NMNEHC (VOCs)		0.007	0.023	3	164
HEXANE		0.001	0.005	0	33

Company	Facility	
Cheniere Energy, Inc.	Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Titan 130 Unit Blowdown Stack	N/A	NA

Emissions Per Event[1]			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
VOC	1,963.00	982.00	654.00
Hexane	393.00	196.00	131.00
CO_2	2,277.96	1,138.98	759.32
CH_4	77,251.92	38,625.96	25,750.64
CO_2-e	1,624,568.28	812,284.14	541,522.76

Emissions Per Year[1]			
Pollutant	3 Events	6 Events	12 Events
	TPY	TPY	TPY
VOC	0.25	0.49	0.98
Hexane	0.05	0.10	0.20
CO_2	0.28	0.57	1.14
CH_4	9.66	19.31	38.63
CO_2-e	203.07	406.14	812.28

(1) Emission calculation methodology provided by Engineering Firm with Site Specific Process Knowledge.

Emission calculations based upon site specific fuel analysis.

BLOW DOWN SYSTEM CALCULATIONS

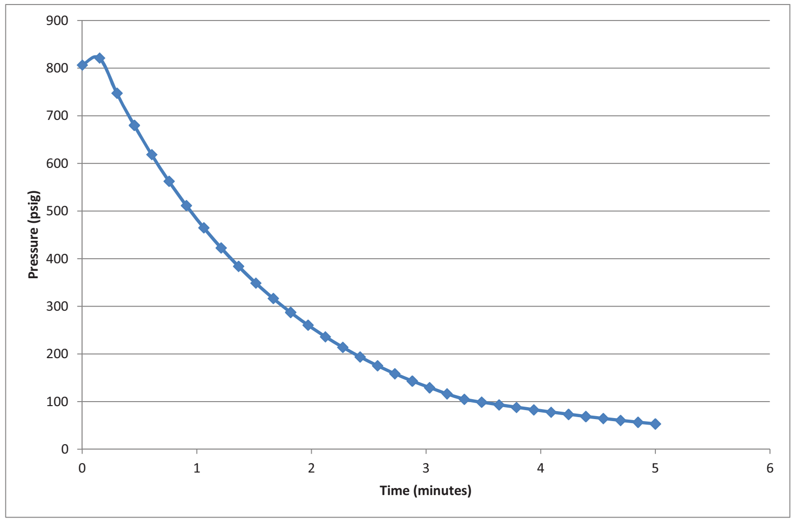
PIPE VOLUME CALCULATIONS

SECTION:	COMPRESSOR UNIT: Station Suction Blowdown	**BDV TAG:**	

Section	Description	Line Number	NPS (in)	Piping Class	Sch / BWG	OD(in)	ID(in)	WT(in)	Length (ft)	Transv Sect Area (ft2)	Cylinder Volume (ft3)	Heads Volume (ft3)	Volume (ft3)	Normal Volume (ft3)	Press (psig)	Temp (°F)	Pseudo-reduced Press	Pseudo-reduced Temp	Z Factor	Moles (lbmol)	Temp x Moles
Comp Suction Header	Piping		42"	D	STD	42.000	41.250	0.375	750	9.281	6960.438		6960	376536	**850**	**75**	1.277	1.519	0.887	1181	632056
Comp Suction	Piping		20"	D	XS	20.000	19.000	0.500	50	1.969	98.447		98	5326	**850**	**75**	1.277	1.519	0.887	17	8940
Comp Suction	Piping		20"	D	XS	20.000	19.000	0.500	50	1.969	98.447		98	5326	**850**	**75**	1.277	1.519	0.887	17	8940
Comp Suction	Piping		30"	D	STD	30.000	29.250	0.375	50	4.666	233.318		233	12622	**850**	**75**	1.277	1.519	0.887	40	21187
Comp Suction Header	Piping		36"	D	STD	36.000	35.250	0.375	350	6.777	2371.994		2372	113477	**750**	**75**	1.129	1.519	0.900	351	187749
Comp Suction Header	Piping		42"	D	STD	42.000	41.250	0.375	300	9.281	2784.175		2784	133196	**750**	**75**	1.129	1.519	0.900	412	220374
Comp Suction	Piping		20"	D	XS	20.000	19.000	0.500	50	1.969	98.447		98	4710	**750**	**75**	1.129	1.519	0.900	15	7792
Comp Suction	Piping		20"	D	XS	20.000	19.000	0.500	50	1.969	98.447		98	4710	**750**	**75**	1.129	1.519	0.900	15	7792
Comp Suction	Piping		30"	D	STD	30.000	29.250	0.375	50	4.666	233.318		233	11162	**750**	**75**	1.129	1.519	0.900	35	18468
													12977	667065			**Total**			2080	1113298
																	T Average			°F	75.00
																	P Average			psig	806.95
																	Std Vol			SCF	789,492.06
																	Molecular Weight			lb/lbmol	17.03
																	Pseudo Critical Pressure			psia	677.4
																	Pseudo Critical Temperature			°R	352.2

BLOWDOWN CALCULATIONS

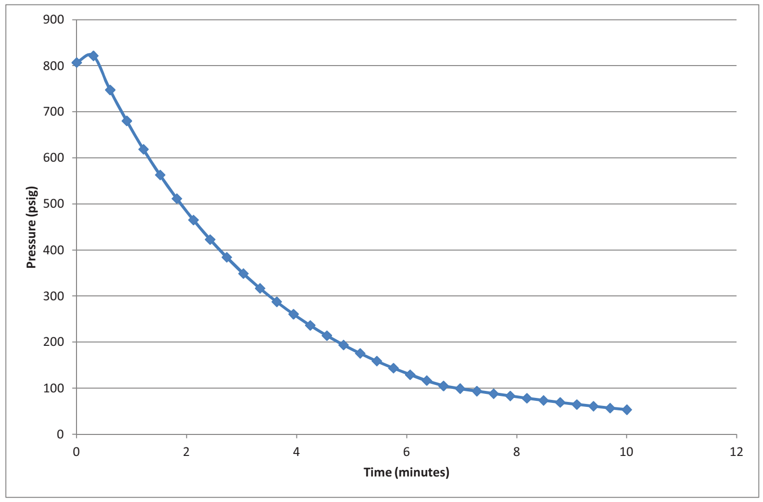
Reference Data		**Initial**	**Change**
Orifice Diameter, Inches		4.384	4.384
Choke Area	in2	15.096	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.549	
Settleout Z		0.988	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		12.860	
Time Increment, seconds		9.091	
Critical Ratio, Pcrt		0.123	
Expansion Factor, Fcr		1.164	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		12,977.034	
Mole to Blowdown, LB-Moles		2,080.348	
Settleout Pressure, psig		806.952	
Ave. Settleout Temp., deg R/deg F		535.150	°R / 75°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	806.95	807.0	0.018	24969639	2080.348	-	
0.15	9	821.58	821.6	0.018	25414076	1914.196	166.2	166.2
0.30	18	747.70	747.7	0.019	23168874	1745.087	169.1	335.3
0.45	27	680.34	680.3	0.021	21122025	1590.918	154.2	489.4
0.61	36	618.94	618.9	0.023	19256004	1450.368	140.5	630.0
0.76	45	562.96	563.0	0.025	17554837	1322.236	128.1	758.1
0.91	55	511.93	511.9	0.028	16003958	1205.423	116.8	874.9
1.06	64	465.40	465.4	0.031	14590092	1098.930	106.5	981.4
1.21	73	422.99	423.0	0.034	13301134	1001.846	97.1	1,078.5
1.36	82	384.32	384.3	0.037	12126048	913.338	88.5	1,167.0
1.52	91	349.07	349.1	0.040	11054775	832.649	80.7	1,247.7
1.67	100	316.93	316.9	0.044	10078143	759.089	73.6	1,321.3
1.82	109	287.63	287.6	0.049	9187792	692.027	67.1	1,388.3
1.97	118	260.92	260.9	0.053	8376098	630.890	61.1	1,449.5
2.12	127	236.57	236.6	0.059	7636113	575.154	55.7	1,505.2
2.27	136	214.38	214.4	0.064	6961503	524.343	50.8	1,556.0
2.42	145	194.14	194.1	0.070	6346490	478.020	46.3	1,602.3
2.58	155	175.69	175.7	0.077	5785811	435.789	42.2	1,644.6
2.73	164	158.87	158.9	0.085	5274665	397.289	38.5	1,683.1
2.88	173	143.53	143.5	0.093	4808676	362.191	35.1	1,718.2
3.03	182	129.56	129.6	0.102	4383854	330.193	32.0	1,750.2
3.18	191	116.81	116.8	0.112	3996563	301.022	29.2	1,779.3
3.33	200	105.19	105.2	0.123	2045066	274.429	26.6	1,805.9
3.48	209	99.25	99.2	0.129	1947474	260.820	13.6	1,819.5
3.64	218	93.59	93.6	0.136	1854368	247.862	13.0	1,832.5
3.79	227	88.20	88.2	0.143	1765532	235.522	12.3	1,844.8
3.94	236	83.06	83.1	0.150	1680762	223.774	11.7	1,856.6
4.09	245	78.18	78.2	0.158	1599863	212.590	11.2	1,867.8
4.24	255	73.53	73.5	0.167	1522649	201.944	10.6	1,878.4
4.39	264	69.10	69.1	0.175	1448942	191.813	10.1	1,888.5
4.55	273	64.89	64.9	0.185	1378571	182.171	9.6	1,898.2
4.70	282	60.88	60.9	0.194	1311375	172.998	9.2	1,907.4
4.85	291	57.07	57.1	0.205	1247198	164.272	8.7	1,916.1
5.00	300	53.44	53.4	0.216	1185894	155.973	8.3	1,924.4

BLOWDOWN CALCULATIONS

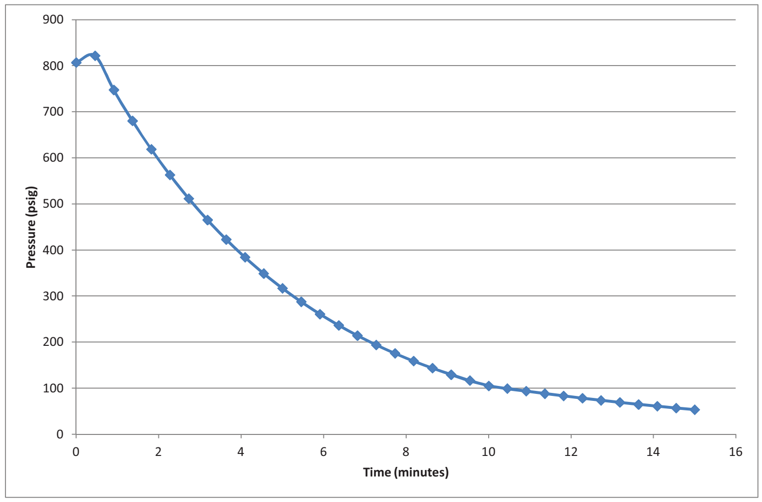
Reference Data		**Initial**	**Change**
Orifice Diameter, Inches		**3.100**	3.100
Choke Area	in2	7.548	
Inlet Pipe OD	in	**8"**	
Inlet Pipe Class		**D**	
Schedule		**40**	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.388	
Settleout Z		0.988	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		12.860	
Time Increment, seconds		**18.182**	
Critical Ratio, Pcrt		0.123	
Expansion Factor, Fcr		1.164	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		**0.000**	
Initial Blowdown Volume, ft3		12,977.034	
Mole to Blowdown, LB-Moles		2,080.348	
Settleout Pressure, psig		806.952	
Ave. Settleout Temp., deg R/deg F		535.150	°R / 75°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	806.95	807.0	0.018	12484820	2080.348	-	
0.30	18	821.58	821.6	0.018	12707038	1914.196	166.2	166.2
0.61	36	747.70	747.7	0.019	11584437	1745.087	169.1	335.3
0.91	55	680.34	680.3	0.021	10561013	1590.918	154.2	489.4
1.21	73	618.94	618.9	0.023	9628002	1450.368	140.5	630.0
1.52	91	562.96	563.0	0.025	8777418	1322.236	128.1	758.1
1.82	109	511.93	511.9	0.028	8001979	1205.423	116.8	874.9
2.12	127	465.40	465.4	0.031	7295046	1098.930	106.5	981.4
2.42	145	422.99	423.0	0.034	6650567	1001.846	97.1	1,078.5
2.73	164	384.32	384.3	0.037	6063024	913.338	88.5	1,167.0
3.03	182	349.07	349.1	0.040	5527387	832.649	80.7	1,247.7
3.33	200	316.93	316.9	0.044	5039071	759.089	73.6	1,321.3
3.64	218	287.63	287.6	0.049	4593896	692.027	67.1	1,388.3
3.94	236	260.92	260.9	0.053	4188049	630.890	61.1	1,449.5
4.24	255	236.57	236.6	0.059	3818057	575.154	55.7	1,505.2
4.55	273	214.38	214.4	0.064	3480751	524.343	50.8	1,556.0
4.85	291	194.14	194.1	0.070	3173245	478.020	46.3	1,602.3
5.15	309	175.69	175.7	0.077	2892905	435.789	42.2	1,644.6
5.45	327	158.87	158.9	0.085	2637332	397.289	38.5	1,683.1
5.76	345	143.53	143.5	0.093	2404338	362.191	35.1	1,718.2
6.06	364	129.56	129.6	0.102	2191927	330.193	32.0	1,750.2
6.36	382	116.81	116.8	0.112	1998282	301.022	29.2	1,779.3
6.67	400	105.19	105.2	0.123	1022533	274.429	26.6	1,805.9
6.97	418	99.25	99.2	0.129	973737	260.820	13.6	1,819.5
7.27	436	93.59	93.6	0.136	927184	247.862	13.0	1,832.5
7.58	455	88.20	88.2	0.143	882766	235.522	12.3	1,844.8
7.88	473	83.06	83.1	0.150	840381	223.774	11.7	1,856.6
8.18	491	78.18	78.2	0.158	799932	212.590	11.2	1,867.8
8.48	509	73.53	73.5	0.167	761325	201.944	10.6	1,878.4
8.79	527	69.10	69.1	0.175	724471	191.813	10.1	1,888.5
9.09	545	64.89	64.9	0.185	689285	182.171	9.6	1,898.2
9.39	564	60.88	60.9	0.194	655687	172.998	9.2	1,907.4
9.70	582	57.07	57.1	0.205	623599	164.272	8.7	1,916.1
10.00	600	53.44	53.4	0.216	592947	155.973	8.3	1,924.4

BLOWDOWN CALCULATIONS

Reference Data		Initial	Change
Orifice Diameter, Inches		2.531	2.531
Choke Area	in2	5.032	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.317	
Settleout Z		0.988	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		12.860	
Time Increment, seconds		27.273	
Critical Ratio, Pcrt		0.123	
Expansion Factor, Fcr		1.164	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		12,977.034	
Mole to Blowdown, LB-Moles		2,080.348	
Settleout Pressure, psig		806.952	
Ave. Settleout Temp., deg R/deg F		535.150	°R / 75°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	806.95	807.0	0.018	8323213	2080.348	-	
0.45	27	821.58	821.6	0.018	8471359	1914.196	166.2	166.2
0.91	55	747.70	747.7	0.019	7722958	1745.087	169.1	335.3
1.36	82	680.34	680.3	0.021	7040675	1590.918	154.2	489.4
1.82	109	618.94	618.9	0.023	6418668	1450.368	140.5	630.0
2.27	136	562.96	563.0	0.025	5851612	1322.236	128.1	758.1
2.73	164	511.93	511.9	0.028	5334653	1205.423	116.8	874.9
3.18	191	465.40	465.4	0.031	4863364	1098.930	106.5	981.4
3.64	218	422.99	423.0	0.034	4433711	1001.846	97.1	1,078.5
4.09	245	384.32	384.3	0.037	4042016	913.338	88.5	1,167.0
4.55	273	349.07	349.1	0.040	3684925	832.649	80.7	1,247.7
5.00	300	316.93	316.9	0.044	3359381	759.089	73.6	1,321.3
5.45	327	287.63	287.6	0.049	3062597	692.027	67.1	1,388.3
5.91	355	260.92	260.9	0.053	2792033	630.890	61.1	1,449.5
6.36	382	236.57	236.6	0.059	2545371	575.154	55.7	1,505.2
6.82	409	214.38	214.4	0.064	2320501	524.343	50.8	1,556.0
7.27	436	194.14	194.1	0.070	2115497	478.020	46.3	1,602.3
7.73	464	175.69	175.7	0.077	1928604	435.789	42.2	1,644.6
8.18	491	158.87	158.9	0.085	1758222	397.289	38.5	1,683.1
8.64	518	143.53	143.5	0.093	1602892	362.191	35.1	1,718.2
9.09	545	129.56	129.6	0.102	1461285	330.193	32.0	1,750.2
9.55	573	116.81	116.8	0.112	1332188	301.022	29.2	1,779.3
10.00	600	105.19	105.2	0.123	681689	274.429	26.6	1,805.9
10.45	627	99.25	99.2	0.129	649158	260.820	13.6	1,819.5
10.91	655	93.59	93.6	0.136	618123	247.862	13.0	1,832.5
11.36	682	88.20	88.2	0.143	588511	235.522	12.3	1,844.8
11.82	709	83.06	83.1	0.150	560254	223.774	11.7	1,856.6
12.27	736	78.18	78.2	0.158	533288	212.590	11.2	1,867.8
12.73	764	73.53	73.5	0.167	507550	201.944	10.6	1,878.4
13.18	791	69.10	69.1	0.175	482980	191.813	10.1	1,888.5
13.64	818	64.89	64.9	0.185	459524	182.171	9.6	1,898.2
14.09	845	60.88	60.9	0.194	437125	172.998	9.2	1,907.4
14.55	873	57.07	57.1	0.205	415733	164.272	8.7	1,916.1
15.00	900	53.44	53.4	0.216	395298	155.973	8.3	1,924.4

Case	Stack Diameter in	Height Above Ground ft	Stack Gas Flow MW	lb/hr	MMSCFD	SCFS	lbmol/hr	Stack Temperature °F	R	Temperature Correction Factor	Stack Pressure psig	psia	Pressure Correction Factor	Corrected Stack Flow ft3/sec	ft3/min	Stack Area ft2	Stack Velocity ft/s
Emergency	84	15	17.039	1,123,972	600	6,944	65,963	80	540	1.174	0	14.700	1.000	8,152	489,107	38.485	211.820
5 min	84	15	17.039	1,122,607	599	6,936	65,883	80	540	1.174	0	14.700	1.000	8,142	488,513	38.485	211.563
10 min	84	15	17.039	561,304	300	3,468	32,941	80	540	1.174	0	14.700	1.000	4,071	244,256	38.485	105.781
15 min	84	15	17.039	374,202	200	2,312	21,961	80	540	1.174	0	14.700	1.000	2,714	162,838	38.485	70.521

	MOLECULAR WEIGHT LB/LBMOL	MOL FRACTION	MASS FRACTION	GAS VOLUME LBMOL	GAS MASS LBM
METHANE	16.042	0.951	0.895	1,978.20	31,734.33
ETHANE	30.069	0.029	0.051	60.33	1,814.07
PROPANE	44.096	0.004	0.011	8.74	385.29
ISO-BUTANE	58.122	0.001	0.003	2.08	120.91
N-BUTANE	58.122	0.001	0.003	1.87	108.82
ISO-PENTANE	72.149	0.000	0.000	0.21	15.01
N-PENTANE	72.149	0.000	0.000	0.21	15.01
N-HEXANE	86.175	0.001	0.005	1.87	161.35
CYCLOHEXANE	84.159	0.000	0.000	0.00	0.00
N-HEPTANE	100.202	0.000	0.000	0.00	0.00
BENZENE	78.112	0.000	0.000	0.00	0.00
TOLUENE	92.138	0.000	0.000	0.00	0.00
ETHYLBENZENE	106.165	0.000	0.000	0.00	0.00
XYLENE	106.165	0.000	0.000	0.00	0.00
STYRENE	104.149	0.000	0.000	0.00	0.00
CARBON DIOXIDE	44.100	0.010	0.026	21.22	935.78
WATER	18.015	0.000	0.000	0.00	0.00
NITROGEN	28.014	0.003	0.004	5.62	157.35
TOTAL	17.04	1.000	1.000	2,080	35,448
THC		0.987	0.969	2,054	34,355
NMHC		0.036	0.074	75	2,620
NMNEHC (VOCs)		0.007	0.023	15	806
HEXANE		0.001	0.005	2	161

Company	Facility	
Cheniere Energy, Inc.	Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Station Suction Blowdown Stack	N/A	NA

Emissions Per Event[1]			
Pollutant	5 min (lb/hr)	10 min (lb/hr)	15 min (lb/hr)
VOC	9,677.00	4,838.00	3,226.00
Hexane	1,936.00	968.00	645.00
CO_2	11,229.36	5,614.68	3,743.12
CH_4	380,811.96	190,405.98	126,937.32
CO_2-e	8,008,280.52	4,004,140.26	2,669,426.84

Emissions Per Year[1]			
Pollutant	2 Events TPY	3 Events TPY	4 Events TPY
VOC	0.81	1.21	1.61
Hexane	0.16	0.24	0.32
CO_2	0.94	1.40	1.87
CH_4	31.73	47.60	63.47
CO_2-e	667.36	1,001.04	1,334.71

(1) Emission calculation methodology provided by Engineering Firm with Site Specific Process Knowledge.

Emission calculations based upon site specific fuel analysis.

BLOW DOWN SYSTEM CALCULATIONS

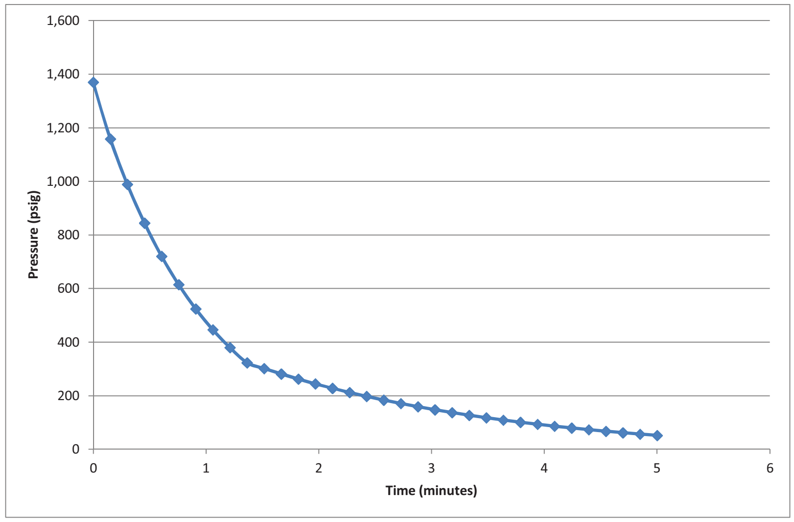
PIPE VOLUME CALCULATIONS

SECTION:	COMPRESSOR UNIT: Station Discharge Blowdown	BDV TAG:	

Section	Description	Line Number	NPS (in)	Piping Class	Sch / BWG	OD(in)	ID(in)	WT(in)	Length (ft)	Transv Sect Area (ft2)	Cylinder Volume (ft3)	Heads Volume (ft3)	Volume (ft3)	Normal Volume (ft3)	Press (psig)	Temp (°F)	Pseudo-reduced Press	Pseudo-reduced Temp	Z Factor	Moles (lbmol)	Temp x Moles
Comp Discharge Header	Piping		42"	D	STD	42.000	41.250	0.375	500	9.281	4640.292		4640	370801	1370	120	2.044	1.647	0.875	1180	684352
													4640	370801			**Total**			1180	684352
																	T Average			°F	120.00
																	P Average			psig	1,370.00
																	Std Vol			SCF	447,662.98
																	Molecular Weight			lb/lbmol	17.03
																	Pseudo Critical Pressure			psia	677.4
																	Pseudo Critical Temperature			°R	352.2

BLOWDOWN CALCULATIONS

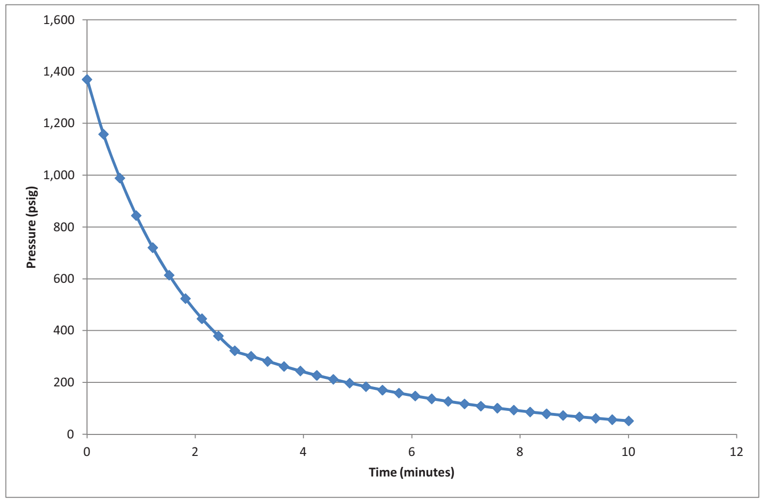
Reference Data		Initial	Change
Orifice Diameter, Inches		3.196	3.196
Choke Area	in2	8.024	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.400	
Settleout Z		0.868	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		44.350	
Time Increment, seconds		9.091	
Critical Ratio, Pcrt		0.041	
Expansion Factor, Fcr		1.397	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		4,640.292	
Mole to Blowdown, LB-Moles		1,179.613	
Settleout Pressure, psig		1,370.000	
Ave. Settleout Temp., deg R/deg F		580.150	°R / 120°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1370.00	1370.0	0.011	25779614	1179.613	-	
0.15	9	1158.00	1158.0	0.013	21832699	1008.071	171.5	171.5
0.30	18	989.00	989.0	0.015	18686279	862.793	145.3	316.8
0.45	27	844.35	844.3	0.017	15993305	738.451	124.3	441.2
0.61	36	720.55	720.5	0.020	13688429	632.029	106.4	547.6
0.76	45	614.59	614.6	0.023	11715720	540.944	91.1	638.7
0.91	55	523.90	523.9	0.027	10027308	462.986	78.0	716.6
1.06	64	446.28	446.3	0.032	8582222	396.263	66.7	783.3
1.21	73	379.84	379.8	0.037	7345395	339.155	57.1	840.5
1.36	82	322.98	323.0	0.044	2787195	290.278	48.9	889.3
1.52	91	301.41	301.4	0.047	2612999	271.732	18.5	907.9
1.67	100	281.18	281.2	0.050	2449632	254.344	17.4	925.3
1.82	109	262.22	262.2	0.053	2296419	238.044	16.3	941.6
1.97	118	244.44	244.4	0.057	2152723	222.763	15.3	956.8
2.12	127	227.78	227.8	0.061	2017950	208.439	14.3	971.2
2.27	136	212.16	212.2	0.065	1891540	195.011	13.4	984.6
2.42	145	197.52	197.5	0.069	1772970	182.424	12.6	997.2
2.58	155	183.79	183.8	0.074	1661749	170.627	11.8	1,009.0
2.73	164	170.93	170.9	0.079	1557414	159.569	11.1	1,020.0
2.88	173	158.87	158.9	0.085	1459535	149.206	10.4	1,030.4
3.03	182	147.57	147.6	0.091	1367705	139.494	9.7	1,040.1
3.18	191	136.99	137.0	0.097	1281543	130.393	9.1	1,049.2
3.33	200	127.07	127.1	0.104	1200693	121.866	8.5	1,057.7
3.48	209	117.77	117.8	0.111	1124820	113.876	8.0	1,065.7
3.64	218	109.07	109.1	0.119	1053608	106.391	7.5	1,073.2
3.79	227	100.91	100.9	0.127	986763	99.380	7.0	1,080.2
3.94	236	93.27	93.3	0.136	924007	92.814	6.6	1,086.8
4.09	245	86.12	86.1	0.146	865081	86.666	6.1	1,092.9
4.24	255	79.42	79.4	0.156	809741	80.909	5.8	1,098.7
4.39	264	73.15	73.2	0.167	757756	75.521	5.4	1,104.1
4.55	273	67.29	67.3	0.179	708911	70.479	5.0	1,109.1
4.70	282	61.80	61.8	0.192	663005	65.762	4.7	1,113.9
4.85	291	56.67	56.7	0.206	619845	61.350	4.4	1,118.3
5.00	300	51.87	51.9	0.221	579255	57.226	4.1	1,122.4

BLOWDOWN CALCULATIONS

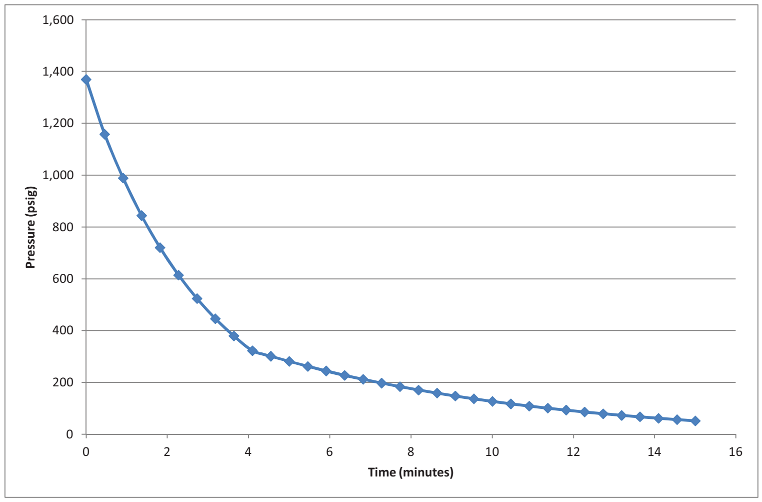
Reference Data		**Initial**	**Change**
Orifice Diameter, Inches		**2.260**	2.260
Choke Area	in2	4.012	
Inlet Pipe OD	in	**8"**	
Inlet Pipe Class		**D**	
Schedule		**40**	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.283	
Settleout Z		0.868	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		44.350	
Time Increment, seconds		**18.182**	
Critical Ratio, Pcrt		0.041	
Expansion Factor, Fcr		1.397	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		**0.000**	
Initial Blowdown Volume, ft3		4,640.292	
Mole to Blowdown, LB-Moles		1,179.613	
Settleout Pressure, psig		1,370.000	
Ave. Settleout Temp., deg R/deg F		580.150	°R / 120°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1370.00	1370.0	0.011	12889804	1179.613	-	
0.30	18	1158.00	1158.0	0.013	10916348	1008.071	171.5	171.5
0.61	36	989.00	989.0	0.015	9343138	862.793	145.3	316.8
0.91	55	844.35	844.3	0.017	7996651	738.451	124.3	441.2
1.21	73	720.55	720.5	0.020	6844214	632.030	106.4	547.6
1.52	91	614.59	614.6	0.023	5857860	540.945	91.1	638.7
1.82	109	523.90	523.9	0.027	5013654	462.986	78.0	716.6
2.12	127	446.28	446.3	0.032	4291111	396.263	66.7	783.3
2.42	145	379.84	379.8	0.037	3672698	339.156	57.1	840.5
2.73	164	322.98	323.0	0.044	1393598	290.278	48.9	889.3
3.03	182	301.41	301.4	0.047	1306500	271.732	18.5	907.9
3.33	200	281.18	281.2	0.050	1224816	254.344	17.4	925.3
3.64	218	262.22	262.2	0.053	1148210	238.044	16.3	941.6
3.94	236	244.44	244.4	0.057	1076362	222.763	15.3	956.8
4.24	255	227.78	227.8	0.061	1008975	208.439	14.3	971.2
4.55	273	212.16	212.2	0.065	945770	195.011	13.4	984.6
4.85	291	197.52	197.5	0.069	886485	182.425	12.6	997.2
5.15	309	183.79	183.8	0.074	830875	170.627	11.8	1,009.0
5.45	327	170.93	170.9	0.079	778707	159.569	11.1	1,020.0
5.76	345	158.87	158.9	0.085	729768	149.206	10.4	1,030.4
6.06	364	147.57	147.6	0.091	683853	139.494	9.7	1,040.1
6.36	382	136.99	137.0	0.097	640772	130.393	9.1	1,049.2
6.67	400	127.07	127.1	0.104	600347	121.866	8.5	1,057.7
6.97	418	117.77	117.8	0.111	562410	113.876	8.0	1,065.7
7.27	436	109.07	109.1	0.119	526804	106.391	7.5	1,073.2
7.58	455	100.91	100.9	0.127	493382	99.380	7.0	1,080.2
7.88	473	93.27	93.3	0.136	462004	92.814	6.6	1,086.8
8.18	491	86.12	86.1	0.146	432541	86.666	6.1	1,092.9
8.48	509	79.42	79.4	0.156	404871	80.909	5.8	1,098.7
8.79	527	73.15	73.2	0.167	378878	75.521	5.4	1,104.1
9.09	545	67.29	67.3	0.179	354456	70.479	5.0	1,109.1
9.39	564	61.80	61.8	0.192	331502	65.762	4.7	1,113.9
9.70	582	56.67	56.7	0.206	309923	61.350	4.4	1,118.3
10.00	600	51.87	51.9	0.221	289627	57.226	4.1	1,122.4

BLOWDOWN CALCULATIONS

Reference Data		Initial	Change
Orifice Diameter, Inches		1.845	1.845
Choke Area	in2	2.675	
Inlet Pipe OD	in	8"	
Inlet Pipe Class		D	
Schedule		40	
Inlet Pipe ID	in	7.981	
Pseudo Critical Pressure		675.500	
Pseudo Critical Temperature		347.900	
Beta Ratio, d2/d1		0.231	
Settleout Z		0.868	
Gas Molecular Weight		17.039	
Gas Gravity		0.588	
Cp/Cv Ratio		44.350	
Time Increment, seconds		27.273	
Critical Ratio, Pcrt		0.041	
Expansion Factor, Fcr		1.397	
Gravity Correction Factor		1.010	
Vent Header Back Pressure, psig		0.000	
Initial Blowdown Volume, ft3		4,640.292	
Mole to Blowdown, LB-Moles		1,179.613	
Settleout Pressure, psig		1,370.000	
Ave. Settleout Temp., deg R/deg F		580.150	°R / 120°F



Time, minutes	Time, seconds	Pi, psig	dP, psi	Po / Pi	Rate, scfh	Inventory Moles	Vented Moles	Total Vent
0.00	0	1370.00	1370.0	0.011	8593204	1179.613	-	
0.45	27	1158.00	1158.0	0.013	7277566	1008.071	171.5	171.5
0.91	55	989.00	989.0	0.015	6228759	862.793	145.3	316.8
1.36	82	844.35	844.3	0.017	5331101	738.451	124.3	441.2
1.82	109	720.55	720.5	0.020	4562810	632.029	106.4	547.6
2.27	136	614.59	614.6	0.023	3905240	540.944	91.1	638.7
2.73	164	523.90	523.9	0.027	3342436	462.986	78.0	716.6
3.18	191	446.28	446.3	0.032	2860741	396.263	66.7	783.3
3.64	218	379.84	379.8	0.037	2448465	339.155	57.1	840.5
4.09	245	322.98	323.0	0.044	929065	290.278	48.9	889.3
4.55	273	301.41	301.4	0.047	871000	271.732	18.5	907.9
5.00	300	281.18	281.2	0.050	816544	254.344	17.4	925.3
5.45	327	262.22	262.2	0.053	765473	238.044	16.3	941.6
5.91	355	244.44	244.4	0.057	717574	222.763	15.3	956.8
6.36	382	227.78	227.8	0.061	672650	208.439	14.3	971.2
6.82	409	212.16	212.2	0.065	630513	195.011	13.4	984.6
7.27	436	197.52	197.5	0.069	590990	182.424	12.6	997.2
7.73	464	183.79	183.8	0.074	553916	170.627	11.8	1,009.0
8.18	491	170.93	170.9	0.079	519138	159.569	11.1	1,020.0
8.64	518	158.87	158.9	0.085	486512	149.206	10.4	1,030.4
9.09	545	147.57	147.6	0.091	455902	139.494	9.7	1,040.1
9.55	573	136.99	137.0	0.097	427181	130.393	9.1	1,049.2
10.00	600	127.07	127.1	0.104	400231	121.866	8.5	1,057.7
10.45	627	117.77	117.8	0.111	374940	113.876	8.0	1,065.7
10.91	655	109.07	109.1	0.119	351203	106.391	7.5	1,073.2
11.36	682	100.91	100.9	0.127	328921	99.380	7.0	1,080.2
11.82	709	93.27	93.3	0.136	308002	92.814	6.6	1,086.8
12.27	736	86.12	86.1	0.146	288360	86.666	6.1	1,092.9
12.73	764	79.42	79.4	0.156	269914	80.909	5.8	1,098.7
13.18	791	73.15	73.2	0.167	252585	75.521	5.4	1,104.1
13.64	818	67.29	67.3	0.179	236304	70.479	5.0	1,109.1
14.09	845	61.80	61.8	0.192	221002	65.762	4.7	1,113.9
14.55	873	56.67	56.7	0.206	206615	61.350	4.4	1,118.3
15.00	900	51.87	51.9	0.221	193085	57.226	4.1	1,122.4

Comments - Exhibit 5

Case	Stack	Height Above	Stack Gas Flow					Stack Temperature		Temperature Correction Factor	Stack Pressure		Pressure Correction Factor	Corrected Stack Flow		Stack Area	Stack
	Diameter in	Ground ft	MW	lb/hr	MMSCFD	SCFS	lbmol/hr	°F	R		psig	psia		ft3/sec	ft3/min	ft2	Velocity ft/s
Emergency	84	15	17.039	1,217,637	650	7,523	71,460	80	540	1.174	0	14.700	1.000	8,831	529,866	38.485	229.471
5 min	84	15	17.039	1,159,023	619	7,161	68,020	80	540	1.174	0	14.700	1.000	8,406	504,359	38.485	218.425
10 min	84	15	17.039	579,511	309	3,581	34,010	80	540	1.174	0	14.700	1.000	4,203	252,180	38.485	109.213
15 min	84	15	17.039	386,341	206	2,387	22,673	80	540	1.174	0	14.700	1.000	2,802	168,120	38.485	72.808

	MOLECULAR WEIGHT LB/LBMOL	MOL FRACTION	MASS FRACTION	GAS VOLUME LBMOL	GAS MASS LBM
METHANE	16.042	0.951	0.895	1,121.69	17,994.21
ETHANE	30.069	0.029	0.051	34.21	1,028.62
PROPANE	44.096	0.004	0.011	4.95	218.47
ISO-BUTANE	58.122	0.001	0.003	1.18	68.56
N-BUTANE	58.122	0.001	0.003	1.06	61.71
ISO-PENTANE	72.149	0.000	0.000	0.12	8.51
N-PENTANE	72.149	0.000	0.000	0.12	8.51
N-HEXANE	86.175	0.001	0.005	1.06	91.49
CYCLOHEXANE	84.159	0.000	0.000	0.00	0.00
N-HEPTANE	100.202	0.000	0.000	0.00	0.00
BENZENE	78.112	0.000	0.000	0.00	0.00
TOLUENE	92.138	0.000	0.000	0.00	0.00
ETHYLBENZENE	106.165	0.000	0.000	0.00	0.00
XYLENE	106.165	0.000	0.000	0.00	0.00
STYRENE	104.149	0.000	0.000	0.00	0.00
CARBON DIOXIDE	44.100	0.010	0.026	12.03	530.61
WATER	18.015	0.000	0.000	0.00	0.00
NITROGEN	28.014	0.003	0.004	3.18	89.22
TOTAL	17.04	1.000	1.000	1,180	20,100
THC		0.987	0.969	1,164	19,480
NMHC		0.036	0.074	43	1,486
NMNEHC (VOCs)		0.007	0.023	8	457
HEXANE		0.001	0.005	1	91

Company		Facility
Cheniere Energy, Inc.		Compressor Station
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Station Discharge Blowdown Stack	N/A	NA

Emissions Per Event(1)			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
VOC	5,487.00	2,743.00	1,829.00
Hexane	1,098.00	549.00	366.00
CO_2	6,367.32	3,183.66	2,122.44
CH_4	215,930.52	107,965.26	71,976.84
CO_2-e	4,540,908.24	2,270,454.12	1,513,636.08

Emissions Per Year(1)			
Pollutant	2 Events	3 Events	4 Events
	TPY	TPY	TPY
VOC	0.46	0.69	0.91
Hexane	0.09	0.14	0.18
CO_2	0.53	0.80	1.06
CH_4	17.99	26.99	35.99
CO_2-e	378.41	567.61	756.82

(1) Emission calculation methodology provided by Engineering Firm with Site Specific Process Knowledge.

Emission calculations based upon site specific fuel analysis.

TRUCK LOADING EMISSION CALCULATIONS

Company Cheniere Energy, Inc.	Facility Compressor Station	
Descriptive Name of Emission Point Condensate Truck Loading	TEMP Subject Item ID N/A	Emission Point ID No. TRKLD

Parameter		Unit
Saturation Factor[1]	0.60	
Temperature of bulk liquid loaded[2]	527.37	R
True Vapor Pressure of liquid loaded[3]	3.50	PSI
Molecular Weight of Vapor[2]	68.00	
Loading Loss Factor = 12.46*S*VP*MW/T		
Loading Loss Factor	3.37	lb/1000 gal
Truck Max Loading Rate	8,400.00	gal/hr
Tank Throughput[2]	51,889.82	gal/yr
Max Loadout VOC Emissions	28.341	lb/hr
Total Loadout VOC Emissions	0.088	TPY

(1) Saturation factor from AP-42 Fifth Edition, Table 5.2-1

(2) Tanks 4.09d, metorological data used in Emission Calculations: Baton Rouge, LA.

(3) AP-42 Fifth Edition, Table 7.1-2. Properties of Selected Petroluem Liquids. Based upon RVP 7 at 70 ^{o}F.

Sabine Pass Liquefaction Project
Sabine Pass Liquefied Natural Gas Terminal Trains 1-4
Stationary Sources
Air Emission Calculations

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

<u>Refrigeration Compressor Turbines -</u>
Criteria Pollutants

No. of Turbines =	24	
Average Operating Rate =	6,656	BTU/Hp-hr/compressor turbine
Annual Operating Time =	8,760	hrs/yr
Power of Compressor=	32,075	kW/ each compressor turbine
	43,013	HP / each compressor turbine

Pollutant	Emission Factor (ppmvd@ 15% O_2)		Ref	Emission Rates (lb/hr/turbine)		Emissions Increase			
						1 Turbine		24 Turbines	
	Original	Revised		Original	Revised	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)
NO_x	20	25	[1], [2]	22.94	28.68	5.74	25.12	137.64	602.86

[1] Vendor Guarantee

[2] NOx concentration increased from 20 ppm to 25 ppm. Based on an email from Ms. Catherine Rourke (Cheniere) to Mr. Jason Swofford (Trinity) on May 21, 2013.

Facility Name: **Sabine Pass Liquefaction, LLC**

AIR CONTAMINANT DATA

1. Emission Point			**2. Component or Air Contaminant Name**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(B) TPY**
WTDYFLR1	WTDYFLR1	Wet/Dry Gas Flare 1 (continuous)	NO_x	5.20
			CO	44.59
			VOC	26.11
			H2S	< 0.01
			SO_2	0.07
		Wet/Dry Gas Flare 1 (MSS)	NO_x	26.80
			CO	229.77
			VOC	21.32
			H2S	< 0.01
			SO_2	0.28
		Wet/Dry Gas Flare 1 (Total)	NO_x	32.00
			CO	274.36
			VOC	47.42
			H2S	< 0.01
			SO_2	0.35
WTDYFLR2	WTDYFLR2	Wet/Dry Gas Flare 2 (continuous)	NO_x	5.20
			CO	44.59
			VOC	26.11
			H2S	< 0.01
			SO_2	0.07
		Wet/Dry Gas Flare 2 (MSS)	NO_x	26.80
			CO	229.77
			VOC	21.32
			H2S	< 0.01
			SO_2	0.28
		Wet/Dry Gas Flare 2 (Total)	NO_x	32.00
			CO	274.36
			VOC	47.42
			H2S	< 0.01
			SO_2	0.35

EPN = Emission Point Number

FIN = Facility Identification Number

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
SO_2	1.53E-02	1.53E-02	6.70E-02	6.70E-02
NO_x	1.67E-02	1.67E-02	7.30E-02	7.30E-02
CO	1.43E-01	1.43E-01	6.26E-01	6.26E-01
VOC	8.64E-04	8.64E-04	3.78E-03	3.78E-03

WET/DRY FLARE CONTINUOUS PURGE

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
NO_x	1.33E+00	6.44E-01	5.13E+00	2.56E+00
CO	1.14E+01	5.52E+00	4.40E+01	2.20E+01
VOC	6.56E+00	3.28E+00	2.61E+01	1.31E+01

[A] The continuous purge from two trains is lined up to one flare, while the continiuous purge from the third train is lined up to the other flare. Since the flares are identical and co-located, the modeling demonstration arbitrarliy assigns the two-train purge to Wet/Dry Flare 1. However, either flare can receive continuous purges from two trains.

WET/DRY FLARE MAINTENANCE AND TURNAROUND

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
NO_x	1.21E+02	1.21E+02	9.63E-01	4.82E-01
CO	1.04E+03	1.04E+03	8.26E+00	4.13E+00
VOC	9.49E+02	9.49E+02	6.90E+00	3.45E+00

WET/DRY FLARE MAJOR OVERHAUL

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	
NO_x	3.69E+02	3.69E+02	2.58E+01	
CO	3.16E+03	3.16E+03	2.22E+02	
VOC	1.05E+02	1.05E+02	1.44E+01	

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare

Pilot Gas Emissions

Number of Pilots =	4	[1]
Flare Pilot Heat Input =	0.065	MMBtu/hr [1]
Heating Value of Fuel =	850.24	Btu/scf
Pilot Gas Molar Flowrate =	0.20	lb-mol/hr
Annual Operating Time =	8,760	hr/yr [1]
VOC DRE (C1-C3 compounds)	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

Pilot Gas Composition [3]

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	5.32E+00	28.01		1.49	8.84E-02	0.00E+00	-	-
Hydrogen Sulfide	3.01E-04	34.08	29	0.0001	6.08E-06	1.76E-04	1.63E-06	3.72E-07
Water	6.67E-02	18.02		0.01	7.13E-04	0.00E+00	-	-
Carbon Dioxide	2.70E-01	44.01		0.12	7.04E-03	0.00E+00	9.42E-02	2.15E-02
Methane	9.37E+01	16.04	21,509	15.04	8.91E-01	1.92E+04	1.19E-01	2.72E-02
Ethane	4.75E-01	30.069	20,426	0.14	8.47E-03	1.73E+02	1.13E-03	2.59E-04
Propane	6.82E-02	44.096	19,919	0.03	1.78E-03	3.55E+01	2.39E-04	5.45E-05
Isobutane	1.83E-02	58.122	19,587	0.01	6.30E-04	1.23E+01	1.69E-04	3.85E-05
n-Butane	1.52E-02	58.122	19,648	0.01	5.24E-04	1.03E+01	1.40E-04	3.20E-05
Isopentane	6.64E-03	72.149	19,305	0.005	2.84E-04	5.48E+00	7.60E-05	1.73E-05
n-Pentane	3.32E-03	72.149	19,339	0.002	1.42E-04	2.74E+00	3.80E-05	8.67E-06
n-Hexane	7.73E-03	86.175	19,245	0.01	3.95E-04	7.60E+00	1.06E-04	2.41E-05
Benzene	1.96E-03	78.11	17,274	0.002	9.10E-05	1.57E+00	2.44E-05	5.56E-06
n-Heptane	4.55E-03	100.2	19,176	0.005	2.70E-04	5.19E+00	7.24E-05	1.65E-05
				16.87		**19,424**		

Pollutant	Emission Factor		Ref	Emission Rates (per Flare) Hourly (lb/hr)	Emission Rates (per Flare) Annual (tpy)
SO_2				1.53E-02	6.70E-02
NO_x	0.0641	lb/MMBtu	[2]	1.67E-02	7.30E-02
CO	0.5496	lb/MMBtu	[2]	1.43E-01	6.26E-01
VOC				8.64E-04	3.78E-03

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Continuous Purges

VOC (C1-C3) DRE	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

Continuous Purge to Flare 1

Propane Feed Gas Flowrate =	276	lb/hr
Ethylene Feed Gas Flowrate =	320	lb/hr
Methane Feed Gas Flowrate =	220	lb/hr
Regen Gas Flowrate =	84	lb/hr
Pipeline Gas Flowrate =	30	lb/hr
Purge hours =	8760	hr/yr (all except pipeline gas)
	12	hr/yr (pipeline gas)

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	2.70E+00	1.18E+01
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	1.88E-02	8.24E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	7.28E-02	3.19E-01
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	3.18E+00	1.39E+01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	1.84E-02	8.05E-02
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	1.13E+01	4.94E+01
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	2.09E+00	9.14E+00
				16.40		**20,407**		

Regen Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Methane	9.65E+01	16.04	21,509	15.48	0.9369	20,152	7.87E-01	3.45E+00
Ethane	3.00E+00	30.069	20,426	0.90	0.0546	1,115	4.59E-02	2.01E-01
Nitrogen	5.00E-01	28.01		0.14	0.0085	0	7.12E-01	3.12E+00
				16.52		**21,267**		

Pipeline Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	2.10E+00	28.01		0.59	0.0361	0	1.08E+00	6.50E-03
Methane	9.79E+01	16.04	21,509	15.70	0.9639	20,732	2.89E-01	1.74E-03
				16.29		**20,732**		

Total heating value for purges = 18.89 MMBtu/hr
160,001 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	1.21E+00	1.33E+00	5.13E+00
CO	0.5496	lb/MMBtu	[2], [6]	1.04E+01	1.14E+01	4.40E+01
VOC			[2], [6]	5.96E+00	6.56E+00	2.61E+01

Continuous Purge to Flare 2

Propane Feed Gas Flowrate =	138	lb/hr
Ethylene Feed Gas Flowrate =	160	lb/hr
Methane Feed Gas Flowrate =	110	lb/hr
Regen Gas Flowrate =	42	lb/hr
Pipeline Gas Flowrate =	0	lb/hr
Purge hours =	8760	hr/yr (all except pipeline gas)
	12	hr/yr (pipeline gas)

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19520.33	1.35E+00	5.92E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139.28	9.41E-03	4.12E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258.17	3.64E-02	1.59E-01
				44.10		**19917.78**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.59E+00	6.97E+00
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	9.19E-03	4.02E-02
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	5.64E+00	2.47E+01
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	1.04E+00	4.57E+00
				16.40		**20,407**		

Regen Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Methane	9.65E+01	16.04	21,509	15.48	0.9369	20,152	3.94E-01	1.72E+00
Ethane	3.00E+00	30.069	20,426	0.90	0.0546	1,115	2.29E-02	1.00E-01
Nitrogen	5.00E-01	28.01		0.14	0.0085	0	3.56E-01	1.56E+00
				16.52		**21,267**		

Total heating value fo: 9.13E+00 MMBtu/hr
8.00E+04 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates		
				Hourly (lb/hr)	Maximum (lb/hr)	Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	5.85E-01	6.44E-01	2.56E+00
CO	0.5496	lb/MMBtu	[2], [6]	5.02E+00	5.52E+00	2.20E+01
VOC			[2], [6]	2.98E+00	3.28E+00	1.31E+01

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Maintenance and Turnaround Emissions

VOC (C1-C3) DRE	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

LNG Train Planned Maintenance Emissions

Borescope Purges

Propane Purge Flowrate =	55,200	lb/purge/turbine
Ethylene Purge Flowrate =	16,400	lb/purge/turbine
Methane Purge Flowrate =	10,400	lb/purge/turbine
Borescope Purge per year =	2	/turbine
Turbines =	6	in each service (18 total)
laximum turbine systems purged at a time =	2	in each service (6 total)
Hours per purge =	3	hr

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	3.61E+02	3.25E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	2.51E+00	2.26E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	9.70E+00	8.73E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.09E+02	9.78E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	6.28E-01	5.65E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	3.55E+02	3.20E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	6.58E+01	5.92E-01
				16.40		**20,407**		

Total heating value for purges =	1,096	MMBtu/hr
	19,732	MMBtu/yr

Pollutant	Emission Factor		Ref	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	7.03E+01	7.73E+01	6.32E-01
CO	0.5496	lb/MMBtu	[2], [6]	6.02E+02	6.63E+02	5.42E+00
VOC			[2], [6]	4.79E+02	5.27E+02	4.31E+00

Combustor Changeout/Hot Section Purge

Propane Purge Flowrate =	55,200	lb/purge/turbine
Ethylene Purge Flowrate =	16,400	lb/purge/turbine
Methane Purge Flowrate =	10,400	lb/purge/turbine
CC/HS Purge per year =	1	/turbine
Turbines =	6	in each service (18 total)
bine systems purged at a time =	2	in each service (6 total)
Hours per purge =	3	hr

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	3.61E+02	1.62E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	2.51E+00	1.13E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	9.70E+00	4.37E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.09E+02	4.89E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	6.28E-01	2.83E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0.00	3.55E+02	1.60E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20406.77	6.58E+01	2.96E-01
				16.40		**20406.77**		

Total heating value for purges =	1,096	MMBtu/hr
	9,866	MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates		
				Hourly (lb/hr)	Maximum (lb/hr)	Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	7.03E+01	7.73E+01	3.16E-01
CO	0.5496	lb/MMBtu	[2], [6]	6.02E+02	6.63E+02	2.71E+00
VOC			[2], [6]	4.79E+02	5.27E+02	2.16E+00

Combustor Changeout/Hot Section Startup

Propane Purge Flowrate =	100,803	lb/purge/turbine
Ethylene Purge Flowrate =	28,158	lb/purge/turbine
Methane Purge Flowrate =		lb/purge/turbine
CC/HS Startup per year =	1	/turbine
Turbines =	6	in each service (18 total)
Maximum turbine systems purged at a time =	2	in each service (6 total)
Hours per purge =	3	hr

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	6.59E+02	2.96E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	4.58E+00	2.06E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	1.77E+01	7.97E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.87E+02	8.40E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	1.08E+00	4.85E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	0.00E+00	0.00E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	0.00E+00	0.00E+00
				16.40		**20,407**		

Total heating value for purges = 1,719 MMBtu/hr
15,474 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	1.10E+02	1.21E+02	4.96E-01
CO	0.5496	lb/MMBtu	[2], [6]	9.45E+02	1.04E+03	4.25E+00
VOC			[2], [6]	8.63E+02	9.49E+02	3.88E+00

[1] Data provided by Cheniere.

[2] The emission factors and destruction efficiencies were obtained from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers; October 2000." Factors are for low Btu streams in non-steam assisted flares. The destruction efficiencies meet the TCEQ BACT guidance for Flares and Vapor Combustors, 8/1/2011.

[3] *LP1 Fuel Gas composition* from "*25744-100-M3-DK-00002.xls* ", provided by Jose Dumlao (Cheniere) to Melissa Ryan (Trinity) on 8/20/12, was used as the pilot gas composition.

[4] Net Heating Values (NHV) were obtained from "Yaws' Handbook of Thermodynamic and Physical Properties of Chemical Compounds".

[5] Feed Gas composition was obtained from "CCLNG-H&MB_for_Air_Permit.xlsx", provided by Cheniere .

[6] Maximum hourly emission rates are based on maximum expected variability during routine operations.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Major Overhaul Intermittent MSS Emissions

VOC (C1-C3) DRE	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

LNG Train Planned Maintenance Emissions

Feed Gas Flowrate =	254,760	lb/hr [1]
Annual Flowrate =	37,738,000	lb/2 trains[1]
Heating Value of Feed Gas =	20,530	Btu/lb
	907	Btu/scf

Feed Gas Composition [5]

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	4.90E-01	28.01		0.14	0.0081	0.00E+00	2.05E+03	-
Carbon Dioxide	1.30E+00	44.01		0.57	0.0336	0.00E+00	8.55E+03	6.34E+02
Methane	9.59E+01	16.04	21508.9	15.38	0.9028	1.94E+04	2.30E+03	1.70E+02
Ethane	1.89E+00	30.069	20425.8	0.57	0.0334	6.81E+02	8.50E+01	6.29E+00
Propane	2.50E-01	44.096	19918.7	0.11	0.0065	1.29E+02	1.65E+01	1.22E+00
Isobutane	6.00E-02	58.122	19586.8	0.15	0.0085	1.67E+02	4.35E+01	3.22E+00
n-Butane	5.00E-02	58.122	19647.5	0.03	0.0020	4.02E+01	1.04E+01	7.72E-01
Isopentane	2.00E-02	72.149	19305.4	0.04	0.0021	4.09E+01	1.08E+01	7.99E-01
n-Pentane	1.00E-02	72.149	19339.4	0.01	0.0008	1.64E+01	4.32E+00	3.20E-01
n-Hexane	2.00E-02	86.175	19245.1	0.01	0.0005	9.73E+00	2.58E+00	1.91E-01
Benzene	1.50E-03	78.11	17274.3	0.02	0.0009	1.58E+01	4.67E+00	3.46E-01
n-Heptane	1.00E-02	100.2	19176	0.01	0.0006	1.13E+01	3.00E+00	2.22E-01
Hydrogen Sulfide	4.00E-04	34.08	28.87	0.0001	0.00001	2.31E-04	4.08E-02	3.02E-03
Water	1.47E-02	18.02		0.003	0.0002	0.00E+00	7.93E-01	-
				17.04	1.00	**20,530**		

Major Overhaul Purge Depressurization

Propane Purge Flowrate =	62,100	lb/purge
Ethylene Purge Flowrate =	18,327	lb/purge
Methane Purge Flowrate =	11,060	lb/purge
Overhaul Purge per year =	2	
Duration of Depressurization Purge =	4	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	3.04E+02	1.22E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	2.12E+00	8.47E-03
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	8.19E+00	3.27E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	9.11E+01	3.64E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	5.26E-01	2.10E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	2.83E+02	1.13E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	5.25E+01	2.10E-01
				16.40		**20,407**		

Total heating value for purge depres = 7.34E+03 MMBtu/yr

Major Overhaul Purge Fuel Gas

Propane Purge Flowrate =	31112	lb/purge
Ethylene Purge Flowrate =	14582	lb/purge
Methane Purge Flowrate =	0	lb/purge
Overhaul Purge per year =	2	
Duration of Fuel Gas Purge =	3	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	2.03E+02	6.10E-01
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	1.41E+00	4.24E-03
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	5.47E+00	1.64E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	28	0.9943	20,160	9.67E+01	2.90E-01
Methane	1.00E+00	16.04	21,509	0	0.0057	124	5.58E-01	1.67E-03
				28		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	0.00E+00	0.00E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	0.00E+00	0.00E+00
				16.40		**20,407**		

Total heating value for purge fuel gas= 3.66E+03 MMBtu/yr

Major Overhaul Startup Fuel Gas

Propane Purge Flowrate =	31112	lb/purge
Ethylene Purge Flowrate =	14582	lb/purge
Methane Purge Flowrate =	0	lb/purge
Overhaul Startup per year =	2	
Duration of Overhaul Startup Fuel Gas =	3	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	2.03E+02	6.10E-01
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	1.41E+00	4.24E-03
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	5.47E+00	1.64E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	9.67E+01	2.90E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	5.58E-01	1.67E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	0.00E+00	0.00E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	0.00E+00	0.00E+00
				16.40		**20,407**		

Total heating value for startup fuel gas= 3.66E+03 MMBtu/yr

Major Overhaul Startup Refrigerant

Propane Purge Flowrate =	151,204	lb/purge
Ethylene Purge Flowrate =	42,237	lb/purge
Methane Purge Flowrate =	14,411	lb/purge
Overhaul Startup per year =	2	
Duration of Overhaul Startup Refrigerant =	4	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	7.41E+02	2.96E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	5.16E+00	2.06E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	1.99E+01	7.97E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	2.10E+02	8.40E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	1.21E+00	4.85E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	3.69E+02	1.48E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	6.84E+01	2.73E-01
				16.40		**20,407**		

Total heating value for startup refrigerant= 1.66E+04 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
SO_2			[6]	3.83E+00	4.22E+00	2.84E-01
NO_x	0.0641	lb/MMBtu	[2], [6]	3.35E+02	3.69E+02	2.58E+01
CO	0.5496	lb/MMBtu	[2], [6]	2.87E+03	3.16E+03	2.22E+02
VOC			[2], [6]	9.57E+01	1.05E+02	1.44E+01
H2S			[2], [6]	4.08E-02	4.49E-02	3.02E-03

[1] Data provided by Cheniere.

[2] The emission factors and destruction efficiencies were obtained from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor

[3] *LP1 Fuel Gas composition* from "*25744-100-M3-DK-00002.xls* ", provided by Jose Dumlao (Cheniere) to Melissa Ryan (Trinity) on 8/20/12, was used as the pilot gas composition.

[4] Net Heating Values (NHV) were obtained from "Yaws' Handbook of Thermodynamic and Physical Properties of Chemical Compounds".

[5] Feed Gas composition was obtained from "CCLNG-H&MB_for_Air_Permit.xlsx", provided by Cheniere .

[6] Maximum hourly emission rates are based on maximum expected variability during routine operations.

Area Name: Sabine Pass Liquefaction, LLC			Customer Reference No.: 604136374		
AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) MTCE/yr**	**(B) TPY**
WTDYFLR1	WTDYFLR1	Wet/Dry Gas Flare 1 (continuous)	CO_2	10,590.18	11,670.38
			CH_4	11.52	12.70
			N_2O	0.02	0.02
		Wet/Dry Gas Flare 1 (MSS)	CO_2	49,230.44	54,251.94
			CH_4	155.31	171.15
			N_2O	0.08	0.09
		Wet/Dry Gas Flare 1 (Total)	CO_2	59,820.62	65,922.33
			CH_4	166.83	183.85
			N_2O	0.10	0.11
WTDYFLR2	WTDYFLR2	Wet/Dry Gas Flare 2 (continuous)	CO_2	10,590.18	11,670.38
			CH_4	11.52	12.70
			N_2O	0.02	0.02
		Wet/Dry Gas Flare 2 (MSS)	CO_2	49,230.44	54,251.94
			CH_4	155.31	171.15
			N_2O	0.08	0.09
		Wet/Dry Gas Flare 2 (Total)	CO_2	59,820.62	65,922.33
			CH_4	166.83	183.85
			N_2O	0.10	0.11

EPN = Emission Point Number

FIN = Facility Identification Number

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Summary of Updated GHG Emission Rates

WET/DRY FLARE PILOTS

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
CO_2	3.33E+01	3.33E+01	1.46E+02	1.46E+02
CH_4	1.19E-01	1.19E-01	2.72E-02	2.72E-02
N_2O	5.73E-05	5.73E-05	1.86E-09	1.86E-09
CO_2e	3.58E+01	3.58E+01	1.46E+02	1.46E+02

BOG COMPRESSOR OVERHAUL

Pollutant	BOG Compressor (lb/hr)	BOG Compressor (tpy)
CO_2	--	--
CH_4	2.88E+02	7.54E-01
N_2O	--	--
CO_2e	6.05E+03	1.58E+01

WET/DRY FLARE CONTINUOUS FLOWS

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
CO_2	2.71E+03	1.32E+03	1.15E+04	5.76E+03
CH_4	3.18E+00	1.45E+00	1.27E+01	6.33E+00
N_2O	4.16E-03	2.01E-03	1.76E-02	8.82E-03
CO_2e	2.78E+03	1.35E+03	1.18E+04	5.90E+03

FUGITIVES

Pollutant	Fugitives (lb/hr)	Fugitives (tpy)
CO_2	5.07E-02	2.22E-01
CH_4	9.89E+01	4.33E+02
N_2O	--	--
CO_2e	2.08E+03	9.09E+03

WET/DRY FLARE MAINTENANCE AND

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
CO_2	2.60E+05	2.60E+05	1.49E+03	7.47E+02
CH_4	6.64E+01	6.64E+01	6.01E-01	3.00E-01
N_2O	3.79E-01	3.79E-01	3.31E-03	1.66E-03
CO_2e	2.60E+05	2.60E+05	1.51E+03	7.54E+02

WET/DRY FLARE MAJOR OVERHAUL

Pollutant	Hourly Emissions		Annual Emissions	
	Wet/Dry Flare 1 (lb/hr)	Wet/Dry Flare 2 (lb/hr)	Wet/Dry Flare 1 (tpy)	Wet/Dry Flare 2 (tpy)
CO_2	7.50E+05	7.50E+05	5.28E+04	0.00E+00
CH_4	2.53E+03	2.53E+03	1.71E+02	0.00E+00
N_2O	1.27E+00	1.27E+00	8.89E-02	0.00E+00
CO_2e	8.03E+05	8.03E+05	5.64E+04	0.00E+00

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Pilot Emissions

Pilot Gas Emissions

Number of Pilots =	4		[1]
Flare Pilot Heat Input =	0.065	MMBtu/hr	[1]
Heating Value of Fuel =	850.24	Btu/scf	
Pilot Gas Molar Flowrate =	0.20	lb-mol/hr	
Annual Operating Time =	8,760	hr/yr	[1]

Emissions From Pilot Gas Combustion

Pollutant	Emission Factor		References	Emission Rate	
				Average (lb/hr)	Annual (tpy)
CO_2			[2]	3.33E+01	1.46E+02
CH_4			[3]	1.19E-01	2.72E-02
N_2O	1.0E-04	kg/MMBtu	[4]	5.73E-05	1.86E-09
CO_2e	--	--	[5]	3.58E+01	1.46E+02

[1] Data provided by Cheniere.

[2] Based on mass balance of carbon in pilot gas.

[3] Emission rate estimated at a DRE of 99%

[4] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[5] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Continuous Flows

Continuous Flow to Flare 1

Continuous Flow Gas Heat Input =	18.89	MMBtu/hr
	160,000.99	MMBtu/yr

Emissions From Continuous Flow Gas Combustion

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	2.71E+03	1.15E+04
CH_4			[2]	3.18E+00	1.27E+01
N_2O	1.0E-04	kg/MMBtu	[3]	4.16E-03	1.76E-02
CO_2e	--	--	[4]	2.78E+03	1.18E+04

Continuous Flow to Flare 2

Continuous Flow Gas Heat Input =	9.13	MMBtu/hr
	79,996.76	MMBtu/yr

Emissions From Continuous Flow Gas Combustion

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.32E+03	5.76E+03
CH_4			[2]	1.45E+00	6.33E+00
N_2O	1.0E-04	kg/MMBtu	[3]	2.01E-03	8.82E-03
CO_2e	--	--	[4]	1.35E+03	5.90E+03

[1] Based on mass balance of carbon in purge gas.

[2] Emission rate estimated at a DRE of 99%

[3] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[4] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Maintenance and Turnaround Emissions

LNG Train Planned Maintenance Emissions

Borescope Purges

Purge Gas Heat Input = 1,096 MMBtu/hr
19,732 MMBtu/yr

Emissions From Borescope Purges

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.62E+05	9.75E+02
CH_4			[2]	6.64E+01	5.98E-01
N_2O	1.0E-04	kg/MMBtu	[3]	2.42E-01	2.18E-03
CO_2e	--	--	[4]	1.64E+05	9.88E+02

Combustor Changeout/Hot Section Purges

Purge Gas Heat Input = 1,096 MMBtu/hr
9,866 MMBtu/yr

Emissions From Combustor Changeout/Hot Section Purges

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.62E+05	4.87E+02
CH_4			[2]	6.64E+01	2.99E-01
N_2O	1.0E-04	kg/MMBtu	[3]	2.42E-01	1.09E-03
CO_2e	--	--	[4]	1.64E+05	4.94E+02

Combustor Changeout/Hot Section Startup

Purge Gas Heat Input = 1,719 MMBtu/hr
15,474 MMBtu/yr

Emissions From Combustor Changeout/Hot Section Startup

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	2.60E+05	7.80E+02
CH_4			[2]	1.08E+00	4.85E-03
N_2O	1.0E-04	kg/MMBtu	[3]	3.79E-01	1.71E-03
CO_2e	--	--	[4]	2.60E+05	7.81E+02

[1] Based on mass balance of carbon in purge gas.

[2] Emission rate estimated at a DRE of 99%

[3] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[4] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Major Overhaul Intermittent MSS Emissions

LNG Train Planned Maintenance Emissions

Purge of Feed Gas

Purge Gas Heat Input =	5,230	MMBtu/hr
	774,774	MMBtu/yr

Emissions From Purge of Feed Gas

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	6.81E+05	5.05E+04
CH_4			[2]	2.30E+03	1.70E+02
N_2O	1.0E-04	kg/MMBtu	[3]	1.15E+00	8.54E-02
CO_2e	--	--	[4]	7.30E+05	5.41E+04

Major Overhaul Purge Depressurization

Purge Gas Heat Input =	917	MMBtu/hr
	7,337	MMBtu/yr

Emissions From Major Overhaul Purge Depressurization

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.22E+05	4.88E+02
CH_4			[2]	5.30E+01	2.12E-01
N_2O	1.0E-04	kg/MMBtu	[3]	2.02E-01	8.09E-04
CO_2e	--	--	[4]	1.23E+05	4.93E+02

Major Overhaul Purge Fuel Gas

Purge Gas Heat Input =	610	MMBtu/hr
	3,662	MMBtu/yr

Emissions From Major Overhaul Purge Fuel Gas

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	9.26E+04	2.78E+02
CH_4			[2]	5.58E-01	1.67E-03
N_2O	1.0E-04	kg/MMBtu	[3]	1.35E-01	4.04E-04
CO_2e	--	--	[4]	9.26E+04	2.78E+02

Major Overhaul Startup Fuel Gas

Purge Gas Heat Input = 610 MMBtu/hr
3,662 MMBtu/yr

Emissions From Major Overhaul Startup Fuel Gas

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	9.26E+04	2.78E+02
CH_4			[2]	5.58E-01	1.67E-03
N_2O	1.0E-04	kg/MMBtu	[3]	1.35E-01	4.04E-04
CO_2e	--	--	[4]	9.26E+04	2.78E+02

Major Overhaul Startup Refrigerant

Purge Gas Heat Input = 2,081 MMBtu/hr
16,650 MMBtu/yr

Emissions From Major Overhaul Startup Refrigerant

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	3.11E+05	1.25E+03
CH_4			[2]	6.96E+01	2.78E-01
N_2O	1.0E-04	kg/MMBtu	[3]	4.59E-01	1.84E-03
CO_2e	--	--	[4]	3.13E+05	1.25E+03

Emissions Summary from Major Overhaul

Pollutant	Emission Rate Hourly [5] (lb/hr)	Emission Rate Maximum [6] (lb/hr)	Emission Rate Annual (tpy)
CO_2	6.81E+05	7.50E+05	5.28E+04
CH_4	2.30E+03	2.53E+03	1.71E+02
N_2O	1.15E+00	1.27E+00	8.89E-02
CO_2e	7.30E+05	8.03E+05	5.64E+04

[1] Based on mass balance of carbon in purge gas.

[2] Emission rate estimated at a DRE of 99%

[3] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[4] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

[5] Purge flows will not occur in same hour as purge of feedgas. Hourly rates are maximum of all scenarios.

[6] Maximum hourly emission rates are based on maximum expected variability during routine operations.

Sabine Pass Liquefaction Project
Sabine Pass Liquefied Natural Gas Terminal Trains 5 and 6
Stationary Sources
Air Emission Calculations

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana
Table 1 - Acid Gas Thermal Oxidizer

Client Data:

Waste gas flow [1]: 43,467 lb/hr
Gas Temperature [1]: 122 °F
Required Destruction Efficiency [1]: 99.99%

Calculated Output:

Waste Gas Stream Ave MW: 42.202 lb/lbmol
Waste Gas Stream Flow: 1,029.96 lbmol/hr

Waste Gas Composition

Composition	MW [4]	Mol% [1]	Flowrate [1]	Component Molar Flow Inlet	Component Molar Flow Exhaust [2,3]	Component Mass Flow Exhaust
	lb/lbmol	%	Lbs/hr	lbmol/hr	lbmol/hr	lb/hr
H2	2.016	0.00000	0.0000	--	--	--
O2	32	0.00000	0.0000	--	--	--
N2	28.02	0.00000	0.0000	--	--	--
CO	28.01	0.00000	0.0000	--	--	--
CO2	44.01	92.98930	42150.9069	9.58E+2	9.65E+2	4.25E+4
C1	16.04	0.44666	73.8003	4.60E+0	4.60E-4	7.38E-3
C2	30.07	0.02233	6.9156	2.30E-1	2.30E-5	6.92E-4
C2=	28.05	0.00000	0.0000	--	--	--
ACETYLENE	26.04	0.00000	0.0000	--	--	--
C3	44.09	0.00388	1.7622	4.00E-2	4.00E-6	1.76E-4
C3=	42.08	0.00000	0.0000	--	--	--
N-C4	58.12	0.00097	0.5807	9.99E-3	9.99E-7	5.81E-5
I-C4	58.12	0.00097	0.5807	9.99E-3	9.99E-7	5.81E-5
C4=	56.1	0.00000	0.0000	--	--	--
N-C5	72.15	0.00049	0.3641	5.05E-3	5.05E-7	3.64E-5
I-C5	72.15	0.00049	0.3641	5.05E-3	5.05E-7	3.64E-5
Neo-C5	72.15	0.00000	0.0000	--	--	--
N-C6	86.17	0.00097	0.8609	9.99E-3	9.99E-7	8.61E-5
N-C7	100.2	0.00097	1.0011	9.99E-3	9.99E-7	1.00E-4
N-C8	114.22	0.00000	0.0000	--	--	--
BENZENE	78.11	0.02816	22.6555	2.90E-1	2.90E-5	2.27E-3
TOLUENE	92.13	0.00000	0.0000	--	--	--
XYLENE	106.16	0.00000	0.0000	--	--	--
METHANOL	32.04	0.00000	0.0000	--	--	--
NH3	17.03	0.00000	0.0000	--	--	--
SO2	64.06	0.00000	0.0000	--	1.03E-2	6.60E-1
H2S	34.08	0.00100	0.3510	1.03E-2	1.03E-6	3.51E-5
H2O	18.016	6.50379	1206.7869	6.70E+1	6.70E+1	1.21E+3
Cl2	70.91	0.00000	0.0000	--	--	--
HCl	36.47	0.00000	0.0000	--	--	--
Total VOC	**--**	**--**	**--**	**3.80E-1**	**3.80E-5**	**2.82E-3**
Total		**100.00**	**43,466.93**	**1,029.96**	**1,031.87**	**43,671.73**

[1] Data supplied by Bechtel on February 10, 2012.
[2] It is assumed that all of the controlled hydrocarbons are oxidized to CO_2.
[3] It is assumed that all of the controlled H_2S is oxidized to SO_2.
[4] Obtained from "Perry's Chemical Engineer's Handbook", Seventh Edition, 1997.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Table 2 - Criteria Pollutant Emissions from Thermal Oxidizer Fuel Gas Combustion

Thermal Oxidizer Heat Input =	23.08	MMBtu/hr [1]
Heating Value of Fuel =	1,013	Btu/scf [6]
Annual Operating Time=	8,760	hr/yr [1]

Pollutant	Emission Factor		References	Emission Rates		
				Average (lb/hr)	Maximum (lb/hr) [5]	Annual (tpy)
PM_{10}	7.6	lb/MMscf	[2]	1.73E-01	1.90E-01	0.75837
$PM_{2.5}$	7.6	lb/MMscf	[2]	1.73E-01	1.90E-01	0.75837
SO_2	0.6	lb/MMscf	[2]	1.37E-02	1.50E-02	0.05987
NO_x	94	lb/MMscf	[3]	2.14E+00	2.36E+00	9.37979
CO	0.37	lb/MMBtu	[4]	8.54E+00	9.39E+00	37.40043
Lead	0.0005	lb/MMscf	[2]	1.14E-05	1.25E-05	0.00005
VOC	5.5	lb/MMscf	[2]	1.25E-01	1.38E-01	0.54882

[1] Data supplied by Bechtel on February 10, 2012.
[2] U.S. EPA AP-42, Volume I, Chapter 1, External Combustion Sources, Section 1.4, Natural Gas Combustion, Table 1.4-2, Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, p.1.4-6, July 1998.
[3] U.S. EPA AP-42, Volume I, Chapter 1, External Combustion Sources, Section 1.4, Natural Gas Combustion, Table 1.4-1, Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion, p.1.4-5, July 1998.
[4] U.S. EPA AP-42, Volume I, Chapter 13, Section 13.5, Industrial Flares, Table 13.5-1, Emission Factors for Flare Operations, p.13.5-4, July 1998.

[5] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.
[6] Assumed to be equal to the heating value of the flare pilot fuel.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Table 3 - Hazardous Air Pollutant Emissions from Thermal Oxidizer Fuel Gas Combustion

Thermal Oxidizer Heat Input =	23.08	MMBtu/hr [1]
Heating Value of Fuel =	1,013	Btu/scf [6]
Annual Operating Time=	8,760	hr/yr [1]

Pollutant	Emission Factor		References	Emission Rates		
				Average (lb/hr)	Maximum (lb/hr) [4]	Annual (tpy)
Arsenic	2.00E-04	lb/MMscf	[5]	4.56E-06	5.01E-06	0.000020
Benzene	2.10E-03	lb/MMscf	[2]	4.78E-05	5.26E-05	0.000210
Beryllium	1.20E-05	lb/MMscf	[5]	2.73E-07	3.01E-07	0.000001
Cadmium	1.10E-03	lb/MMscf	[5]	2.51E-05	2.76E-05	0.000110
Chromium	1.40E-03	lb/MMscf	[5]	3.19E-05	3.51E-05	0.000140
Cobalt	8.40E-05	lb/MMscf	[5]	1.91E-06	2.11E-06	0.000008
Dichlorobenzene	1.20E-03	lb/MMscf	[2]	2.73E-05	3.01E-05	0.000120
Formaldehyde	7.50E-02	lb/MMscf	[2]	1.71E-03	1.88E-03	0.007484
Hexane	1.80E+00	lb/MMscf	[2]	4.10E-02	4.51E-02	0.179613
Manganese	3.80E-04	lb/MMscf	[5]	8.66E-06	9.52E-06	0.000038
Mercury	2.60E-04	lb/MMscf	[5]	5.92E-06	6.52E-06	0.000026
Naphthalene	6.10E-04	lb/MMscf	[2]	1.39E-05	1.53E-05	0.000061
Nickel	2.10E-03	lb/MMscf	[5]	4.78E-05	5.26E-05	0.000210
Selenium	2.40E-05	lb/MMscf	[5]	5.47E-07	6.01E-07	0.000002
Toluene	3.40E-03	lb/MMscf	[2]	7.75E-05	8.52E-05	0.000339
Total POM	8.82E-05	lb/MMscf	[2], [3]	2.01E-06	2.21E-06	8.80E-06

[1] Data supplied by Bechtel on February 10, 2012.
[2] U.S. EPA AP-42, Volume I, Chapter 1, External Combustion Sources, Section 1.4, Natural Gas Combustion, Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion, p.1.4-7, July 1998.
[3] Polycyclic Organic Matter (POM)
[4] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.
[5] U.S. EPA AP-42, Volume I, Chapter 1, External Combustion Sources, Section 1.4, Natural Gas Combustion, Table 1.4-4, Emission Factors for Metals from Natural Gas Combustion, p.1.4-9, July 1998.
[6] Assumed to be equal to the heating value of the flare pilot fuel.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Table 4 - Greenhouse Gas Emissions from Thermal Oxidizer Fuel Gas Combustion

Average Operating Rate = 23.08 MMBtu/hr [1]
Annual Operating Time = 8760 hrs/yr [1]

Pollutant	Emission Factor		References	Average (lb/hr)	Annual (tpy)
CO_2	53.02	kg/MMBtu	[2]	2.70E+03	1.18E+04
CH_4	1.0E-03	kg/MMBtu	[2]	5.09E-02	2.23E-01
N_2O	1.0E-04	kg/MMBtu	[2]	5.09E-03	2.23E-02
CO_2e	--	--	[3]	2.70E+03	1.18E+04

[1] Data supplied by Bechtel on February 10, 2012.
[2] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.
[3] CH_4, CO_2, and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potentials (GWP). The GWP of CH_4 is 21, of CO_2 is 1, and of N_2O is 310.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Table 5 - Overall Thermal Oxidzer Vent Emissions

Pollutant	Controlled Acid Gas vent with Thermal Oxidizer Emissions		
	Average lb/hr	**Maximum** lb/hr	**Annual** tpy
PM_{10}	1.73E-01	1.90E-01	0.75837
$PM_{2.5}$	1.73E-01	1.90E-01	0.75837
NO_X	2.14E+00	2.36E+00	9.37979
SO_2	6.73E-01	7.41E-01	2.94948
CO	8.54E+00	9.39E+00	37.40043
VOC	1.28E-01	1.41E-01	0.56116
H_2S	3.51E-05	3.86E-05	0.00015
Benzene	2.31E-03	2.54E-03	0.01013
Formaldehyde	1.71E-03	1.88E-03	0.00748
n-Hexane	4.11E-02	4.52E-02	0.17999
CO_2	4.52E+04	--	197810.75671
CH_4	5.83E-02	--	0.25521
N_2O	5.09E-03	--	0.02229
CO_2e	4.52E+04	--	197823.02553

Facility Name:	**Sabine Pass Liquefaction, LLC**			
AIR CONTAMINANT DATA				
1. Emission Point			**2. Component or Air Contaminant Name**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(B) TPY**
WTDYFLR3	WTDYFLR3	Wet/Dry Gas Flare 3 (continuous)	NO_x	5.20
			CO	44.59
			VOC	26.11
			H2S	< 0.01
			SO_2	0.07
		Wet/Dry Gas Flare 3 (MSS)	NO_x	26.80
			CO	229.77
			VOC	21.32
			H2S	< 0.01
			SO_2	0.28
		Wet/Dry Gas Flare 3 (Total)	NO_x	32.00
			CO	274.36
			VOC	47.42
			H2S	< 0.01
			SO_2	0.35

EPN = Emission Point Number

FIN = Facility Identification Number

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Continuous Purges

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
SO_2	1.53E-02	6.70E-02
NO_x	1.67E-02	7.30E-02
CO	1.43E-01	6.26E-01
VOC	8.64E-04	3.78E-03

WET/DRY FLARE CONTINUOUS PURGE

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
NO_x	1.33E+00	5.13E+00
CO	1.14E+01	4.40E+01
VOC	6.56E+00	2.61E+01

WET/DRY FLARE MAINTENANCE AND TURNAROUND

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
NO_x	1.21E+02	9.63E-01
CO	1.04E+03	8.26E+00
VOC	9.49E+02	6.90E+00

WET/DRY FLARE MAJOR OVERHAUL

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
NO_x	3.69E+02	2.58E+01
CO	3.16E+03	2.22E+02
VOC	1.05E+02	1.44E+01

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare

Pilot Gas Emissions

Number of Pilots =	4	[1]
Flare Pilot Heat Input =	0.065	MMBtu/hr [1]
Heating Value of Fuel =	850.24	Btu/scf
Pilot Gas Molar Flowrate =	0.20	lb-mol/hr
Annual Operating Time =	8,760	hr/yr [1]
VOC DRE (C1-C3 compounds)	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

Pilot Gas Composition [3]

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	5.32E+00	28.01		1.49	8.84E-02	0.00E+00	-	-
Hydrogen Sulfide	3.01E-04	34.08	29	0.0001	6.08E-06	1.76E-04	1.63E-06	3.72E-07
Water	6.67E-02	18.02		0.01	7.13E-04	0.00E+00	-	-
Carbon Dioxide	2.70E-01	44.01		0.12	7.04E-03	0.00E+00	9.42E-02	2.15E-02
Methane	9.37E+01	16.04	21,509	15.04	8.91E-01	1.92E+04	1.19E-01	2.72E-02
Ethane	4.75E-01	30.069	20,426	0.14	8.47E-03	1.73E+02	1.13E-03	2.59E-04
Propane	6.82E-02	44.096	19,919	0.03	1.78E-03	3.55E+01	2.39E-04	5.45E-05
Isobutane	1.83E-02	58.122	19,587	0.01	6.30E-04	1.23E+01	1.69E-04	3.85E-05
n-Butane	1.52E-02	58.122	19,648	0.01	5.24E-04	1.03E+01	1.40E-04	3.20E-05
Isopentane	6.64E-03	72.149	19,305	0.005	2.84E-04	5.48E+00	7.60E-05	1.73E-05
n-Pentane	3.32E-03	72.149	19,339	0.002	1.42E-04	2.74E+00	3.80E-05	8.67E-06
n-Hexane	7.73E-03	86.175	19,245	0.01	3.95E-04	7.60E+00	1.06E-04	2.41E-05
Benzene	1.96E-03	78.11	17,274	0.002	9.10E-05	1.57E+00	2.44E-05	5.56E-06
n-Heptane	4.55E-03	100.2	19,176	0.005	2.70E-04	5.19E+00	7.24E-05	1.65E-05
				16.87		**19,424**		

Pollutant	Emission Factor		Ref	Emission Rates (per Flare) Hourly (lb/hr)	Emission Rates (per Flare) Annual (tpy)
SO_2				1.53E-02	6.70E-02
NO_x	0.0641	lb/MMBtu	[2]	1.67E-02	7.30E-02
CO	0.5496	lb/MMBtu	[2]	1.43E-01	6.26E-01
VOC				8.64E-04	3.78E-03

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Continuous Purges

VOC (C1-C3) DRE	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

Continuous Purge to Flare 3

Propane Feed Gas Flowrate =	276	lb/hr
Ethylene Feed Gas Flowrate =	320	lb/hr
Methane Feed Gas Flowrate =	220	lb/hr
Regen Gas Flowrate =	84	lb/hr
Pipeline Gas Flowrate =	30	lb/hr
Purge hours =	8760	hr/yr (all except pipeline gas)
	12	hr/yr (pipeline gas)

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	2.70E+00	1.18E+01
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	1.88E-02	8.24E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	7.28E-02	3.19E-01
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	3.18E+00	1.39E+01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	1.84E-02	8.05E-02
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	1.13E+01	4.94E+01
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	2.09E+00	9.14E+00
				16.40		**20,407**		

Regen Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Methane	9.65E+01	16.04	21,509	15.48	0.9369	20,152	7.87E-01	3.45E+00
Ethane	3.00E+00	30.069	20,426	0.90	0.0546	1,115	4.59E-02	2.01E-01
Nitrogen	5.00E-01	28.01		0.14	0.0085	0	7.12E-01	3.12E+00
				16.52		**21,267**		

Pipeline Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	2.10E+00	28.01		0.59	0.0361	0	1.08E+00	6.50E-03
Methane	9.79E+01	16.04	21,509	15.70	0.9639	20,732	2.89E-01	1.74E-03
				16.29		**20,732**		

Total heating value for purges = 18.89 MMBtu/hr
160,001 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	1.21E+00	1.33E+00	5.13E+00
CO	0.5496	lb/MMBtu	[2], [6]	1.04E+01	1.14E+01	4.40E+01
VOC			[2], [6]	5.96E+00	6.56E+00	2.61E+01

Continuous Purge to Flare 2

Propane Feed Gas Flowrate = 138 lb/hr
Ethylene Feed Gas Flowrate = 160 lb/hr
Methane Feed Gas Flowrate = 110 lb/hr
Regen Gas Flowrate = 42 lb/hr
Pipeline Gas Flowrate = 0 lb/hr
Purge hours = 8760 hr/yr (all except pipeline gas)
12 hr/yr (pipeline gas)

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19520.33	1.35E+00	5.92E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139.28	9.41E-03	4.12E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258.17	3.64E-02	1.59E-01
				44.10		**19917.78**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.59E+00	6.97E+00
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	9.19E-03	4.02E-02
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	5.64E+00	2.47E+01
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	1.04E+00	4.57E+00
				16.40		**20,407**		

Regen Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Methane	9.65E+01	16.04	21,509	15.48	0.9369	20,152	3.94E-01	1.72E+00
Ethane	3.00E+00	30.069	20,426	0.90	0.0546	1,115	2.29E-02	1.00E-01
Nitrogen	5.00E-01	28.01		0.14	0.0085	0	3.56E-01	1.56E+00
				16.52		**21,267**		

Total heating value fo 9.13E+00 MMBtu/hr
8.00E+04 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates		
				Hourly (lb/hr)	Maximum (lb/hr)	Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	5.85E-01	6.44E-01	2.56E+00
CO	0.5496	lb/MMBtu	[2], [6]	5.02E+00	5.52E+00	2.20E+01
VOC			[2], [6]	2.98E+00	3.28E+00	1.31E+01

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Maintenance and Turnaround Emissions

VOC (C1-C3) DRE	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

LNG Train Planned Maintenance Emissions

Borescope Purges

Propane Purge Flowrate =	55,200	lb/purge/turbine
Ethylene Purge Flowrate =	16,400	lb/purge/turbine
Methane Purge Flowrate =	10,400	lb/purge/turbine
Borescope Purge per year =	2	/turbine
Turbines =	6	in each service (18 total)
laximum turbine systems purged at a time =	2	in each service (6 total)
Hours per purge =	3	hr

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	3.61E+02	3.25E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	2.51E+00	2.26E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	9.70E+00	8.73E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.09E+02	9.78E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	6.28E-01	5.65E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	3.55E+02	3.20E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	6.58E+01	5.92E-01
				16.40		**20,407**		

Total heating value for purges =	1,096	MMBtu/hr
	19,732	MMBtu/yr

Pollutant	Emission Factor		Ref	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	7.03E+01	7.73E+01	6.32E-01
CO	0.5496	lb/MMBtu	[2], [6]	6.02E+02	6.63E+02	5.42E+00
VOC			[2], [6]	4.79E+02	5.27E+02	4.31E+00

Combustor Changeout/Hot Section Purge

Propane Purge Flowrate =	55,200	lb/purge/turbine
Ethylene Purge Flowrate =	16,400	lb/purge/turbine
Methane Purge Flowrate =	10,400	lb/purge/turbine
CC/HS Purge per year =	1	/turbine
Turbines =	6	in each service (18 total)
ɔine systems purged at a time =	2	in each service (6 total)
Hours per purge =	3	hr

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	3.61E+02	1.62E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	2.51E+00	1.13E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	9.70E+00	4.37E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.09E+02	4.89E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	6.28E-01	2.83E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0.00	3.55E+02	1.60E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20406.77	6.58E+01	2.96E-01
				16.40		**20406.77**		

Total heating value for purges = 1,096 MMBtu/hr
9,866 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	7.03E+01	7.73E+01	3.16E-01
CO	0.5496	lb/MMBtu	[2], [6]	6.02E+02	6.63E+02	2.71E+00
VOC			[2], [6]	4.79E+02	5.27E+02	2.16E+00

Combustor Changeout/Hot Section Startup

Propane Purge Flowrate =	100,803	lb/purge/turbine
Ethylene Purge Flowrate =	28,158	lb/purge/turbine
Methane Purge Flowrate =		lb/purge/turbine
CC/HS Startup per year =	1	/turbine
Turbines =	6	in each service (18 total)
Maximum turbine systems purged at a time =	2	in each service (6 total)
Hours per purge =	3	hr

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	6.59E+02	2.96E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	4.58E+00	2.06E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	1.77E+01	7.97E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	1.87E+02	8.40E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	1.08E+00	4.85E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	0.00E+00	0.00E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	0.00E+00	0.00E+00
				16.40		**20,407**		

Total heating value for purges = 1,719 MMBtu/hr
15,474 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
NO_x	0.0641	lb/MMBtu	[2], [6]	1.10E+02	1.21E+02	4.96E-01
CO	0.5496	lb/MMBtu	[2], [6]	9.45E+02	1.04E+03	4.25E+00
VOC			[2], [6]	8.63E+02	9.49E+02	3.88E+00

[1] Data provided by Cheniere.

[2] The emission factors and destruction efficiencies were obtained from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers; October 2000." Factors are for low Btu streams in non-steam assisted flares. The destruction efficiencies meet the TCEQ BACT guidance for Flares and Vapor Combustors, 8/1/2011.

[3] *LP1 Fuel Gas composition* from "*25744-100-M3-DK-00002.xls* ", provided by Jose Dumlao (Cheniere) to Melissa Ryan (Trinity) on 8/20/12, was used as the pilot gas composition.

[4] Net Heating Values (NHV) were obtained from "Yaws' Handbook of Thermodynamic and Physical Properties of Chemical Compounds".

[5] Feed Gas composition was obtained from "CCLNG-H&MB_for_Air_Permit.xlsx", provided by Cheniere .

[6] Maximum hourly emission rates are based on maximum expected variability during routine operations.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Major Overhaul Intermittent MSS Emissions

VOC (C1-C3) DRE	99.00%	[2]
H2S and VOC (C4+) DRE	98.00%	[2]

LNG Train Planned Maintenance Emissions

Feed Gas Flowrate =	254,760	lb/hr [1]
Annual Flowrate =	37,738,000	lb/2 trains[1]
Heating Value of Feed Gas =	20,530	Btu/lb
	907	Btu/scf

Feed Gas Composition [5]

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	4.90E-01	28.01		0.14	0.0081	0.00E+00	2.05E+03	-
Carbon Dioxide	1.30E+00	44.01		0.57	0.0336	0.00E+00	8.55E+03	6.34E+02
Methane	9.59E+01	16.04	21508.9	15.38	0.9028	1.94E+04	2.30E+03	1.70E+02
Ethane	1.89E+00	30.069	20425.8	0.57	0.0334	6.81E+02	8.50E+01	6.29E+00
Propane	2.50E-01	44.096	19918.7	0.11	0.0065	1.29E+02	1.65E+01	1.22E+00
Isobutane	6.00E-02	58.122	19586.8	0.15	0.0085	1.67E+02	4.35E+01	3.22E+00
n-Butane	5.00E-02	58.122	19647.5	0.03	0.0020	4.02E+01	1.04E+01	7.72E-01
Isopentane	2.00E-02	72.149	19305.4	0.04	0.0021	4.09E+01	1.08E+01	7.99E-01
n-Pentane	1.00E-02	72.149	19339.4	0.01	0.0008	1.64E+01	4.32E+00	3.20E-01
n-Hexane	2.00E-02	86.175	19245.1	0.01	0.0005	9.73E+00	2.58E+00	1.91E-01
Benzene	1.50E-03	78.11	17274.3	0.02	0.0009	1.58E+01	4.67E+00	3.46E-01
n-Heptane	1.00E-02	100.2	19176	0.01	0.0006	1.13E+01	3.00E+00	2.22E-01
Hydrogen Sulfide	4.00E-04	34.08	28.87	0.0001	0.00001	2.31E-04	4.08E-02	3.02E-03
Water	1.47E-02	18.02		0.003	0.0002	0.00E+00	7.93E-01	-
				17.04	1.00	**20,530**		

Major Overhaul Purge Depressurization

Propane Purge Flowrate =	62,100	lb/purge
Ethylene Purge Flowrate =	18,327	lb/purge
Methane Purge Flowrate =	11,060	lb/purge
Overhaul Purge per year =	2	
Duration of Depressurization Purge =	4	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	3.04E+02	1.22E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	2.12E+00	8.47E-03
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	8.19E+00	3.27E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	9.11E+01	3.64E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	5.26E-01	2.10E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	2.83E+02	1.13E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	5.25E+01	2.10E-01
				16.40		**20,407**		

Total heating value for purge depres = 7.34E+03 MMBtu/yr

Major Overhaul Purge Fuel Gas

Propane Purge Flowrate =	31112	lb/purge
Ethylene Purge Flowrate =	14582	lb/purge
Methane Purge Flowrate =	0	lb/purge
Overhaul Purge per year =	2	
Duration of Fuel Gas Purge =	3	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	2.03E+02	6.10E-01
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	1.41E+00	4.24E-03
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	5.47E+00	1.64E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	28	0.9943	20,160	9.67E+01	2.90E-01
Methane	1.00E+00	16.04	21,509	0	0.0057	124	5.58E-01	1.67E-03
				28		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	0.00E+00	0.00E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	0.00E+00	0.00E+00
				16.40		**20,407**		

Total heating value for purge fuel gas= 3.66E+03 MMBtu/yr

Major Overhaul Startup Fuel Gas

Propane Purge Flowrate =	31112	lb/purge
Ethylene Purge Flowrate =	14582	lb/purge
Methane Purge Flowrate =	0	lb/purge
Overhaul Startup per year =	2	
Duration of Overhaul Startup Fuel Gas =	3	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	2.03E+02	6.10E-01
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	1.41E+00	4.24E-03
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	5.47E+00	1.64E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	9.67E+01	2.90E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	5.58E-01	1.67E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates	
							Hourly (lb/hr)	Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	0.00E+00	0.00E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	0.00E+00	0.00E+00
				16.40		**20,407**		

Total heating value for startup fuel gas= 3.66E+03 MMBtu/yr

Major Overhaul Startup Refrigerant

Propane Purge Flowrate =	151,204	lb/purge
Ethylene Purge Flowrate =	42,237	lb/purge
Methane Purge Flowrate =	14,411	lb/purge
Overhaul Startup per year =	2	
Duration of Overhaul Startup Refrigerant =	4	hr
Turbine Systems =	2	in each service (6 total)

Purge flowrates will not occur during same hours as Feed Gas Flowrate to flare calculated above. Hourly emissions from Feed Gas Flowrate are worst case. Only annual emissions are calculated for purge flowrates.

Propane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Propane	9.80E+01	44.096	19,919	43.21	0.9800	19,520	7.41E+02	2.96E+00
Ethane	1.00E+00	30.069	20,426	0.30	0.0068	139	5.16E+00	2.06E-02
i-Butane	1.00E+00	58.122	19,587	0.58	0.0132	258	1.99E+01	7.97E-02
				44.10		**19,918**		

Ethylene Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Ethylene	9.90E+01	28.054	20,277	27.77	0.9943	20,160	2.10E+02	8.40E-01
Methane	1.00E+00	16.04	21,509	0.16	0.0057	124	1.21E+00	4.85E-03
				27.93		**20,284**		

Methane Gas Composition

Constituents	Mol %	Molecular Weight (lb/lb-mol)	NHV [4] Btu/lb	Molar mass	Weight Fraction	Net Heat Release Btu/lb	Emission Rates Hourly (lb/hr)	Emission Rates Annual (tpy)
Nitrogen	3.00E+00	28.01		0.84	0.0512	0	3.69E+02	1.48E+00
Methane	9.70E+01	16.04	21,509	15.56	0.9488	20,407	6.84E+01	2.73E-01
				16.40		**20,407**		

Total heating value for startup refrigerant= 1.66E+04 MMBtu/yr

Pollutant	Emission Factor		References	Emission Rates Hourly (lb/hr)	Emission Rates Maximum (lb/hr)	Emission Rates Annual (tpy)
SO_2			[6]	3.83E+00	4.22E+00	2.84E-01
NO_x	0.0641	lb/MMBtu	[2], [6]	3.35E+02	3.69E+02	2.58E+01
CO	0.5496	lb/MMBtu	[2], [6]	2.87E+03	3.16E+03	2.22E+02
VOC			[2], [6]	9.57E+01	1.05E+02	1.44E+01
H2S			[2], [6]	4.08E-02	4.49E-02	3.02E-03

[1] Data provided by Cheniere.

[2] The emission factors and destruction efficiencies were obtained from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor

[3] *LP1 Fuel Gas composition* from "*25744-100-M3-DK-00002.xls* ", provided by Jose Dumlao (Cheniere) to Melissa Ryan (Trinity) on 8/20/12, was used as the pilot gas composition.

[4] Net Heating Values (NHV) were obtained from "Yaws' Handbook of Thermodynamic and Physical Properties of Chemical Compounds".

[5] Feed Gas composition was obtained from "CCLNG-H&MB_for_Air_Permit.xlsx", provided by Cheniere .

[6] Maximum hourly emission rates are based on maximum expected variability during routine operations.

Area Name:	**Sabine Pass Liquefaction, LLC**			**Customer Reference No. 604136574**	
AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) MTCE/yr**	**(B) TPY**
WTDYFLR3	WTDYFLR3	Wet/Dry Gas Flare 3 (continuous)	CO_2	10,590.18	11,670.38
			CH_4	11.52	12.70
			N_2O	0.02	0.02
		Wet/Dry Gas Flare 3 (MSS)	CO_2	49,230.44	54,251.94
			CH_4	155.31	171.15
			N_2O	0.08	0.09
		Wet/Dry Gas Flare 3 (Total)	CO_2	59,820.62	65,922.33
			CH_4	166.83	183.85
			N_2O	0.10	0.11
			CO_2e	63,354.49	69,816.65

EPN = Emission Point Number

FIN = Facility Identification Number

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Summary of Updated GHG Emission Rates

WET/DRY FLARE PILOTS

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
CO_2	3.33E+01	1.46E+02
CH_4	1.19E-01	2.72E-02
N_2O	5.73E-05	1.86E-09
CO_2e	3.58E+01	1.46E+02

BOG COMPRESSOR OVERHAUL

Pollutant	BOG Compressor (lb/hr)	BOG Compressor (tpy)
CO_2	--	--
CH_4	2.88E+02	7.54E-01
N_2O	--	--
CO_2e	6.05E+03	1.58E+01

WET/DRY FLARE CONTINUOUS FLOWS

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
CO_2	2.71E+03	1.15E+04
CH_4	3.18E+00	1.27E+01
N_2O	4.16E-03	1.76E-02
CO_2e	2.78E+03	1.18E+04

FUGITIVES

Pollutant	Fugitives (lb/hr)	Fugitives (tpy)
CO_2	5.07E-02	2.22E-01
CH_4	9.89E+01	4.33E+02
N_2O	--	--
CO_2e	2.08E+03	9.09E+03

WET/DRY FLARE

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
CO_2	2.60E+05	1.49E+03
CH_4	6.64E+01	6.01E-01
N_2O	3.79E-01	3.31E-03
CO_2e	2.60E+05	1.51E+03

WET/DRY FLARE MAJOR

Pollutant	Hourly Emissions Wet/Dry Flare 3 (lb/hr)	Annual Emissions Wet/Dry Flare 3 (tpy)
CO_2	7.50E+05	5.28E+04
CH_4	2.53E+03	1.71E+02
N_2O	1.27E+00	8.89E-02
CO_2e	8.03E+05	5.64E+04

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Pilot Emissions

Pilot Gas Emissions

Number of Pilots =	4	[1]
Flare Pilot Heat Input =	0.065	MMBtu/hr [1]
Heating Value of Fuel =	850.24	Btu/scf
Pilot Gas Molar Flowrate =	0.20	lb-mol/hr
Annual Operating Time =	8,760	hr/yr [1]

Emissions From Pilot Gas Combustion

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[2]	3.33E+01	1.46E+02
CH_4			[3]	1.19E-01	2.72E-02
N_2O	1.0E-04	kg/MMBtu	[4]	5.73E-05	1.86E-09
CO_2e	--	--	[5]	3.58E+01	1.46E+02

[1] Data provided by Cheniere.

[2] Based on mass balance of carbon in pilot gas.

[3] Emission rate estimated at a DRE of 99%

[4] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[5] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Continuous Flows

Continuous Flow to Flare 3

Continuous Flow Gas Heat Input =	19	MMBtu/hr
	160,001	MMBtu/yr

Emissions From Continuous Flow Gas Combustion

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	2.71E+03	1.15E+04
CH_4			[2]	3.18E+00	1.27E+01
N_2O	1.0E-04	kg/MMBtu	[3]	4.16E-03	1.76E-02
CO_2e	--	--	[4]	2.78E+03	1.18E+04

Continuous Flow to Flare 2

Continuous Flow Gas Heat Input =	9	MMBtu/hr
	79,997	MMBtu/yr

Emissions From Continuous Flow Gas Combustion

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.32E+03	5.76E+03
CH_4			[2]	1.45E+00	6.33E+00
N_2O	1.0E-04	kg/MMBtu	[3]	2.01E-03	8.82E-03
CO_2e	--	--	[4]	1.35E+03	5.90E+03

[1] Based on mass balance of carbon in purge gas.

[2] Emission rate estimated at a DRE of 99%

[3] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[4] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Maintenance and Turnaround Emissions

LNG Train Planned Maintenance Emissions

Borescope Purges

Purge Gas Heat Input = 1,096 MMBtu/hr
19,732 MMBtu/yr

Emissions From Borescope Purges

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.62E+05	9.75E+02
CH_4			[2]	6.64E+01	5.98E-01
N_2O	1.0E-04	kg/MMBtu	[3]	2.42E-01	2.18E-03
CO_2e	--	--	[4]	1.64E+05	9.88E+02

Combustor Changeout/Hot Section Purges

Purge Gas Heat Input = 1,096 MMBtu/hr
9,866 MMBtu/yr

Emissions From Combustor Changeout/Hot Section Purges

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.62E+05	4.87E+02
CH_4			[2]	6.64E+01	2.99E-01
N_2O	1.0E-04	kg/MMBtu	[3]	2.42E-01	1.09E-03
CO_2e	--	--	[4]	1.64E+05	4.94E+02

Combustor Changeout/Hot Section Startup

Purge Gas Heat Input = 1,719 MMBtu/hr
15,474 MMBtu/yr

Emissions From Combustor Changeout/Hot Section Startup

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	2.60E+05	7.80E+02
CH_4			[2]	1.08E+00	4.85E-03
N_2O	1.0E-04	kg/MMBtu	[3]	3.79E-01	1.71E-03
CO_2e	--	--	[4]	2.60E+05	7.81E+02

[1] Based on mass balance of carbon in purge gas.

[2] Emission rate estimated at a DRE of 99%

[3] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[4] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

Sabine Pass Liquefaction, LLC
Sabine Pass Liquefaction Project
Wet/Dry Flare Major Overhaul Intermittent MSS Emissions

<u>LNG Train Planned Maintenance Emissions</u>

Purge of Feed Gas

Purge Gas Heat Input =	5,230	MMBtu/hr
	774,774	MMBtu/yr

Emissions From Purge of Feed Gas

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	6.81E+05	5.05E+04
CH_4			[2]	2.30E+03	1.70E+02
N_2O	1.0E-04	kg/MMBtu	[3]	1.15E+00	8.54E-02
CO_2e	--	--	[4]	7.30E+05	5.41E+04

Major Overhaul Purge Depressurization

Purge Gas Heat Input =	917	MMBtu/hr
	7,337	MMBtu/yr

Emissions From Major Overhaul Purge Depressurization

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	1.22E+05	4.88E+02
CH_4			[2]	5.30E+01	2.12E-01
N_2O	1.0E-04	kg/MMBtu	[3]	2.02E-01	8.09E-04
CO_2e	--	--	[4]	1.23E+05	4.93E+02

Major Overhaul Purge Fuel Gas

Purge Gas Heat Input =	610	MMBtu/hr
	3,662	MMBtu/yr

Emissions From Major Overhaul Purge Fuel Gas

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	9.26E+04	2.78E+02
CH_4			[2]	5.58E-01	1.67E-03
N_2O	1.0E-04	kg/MMBtu	[3]	1.35E-01	4.04E-04
CO_2e	--	--	[4]	9.26E+04	2.78E+02

Major Overhaul Startup Fuel Gas

Purge Gas Heat Input =	610	MMBtu/hr
	3,662	MMBtu/yr

Emissions From Major Overhaul Startup Fuel Gas

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	9.26E+04	2.78E+02
CH_4			[2]	5.58E-01	1.67E-03
N_2O	1.0E-04	kg/MMBtu	[3]	1.35E-01	4.04E-04
CO_2e	--	--	[4]	9.26E+04	2.78E+02

Major Overhaul Startup Refrigerant

Purge Gas Heat Input =	2,081	MMBtu/hr
	16,650	MMBtu/yr

Emissions From Major Overhaul Startup Refrigerant

Pollutant	Emission Factor		References	Emission Rate Average (lb/hr)	Emission Rate Annual (tpy)
CO_2			[1]	3.11E+05	1.25E+03
CH_4			[2]	6.96E+01	2.78E-01
N_2O	1.0E-04	kg/MMBtu	[3]	4.59E-01	1.84E-03
CO_2e	--	--	[4]	3.13E+05	1.25E+03

Emissions Summary from Major Overhaul

Pollutant	Emission Rate Hourly [5] (lb/hr)	Emission Rate Maximum [6] (lb/hr)	Emission Rate Annual (tpy)
CO_2	6.81E+05	7.50E+05	5.28E+04
CH_4	2.30E+03	2.53E+03	1.71E+02
N_2O	1.15E+00	1.27E+00	8.89E-02
CO_2e	7.30E+05	8.03E+05	5.64E+04

[1] Based on mass balance of carbon in purge gas.

[2] Emission rate estimated at a DRE of 99%

[3] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[4] CH4, CO2, and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potentials (GWP). The GWP of CH4 is 21, of CO2 is 1, and of N2O is 310.

[5] Purge flows will not occur in same hour as purge of feedgas. Hourly rates are maximum of all scenarios.

[6] Maximum hourly emission rates are based on maximum expected variability during routine operations.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Refrigeration Compressor Turbines - Criteria Pollutants

No. of Turbines =	12	
Average Operating Rate =	6,656	BTU/Hp-hr/compressor turbine [4]
Annual Operating Time =	8,760	hrs/yr [4]
Power of Compressor=	32,075	kW/ each compressor turbine [4]
	43,013	HP / each compressor turbine [4]
% Sulfur in Fuel =	0	% [5]

Pollutant	Emission Factor		References	Emission Rates per Turbine Average (lb/hr)	Maximum (lb/hr)	Annual (tpy)
PM_{10}	6.60E-03	lb/MMBtu	[1], [2]	1.89E+00	2.08E+00	8.28E+00
$PM_{2.5}$	6.60E-03	lb/MMBtu	[1], [2], [6]	1.89E+00	2.08E+00	8.28E+00
NO_x	25	ppm	[3], [7]	2.29E+01	2.87E+01	1.26E+02
CO	58.4	ppm	[3], [8]	4.36E+01	4.36E+01	1.91E+02
VOC	2.10E-03	lb/MMBtu	[1], [2]	6.01E-01	6.61E-01	2.63E+00

[1] U.S. EPA AP-42, Volume I, Chapter 3, Section 3.1, Stationary Gas Turbines, Table 3.1-2a, Emission Factors for Criteria Pollutants and Greenhouse Gases From Stationary Gas Turbines, p.3.1-11, July 1998.

[2] A contingency factor of 10% is added to the average emission rate to estimate the maximum emission rate.

[3] Vendor Guarantee

[4] Data supplied by Bechtel on September 24, 2010.

[5] Data supplied by Bechtel on August 1, 2010 for sulfur content of fuel.

[6] $PM_{2.5}$ emission factor is assumed to be equal to PM_{10} emission factor.

[7] NOx concentration increased from 20 ppm to 25 ppm. Based on an email from Ms. Catherine Rourke (Cheniere) to Mr. Jason Swofford (Trinity) on May 21, 2013.

[8] CO concentration increased from 25 ppm to 58.4 ppm. Obtained CO emission rate from "GE Industrial Aeroderivative Gas Turbines", LM2500 Industrial Applications Memo 2500-11-012A. Based upon Personal Communication, Email Communication between Ms. Cathy Rourke (Sabine Pass LNG) and Mr. Bill Bruscino

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Refrigeration Compressor Turbines -
Hazardous Air Pollutant Emissions

No. of Turbines =	12	
Average Operating Rate =	6,656	BTU/Hp-hr/compressor turbine [1]
Annual Operating Time =	8,760	hrs/yr [1]
Power of Compressor=	32,075	kW/ each compressor turbine [1]
	43,013	HP / each compressor turbine [1]

Pollutant	Emission Factor		References	Emission Rates per Turbine Average (lb/hr)	Maximum (lb/hr) [3]	Annual (tpy)
1,3-Butadiene	4.30E-07	lb/MMBtu	[2]	1.23E-04	1.35E-04	5.4E-04
Acetaldehyde	4.00E-05	lb/MMBtu	[2]	1.15E-02	1.26E-02	5.0E-02
Acrolein	6.40E-06	lb/MMBtu	[2]	1.83E-03	2.02E-03	8.0E-03
Benzene	1.20E-05	lb/MMBtu	[2]	3.44E-03	3.78E-03	1.5E-02
Ethylbenzene	3.20E-05	lb/MMBtu	[2]	9.16E-03	1.01E-02	4.0E-02
Formaldehyde	7.10E-04	lb/MMBtu	[2]	2.03E-01	2.24E-01	8.9E-01
Naphthalene	1.30E-06	lb/MMBtu	[2]	3.72E-04	4.09E-04	1.6E-03
PAH	2.20E-06	lb/MMBtu	[2]	6.30E-04	6.93E-04	2.8E-03
Propylene Oxide	2.90E-05	lb/MMBtu	[2]	8.30E-03	9.13E-03	3.6E-02
Toluene	1.30E-04	lb/MMBtu	[2]	3.72E-02	4.09E-02	1.6E-01
Xylene (Mixed Isomers)	6.40E-05	lb/MMBtu	[2]	1.83E-02	2.02E-02	8.0E-02

[1] Data supplied by Bechtel on September 24, 2010.

[2] U.S. EPA AP-42, Volume I, Chapter 3, Section 3.1, Stationary Gas Turbines, Table 3.1-3, Emission Factors for Hazardous Air Pollutants From Natural Gas Fired Stationary Gas Turbines, p.3.1-13, July 1998.

[3] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Refrigeration Compressor Turbines -
Greenhouse Gases

No. of Turbines =	12	
Average Operating Rate =	6,656	BTU/Hp-hr/compressor turbine [1]
Annual Operating Time =	8,760	hrs/yr [1]
Power of Compressor=	32,075	kW/ each compressor turbine [1]
	43,013	HP / each compressor turbine [1]

Pollutant	Emission Factor		References	Emission Rates per Turbine Average (lb/hr)	Emission Rates per Turbine Annual (tpy)
CO_2	53.02	kg/MMBtu	[2]	3.35E+04	1.47E+05
CH_4	1.0E-03	kg/MMBtu	[2]	6.31E-01	2.77E+00
N_2O	1.0E-04	kg/MMBtu	[2]	6.31E-02	2.77E-01
CO_2e	--	--	[3]	3.35E+04	1.47E+05

[1] Data supplied by Bechtel on September 24, 2010.
[2] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.
[3] CH_4, CO_2, and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potentials (GWP). The GWP of CH_4 is 21, of CO_2 is 1, and of N_2O is 310.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Proposed Natural Gas-Fired Generator Turbines - Criteria Pollutants

No. of Turbines =	2	
Average Operating Rate =	6,656	Btu/Hp-hr/compressor turbine [4]
Annual Operating Time =	8,760	hrs/yr [4]
Power of Compressor=	32,075	kW/ each compressor turbine [4]
	43,013	HP / each compressor turbine [4]
% Sulfur in Fuel =	0	% [5]

Pollutant	Emission Factor		References	Emission Rates per Turbine Average (lb/hr)	Maximum (lb/hr)	Annual (tpy)
PM_{10}	6.60E-03	lb/MMBtu	[1], [2]	1.89E+00	2.08E+00	8.28E+00
$PM_{2.5}$	6.60E-03	lb/MMBtu	[1], [2], [6]	1.89E+00	2.08E+00	8.28E+00
NO_x	25	ppm	[3]	2.87E+01	2.87E+01	1.26E+02
CO	25	ppm	[3]	1.75E+01	1.75E+01	7.65E+01
VOC	2.10E-03	lb/MMBtu	[1], [2]	6.01E-01	6.61E-01	2.63E+00

[1] U.S. EPA AP-42, Volume I, Chapter 3, Section 3.1, Stationary Gas Turbines, Table 3.1-2a, Emission Factors for Criteria Pollutants and Greenhouse Gases From Stationary Gas Turbines, p.3.1-11, July 1998.

[2] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.

[3] Vendor Guarantee

[4] Data supplied by Bechtel on September 24, 2010.

[5] Data supplied by Bechtel on August 1, 2010 for sulfur content of fuel.

[6] $PM_{2.5}$ emission factor is assumed to be equal to PM_{10} emission factor.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Proposed Natural Gas-Fired Generator Turbines -
Hazardous Air Pollutant Emissions

No. of Turbines =	2	
Average Operating Rate =	6,656	BTU/Hp-hr/compressor turbine [1]
Annual Operating Time =	8,760	hrs/yr [1]
Power of Compressor=	32,075	kW/ each compressor turbine [1]
	43,013	HP / each compressor turbine [1]

				Emission Rates per Turbine		
Pollutant	Emission Factor		References	Average (lb/hr)	Maximum (lb/hr) [3]	Annual (tpy)
1,3-Butadiene	4.30E-07	lb/MMBtu	[2]	1.23E-04	1.35E-04	5.4E-04
Acetaldehyde	4.00E-05	lb/MMBtu	[2]	1.15E-02	1.26E-02	5.0E-02
Acrolein	6.40E-06	lb/MMBtu	[2]	1.83E-03	2.02E-03	8.0E-03
Benzene	1.20E-05	lb/MMBtu	[2]	3.44E-03	3.78E-03	1.5E-02
Ethylbenzene	3.20E-05	lb/MMBtu	[2]	9.16E-03	1.01E-02	4.0E-02
Formaldehyde	7.10E-04	lb/MMBtu	[2]	2.03E-01	2.24E-01	8.9E-01
Naphthalene	1.30E-06	lb/MMBtu	[2]	3.72E-04	4.09E-04	1.6E-03
PAH	2.20E-06	lb/MMBtu	[2]	6.30E-04	6.93E-04	2.8E-03
Propylene Oxide	2.90E-05	lb/MMBtu	[2]	8.30E-03	9.13E-03	3.6E-02
Toluene	1.30E-04	lb/MMBtu	[2]	3.72E-02	4.09E-02	1.6E-01
Xylene (Mixed Isomers)	6.40E-05	lb/MMBtu	[2]	1.83E-02	2.02E-02	8.0E-02

[1] Data supplied by Bechtel on September 24, 2010.

[2] U.S. EPA AP-42, Volume I, Chapter 3, Section 3.1, Stationary Gas Turbines, Table 3.1-3, Emission Factors for Hazardous Air Pollutants From Natural Gas Fired Stationary Gas Turbines, p.3.1-13, July 1998.

[3] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Proposed Natural Gas-Fired Generator Turbines - Greenhouse Gases

No. of Turbines =	2	
Average Operating Rate =	6,656	BTU/Hp-hr/compressor turbine [1]
Annual Operating Time =	8,760	hrs/yr [1]
Power of Compressor=	32,075	kW/ each compressor turbine [1]
	43,013	HP / each compressor turbine [1]

Pollutant	Emission Factor		References	Emission Rates per Turbine Average (lb/hr)	Emission Rates per Turbine Annual (tpy)
CO_2	53.02	kg/MMBtu	[2]	3.35E+04	1.47E+05
CH_4	1.0E-03	kg/MMBtu	[2]	6.31E-01	2.77E+00
N_2O	1.0E-04	kg/MMBtu	[2]	6.31E-02	2.77E-01
CO_2e	--	--	[3]	3.35E+04	1.47E+05

[1] Data supplied by Bechtel on September 24, 2010.

[2] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for natural gas.

[3] CH_4, CO_2, and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potentials (GWP). The GWP of CH_4 is 21, of CO_2 is 1, and of N_2O is 310.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Standby Generator -
Criteria Air Pollutants

Operating Time [1] =	500	hrs/yr
Generator Rating [1] =	1,655	KW each
Generator Rating [1] =	2,220	HP each
No of Generators [1] =	2	

Pollutant	Emission Factor		References	Emission Rate per Engine		
				Average (lb/hr)	Maximum (lb/hr) [5]	Annual (tpy)
PM_{10}	2.00E-01	g/kw-hr	[7]	7.30E-01	8.03E-01	1.82E-01
$PM_{2.5}$	2.00E-01	g/kw-hr	[4], [7]	7.30E-01	8.03E-01	1.82E-01
SO_2	1.21E-05	lb/hp-hr	[2], [3]	2.69E-02	2.96E-02	6.73E-03
NO_X	6.40E+00	g/kw-hr	[7]	2.34E+01	2.57E+01	5.84E+00
CO	3.50E+00	g/kw-hr	[7]	1.28E+01	1.41E+01	3.19E+00
VOC	6.42E-04	lb/hp-hr	[2],[6]	1.43E+00	1.57E+00	3.56E-01

Notes:
[1] Data supplied by Bechtel . Operating time was assumed to be 500 hrs/yr.
[2] AP-42, Section 3.4 - Large Stationary Diesel and All Stationary Dual-fuel Engines, Table 3.4-1, Gaseous Emission factors for Large Uncontrolled Stationary Engines and All Stationary Dual-fuel Engines, October 1996.
[3] Emission factor based on maximum 15 ppm of Sulfur content as per 40 CFR 60.4207(b) and 40 CFR 80.510(b)(1)(i).
[4] $PM_{2.5}$ emission factor is limited by the PM_{10} emission standards as set in 40 CFR 89.112(a), Table 1 for Stationary Emergency CI Engines < 3,000 HP and a displacement of less than 10 liters per cylinder.
[5] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.
[6] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.
[7] Based on PM, NO_X, and CO emission standards set in 40 CFR 89.112(a), Table 1 for Stationary Emergency CI Engines $\leq$ 3,000 HP and a displacement of less than 10 liters per cylinder.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Standby Generator -
Hazardous Air Pollutants

Operating Time [1] =	500	hrs/yr
Generator Rating [1] =	1,655	KW each
Generator Rating [1] =	2,220	HP each
Design Rating [1] =	5.7	MMBtu/hr
No of Generators [1] =	2	

Pollutant	Emission Factor		References	Emission Rate per Turbine		
				Average (lb/hr)	Maximum (lb/hr) [4]	Annual (tpy)
Acetaldehyde	2.52E-05	lb/MMBtu	[2]	1.42E-04	1.57E-04	0.0000356
Acrolein	7.88E-06	lb/MMBtu	[2]	4.45E-05	4.90E-05	0.0000111
Benzene	7.76E-04	lb/MMBtu	[2]	4.38E-03	4.82E-03	0.0010961
Formaldehyde	7.89E-05	lb/MMBtu	[2]	4.46E-04	4.90E-04	0.0001114
Naphthalene	1.30E-04	lb/MMBtu	[3]	7.35E-04	8.08E-04	0.0001836
Toluene	2.81E-04	lb/MMBtu	[2]	1.59E-03	1.75E-03	0.0003969
Xylene	1.93E-04	lb/MMBtu	[2]	1.09E-03	1.20E-03	0.0002726

Notes:
[1] Data supplied by Bechtel on . Operating time was assumed to be 500 hrs/yr.
[2] AP-42, Section 3.4 - Large Stationary Diesel and All Stationary Dual-fuel Engines, Table 3.4-3, SpeciatedOrganic Compound Emission factors For Large Uncontrolled Stationary Diesel Engines, October 1996.
[3] AP-42, Section 3.4 - Large Stationary Diesel and All Stationary Dual-fuel Engines, Table 3.4-4, PAH Emission factors For Large Uncontrolled Stationary Diesel Engines, October 1996..
[4] A contingency factor of ten percent is added to the average emission rate to estimate the maximum emission rate.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Standby Generator -
Greenhouse Gases

Generator Rating [1] =	1,655	KW each
Generator Rating [1] =	2,220	HP each
Design Operating Rate [1] =	5.7	MMBtu/hr
Annual Operating Time [1] =	500	hrs/yr
No of Generators [1] =	2	

Pollutant	Emission Factor		References	Emission Rate per Turbine Average Emissions (lbs/hr)	Emission Rate per Turbine Annual Emissions (tpy)
CO_2	73.96	kg/MMBtu	[2]	9.21E+02	2.30E+02
CH_4	3.0E-03	kg/MMBtu	[2]	3.74E-02	9.34E-03
N_2O	6.0E-04	kg/MMBtu	[2]	7.48E-03	1.87E-03
CO_2e	--	--	[3]	9.25E+02	2.31E+02

Notes:
[1] Data supplied by Bechtel on . Operating time was assumed to be 500 hrs/yr.
[2] Based on EPA default factors in U.S. EPA, 40 CFR 98 Subpart C, Tables C-1 and C-2 for diesel.
[3] CH_4, CO_2, and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potentials (GWP). The GWP of CH_4 is 21, of CO_2 is 1, and of N_2O is 310.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Fugitive Emissions - Criteria Pollutants

Component Type[2]	Service[2]	Quantity[3] (per train)	Avg. Wt Fraction[2] (WTOC)	Emission Factor (kg/hr)/source[1]	Emission Factor (lb/hr)/source	Hours of Operation[2] (hrs/yr)
Connectors	Gas	506	1	2.00E-04	4.41E-04	8,760
Flanges	Gas	7,552	1	3.90E-04	8.60E-04	8,760
Pump Seals	Oil/Water	88	1	2.40E-05	5.29E-05	8,760
Valves	Gas	3,830	1	4.50E-03	9.92E-03	8,760
	Gas	1,365	1	4.50E-03	9.92E-03	52
	Oil	31	0.2	2.50E-03	5.51E-03	8,760
	Oil/Water	30	0.1	9.80E-05	2.16E-04	8,760
Other	Gas	180	1	8.80E-03	1.94E-02	8,760

Speciation Factors[2]

Substance	Gas	Light Oil	Oil/Water
VOC	0.01	0.296	0.296

Component Type	Service	VOC Emissions Average (lb/hr)	VOC Emissions Maximum (lb/hr)	VOC Emissions Annual (tpy)
Connectors	Gas	2.23E-03	2.23E-03	9.77E-03
Flanges	Gas	6.49E-02	6.49E-02	2.84E-01
Pump Seals	Oil/Water	1.38E-03	1.38E-03	6.04E-03
Valves	Gas	3.80E-01	3.80E-01	1.66E+00
	Gas	1.35E-01	1.35E-01	3.52E-03
	Oil	1.01E-02	1.01E-02	4.43E-02
	Oil/Water	1.92E-04	1.92E-04	8.40E-04
Other	Gas	3.49E-02	3.49E-02	1.53E-01
Total / Train		6.29E-01	6.29E-01	2.17E+00
Total 2 Trains		2.52E+00	2.52E+00	4.33E+00

[1] Emission factors based on U.S. EPA's "Protocol for Equipment Leak Emission Estimates", Table 2-4, Oil and Gas Production Operations Average Emission Factors, November 1995.

[2] Based on information provided by Bechtel on August 2, 2010. VOC speciation factor conservatively estimated as worst-case vapor stream.

[3] Based on information provided by Cathy Rourke (Cheniere) to Bill Bruscino (Trinity) on May 8, 2011.

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Fugitive Emissions - Greenhouse Gases

Density of Gas Fuel = 1.92E-02 kg/scf [2]
Fraction of Time Component Leaks = 0.04 (4%) of the year [6]

Component Type[2]	Service[2]	Quantity[7] (per train)	Avg. Wt Fraction[2] (WTOC)	Emission Factor (scf/hr)/source[1]	Emission Factor (lb/hr)/source	Hours of Operation[2] (hrs/yr)
Connectors	Gas	506	1	5.80	0.24	8,760
Flanges	Gas	7,552	1	5.80	0.24	8,760
Valves	Gas	3,830	1	6.52	0.27	8,760
	Gas	1,365	1	6.52	0.27	52
Other	Gas	180	1	11.44	0.48	8,760

Speciation Factors [3]

Substance	Gas
CO_2	0.013
CH_4	0.959

Component Type	Service	CO_2 Emissions Average (lb/hr) [4]	CO_2 Emissions Annual (tpy)
Connectors	Gas	6.61E-02	2.89E-01
Flanges	Gas	9.86E-01	4.32E+00
Valves	Gas	5.62E-01	2.46E+00
	Gas	2.00E-01	5.21E-03
Other	Gas	4.64E-02	2.03E-01
Total / Train		1.86E+00	7.28E+00
Total 2 Trains		7.45E+00	1.46E+01

Component Type	Service	CH_4 Emissions Average (lb/hr) [4]	CH_4 Emissions Annual (tpy)
Connectors	Gas	4.88E+00	2.14E+01
Flanges	Gas	7.28E+01	3.19E+02
Valves	Gas	4.15E+01	1.82E+02
	Gas	1.48E+01	3.84E-01
Other	Gas	3.42E+00	1.50E+01
Total / Train		1.37E+02	5.37E+02
Total 2 Trains		5.49E+02	1.07E+03

Sabine Pass Liquefaction Project
Johnsons Bayou, Cameron Parish, Louisiana

Fugitive Emissions - Greenhouse Gases (continued)

Component Type	Service	CO_2e Emissions [5]	
		Average (lb/hr) [4]	Annual (tpy)
Connectors	Gas	1.02E+02	4.49E+02
Flanges	Gas	1.53E+03	6.70E+03
Valves	Gas	8.72E+02	3.82E+03
	Gas	3.11E+02	8.08E+00
Other	Gas	7.19E+01	3.15E+02
Total / Train		2.89E+03	1.13E+04
Total 2 Trains		5.77E+03	2.26E+04

[1] Emission factors based on U.S. EPA, 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases Petroleum and Natural Gas Systems, Subpart W (final), Table W-2, November 2010.
[2] Based on information provided by Bechtel on August 2, 2010.
[3] Speciation Factors for gases conservatively assumed to be equal to Gas Analysis, Stream 1 data provided by Bechtel on September 24, 2010.
[4] Calculated using Equation W-30, U.S. EPA, 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases Petroleum and Natural Gas Systems, Subpart W (final), November 2010.
[5] CH_4, CO_2, and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potentials (GWP). The GWP of CH_4 is 21, of CO_2 is 1, and of N_2O is 310.
[6] The fraction of time component leaks is conservatively assumed to be 15 days per year per LAC 33:III.2121.B.3 (4% of the year).
[7] Based on information provided by Cathy Rourke (Cheniere) to Bill Bruscino (Trinity) on May 8, 2011.

APPENDIX 9C

Air Quality Dispersion Modeling Protocol Including Marine Sources

DRAFT
AIR QUALITY DISPERSION MODELING PROTOCOL
INCLUDING MARINE SOURCES

Sabine Pass Liquefaction Expansion, LLC

CHENIERE

July 2013

As requested by the Federal Energy Regulatory Commission (FERC), Sabine Pass Liquefaction Expansion, LLC. (SPL) proposes to conduct an air quality dispersion analysis for the Sabine Pass LNG Terminal located in Cameron Parish, Louisiana. This model will include marine sources in addition to modeling performed for the Louisiana Department of Environmental Quality (LDEQ) for demonstration of compliance with the National Ambient Air Quality Standards (NAAQS).

SPL currently operates under Title V Permit No. 0560-00214-V4 issued on March 22, 2013 and Prevention of Significant Deterioration (PSD) Permit No. PSD-LA-703 (M-4) issued on March 22, 2013. SPL is proposing to add two additional trains at the Sabine Pass LNG site. The proposed expansion project will require the submittal of a modification to the existing PSD and Title V Permits to LDEQ.

SPL plans to for up to 400 LNG Carriers (LNGCs) per year to call on the facility. Each LNGC call will include 4 tug boats (dedicated to SLPNG) and a security vessel provided by USCG or Jefferson County Sheriff's Waterway Patrol unit, if so requested by USCG.

In accordance with Title 40 of the Code of Federal Regulations (CFR) Part 52.21, a demonstration of compliance with the NAAQS is required for the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable under the Clean Air Act (CAA).

The purpose of this modeling protocol is to provide the FERC with an opportunity to review and approve the proposed modeling methodology, modified to include marine vessels while inside the security zone. This protocol in general follows the current U.S. Environmental Protection Agency (U.S. EPA)[1] and the Louisiana Department of Environmental Quality (LDEQ)[2] modeling guidelines, with the exception of including marine (mobile) sources.

Section 1 describes the proposed modeling methodology, which includes a discussion of the PSD Screening Analysis and NAAQS Analysis. If a full impacts analysis is required, the air dispersion modeling results (i.e., modeling of the SPL sources plus the appropriate marine sources) for a single pollutant will be added to the corresponding background concentration for that pollutant and then compared to the appropriate NAAQS on a receptor grid surrounding the SPL facility according to and consistent with available U.S. EPA guidance. This methodology is explained in more detail in Section 1.

Section 2 describes the model selection and inputs, which includes a discussion of the dispersion model selection, meteorological data, land use, topography, Good Engineering Practice (GEP) Stack Height analysis, building wake effects, receptor grid, emission rates, and source parameters.

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[1] EPA's *Guideline on Air Quality Models (Revised)*, Federal Register Vol. 70, No. 216, pp. 68,218 – 68,261, November 9, 2005. Codified at 40 CFR Part 51, Appendix W and EPA's *New Source Review Workshop Manual (DRAFT)* (1990).

[2] *Air Quality Modeling Procedures*, Air Quality Assessment Division, LDEQ, August 2006.

1. AIR QUALITY DISPERSION MODELING METHODOLOGY

The purpose of the proposed air quality analysis is to demonstrate that emissions of NO_2, CO, PM_{10}, and $PM_{2.5}$ from the proposed project, including mobile sources, will not cause or significantly contribute to a modeled exceedance of the NAAQS. As discussed in detail in the following sections, the air dispersion modeling analysis will be conducted in accordance with the U.S. EPA's Guideline on Air Quality Models (the "*Guideline*"),[3] the LDEQ's Air Quality Modeling Procedures,[4] and other appropriate guidance such as the Draft New Source Review Workshop Manual[5] and recent U.S. EPA Modeling Clearinghouse "Clarification Memos."

1.1 METHODOLOGY

1.1.1 Special Considerations for $PM_{2.5}$

On May 16, 2008, U.S. EPA issued the final $PM_{2.5}$ New Source Review (NSR) Implementation Rule, which requires sources in delegated states, such as Louisiana, to conduct an ambient air quality analysis for $PM_{2.5}$ in accordance with 40 CFR §52.21(m).[6] In a March 23, 2010, U.S. EPA Memorandum,[7] EPA recommended that the highest average of the modeled annual averages of $PM_{2.5}$ concentrations based on 5 years of National Weather Service data or the highest modeled annual average of $PM_{2.5}$ concentration based on 1 year of site-specific meteorological data be compared to the annual SIL. Similarly, EPA recommended that the highest average of the maximum 24-hour averages of $PM_{2.5}$ concentrations based on 5 years of National Weather Service data or the highest modeled 24-hour average of $PM_{2.5}$ concentration based on 1 year of site-specific meteorological data be compared to the 24-hour SIL. SPL is proposing to use the annual and 24-hour options based on 5 years of National Weather Service data. Additionally, the impacts of $PM_{2.5}$ will be analyzed using the 8th highest modeled result per most recent U.S. EPA guidance.

1.1.2 Special Considerations for NO_2

In the "Models for Nitrogen Dioxide" section of the *Guideline* (Section 5.2.4), U.S. EPA recommends a tiered screening approach for estimating annual NO_2 impacts from point sources in PSD modeling analyses. Since the *Guideline* has not been revised to specifically address recommended modeling methodologies for the 1-hour NO_2 NAAQS analysis, the approaches identified for the annual standard will also be applied to the new 1-hour standard.

Under the initial and most conservative Tier 1 screening level, all NO_X emitted is modeled as NO_2, *i.e.*, total conversion of NO (the primary chemical form of NO_X) to NO_2 is assumed. If the impacts predicted using this approach result in exceedances of the NAAQS, a more refined technique could be used.

For the Tier 2 screening level, U.S. EPA recommends multiplying the Tier 1 results by an empirically derived national annual average default NO_2:NO_X ambient equilibrium ratio of 0.80. As an alternative to the default value, the reviewing agency may also establish a project-specific NO_2:NO_X ratio based on existing air quality

[3] Federal Register Vol. 70, No. 216, pp. 68,218 – 68,261, November 9, 2005. Codified at 40 CFR Part 51, Appendix W.

[4] *Air Quality Modeling Procedures*, Air Quality Assessment Division, LDEQ, August 2006.

[5] EPA's *New Source Review Workshop Manual (DRAFT)* (1990).

[6] Federal Register, Vol. 73, p. 28,321.

[7] Based on U.S. EPA Memorandum from Stephen D. Page to Bill Harnett, et al. titled, "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS". March 23, 2010.

data collected at representative ambient monitoring stations. Should the impacts predicted using the Tier 2 approach still result in modeled exceedances of the NAAQS, the case-by-case Tier 3 approach could be relied upon to estimate 1-hour NO_2 impacts.

Since the impact of an individual NO_X source on ambient NO_2 depends on the chemical environment into which the source's plume is emitted, modeling techniques that account for this atmospheric chemistry such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM) can be considered under the most refined Tier 3 approach identified by U.S. EPA.

SPL proposes to use the Tier 2 screening level. If additional refinement is required, the Tier 3 screening level will be used and the details of in-stack ratio, final conversion, and ozone background will be supplied in the final report.

1.2 PSD SCREENING ANALYSIS

The screening analysis consists of three separate determinations that are listed as follows: the Significance Analysis, an AOI Analysis, and a Preconstruction Monitoring Analysis. The most recent U.S. EPA guidance will be used for all three determinations.

More specifically, the Significance Impact Analysis (SIA) determines whether 40 CFR 52.21 requires a full impact analysis (i.e., NAAQS modeling) for compliance. For each compound that requires PSD review, the air dispersion model incorporates all project sources, project-affected sources, and any emissions sources that have emissions increases or decreases within the project's contemporaneous period. The modeled emissions rate may reflect the net emissions change (increase or decrease) from the project, the net emissions change (increase or decrease) from the project's contemporaneous period, or both if applicable. The net emissions increase as determined for the PSD applicability analysis should be modeled for the SIA.[8]

The significance analysis compares the maximum concentration from the significance model to the appropriate significance level. If the maximum concentration for a pollutant is less than its respective significance level, the project's impact is not significant, and no further analysis is required. If the maximum concentration for a pollutant is greater than or equal to its respective significance level, the project's impact is potentially significant, and a full impact analysis is required.

1.3 NAAQS ANALYSIS

The National Ambient Air Quality Standards (NAAQS) are limits defined as the total allowable concentration of a pollutant in the atmosphere. For criteria pollutants with a significant off-property impact, the PSD analysis requires a NAAQS analysis. The NAAQS analysis demonstrates that the proposed project will not cause or contribute to a violation of federal ambient air concentration thresholds. The NAAQS uses the sum of the dispersion model and an ambient monitoring concentration to demonstrate compliance.

For each pollutant that requires a NAAQS analysis (i.e., pollutants that are shown in the significant impact analysis to be above their corresponding significant impact limits), the air dispersion model incorporates both facility-wide (both permitted and grandfathered sources) and marine off-property emissions sources at their post-project, potential emissions rate (PTE). For facility sources, the appropriate emissions rate depends upon the averaging period. For short-term averaging periods (1-hour, 8-hour, or 24-hour), the model

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[8] Air Quality Modeling Procedures, Air Quality Assessment Division, LDEQ, August 2006, Section 2.1.1.

includes the maximum, hourly PTE. For annual averaging periods, the model includes the average annual PTE.

The expected, post-project ambient concentration will be compared to the NAAQS. Initially, the total modeled ambient concentration is the appropriate ground-level concentration from the NAAQS model added to the background concentration for the facility. Additional information on background concentration is presented in Section 2.4. For annual averaging periods, the maximum GLC will be used for the model concentration in the NAAQS analysis. For short-term averaging periods, the appropriate GLC depends upon the pollutant under review.

If the expected ambient concentration is less than the applicable NAAQS, the proposed project does not cause or contribute to an exceedance of the NAAQS and, therefore, no further analysis is required. If the expected ambient concentration is greater than or equal to the NAAQS, a culpability analysis will be performed to determine if the contribution from the significant impact analysis is significant at the same time and location of the modeled exceedance.

1.4 BACKGROUND CONCENTRATIONS

Per U.S. EPA guidance, a background concentration for each pollutant must be added to the modeled impacts – to estimate at a maximum, total predicted impact – prior to comparison with the NAAQS. The background concentration includes emissions from non-industrial emission sources (*e.g.*, vehicles, recreational watercraft, etc.), which are not included in the model. However, the background concentration may also include industrial emission sources already accounted for in the inventory. Therefore, adding the background concentration to the modeled concentrations should be conservative since impacts from the inventory sources are included in both the modeled concentration and the background concentration.

SPL proposes to use onsite monitoring data to determine the background concentrations for $PM_{2.5}$ and NO_X. SPL has already completed one year of NO_2 and $PM_{2.5}$ monitoring from December 2011 to November 2012 and has removed the monitoring site because a representative data set for the Sabine Pass LNG Terminal has been collected. Data were collected hourly over the sampling time period (approximately 8,000 data points). The data obtained from this pre-construction ambient monitoring will be used to establish $PM_{2.5}$ and NO_X background concentrations for the required NAAQS analyses.

SPL will use the NO_2 and $PM_{2.5}$ background concentrations as recorded from the onsite ambient monitors from December 2011 to November 2012. As per the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD),"

> *The current monitor location can represent the combined impact of proposed source and existing sources. If the proposed construction will be in an area of multisource emissions and flat terrain, then the proposed source or modification may propose to use existing data at nearby monitoring sites if either of the following criteria is met.*
>
> - *Existing monitor within 10 km of the points of proposed emissions, or*
> - *Existing monitor is within or not farther than 1 km away from either the areas of the maximum air pollutant concentration from existing sources or the areas of the combined maximum impact from existing and proposed sources.*
>
> *If the existing monitors meets either of the above two conditions then the data could be used together with model estimates to determine concentrations.*

For all pollutants less than full year will be accepted if the applicant can demonstrate (through historic data or modeling) that data is obtained during a time period when maximum air quality levels can be expected. Minimum 4 months of air quality data required.

The rationale for considering the use of existing data collected from monitors satisfying the above criteria is that modelers have reasonable degree of confidence in the modeling results within 10 km distance and maximum concentration from most sources are likely to occur within this distance.

SPL proposes to use data from a representative monitoring site for other pollutants. Table 1-1 lists the proposed ambient monitors as representative for the facility. To select the monitors, SPL considered the surrounding area, the availability of data, and the proximity to the Sabine Pass LNG Terminal.

Table 1-1. Proposed Monitors

Monitoring Site	Parameter Monitored	Monitor Location	Distance of Monitor from Facility (km)	Monitoring Data Meets EPA QA Criteria? (Yes/No)
Nederland High School C1035	CO	Nederland, Texas	28.87	Yes
Port Arthur West C28/A128/A228	SO_2	Port Arthur, Texas	19.67	Yes
Port Allen (PA)	PM_{10}	Port Allen, Louisiana	265.7	Yes

1.5 CULPABILITY ANALYSIS

A source is not considered to have caused or contributed to the violation if its own impact from the modeling significance analysis is not significant (i.e., is less than the SIL) at the violating receptor at the time of the predicted violation. If a culpability analysis is required for modeled exceedances, SPL will determine culpability.

If the maximum contribution from the significance analysis is less than the significance level at any receptor(s) and time(s) of the potential NAAQS exceedance(s), the proposed project will not cause or contribute to the potential NAAQS exceedance(s). If this is the case, no further analysis is required.

2. MODEL SELECTION AND INPUTS

This modeling protocol proposes certain dispersion models and input parameters for approval by LDEQ. Section 2.1 describes the potential computer models for the analysis. Section 2.2 describes the meteorological data. Section 2.3 describes the land use of the area surrounding the facility. Section 2.4 describes the topography of the area surrounding the facility. Section 2.5 describes the stack height analysis. Section 2.6 describes the building wake (downwash) analysis. Section 2.7 describes the receptor grids. Section 2.8 describes the proposed emission rates and averaging periods for the modeling analysis. Section 2.9 describes the default source parameters used in the analysis, if applicable.

2.1 DISPERSION MODEL SELECTION

The American Meteorological Society / Environmental Protection Agency Regulatory Model (AERMOD) is the Guideline-recommended model for evaluating near-field impacts (i.e., source receptor distances of less than 50 km). The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERMET, the meteorological preprocessor; and AERMOD, the control module and modeling processor. Additionally, a fourth processor, the AERSURFACE tool, is used to estimate surface characteristics required for input to AERMET. The most recent versions of each processor will be used: for AERMOD, version 12345; for AERMET, version 12345; for AERMAP, version 11103; and for AERSURFACE, version 13016.

2.2 METEOROLOGICAL DATA

The EPA AERMOD program requires meteorological data preprocessed with the AERMET program. Three additional variables are considered when preprocessing the surface and meteorological data for a site. These variables are:

- Surface roughness;
- Albedo; and
- Bowen Ratio.

The EPA has developed a software program called AERSURFACE that can be used to determine realistic and reproducible surface characteristics values, including Albedo, Bowen Ratio, and Surface roughness parameters. AERSURFACE requires the input of land cover data from the United States Geological Survey (USGS) National Land Cover Data 1992 archives (NLCD92), which it uses to determine the values of surface characteristics based on the land cover type for the study area. AERSURFACE will be used to determine the surface characteristics values for the area surrounding the NWS station for input to AERMET. Modeling will be performed using preprocessed hourly surface data and upper air station data from the NWS Station at the Lake Charles Regional Airport (NWS Station 03937). That data will be processed in AERMET using the surface characteristics values generated by AERSURFACE. If the appropriate input data are available allowing the accurate use of AERMINUTE, AERMINUTE will be used. If more accurate results are expected using AERMET without AERMINUTE (e.g., if AERMINUTE input data do not meet availability or accuracy criteria), then only AERMET will be used.

2.3 LAND USE

SPL's Sabine Pass LNG Terminal is located in Cameron Parish, Louisiana. An Auer Land Use analysis[9] for a 3-kilometer radius surrounding the facility was performed in conjunction with the June 2012 and prior modeling analyses. Consistent with previous analyses, the land within a 3-kilometer radius of the facility is predominately rural. The results of the Land Use Analysis are presented below in Table 2-1.

Table 2-1. Land Use Analysis Results

Auer's Land Type	Classification	Percent
I1 – Heavy Industrial	Urban	4.67
I2 – Light Industrial	Urban	2.05
C1 - Commercial	Urban	0.59
R1 – Common Residential	Urban	0
A1 – Metropolitan Natural	Rural	0.76
A3 – Undeveloped Rural	Rural	69.13
A5 – Water Surfaces	Rural	22.79
Total Urban	**--**	**26.96**
Total Rural	**--**	**73.04**

2.4 TOPOGRAPHY

The terrain elevation for each modeled building, source, and receptor will be determined using USGS National Elevation Data set (NED). The terrain height for each modeled receptor will be calculated using AERMAP (version 11103), a terrain preprocessor developed specifically for the AERMOD model. AERMAP computes the terrain height and hill height scale from the digital terrain elevations surrounding the modeled receptors. AERMAP also computes the terrain height for modeled sources and buildings. AERMAP is used to search for the terrain height and location that has the greatest influence on dispersion for an individual receptor. Input to AERMAP consists of USGS Digital Elevation Model (DEM) data.

2.5 GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT

A good engineering practice (GEP) stack height evaluation determines if avoidance of building wake effects allow a point source to be modeled at a height greater than 65 meters. The GEP formula stack height is expressed as the greater of 65 meters or GEP = $H_b + 1.5L$ (where H_b is the building height, and L is the lesser of the building's height or maximum projected width). These procedures follow EPA Guidelines for Determination of Good Engineering Practice Stack Height.[10]

For stacks in the NAAQS Inventory that have a stack height greater than 65 meters, SPL will model these stack heights at 65 meters.

[9] Auer, Jr., A.H., 1978. "Correlation of Land Use and Cover with Meteorological Anomalies." Journal of Applied Meteorology, 17:636-643.

[10] EPA, Guideline for Determination of Good Stack height (Technical Support Document for the Stack Height Regulations) (Revised), 1985.

2.6 BUILDING WAKE (DOWNWASH) EFFECTS

The emissions sources at the Sabine Pass LNG Terminal will be evaluated in terms of their proximity to nearby structures. The purpose of this evaluation is to determine if stack discharges may become caught in the turbulent wakes generated by these structures. AERMOD incorporates the Plume Rise Model Enhancements (PRIME) algorithms for estimating enhanced plume growth and restricted plume rise for plumes affected by building wakes.[11]

Direction-specific structure dimensions and the dominant downwash structure parameters used as input to AERMOD will be determined using the BREEZE® Building Profile Input Program – PRIME Model (BPIPPRM) software, developed by Trinity Consultants, Inc. The software incorporates the algorithms of the U.S. EPA's sanctioned BREEZE® BPIP PRIME (BPIPPRM), version 04274.[12]

The output from the BPIPPRM downwash analysis lists the names and dimensions of the structures generating wake effects and the locations and heights of the affected emissions sources (i.e., stacks). In addition, the output contains a summary of the dominant structure for each emissions source (considering all wind directions) and the actual structure height and projected widths for all wind directions. This information will be incorporated into the AERMOD data input files.

2.7 RECEPTOR GRID

The receptor grids used in the preliminary modeling analysis will follow available U.S. EPA guidance. For the modeling analysis, SPL is proposing to use a Cartesian receptor grid to locate off-property, ground-level concentrations. Note that the AOI will not extend greater than 50 kilometers from the facility due to accuracy constraints of the dispersion models. For NAAQS modeling, the results will be compared to the appropriate NAAQS on a receptor grid near the facility according to and consistent with available U.S. EPA guidance.

2.8 EMISSION RATES

The modeled emission rates for the Significance Modeling Analysis are the net emissions increase, as presented in the Netting Analysis of the permit application.

For the NAAQS analysis, the modeled emission rates are the potential emission rates (PTE). For short-term averaging periods, the modeled emission rates are the hourly maximum PTE. For the annual averaging period, the modeled emission rates are the average annual PTE.

SPL's insignificant and/or GCXVII activity emissions will be included in the modeling scenarios according to U.S. EPA guidance for the particular pollutant and averaging period.

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[11] L.L. Schulman, D.G. Strimaitis, and J.S. Scire, Development and Evaluation of the Prime Plume Rise and Building Downwash Model, *AWMA*, 50:378-390, 2000.

[12] U.S. Environmental Protection Agency, *User's Guide to the Building Profile Input Program*, Research Triangle Park, NC, EPA-454/R-93-038.

2.9 SOURCE PARAMETERS

Please note that SPL is still in the planning stages of this air quality analysis; therefore, source parameters have not been included in this protocol. The final modeling report will provide all modeled source parameters and emissions rates.

For missing or unavailable data, SPL will use the following source parameters as outlined in LDEQ's *AQMP* or provide documentation to the LDEQ for use of parameters from comparable equipment:

- Default height is 3.28 feet (1 meter);
- Default exit temperature is -459.67 °F (0 Kelvin);
- Default exit velocity is 0.00328 feet per second (0.001 meters per second); and
- Default diameter is 3.28 feet (1 meter, not applicable to flares).

For horizontal releases, if any, SPL will use the following source parameters as outlined in LDEQ's *AQMP* or provide documentation to the LDEQ for use of parameters from comparable equipment:

- Model height is lesser of actual or GEP stack height;
- Model temperature is actual stack temperature;
- Model velocity is 0.00328-feet-per-second (0.001-meters-per-second); and
- Model diameter is 3.28-feet (or 1-meter).

For downward releases, if any, SPL will conservatively assume that the stack parameters are the same as that for horizontal releases in order to avoid attributing momentum or buoyancy effects to the plume.

For stacks that are inclined at an angle of 45° from vertical, if any, the stack velocity is considered to be equal to the vertical velocity component. The vertical velocity component is calculated by multiplying the actual stack velocity by cosine of the offset angle (45°) from the vertical.

The stack parameters for stacks that are inclined at an angle of 45° will be the following:

- Model height is lesser of actual or GEP stack height;
- Model temperature is actual stack temperature;
- Model velocity is the vertical velocity component; and
- Model diameter is actual stack diameter.

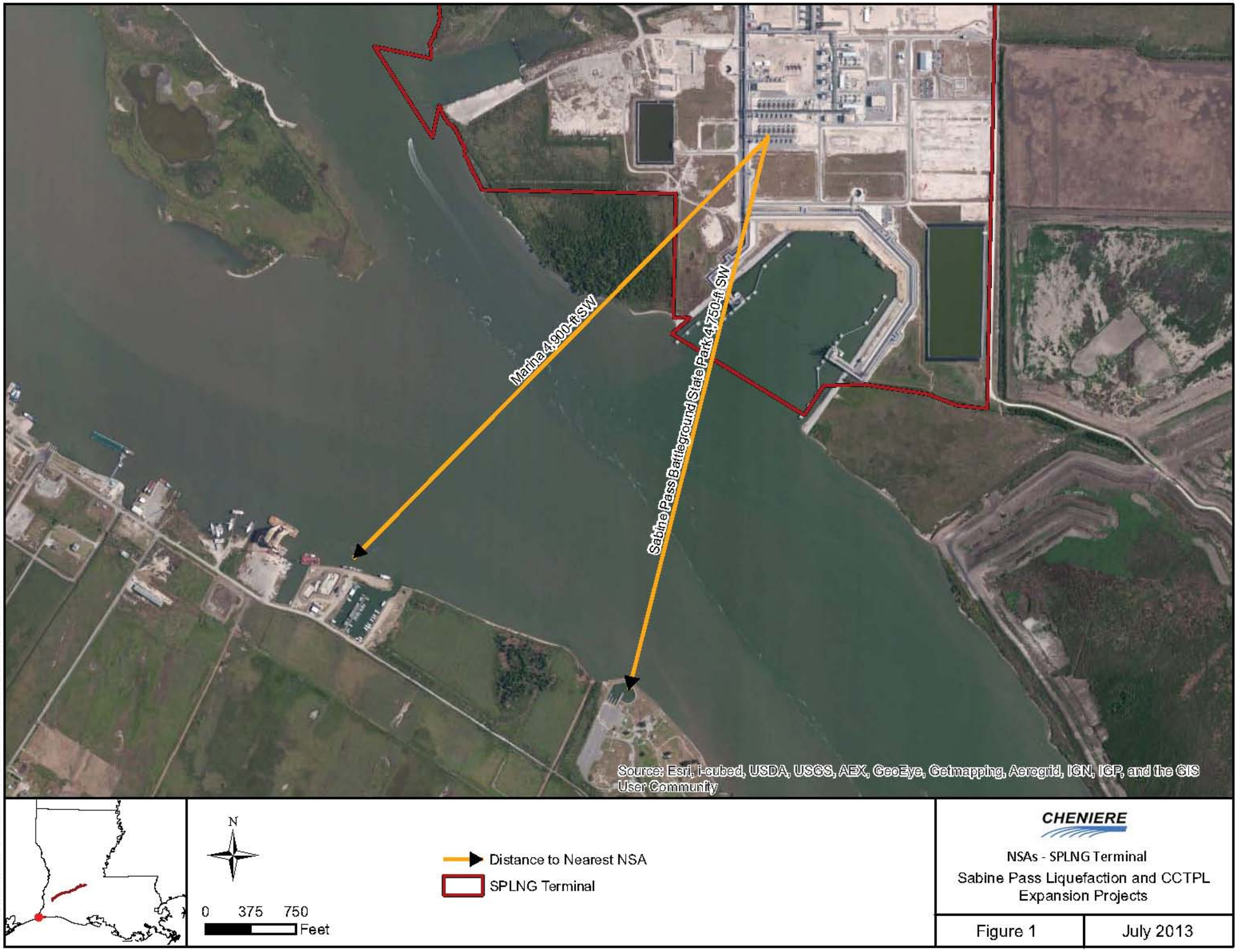
3. MODELING REPORT CONTENTS

A document that details the modeling methodology and summarizes the modeling results will be submitted to the FERC. The air dispersion modeling report will include the following information:

- Brief overview of the proposed project;
- Facility plot plan indicating sources, property line, clear scale, and true north;
- Emissions rate summary for all facility sources, with units consistent with modeling;
- Stack parameter summary for all facility sources, with units consistent with modeling;
- Approved modeling protocol;
- Technical basis for any nonstandard procedures;
- Summary of all model inputs (e.g., model used, met data, rural or urban dispersion coefficients, etc.); and
- Comparison of all modeling results to the applicable standards.

APPENDIX 9D

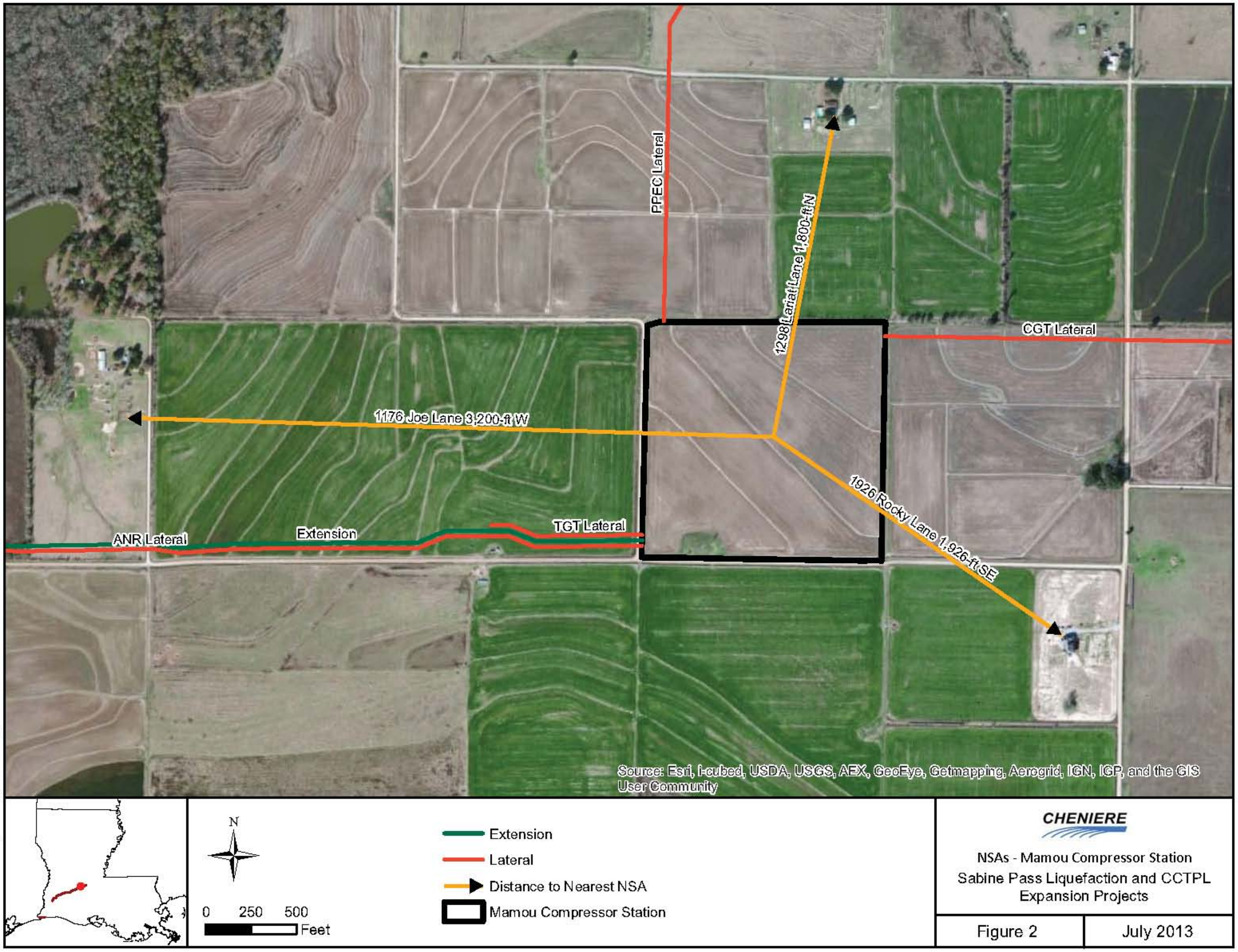
Noise Sensitive Areas



NSAs - SPLNG Terminal

Sabine Pass Liquefaction and CCTPL Expansion Projects

Figure 1 | July 2013


PPEC Lateral
1298 Lariat Lane 1,800-ft N
CGT Lateral
1176 Joe Lane 3,200-ft W
1926 Rocky Lane 1,926-ft SE
TGT Lateral
ANR Lateral
Extension
Source: Esri, i-cubed, USDA, USGS, AEX, GeoEye, Getmapping, Aerogrid, IGN, IGP, and the GIS User Community
N
0 250 500
Feet
Extension
Lateral
Distance to Nearest NSA
Mamou Compressor Station
CHENIERE
NSAs - Mamou Compressor Station
Sabine Pass Liquefaction and CCTPL
Expansion Projects
Figure 2
July 2013

PSD and Title V Permitting Guidance for Greenhouse Gases

EPA-457/B-11-001
March 2011

PSD and Title V Permitting Guidance for Greenhouse Gases

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Policy Division
Research Triangle Park, NC

Disclaimer

This document explains the requirements of EPA regulations, describes EPA policies, and recommends procedures for permitting authorities to use to ensure that permitting decisions are consistent with applicable regulations. This document is not a rule or regulation, and the guidance it contains may not apply to a particular situation based upon the individual facts and circumstances. This guidance does not change or substitute for any law, regulation, or any other legally binding requirement and is not legally enforceable. The use of non-mandatory language such as "guidance," "recommend," "may," "should," and "can," is intended to describe EPA policies and recommendations. Mandatory terminology such as "must" and "required" are intended to describe controlling requirements under the terms of the Clean Air Act and EPA regulations, but this document does not establish legally binding requirements in and of itself.

Table of Contents

List of Appendices

I. Introduction

EPA is issuing this guidance document to assist permit writers and permit applicants in addressing the prevention of significant deterioration (PSD) and title V permitting requirements[1] for greenhouse gases (GHGs) that begin to apply on January 2, 2011. This document: (1) describes, in general terms and through examples, the requirements of the PSD and title V permit regulations; (2) reiterates and emphasizes relevant past EPA guidance on the PSD and title V review processes for other regulated air pollutants;[2] and (3) provides additional recommendations and suggested methods for meeting the permitting requirements for GHGs, which are illustrated in many cases by examples. We believe this guidance is necessary to respond to inquiries from permitting authorities and other stakeholders regarding how these permitting programs will apply to greenhouse gas (GHG) emissions.

This document is organized into sections with supporting appendices. Section I describes the purpose of this document, describes the actions that led to the permitting of sources of GHGs, and provides a general background for the permitting of major stationary sources. Section II describes PSD applicability criteria and how to determine if a proposed new or modified stationary source is required to obtain a PSD permit for GHGs. Section III discusses the process that EPA recommends following to determine best available control technology (BACT) for GHGs for new sources and modified emissions units. Section IV discusses how other PSD permitting requirements are generally inapplicable or have limited relevance to GHGs. Section V describes considerations for permitting of GHGs under title V of the Clean Air Act (CAA or Act). The appendices located at the end of this document include PSD applicability flowcharts for new and modified sources of GHGs, an example PSD applicability analysis for a modified source, example BACT analyses, compilations of resources for estimating emissions of GHGs and for finding control measures for sources of GHGs, and cost effectiveness calculation methodology.

EPA initially issued this GHG permitting guidance in November 2010. This version reflects a limited number of clarifying edits to the November 2010 guidance and replaces it.

[1] Such requirements are reflected in provisions of the Clean Air Act, EPA rules, and approved State Implementation Plans. See 75 FR 17004 (Apr. 2, 2010).

[2] Collections of past EPA guidance on the PSD and title V review processes include:

- EPA websites listing some existing guidance documents for NSR (including PSD) (http://www.epa.gov/nsr/guidance.html) and title V (http://www.epa.gov/ttn/oarpg/t5pgm.html);
- Environmental Appeals Board (EAB) decisions on PSD permitting (http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/PSD+Permit+Appeals+(CAA)?OpenView) and title V permitting (http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Title+V+Permit+Appeals?OpenView); and
- EPA Region 7's online searchable database of many PSD and title V guidance documents issued by EPA headquarters offices and EPA Regions (http://www.epa.gov/region07/air/policy/search.htm).

Most of the EPA documents cited in this document can be found in one of these locations. To the extent this guidance relies on a document that is not located in one of the above collections, we have attempted to provide a website link or other relevant information to help locate the document.

Relevant Background

New major stationary sources and major modifications at existing major stationary sources are required by the CAA to, among other things, obtain an air pollution permit before commencing construction. This permitting process for major stationary sources is called new source review (NSR) and is required whether the major source or major modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where the NAAQS have not been exceeded (attainment and unclassifiable areas). In general, permits for sources in attainment areas and for other pollutants regulated under the major source program are referred to as prevention of significant deterioration (PSD) permits, while permits for major sources emitting nonattainment pollutants and located in nonattainment areas are referred to as nonattainment NSR (NNSR) permits. The entire preconstruction permitting program, including both the PSD and NNSR permitting programs, is referred to as the NSR program. Since EPA has not established a NAAQS for GHGs, the nonattainment component of the NSR program does not apply. Thus, the NSR portions of this guidance focus on the PSD requirements that apply once GHGs become a regulated NSR pollutant.

Major stationary sources and certain other sources are also required by the CAA to obtain title V operating permits. While title V permits generally do not establish new emissions limits, they consolidate requirements under the CAA, including applicable GHG requirements, into a comprehensive air permit.

Over the past year, EPA has taken several actions regarding GHGs under the CAA. The result of these EPA actions, explained in more detail below, is that certain PSD permits and certain title V permits issued on or after January 2, 2011, must address emissions of GHGs. These actions included new rules that established a common sense approach to phase in permitting requirements for GHG emissions from stationary sources, beginning with large industrial sources that are already subject to PSD and title V permitting requirements.

On December 15, 2009, EPA found that elevated atmospheric concentrations of six well-mixed GHGs, taken in combination, endanger both public health and welfare (“the endangerment finding”), and that the combined emissions of these GHGs from new motor vehicles cause and contribute to the air pollution that endangers public health and welfare (“the cause and contribute finding”).[3] These findings did not themselves impose any requirements to control GHG emissions, but they were a prerequisite to finalizing GHG standards for vehicles under title II of the Act. Thereafter, on May 7, 2010, EPA issued a final rule – the Light-Duty Vehicle Rule (LDVR) – establishing national GHG emissions standards for vehicles under the CAA.[4] The new LDVR standards apply to new passenger cars, light-duty trucks, and medium-duty passenger vehicles, starting with model year 2012.

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[3] 74 FR 66496 (Dec. 15, 2009).
[4] 75 FR 25324 (May 7, 2010). As part of this joint rulemaking, the Department of Transportation’s National Highway Traffic Safety Administration (NHTSA) issued Corporate Average Fuel Economy (CAFE) standards for these vehicles under the Energy Policy and Conservation Act, as amended.

For stationary sources, on March 29, 2010, EPA made a final decision to continue applying (with one refinement) the Agency's existing interpretation regarding when a pollutant becomes "subject to regulation" under the Act, and thus covered under the PSD and title V permitting programs applicable to such sources. EPA published notice of this decision on April 2, 2010.[5] Under EPA's final interpretation, a pollutant becomes "subject to regulation" on the date that a requirement in the CAA or a rule adopted by EPA under the Act to actually control emissions of that pollutant "takes effect" or becomes applicable to the regulated activity (rather than upon promulgation or the legal effective date of the rule containing such a requirement). EPA's April 2, 2010 notice also explained that, based on the anticipated promulgation of the LDVR, the GHG requirements of the LDVR would take effect on January 2, 2011, if the LDVR was finalized as proposed for model year 2012 vehicles. Thus, under EPA's interpretation of the Act and applicable rules, construction permits issued[6] under the PSD program on or after January 2, 2011, must contain conditions addressing GHG emissions.

With respect to title V operating permits, the April 2, 2010 notice reiterated EPA's interpretation that the 100 tons per year (TPY) major source threshold for title V operating permits is triggered only by pollutants "subject to regulation" under the Act. EPA also explained that the Agency interprets "subject to regulation" for title V purposes in the same way it interprets that term for PSD purposes (*i.e.,* a pollutant is subject to regulation when an actual control requirement under the Act takes effect).

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of the PSD and title V programs to enable EPA and states to phase in permitting requirements for GHGs in a common sense manner ("Tailoring Rule").[7] The Tailoring Rule focuses on first applying the CAA permitting requirements for GHG emissions to the largest sources with the most CAA permitting experience. Under the Tailoring Rule, facilities responsible for nearly 70 percent of the national GHG emissions from stationary sources are subject to permitting requirements beginning in 2011, including the nation's largest GHG emitters (*i.e.,* power plants, refineries, and cement production facilities). Emissions from small farms, churches, restaurants,

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[5] 75 FR 17004 (April 2, 2010).

[6] Consistent with its regulations in 40 CFR Part 124, EPA uses the term "issued" to describe the time when a permitting authority issues a PSD permit after public comment on a draft permit or preliminary determination to issue a PSD permit. Depending on the applicable administrative procedures, the date a permit is issued is not necessarily the same as the date the permit becomes effective or final agency action for purposes of judicial review. Under EPA's procedural regulations, a permit is "issued" when the Regional Office makes a final decision to grant the application, not when the permit becomes effective or final agency action. 40 CFR 124.15; 40 CFR 124.19(f). EPA generally applies the requirements in effect at the time a permit is issued by a Regional office unless the Agency has expressed an intent when adopting a new requirement that the requirement apply to permits that were issued earlier but not yet effective or final agency action by the time the new requirement takes effect. *In re: Dominion Energy Brayton Point, L.L.C.*, 12 E.A.D. 490, 616 (EAB 2006). In its actions discussing the January 2, 2011 date when GHGs will become a regulated NSR pollutant, EPA did not indicate that GHG requirements should apply to any permits issued before January 2, 2011. Thus, EPA does not intend to require PSD permits that are issued (as described in 40 CFR 124.15) prior to January 2, 2011 to address GHGs, even if the permit is not effective until after January 2, 2011 by virtue of a delayed effective date or an appeal to the Environmental Appeals Board. See, 40 CFR 124.15(b); 40 CFR 124.19(f). A similar approach may be appropriate in states with approved PSD programs that have analogous administrative procedures.

[7] 75 FR 31514 (June 3, 2010).

and small commercial facilities are examples of source types that are not likely to be covered by these programs under the Tailoring Rule. The rule then expands to cover the largest sources of GHGs that may not have been previously covered by the CAA for other pollutants.

As discussed in detail below, under the Tailoring Rule, application of PSD to GHGs will be implemented in multiple steps, which we refer to in this document as "Tailoring Rule Steps" to avoid confusion with the five steps for implementing the "top down" best available control technology (BACT) analysis and the two steps of the applicability procedures for modifications. The first Tailoring Rule step begins on January 2, 2011, and ends on June 30, 2011, and this step covers what EPA has called "anyway sources" and "anyway modifications" that would be subject to PSD "anyway" based on emissions of pollutants other than GHGs. The second step begins on July 1, 2011, and continues thereafter to cover both anyway sources and certain other large emitters of GHGs. EPA has committed to completing another rulemaking no later than July 1, 2012, to solicit comments on whether to take a third step of the implementation process to apply the permitting programs to additional sources. EPA has also committed to undertaking another rulemaking after 2012. Sources subject to the permitting programs under the first two steps will remain subject to these programs through any future steps. Future steps are not discussed further in this guidance document, since the outcomes of those rulemaking efforts are not yet known. Under the Tailoring Rule, in no event are sources with a potential to emit (PTE) less than 50,000 TPY of CO_2 equivalent (CO_2e) subject to PSD or title V permitting for GHG emissions before 2016. For additional information regarding the steps of the PSD and title V implementation processes for GHGs, please refer to the preamble of the Tailoring Rule.[8]

This guidance does not reiterate all the provisions of the Tailoring Rule or other EPA rules; rather, it takes the applicable provisions and lays them out in a way designed to explain and simplify the procedures for applicants and other stakeholders going through the PSD and title V permitting processes. Should there be any inconsistency between this document and the rules, the rules shall govern.

The fundamental aspects of the PSD and title V permitting programs are generally not affected by the integration of GHGs into these programs. Therefore, this document does not elaborate on topics such as public notice requirements, aggregation of related physical or operational changes, the definition of a stationary source, debottlenecking, treatment of fugitive emissions, determining creditable emissions reductions, or routine maintenance, repair and replacement. Readers that are interested in understanding these aspects of the federal program should rely on current EPA rules and guidance when permitting GHGs.

EPA Regional Offices should apply the policies and practices reflected in this document when issuing permits under the federal PSD and title V permitting programs, unless the facts and the record in an individual case demonstrate grounds to approach the subjects discussed in a different manner. State, local and tribal permitting authorities that issue permits under a delegation of federal authority from EPA Regional Offices should do likewise. EPA also recommends that permitting authorities with approved PSD or title V permit programs apply the guidance reflected in this document, but these permitting authorities have the discretion to apply alternative approaches that comply with state and/or local laws and the requirements of the CAA

[8] 75 FR at 31522-525.

and approved state, local or tribal programs. As is always the case, permitting authorities have the discretion to establish requirements in their permits that are more stringent than those suggested in this guidance or prescribed by EPA regulations.[9]

[9] 42 USC 7416.

II. PSD Applicability

General Concepts

Under the CAA, new major stationary sources of certain air pollutants, defined as "regulated NSR pollutants," and major modifications to existing major sources are required to, among other things, obtain a PSD permit prior to construction or major modification. We refer to the set of requirements that determine which sources and modifications are subject to PSD as the "applicability" requirements. Once major sources become subject to PSD, these sources must, in order to obtain a PSD permit, meet the various PSD requirements. For example, they must apply BACT, demonstrate compliance with air quality related values and PSD increments, address impacts on special Class I areas (*e.g.,* some national parks and wilderness areas), and assess impacts on soils, vegetation, and visibility. These PSD requirements are the subject of Sections III and IV of this document.

In this section, we discuss how the CAA and relevant EPA regulations describe the PSD applicability requirements. The CAA applies the PSD requirements to any "major emitting facility" that constructs (if the facility is new) or undertakes a modification (if the facility is an existing source).[10] The term "major emitting facility" is defined as a stationary source that emits, or has a PTE of, at least 100 TPY, if the source is in one of 28 listed source categories, or, if the source is not, then at least 250 TPY, of "any air pollutant."[11] For existing facilities, the CAA adds a definition of modification, which, in general, is any physical or operational change that "increases the amount" of any air pollutant emitted by the source.[12]

EPA's regulations implement these PSD applicability requirements through use of different terminology, and, in the case of GHGs, with additional limitations. Specifically, the regulations apply the PSD requirements to any major stationary source that begins actual construction[13] (if the source is new) or that undertakes a major modification (if the source is existing).[14] The term major stationary source is defined as a stationary source that emits, or has a PTE of, at least 100 TPY if the source is in one of 28 listed source categories, or, if the source is not, then at least 250 TPY, of regulated NSR pollutants.[15] We refer to these 100- or 250-TPY amounts as the major source limits or thresholds.

A major modification is defined as "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase [ ] of a regulated NSR pollutant [ ]; and a significant net emissions increase of that pollutant from the major stationary source."[16] EPA rules specify what amount of emissions increase is "significant" for listed regulated NSR pollutants (*e.g.,* 40 TPY for sulfur dioxide, 100 TPY for carbon

[10] 42 USC 7475(a), 7479(1).
[11] 42 USC 7479(1).
[12] 42 USC 7479(1), 7411(a)(4).
[13] 40 CFR 52.21(b)(11).
[14] 40 CFR 52.21(a)(2).
[15] 40 CFR 52.21(b)(1)(i).
[16] 40 CFR 52.21(b)(2)(i) and the term "net emissions increase" as defined at 40 CFR 52.21(b)(3).

monoxide), but for any regulated NSR pollutant that is not listed in the regulations, any increase is significant.[17]

A pollutant is a "regulated NSR pollutant" if it meets at least one of four requirements, which are, in general, any pollutant for which EPA has promulgated a NAAQS or a new source performance standard (NSPS), certain ozone depleting substances, and "[a]ny pollutant that otherwise is subject to regulation under the Act."[18] PSD applies on a regulated-NSR-pollutant-by-regulated-NSR-pollutant basis. The PSD requirements do not apply to regulated NSR pollutants for which the area is designated as nonattainment. Further, some modifications are exempt from PSD review (*e.g.,* routine maintenance, repair and replacement).[19]

For proposed modifications at existing major sources, PSD applies to each regulated NSR pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase. This is true even if the increased pollutant is different than the pollutant for which the source is major. Thus, the regulations quoted above require a two-step applicability process for modifications. Step 1 involves determining if the modification by itself results in a significant increase. No emissions decreases are considered in Step 1.[20] If there is no significant increase in Step 1, then PSD does not apply. If there is a significant increase in Step 1, then Step 2 applies, which involves determining if the modification results in a significant net emissions increase. The Step 2 calculation includes creditable emissions increases and decreases from the modification by itself and also includes creditable emissions increases and decreases at the existing source over a "contemporaneous period." This period is defined in the federal regulations as the period that extends back 5 years prior to the date that construction commences on the modification and forward to the date that the increase from the modification occurs.

To determine PSD applicability of an existing stationary source, an owner or operator may use one of two tests to determine the emissions increase from an existing emissions unit: the actual-to-projected-actual" emissions test or the "actual-to-potential" emissions test.[21] If the emissions unit at an existing source is new, the owner or operator must use the "actual-to-potential" emissions test to calculate emissions increases. Also, the "baseline actual emissions" for existing emissions units are generally the actual emissions in TPY from the unit for any consecutive 24-month period (selected by the applicant) in the prior 10 years, or 5 years if the source is an Electric Generating Unit (EGU).[22] Assuming a source applies the actual-to-projected-actual applicability test for its modifications, it should be noted that some projects that sources undertake to improve the energy or process efficiency of their operations may not be subject to PSD review. This is because the increased efficiency of the project can translate into less raw material and/or fuel consumption for the same amount of output of product. Consequently, as long as the output from the affected unit(s) is not reasonably expected to increase, the projected actual annual emissions for all of the pollutants emitted from the process

[17] 40 CFR 52.21(b)(23)(i)-(ii).
[18] 40 CFR 52.21(b)(50).
[19] 40 CFR 52.21(b)(2)(iii).
[20] Letter from Barbara A. Finazzo, Region II, to Kathleen Antoine, HOVENZA LLC (March 30, 2010).
[21] 40 CFR 52.21(b)(41).
[22] 40 CFR 52.21(b)(48).

is likely be less than the baseline actual emissions, resulting in a no emission increase for the change in emissions of the pollutants using the actual-to-projected-actual applicability test.[23] Of course, other factors must be considered as well when calculating the projected actual annual emissions resulting from a modification (*e.g.,* whether the projected actual emissions increase could have been accommodated at the changed emissions unit(s) and is also unrelated to the particular project). These and other factors may influence whether a modification involving an energy or process efficiency improvement is subject to PSD.

Before beginning actual construction, a source may limit its PTE to avoid application of the PSD permitting program. To appropriately limit PTE, a source's permit must contain a production or operational limitation in addition to the unit-specific emissions limitation in cases where the emissions limitation does not reflect the maximum emissions of the source operating at full design capacity. Restrictions on production or operation that limit a source's PTE include limitations on quantities of raw materials consumed, fuel combusted, hours of operation, or conditions which specify that the source must install, operate, and maintain controls that reduce emissions to a specified emission rate or to a specified control efficiency. Production and operational limits must be stated as conditions that can be enforced independently of one another. For example, restrictions on fuel that relate to both type and amount of fuel combusted should state each as an independent condition in the permit. This is necessary to make the PTE restrictions enforceable as a practical matter.[24]

As an alternative applicability procedure, applicants may secure an enforceable plantwide applicability limit (PAL) in TPY at existing major stationary sources for one or more regulated NSR pollutants prior to any modification.[25] Once properly established in the source's permit, subsequent modifications to existing emissions units, or the addition of new emissions units, are not subject to PSD for the PAL pollutant if the emissions of all emissions units under the PAL remain below the PAL limit and all other PAL requirements are met.

GHG-Specific Considerations

Beginning on January 2, 2011, GHGs are a regulated NSR pollutant under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time. For PSD purposes, GHGs are a single air pollutant defined[26] as the aggregate group of the following six gases:

- carbon dioxide (CO_2)
- nitrous oxide (N_2O)
- methane (CH_4)
- hydrofluorocarbons (HFCs)

[23] The source must be able to substantiate its projections, and if it fails to do so or if it fails to operate its unit in accordance with their projection, PSD may apply.
[24] *See, generally,* EPA Guidance on Limiting Potential to Emit (PTE) in New Source Permitting (June 13, 1989), available at http://www.epa.gov/reg3artd/permitting/t5_epa_guidance.htm.
[25] 40 CFR 52.21(a)(2)(v), (b)(2)(iv) and (aa)(1)(ii).
[26] 40 CFR 52.21(b)(49)(i).

- perfluorocarbons (PFCs)
- sulfur hexafluoride (SF_6)

Specifically, in Tailoring Rule Step 1, beginning on January 2, 2011, and continuing through June 30, 2011, GHGs that are emitted in at least specified threshold amounts from a new source that is subject to PSD anyway, due to emissions of another regulated NSR pollutant, are subject to regulation and therefore a regulated NSR pollutant from that source. By the same token, when an existing major source undertakes a physical or operational change that would be subject to PSD anyway due to emissions of another regulated NSR pollutant and increases its emissions of GHGs by at least the specified threshold amounts, the GHGs are treated as subject to regulation and therefore as a regulated NSR pollutant from that source. (We call such a modification an "anyway modification.") In Tailoring Rule Step 2, beginning on July 1, 2011, and continuing thereafter, GHGs emitted by anyway sources and anyway modifications remain a regulated NSR pollutant in the same manner as under Step 1. In addition, for new sources that are not anyway sources and for modifications that are not anyway modifications, emissions of GHGs in at least specified threshold amounts are also treated as subject to regulation and therefore as a regulated NSR pollutant.

For GHGs, the Tailoring Rule does not change the basic PSD applicability process for evaluating whether there is a new major source or modification. However, due to the nature of GHGs and their incorporation into the definition of regulated NSR pollutant, the process for determining whether a source is emitting GHGs in an amount that would make the GHGs a regulated NSR pollutant, includes a calculation of, and applicability threshold for, the source based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:[27]

- the sum of the CO_2e emissions in TPY of the six GHGs, in order to determine whether the source's emissions are a regulated NSR pollutant; and, if so

- the sum of the mass emissions in TPY of the six GHGs, in order to determine if there is a major source or major modification of such emissions.

This applicability process is laid out in more detail in Sections II.B through D of this guidance, as well as in flowcharts in Appendices A through D.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). Since GWP values may vary, applicants should use the GWP values in Table A-1 of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A, Table A-1). Note that the GHGRP does not require reporting of all emissions and emission sources that may be subject to a PSD applicability analysis.

[27] As we explained in the Tailoring Rule preamble, while evaluation of the mass-based thresholds is technically the second step in the PSD applicability analysis, we understand that most sources are likely to treat this mass-based evaluation as an initial screen from a practical standpoint, since they would not proceed to calculate emissions on a CO_2e basis if they do not trigger PSD or title V on a mass basis. See 75 FR at 31522.

In the annual US inventory of GHG emissions and sinks, EPA has reported that the Land-Use, Land-Use Change, and Forestry (LULUCF) sector (including those stationary sources using biomass for energy) in the United States is a net carbon sink, taking into account the carbon gains (*e.g.,* terrestrial sequestration) and losses (*e.g.,* emissions or harvesting) from that sector.[28] On the basis of the inventory results and other considerations, numerous stakeholders requested that EPA exclude, either partially or wholly, emissions of GHG from bioenergy and other biogenic sources for the purposes of the BACT analysis and the PSD program based on the view that the biomass used to produce bioenergy feedstocks can also be a carbon sink and, therefore, management of that biomass can play a role in reducing GHGs.[29] EPA plans to provide further guidance on how to consider the unique GHG attributes of biomass as fuel. Specifically, the EPA Administrator recently announced that EPA will complete a rulemaking by July 1, 2011 to defer for three years PSD applicability for biomass and other biogenic CO_2 emissions. The 3-year deferral will give EPA time to examine the science associated with biogenic CO_2 emissions and to consider the technical issues that the Agency must resolve in order to account for biogenic CO_2 emissions for PSD applicability purposes.[30] EPA published the proposed deferral rule on March 21, 2011 (76 FR 15249).

Before this rule becomes final, however, permitting authorities may consider, when carrying out their BACT analyses for GHG, the environmental, energy, and economic benefits that may accrue from the use of certain types of biomass and other biogenic sources (*e.g.,* biogas from landfills) for energy generation, consistent with existing air quality standards. In particular, a variety of federal and state policies have recognized that some types of biomass can be part of a national strategy to reduce dependence on fossil fuels and to reduce emissions of GHGs. Federal and state policies, along with a number of state and regional efforts, are currently under way to foster the expansion of renewable resources and promote biomass as a way of addressing climate change and enhancing forest-management. EPA believes that it is appropriate for permitting authorities to account for both existing federal and state policies and their underlying objectives in evaluating the environmental, energy, and economic benefits of biomass fuel. Based on these considerations, permitting authorities might determine that, with respect to the biomass component of a facility's fuel stream, certain types of biomass by themselves are BACT for GHGs.

To assist permitting authorities further in considering these factors, as well as to provide a measure of national consistency and certainty, in March 2011 EPA issued guidance that provides a suggested framework for undertaking an analysis of the environmental, energy, and economic benefits of biomass in Step 4 of the top-down BACT process, that, as a result, may enable permitting authorities to simplify and streamline BACT determinations with respect to certain types of biomass used in energy generation.[31] The guidance includes qualitative information on useful issues to consider with respect to biomass combustion. While the guidance does not provide a final determination of BACT for a particular source, since such determinations can only be made by individual permitting authorities on a case-by-case basis, EPA believes the

[28] 2010 US Inventory Report at http://epa.gov/climatechange/emissions/usinventoryreport.html.
[29] GHG emissions from bioenergy and other biogenic sources are generated during combustion or decomposition of biologically-based material, and include sources such as utilization of forest or agricultural products for energy, wastewater treatment and livestock management facilities, and fermentation processes for ethanol production.
[30] Letter from Lisa P. Jackson, EPA Administrator, to Senator Max Baucus (January 12, 2011).
[31] http://www.epa.gov/nsr/ghgdocs/bioenergyguidance.pdf

analysis provided in the guidance will be sufficient in most cases, during the interim period until the biomass deferral rulemaking is finalized and incorporated into applicable implementation plans to support the conclusion that utilization of biomass fuel alone is BACT for a bioenergy facility.

A. Calculating GHG Mass-Based and CO_2e-Based Emissions

For any source, since GHG emissions may be a mixture of up to six compounds, the amount of GHG emissions calculated for the PSD applicability analysis is a sum of the compounds emitted at the emissions unit. The following example illustrates the method to calculate GHG emissions on both a mass basis and CO_2e basis.

A proposed emissions unit emits five of the six GHG compounds in the following amounts:

50,000 TPY of CO_2
60 TPY of methane
1 TPY of nitrous oxide
5 TPY of HFC-32 (a hydrofluorocarbon)
3 TPY of PFC-14 (a perfluorocarbon)

The GWP for each of the GHGs used in this example are:

GHG	GWP*
Carbon Dioxide	1
Nitrous Oxide	310
Methane	21
HFC-32	650
PFC-14	6,500

** as of the date of this document (see 40 CFR Part 98, Subpart A, Table A-1)*

The ***GHGs mass-based emissions*** of the unit are calculated as follows:

50,000 TPY + 60 TPY + 1 TPY + 5 TPY + 3TPY = 50,069 TPY of GHGs

The ***CO_2e-based emissions*** of the unit are calculated as follows:

(50,000 TPY x 1) + (60 TPY x 21) + (1 TPY x 310) + (5 TPY x 650) + (3 TPY x 6,500)

= 50,000 + 1,260 + 310 + 3,250 + 19,500 = 74,320 TPY CO_2e

Note: Short tons (2,000 lbs), not long or metric tons, are used in PSD applicability calculations.[32]

[32] Metric tonnes (*i.e.*, 1,000 kg) are used in the GHG reporting rule.

B. PSD Applicability for GHGs - New Sources

1. *Tailoring Rule Step 1 - PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011, to June 30, 2011*

PSD applies to the GHG emissions from a proposed new source if ***both*** of the following are true:[33]

- Not considering its emissions of GHGs, the new source is considered a major source for PSD applicability and is required to obtain a PSD permit (called an "anyway source"), ***and***
- The potential emissions of GHGs from the new source would be equal to or greater than 75,000 TPY on a CO_2e basis.

2. *Tailoring Rule Step 2 - PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011*

PSD applies to the GHG emissions from a proposed new source if ***either*** of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1, ***or***
- The potential emissions of GHGs from the new source would be equal to or greater than 100,000 TPY CO_2e basis ***and*** equal to or greater than the applicable major source threshold (*i.e.,* 100 or 250 TPY, depending on the source category[34]) on a mass basis for GHGs.

In addition, as noted in the Tailoring Rule, if a minor source construction permit is issued to a source before July 1, 2011, and that permit does not contain synthetic minor limitations on GHG emissions, and the source has a PTE of GHG emissions that would trigger PSD on or after July 1, 2011, then the source must either (1) begin actual construction before July 1, 2011, or (2) seek a permit revision to include a minor source limit for the GHG emissions. If neither (1) nor (2) occurs, the source must obtain a PSD permit for GHGs.[35]

The PSD applicability criteria discussed above for new sources are summarized in Table II-A below. Flowcharts for applicability determinations for new sources in each of the two Tailoring Rule steps are presented in Appendices A and B, respectively.

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[33] While the Tailoring Rule specified that potential emissions calculations for GHG applicability determinations would also involve a finding that potential emissions would be equal to or greater than the applicable significant emission rate on a mass basis, in the interest of clarity and simplicity, this guidance does not discuss this requirement with regard to new sources, because the lack of a netting analysis in a new source determination means that any new source that meets the 75,000 TPY CO_2e requirements would automatically exceed the applicable significant emissions rate for GHGs, which is 0 TPY on a mass basis.

[34] 42 USC 7479(1) (providing list of 100 TPY sources).

[35] 75 FR at 31527.

Table II-A. Summary of PSD Applicability Criteria for New Sources of GHGs

Permits issued from January 2, 2011, to June 30, 2011 (Step 1 of the Tailoring Rule)	Permits issued on or after July 1, 2011 (Step 2 of the Tailoring Rule)
PSD applies to GHGs, if: • The source is otherwise subject to PSD (for another regulated NSR pollutant), **and** • The source has a GHG PTE equal to or greater than: o 75,000 TPY CO_2e	**PSD applies to GHGs, if:** • The source is otherwise subject to PSD (for another regulated NSR pollutant), **and** • The source has a GHG PTE equal to or greater than: o 75,000 TPY CO_2e **OR** • Source has a GHG PTE equal to or greater than: o 100,000 TPY CO_2e, **and** o 100/250 TPY mass basis

C. PSD Applicability for GHGs - Modified Sources

1. General Requirements

a. *Tailoring Rule Step 1 - PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011, to June 30, 2011*

PSD applies to the GHG emissions from a proposed modification to an existing major source if ***both*** of the following are true:

- Not considering its emissions of GHGs, the modification would be considered a major modification anyway and therefore would be required to obtain a PSD permit (called an "anyway modification"), ***and***

- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

b. *Tailoring Rule Step 2 - PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011*

PSD applies to the GHG emissions from a proposed modification to an existing source if any of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1.

OR BOTH:

- The existing source's PTE for GHGs is equal to or greater than 100,000 TPY on a CO_2e basis ***and*** is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis,[36] ***and***

- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

OR BOTH:

- The existing source is minor[37] for PSD (including GHGs) before the modification, ***and***

- The actual or potential emissions of GHGs from the modification *alone* would be equal to or greater than 100,000 TPY on a CO_2e basis ***and*** equal to or greater than the applicable major source threshold of 100/250 TPY on a mass basis. Note that minor PSD sources cannot "net" out of PSD review.

The PSD applicability criteria for modified existing sources discussed above are summarized in Table II-B below. Flowcharts for applicability determinations for existing sources in each of the two Tailoring Rule steps are presented in Appendices C and D, respectively.

[36] The mass basis calculation for the amount of GHGs determines whether the GHGs are emitted at the major source level, so that GHGs are considered to be emitted at the major source level if they are emitted in an amount that is equals to or greater than 100/250 TPY (depending on the source category) on a mass basis. In contrast, the CO_2e basis calculation for the amount of GHGs is relevant for determining whether the GHGs are subject to regulation as a regulated NSR pollutant, but not for determining whether GHGs are emitted at the major source level.

[37] A source is considered minor for PSD if it does not emit any regulated NSR pollutants in amounts that equal or exceed 100/250 TPY (depending on the source category).

Table II-B. Summary PSD Applicability Criteria for Modified Sources of GHGs

Permits issued from January 2, 2011, to June 30, 2011 (Step 1 of the Tailoring Rule)	**Permits issued on or after July 1, 2011 (Step 2 of the Tailoring Rule)**
PSD applies to GHGs, if: • Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase: o Equal to or greater than 75,000 TPY CO_2e, **and** o Greater than -0- TPY mass basis,	**PSD applies to GHGs, if:** • Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase: o Equal to or greater than 75,000 TPY CO_2e, **and** o Greater than -0- TPY mass basis **OR BOTH:** • The existing source has a PTE equal to or greater than: o 100,000 TPY CO_2e **and** o 100/250 TPY mass basis • Modification has a GHG emissions increase and net emissions increase: o Equal to or greater than 75,000 TPY CO_2e, **and** o Greater than -0- TPY mass basis **OR BOTH:** • The source is an existing minor source for PSD, **and** • Modification alone has actual or potential GHG emissions equal to or greater than: o 100,000 TPY CO_2e, **and** o 100/250 TPY mass basis

2. Contemporaneous Netting

As noted above, assessing PSD applicability for a modification at an existing major stationary source against the GHG emissions thresholds is a two-step process. Step 1 of the applicability analysis considers only the emissions increases from the proposed modification itself. Step 2 of the applicability analysis, which is often referred to as "contemporaneous netting," considers all creditable emissions increases and decreases (including decreases resulting from the proposed modification) occurring at the source during the "contemporaneous period." The federal "contemporaneous period" for GHG emissions is no different than the federal contemporaneous period for other regulated NSR pollutants, which covers the period beginning 5 years before construction of the proposed modification through the date that the increase from the modification occurs.

It should be noted that both the contemporaneous period and the baseline period will, at least for a while, require reference to emissions prior to the January 2, 2011 date that PSD applies to GHG-emitting sources. That is, because the contemporaneous period includes a five-year "look back," for several years after January 2, 2011, the contemporaneous period for netting of GHG emissions includes periods before January 2, 2011. By the same token, when calculating the "baseline actual emissions" for existing units included in PSD applicability calculations, the selected 24-month time period for determining actual emissions may include time periods that begin before January 2, 2011.

Because PSD applicability for modifications at existing sources requires a two-step analysis, and because, for GHGs, each step requires a mass-based calculation and a CO_2e-based calculation, a total of four applicability conditions must be met in order for modifications involving GHG emissions at existing major sources to be subject to PSD. These four conditions are summarized below.[38]

1) The CO_2e emissions increase resulting from the modification, calculated as the sum of the six GHGs on a CO_2e basis (*i.e.,* with GWPs applied) is equal to or greater than 75,000 TPY CO_2e. No emissions decreases are considered in this calculation (*i.e.,* if the sum of the change in the six GHGs on a CO_2e basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in this calculation to offset increases at other emissions units).

2) The "net emissions increase" of CO_2e over the contemporaneous period is equal to or greater than 75,000 TPY.

3) The GHG emissions increase resulting from the modification, calculated as the sum of the six GHGs on a mass basis (*i.e.,* with no GWPs applied) is greater than zero TPY. No emissions decreases are considered in this calculation (*i.e.,* if the sum of the change in the six GHGs on a mass basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in this calculation to offset increases at other emissions units).

4) The "net emissions increase" of GHGs (on a mass basis) over the contemporaneous period is greater than zero TPY.

Flowcharts of the above four-part PSD applicability test for modified sources of GHGs are presented in Appendices C and D. Appendix E provides a detailed example of the application of the test to a modified existing major source.

[38] In addition, as discussed above, either the modification must be an "anyway" modification or the source must emit, prior to the modification, GHGs in the amount of 100,000 TPY CO_2e and 100/250 TPY mass basis.

III. BACT Analysis

Under the CAA and applicable regulations, a PSD permit must contain emissions limitations based on application of BACT for each regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other PSD regulated pollutant.

The BACT requirement is set forth in section 165(a)(4) of the CAA, in federal regulations at 40 CFR 52.21(j), in rules setting forth the requirements for approval of a state implementation plan (SIP) for a State PSD program at 40 CFR 51.166(j), and in the specific SIPs of the various states at 40 CFR Part 52, Subpart A - Subpart FFF. CAA § 169(3) defines BACT as:

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant….

Each new source or modified emission unit subject to PSD is required to undergo a BACT review.

The CAA and corresponding implementing regulations require that a permitting authority conduct a BACT analysis on a case-by-case basis, and the permitting authority must evaluate the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. Based on this assessment, the permitting authority must establish a numeric emissions limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT through the application of the selected technology or technique. However, if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement.[39]

<u>Top-Down BACT Process</u>

EPA recommends that permitting authorities continue to use the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[40] In brief, the top-down process calls for

[39] 40 CFR 51.166(b)(12); 40 CFR 52.21(b)(12).

[40] The Clean Air Act Advisory Committee (CAAAC) recognized that the top-down framework is the "predominant method for determining BACT" and recommended that permitting authorities continue to use their existing BACT determinations process, such as the top-down framework, in conducting BACT analyses for GHGs. CAAAC, *Interim Phase I Report of the Climate Change Work Group of the Permits, New Source Review and Toxics*

all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.[41]

EPA has broken down this analytical process into the following five steps, which are each discussed in detail later in this section.

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

To illustrate how the analysis proceeds through these steps, assume at Step 1 that the permit applicant and permitting authority identify four control strategies that may be applicable to the particular source under review. At the second step of the process, assume that one of these four options is demonstrated to be technically infeasible for the source and is eliminated from further consideration. The remaining three pollution control options should then be ranked from the most to the least effective at the third step of the process. In the fourth step, the permit applicant and permitting authority should begin by evaluating the energy, environmental, and economic impacts of the top-ranked option. If these considerations do not justify eliminating the top-ranked option, it should be selected as BACT at the fifth step. However, if the energy, environmental, or economic impacts of the top-ranked option demonstrate that this option is not achievable, then the evaluation remains in Step 4 of the process and continues with an examination of the energy, environmental, and economic impacts of the second-ranked option. This Step 4 assessment should continue until an achievable option is identified for each source. The highest-ranked option that cannot be eliminated is selected as BACT at Step 5, which includes the development of an emissions limitation that is achievable by the particular source using the selected control strategy. Thus, the inclusion and evaluation of an option as part of a top-down BACT analysis for a particular source does not necessarily mean that option will ultimately be required as BACT for that source.

Subcommittee (Feb. 3, 2010) at 16 and 18, *available at* http://www.epa.gov/oar/caaac/climate/2010_02_InterimPhaseIReport.pdf.

[41] 1990 Workshop Manual at B.2.

EPA developed the top-down process in order to improve the application of the BACT selection criteria and provide consistency.[42] For over 20 years, EPA has applied and recommended that permitting authorities apply the top-down approach to ensure compliance with the BACT criteria in the CAA and applicable regulations. EPA Regional Offices that implement the federal PSD program (through Federal Implementation Plans (FIPs)) and state permitting authorities that implement the federal program through a delegation of federal authority from an EPA Regional Office should apply the top-down BACT process in accordance with EPA policies and interpretations articulated in this document and others that are referenced. However, EPA has not established the top-down BACT process as a binding requirement through rule.[43] Thus, permitting authorities that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue, including BACT for GHGs, so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements.[44] EPA does not require states to apply the top-down process in order to obtain EPA approval of a PSD program, but EPA regulations do require that each state program apply the applicable criteria in the definition of BACT.[45] Furthermore, EPA has certain oversight responsibilities with respect to the issuance of PSD permits under state permitting programs. In that capacity, EPA does not seek to substitute its judgment for state permitting authorities in BACT determinations, but EPA does seek to ensure that individual BACT determinations by states with approved programs are reasoned and faithful to the requirements of the CAA and the approved state program regulations.[46]

The discussion that follows in Section III provides an overview of the top-down BACT process, with discussion of how each step may apply to the aspects that are unique to GHGs. In addition, Appendices F, G, and H to this document provide illustrative examples of the application of the top-down BACT process to emissions of GHGs. These examples provide only basic illustrations of the concepts discussed in this document. A successful BACT analysis requires a more detailed record (that is, case- and fact-specific) to justify the conclusions reached by the permitting authority than can be provided in this guidance.

The most comprehensive discussion of the five-step top-down BACT process can be found in EPA's 1990 Draft New Source Review Workshop Manual ("1990 Workshop Manual"),[47] and the method has been progressively refined through federal permitting decisions by EPA, orders on title V permitting decisions, and opinions of the EPA Environmental Appeals Board (EAB) that have adopted many of the principles from the 1990 Workshop Manual and

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[42] Memorandum from Craig Potter, EPA Assistant Administrator for Air and Radiation, to Regional Administrators, *Improving New Source Review Implementation* (Dec. 1, 1987); Memorandum from John Calcagni, EPA Air Quality Management Division, *Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT)* (June 13, 1989).

[43] *Alaska Department of Environmental Conservation v. EPA*, 124 S.Ct. 983, 995 n. 7 (2004).

[44] *In re Cardinal FG Company*, 12 E.A.D. 153, 162 (EAB 2005) and cases cited therein.

[45] 40 CFR 51.166(b)(12); 40 CFR 51.166(j).

[46] *Alaska Department of Environmental Conservation v. EPA*, 124 S.Ct. 983 (2004); *In the Matter of Cash Creek Generation, LLC*, Petition Nos. IV-2008-1 & IV-2008-2 (Order on Petition) (December 15, 2009).

[47] A copy of the 1990 Workshop Manual is available at http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf. There is another draft version of the 1990 Workshop Manual that has jigsaw puzzle pieces on the cover, is not available online, and has some minor differences from the online version. For ease of reference, any citations to the 1990 Workshop Manual in this document refer to the version that is available at the link provided above.

expanded upon them. Thus, EPA recommends that permitting authorities seeking more detailed guidance on particular aspects of the top-down BACT process take care to consider more recent EPA actions (many of which are referenced in this document) in addition to the discussions in the 1990 Workshop Manual.[48]

Since the BACT provisions in the CAA and EPA's rules provide discretion to permitting authorities, a critical and essential component of a successful BACT analysis (whether it follows the top-down process or another approach) is the record supporting the decisions reached by the permitting authority. Permitting authorities should ensure that the BACT requirements contained in the final PSD permit are supported and justified by the information and analysis presented in a thorough and complete permit record. The record should clearly explain the reasons for selection or rejection of possible control and emissions reductions options and include appropriate supporting analysis.[49] In accordance with relevant statutory and regulatory requirements, the permitting authority must also provide notice of its preliminary decision on a source's application for a PSD permit and an opportunity for the public to comment on that preliminary decision. Thus, the record must also reflect careful consideration and response to each significant consideration raised in public comments. Each BACT analysis must be supported by a complete permitting record that shows consideration of all the relevant factors.

This guidance (including the appendices) provides some preliminary EPA views on some key issues that may arise in a BACT analysis for GHGs. It is important to recognize that this document does not provide any final determination of BACT for a particular source, since such determinations can only be made by individual permitting authorities on a case-by-case basis after consideration of the record in each case. Upon considering the record in an individual case, if a permitting authority has a reasoned basis to address particular issues discussed in this document in a different manner than EPA recommends here, permitting authorities (including EPA) have the discretion to do so in decisions on individual permit applications consistent with the relevant requirements in the CAA and regulations. Thus, depending on the relevant facts and circumstances, permitting authorities have the discretion to establish BACT limitations that are more or less stringent than levels that might appear to result if one were to follow the recommendations in this guidance.

Relationship of BACT and New Source Performance Standards (NSPS)

The CAA specifies that BACT cannot be less stringent than any applicable standard of performance under the New Source Performance Standards (NSPS).[50] As of the date of this guidance, EPA has not promulgated any NSPS that contain emissions limits for GHGs. EPA has developed this permitting guidance and associated technical "white papers"[51] to support initial

[48] See the collections of PSD guidance provided in footnote 2, *supra*.
[49] *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 131 (EAB 1999) ("The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record."); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 224-25 (EAB 2000) (remanding BACT limitation where permit issuer failed to provide adequate explanation for why limits deviated from those of other facilities).
[50] 42 USC 7479(3).
[51] These technical "white papers", targeting specific industrial sectors, provide basic information on GHG control options to assist states and local air pollution control agencies, tribal authorities and regulated entities implementing measures to reduce GHG, particularly in the assessment of best available control technology (BACT) under the PSD

BACT determinations for GHGs that will need to be made without the benefit of having an NSPS and supporting technical documents to inform the evaluation of the performance of available control systems and techniques.

To the extent EPA completes an NSPS for a relevant source category, BACT determinations that follow will need to consider the levels of the GHG standards and the supporting rationale for the NSPS. The process of developing NSPS and considering public input on proposed standards will advance the technical record on GHG control strategies and may reflect advances in control technology or reductions in the costs or other impacts of using particular control strategies. Thus, the guidance in this document should be viewed taking into consideration the potential development of an NSPS for a particular source category. In addition, the fact that a NSPS for a source category does not require a more stringent level of control does not preclude its consideration in a top-down BACT analysis.

Importance of Energy Efficiency

As discussed in greater detail below, EPA believes that it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis. For example, coal-fired boilers operating at supercritical steam conditions consume approximately 5 percent less fuel per megawatt hour produced than boilers operating at subcritical steam conditions.[52] Thus, considering the most energy efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (*e.g.,* NO_X, SO_2, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, it is also important to emphasize that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs). Additional considerations concerning energy efficiency in the determination of BACT for GHGs are discussed in more detail below.

An available tool that is particularly useful when assessing energy efficiency opportunities and options is performance benchmarking. Performance benchmarking information, to the extent it is specific and relevant to the source in question, may provide useful information regarding energy efficient technologies and processes for consideration in the BACT assessment. Comparison of the unit's or source's energy performance with a benchmark may highlight the need to assess additional energy efficiency possibilities. To the extent that benchmarking an emissions unit or source shows it to be a poor-to-average performer, the permitting authority may need to document and evaluate whether greater efficiencies are achievable. To ensure that the source is constructed and operated in a manner consistent with achieving the energy efficiency goals determined to be BACT, consideration should be given to

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permitting program. These papers provide basic technical information that may be useful in a BACT analysis but they do not define BACT for each sector.

[52] U.S. Department of Energy, *Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL-2007/1281, Final Report, Revision 1 (August 2007) at 6 (finding that the absolute efficiency difference between supercritical and subcritical boilers is 2.3% (39.1% compared to 36.8%), which is equivalent to a 5.9% reduction in fuel use), *available at* http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.

the individual and overall impact of the various measures under consideration. For example, in the case of numerous small energy saving measures, the intended effect of such measures could be reflected in projecting the GHG emissions limit or output-based standard for the emissions unit. On the other hand, it may be appropriate to include specific energy efficiency measures or techniques in the permit (as well as reflected in the GHG emissions limit) where such measures would clearly have a noticeable effect on energy savings.

There are a number of resources available for benchmarking facilities. For example, EPA's ENERGY STAR program for industrial sources offers several resources that can assist with performance benchmarking. To evaluate the energy performance of an entire facility,[53] ENERGY STAR developed sector-specific benchmarking tools called plant Energy Performance Indicators (EPIs).[54] For sectors where an EPI has been developed, these tools may be used to assess a plant's performance compared to the industry. At a unit and process level, ENERGY STAR has developed sector-specific Energy Guides for a number of industries. These Energy Guides discuss in detail processes and technologies that a permit applicant or permitting authority may wish to consider. This type of information may be particularly useful at the initial stages of the GHG BACT permitting process as the RACT/BACT/LAER clearinghouse (RBLC) is populated and updated with case-specific information.[55] Additional resources can be found in Appendix J of this document.

A. Determining the Scope of the BACT Analyses

<u>General Concepts</u>

An initial consideration that is not directly covered in the five steps of the top-down BACT process is the scope of the entity or equipment to which a top-down BACT analysis is applied. EPA has generally recommended that permit applicants and permitting authorities conduct a separate BACT analysis for each emissions unit[56] at a facility and has also encouraged applicants and permitting authorities to consider logical groupings of emissions units as appropriate on a case-by-case basis.[57]

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[53] For PSD applicability, the scope of the "major stationary source" is determined by the definition in 40 CFR 52.21(b)(1), and the title V "major source" is defined in 40 CFR 70.2. The PSD and title V regulations distinguish between a "facility" and a "stationary source"; in fact, the regulations include a facility as type of stationary source. 40 CFR 52.21(b)(5)-(6), 40 CFR 71.2. However, in this guidance, source and facility are used interchangeably to generally designate pollutant emitting structures and do not designate official positions regarding applicability unless otherwise noted.
[54] Current ENERGY STAR industrial sector EPIs can be found at http://www.energystar.gov/EPIS.
[55] The RBLC provides access to information and decisions about pollution control measures required by air pollution emission permits issued by state and local permitting agencies so that the information is accessible to all permitting authorities working on similar projects. The expanded RBLC includes GHG control and test data, and a GHG message board for permitting authorities.
[56] 40 CFR 52.21(b)(7).
[57] 1990 Workshop Manual at B.10; *In re General Motors, Inc.*, 10 E.A.D. 360, 382 (EAB 2002). EPA has also supported grouping emissions units in the similar context of evaluating options for meeting the technology-based LAER standards under the nonattainment NSR program. Memorandum from John Calcagni, Air Quality

For new sources triggering PSD review, the CAA and EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis by taking into account operations and equipment which affect the environmental performance of the overall facility. The term "facility" and "source" used in applicable provisions of the CAA and EPA rules encompass the entire facility and are not limited to individual emissions units.[58]

For existing sources triggering PSD review, EPA rules are more explicit that BACT applies to those emission units at which a net emissions increase would occur at the source[59] as a result of a physical change or change in the method of operation.[60] EPA has interpreted these provisions to mean that BACT applies in the context of a modification to only an emissions unit that has been modified or added to an existing facility.[61]

<u>GHG-Specific Considerations</u>

The application of BACT to GHGs has the potential to place greater importance on determining the scope of the entity or equipment to which BACT applies. Under existing rules, a permitting authority evaluating applications to construct new sources has the flexibility to consider source-wide energy efficiency strategies (over an entire production process or across multiple production process) to reduce GHG emissions from the proposed new source. EPA interprets the language of the BACT definition in CAA §169, which requires consideration of "production processes and available methods, systems, and techniques ... for control of [each] pollutant," to include control methods that can be used facility-wide. As noted above, for a

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Management Division to David Kee, Region V, *Transfer of Technology in Determining Lowest Achievable Emissions Rate (LAER)* (Aug. 29, 1988).

[58] 42 USC 7479(1) and (3); 40 CFR 52.21(b)(1) and (5).

[59] For the purposes of determining whether a PSD permit is required (applicability of PSD), EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emissions increases that result from the modification. Thus, EPA has considered downstream and upstream emissions increases and decreases from emissions units that are not physically or operationally changed when determining the level of emissions increase that results from a modification. This concept is frequently described as "debottlenecking" because the upstream or downstream emission increases that are accounted for in the analysis are often the result of increased throughput across the source resulting from the removal of a bottleneck in the equipment that is physically changed. 1990 Workshop Manual at A.46; Letter from Kathleen Henry, Region III to John M. Daniel, Virginia DEQ (Oct. 23, 1998) (Intermet Archer Creek Facility). In 2006, EPA proposed potential changes to its approach to debottlenecking based on an analysis that the agency had flexibility to define the causation of an increase. 71 FR 54235 (Sept. 14, 2006). However, that proposal was not adopted by the Agency and explicitly withdrawn. The discussion of this concept in this note is intended solely to provide context for the BACT requirement. This note is in no way intended to modify the Agency's approach to this aspect of PSD applicability, as applied prior the 2006 proposal referenced above and continuing to this day.

[60] 40 CFR 52.21(j)(3).

[61] In the preamble for the 1980 rule that established the current version of 40 CFR 52.21(j)(3), EPA explained that "BACT applies only to the units actually modified." 45 FR 52676, 52681 (Aug. 7, 1980). Later in this preamble, EPA elaborated as follows with a specific example:

> The proposal required BACT for the new or modified emissions units which were associated with the modification and not for those unchanged emissions units at the same source. Thus, if an existing boiler at a source were modified or a new boiler added in such a way as to significantly increase particulate emissions, only that boiler would be subject to BACT, not the other emissions units at the source.

Id. at 52722. *See also* Letter from Robert Miller, EPA Region 5 to Lloyd Eagan, Wisconsin DNR (Feb. 8, 2000) (PSD applicability for debottlenecked source).

modification of an existing facility, EPA's existing regulations state that BACT only applies to emission units that are physically or operationally changed.[62]

EPA has historically interpreted the BACT requirement to be inapplicable to secondary emissions, which are defined to include emissions that may occur as a result of the construction or operation of a major stationary source but do not come from the source itself.[63] Thus, under this interpretation of EPA rules, a BACT analysis should not include (in Step 1 of the process) energy efficient options that may achieve reductions in a facility's demand for energy from the electric grid but that cannot be demonstrated to achieve reduction in emissions released from the stationary source (*e.g.,* within the property boundary). Nevertheless, as discussed in more detail below, EPA recommends that permitting authorities consider in a portion of the BACT analysis (Step 4) how available strategies for reducing GHG emissions from a stationary source may affect the level of GHG emissions from offsite locations.

B. BACT Step 1 – Identify All Available Control Options

General Concepts

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation. To satisfy the statutory requirements of BACT, EPA believes that the applicant must focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

Air pollution control technologies and techniques include the application of alternative production processes, methods, systems, and techniques, including clean fuels or treatment or innovative fuel combustion techniques for control of the affected pollutant. In some circumstances, inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control options should include not only existing controls for the source category in question, but also controls determined through "technology transfer" that are applied to source categories with exhaust streams that are similar to the source category in question. The 1990 Workshop Manual provides useful guidelines for issues related to technology transfer among process applications. Primary factors that should be considered are the characteristics of the gas stream to be controlled, the comparability of the production processes (*e.g.,* batch versus continuous operation, frequency of process interruptions, special product quality concerns, etc.), and the potential impacts on other emission points within the source. Also, technologies in application outside the United States should be considered to the extent that the technologies have been successfully demonstrated in practice. In general, if a control option has been demonstrated in practice on a range of exhaust gases with similar physical and chemical characteristics and does not have a significant negative impact on process

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[62] 40 CFR 52.21(j)(3).
[63] 44 FR 51924, 51947 (Sept. 5, 1979); 40 CFR 52.21(b)(18).

operations, product quality, or the control of other emissions, it may be considered as potentially feasible for application to another process.

Technologies that formed the basis for an applicable NSPS (if any) should, in most circumstances, be included in the analysis, as BACT cannot be set at an emission control level that is less stringent than that required by the NSPS.[64] In cases where a NSPS is proposed, the NSPS will not be controlling for BACT purposes since it is not a final action and the proposed standard may change, but the record of the proposed standard (including any significant public comments on EPA's evaluation) should be weighed when considering available control strategies and achievable emission levels for BACT determinations made that are completed before a final standard is set by EPA. However, even though a proposed NSPS is not a controlling floor for BACT, the NSPS is an independent requirement that will apply to an NSPS source that commences construction after an NSPS is proposed and carries with it a strong presumption as to what level of control is achievable. This is not intended to limit available options to only those considered in the development of the NSPS. For example, in addition to considering controls addressed in an NSPS rulemaking, controls selected in lowest achievable emission rate (LAER) determinations are available for BACT purposes, should be included as control alternatives included in BACT Step 1, and may frequently be found to represent the top control alternative at later steps in the BACT analysis.[65]

EPA has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

- ***Inherently Lower-Emitting Processes/Practices/Designs,***[66]
- ***Add-on Controls*, and**
- ***Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-on Controls*.**

The BACT analysis should consider potentially applicable control techniques from all of the above three categories. Lower-polluting processes (including design considerations) should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream.

[64] 40 CFR 52.21(b)(12). While this guidance is being issued at a time when no NSPS have been established for GHGs, permitting authorities must consider any applicable NSPS as a controlling floor in determining BACT once any such standards are final.

[65] EPA has stated that technologies designated as meeting lowest achievable emission rate (LAER) – which are required in NSR permits issues to sources in non-attainment areas – are available for BACT purposes, must be included in the list of control alternatives in step 1, and will usually represent the top control alternative. 1990 Workshop Manual at B.5.

[66] While the 1990 Workshop Manual generally refers to "Inherently Lower Polluting Processes/Practices," the discussion contained in that portion of the Manual makes it clear that lower emitting *designs* may also be considered in Step 1 of the top-down analysis. See 1990 Workshop Manual at B.14 (stating that "the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source").

As explained later in this guidance, in the course of the BACT analysis, one or more of the available options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case- and fact-specific basis. However, such options should still be included in Step 1 of the BACT process, since the purpose of Step 1 of the process is to cast a wide net and identify all control options with potential application to the emissions unit under review that should be subject to scrutiny under later steps of the process.

While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.[67] BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities apply the analytical framework recently articulated by the Environmental Appeals Board.[68] Under this framework, a permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application. The underlying record will be an essential component of a supportable BACT determination that a proposed control technology redefines the source.[69] The permitting authority should then take a "hard look" at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility. In doing so, the permitting authority should keep in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.[70] This approach does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicants' proposed facility design in order to achieve pollutant reductions

[67] *In re Prairie State Generating Company*, 13 E.A.D. 1, 23 (EAB 2006).
[68] *See, generally, In the Matter of American Electric Power Service Corporation, Southwest Electric Power Company, John W. Turk Plant*, Petition No. VI-2008-01 (Order on Petition) (December 15, 2009) (title V order referencing and applying framework developed by the EAB) ; *In the Matter of Cash Creek Generation, LLC*, Petition Nos. IV-2008-1 & IV-2008-2 (Order on Petition) (December 15, 2009) (same).
[69] *In re Desert Rock Energy Company*, PSD Appeal No. 08-03 et al. (EAB Sept. 24, 2009), slip op. at 65, 76.
[70] The EPA Environmental Appeals Board has applied this framework for evaluating redefining the source questions in three cases involving coal-fired power plants. *In re Desert Rock Energy Company*, PSD Appeal No. 08-03 et al. (EAB Sept. 24, 2009); *In re Northern Michigan University*, PSD Appeal No. 08-02 (EAB Feb. 18, 2009); *In re Prairie State Generating Company*, 13 E.A.D. 1 (EAB 2006). For additional examples of how EPA approached the redefining the source issue in the context of power plants prior to developing this analytical framework, see the following decisions. *In re Old Dominion Electric Cooperative*, 3 E.A.D. 779 (Adm'r 1992); *In re Hawaiian Commercial & Sugar Co.*, 4 E.A.D. 95 (EAB 1992); *In re SEI Birchwood Inc.*, 5 E.A.D. 25 (EAB 1994). EPA also considered this issue in the context of waste incinerators prior to developing the recommended analytical framework. *In re Pennsauken*, 2 E.A.D. 667 (Adm'r 1988); *In the Matter of Spokane Regional Waste-to-Energy Facility*, 2 E.A.D. 809 (Adm'r 1989); *In the Matter of Brooklyn Navy Yard Resource Recovery Facility*, 3 E.A.D. 867 (EAB 1992); *In re Hillman Power Co., LLC*, 10 E.A.D. 673, 684 (EAB 2002). In another case, EPA considered this question in the context of a conversion of a natural-gas fired taconite ore facility to a petcoke fuel. *In re Hibbing Taconite Co*., 2 E.A.D. 838 (Adm'r 1989). For an example of the application of this concept to a fiberglass manufacturing facility, see *In re Knauf Fiber Glass*, 8 E.A.D 121 (EAB 1998).

that may or may not be deemed achievable after further evaluation at later steps of the process. EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire.[71] The "redefining the source" issue is ultimately a question of degree that is within the discretion of the permitting authority. However, any decision to exclude an option on "redefining the source" grounds must be explained and documented in the permit record, especially where such an option has been identified as significant in public comments.[72]

In circumstances where there are varying configurations for a particular type of source, the applicant should include in the application a discussion of the reasons why that particular configuration is necessary to achieve the fundamental business objective for the proposed construction project. The permitting authority should determine the applicant's basic or fundamental business purpose or objective based on the record in each individual case. For example, the permitting authority can consider the intended function of an electric generating facility as a baseload or peaking unit in assessing the fundamental business purpose of a permit applicant.[73] However, a factor that might be considered at later steps of the top-down BACT process, such as whether a process or technology can be applied on a specific type of source (Step 2) or the cost of constructing a source with particular characteristics (Step 4), should not be used as a justification for eliminating an option in Step 1 of the BACT analysis. Thus, cost savings and avoiding the risk of an apparently achievable technology transfer are not appropriately considered to be a part of the applicant's basic design or fundamental business purpose or objective.[74] Since BACT Step 4 also includes consideration of "energy" impacts from the control options under consideration, such impacts should not be used to justify excluding an option in Step 1 of a top-down BACT analysis.

The CAA includes "clean fuels" in the definition of BACT.[75] Thus, clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.,* coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit.[76] Ultimately,

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[71] *In re Hawaiian Commercial & Sugar Co.*, 4 E.A.D. at 100; *In re Knauf Fiber Glass*, 8 E.A.D. at 136.
[72] *In re Desert Rock Energy Company*, slip op. at 70-71, 76-77; *In the Matter of Cash Creek Generation*, Order at 7-10.
[73] *In re Prairie State Generating Company*, 13 E.A.D. at 25 (recognizing distinction between sources designed to provide base load power and those designed to function as peaking facilities).
[74] *In re Prairie State Generating Company*, 13 E.A.D. at 23, n.23.
[75] 42 USC 7579(3). EPA has not yet updated the definition of BACT in the PSD regulations to reflect the addition of the "clean fuels" language that occurred in the 1990 amendments to the Clean Air Act. 40 CFR 52.21(b)(12); 40 CFR 51.166(b)(12). Nevertheless, EPA reads and applies its regulations consistent with the terms of the Clean Air Act.
[76] *See, e.g.,* 1990 Workshop Manual at B.13; *In re Old Dominion Electric Cooperative*, 3 E.A.D. at 793-94; *In re SEI Birchwood Inc.*, 5 E.A.D. at 28, n. 8. *But see In re Hibbing Taconite Co.,* 2 E.A.D. 838, 843(Adm'r 1989) (finding it reasonable to consider burning natural gas instead of or in combination with coal where the plant at issue was already equipped to burn natural gas).

however, a permitting authority retains the discretion to conduct a broader BACT analysis and to consider changes in the primary fuel in Step 1 of the analysis. EPA does not classify the option of using a cleaner form of the same type of fuel that a permit applicant proposes to use as a change in primary fuel, so these types of options should be assessed in a top-down BACT analysis in most cases.[77] For example, a permitting authority may consider that some types of coal can have lower emissions of GHG than other forms of coal, and they may insist that the lower emitting coal be evaluated in the BACT review. Furthermore, when a permit applicant has incorporated a particular fuel into one aspect of the project design (such as startup or auxiliary applications), this suggests that a fuel is "available" to a permit applicant. In such circumstances, greater utilization of a fuel that the applicant is already proposing to use in some aspect of the project design should be listed as an option in Step 1 unless it can be demonstrated that such an option would disrupt the applicant's basic business purpose for the proposed facility.[78]

Although not required in Step 1 of the BACT process, the applicant may also evaluate and propose to apply innovative technologies that qualify for coverage under the innovative control technology waiver in EPA rules.[79] Under this waiver, a source is allowed an extended period of time to bring innovative technology into compliance with the required performance level. To be considered "innovative," a control technique must meet the provisions of 40 CFR 52.21(b)(19) or, where appropriate, the applicable definition in a state SIP. In the early 1990s, EPA did not consider it appropriate to grant applications for this waiver for proposed projects that were the same as or similar to projects for which the waiver had previously been granted.[80] However, in 1996, EPA said that it was inclined to allow additional waivers if the criteria in the CAA for such a waiver under the NSPS program were met. EPA proposed revisions to this provision in the PSD rules to incorporate the statutory criteria from the NSPS program, which specifies that such waivers may not exceed the number the administrator finds necessary to ascertain whether the criteria for issuing a waiver are met.[81] Though the 1996 proposal was never issued as final policy, EPA continues to adhere to the view expressed in that 1996 proposal and will consider approving more than one waiver under these conditions.

GHG-Specific Considerations

Permit applicants and permitting authorities should identify all "available" GHG control options that have the potential for practical application to the source under consideration. The application of BACT to GHGs does not affect the discretion of a permitting authority to exclude options that would fundamentally redefine a proposed source. GHG control technologies are

[77] *See In re Old Dominion Electric Cooperative*, 3 E.A.D. at 793 (stating that the BACT analysis includes consideration of fuels cleaner than that proposed by the applicant); *In re Inter-Power of New York,* 5 E.A.D. 130, 145-150 (EAB 1994) (upholding permitting authorities BACT analysis involving coals with different sulfur contents). *But see In re Prairie State Generating Company*, 13 E.A.D. at 27-28 (finding the permitting authority properly excluded consideration of lower sulfur coal as redefining the source since the power plant at issue was co-located with a mine and designed to burn the coal from that mine) .

[78] *In the Matter of Cash Creek Generation*, Order at 7-10.

[79] 40 CFR 52.21(v); 40 CFR 51.166(s).

[80] 1990 Workshop Manual at B.13; Memo from Ed Lillis, Chief, Permits Program Branch, to Kenneth Eng, Chief, Air Compliance Branch, *Kamine Development Corporation's (KDC) Request for a Prevention of Significant Deterioration (PSD) Innovative Control Technology Waiver* (August 20, 1991).

[81] 61 FR 38250, 38281 (July 23, 1996).

likely to vary based on the type of facility, processes involved, and GHGs being addressed. The discussion below is focused on energy efficiency and carbon capture and storage (CCS) because these control approaches may be applicable to a wide range of facilities that emit large amounts of CO_2. Information on other technologies and mitigation approaches to control CO_2 as well as the other GHGs (*e.g.,* methane) is found in Appendix J.

The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of "lower-polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews. In some cases, a more energy efficient process or project design may be used effectively alone; whereas in other cases, an energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control of criteria pollutants. Applying the most energy efficient technologies at a source should in most cases translate into fewer overall emissions of all air pollutants per unit of energy produced. Selecting technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review, but it also may achieve collateral reductions of emissions of other pollutants, as well as GHGs.

For these reasons, EPA encourages permitting authorities to use the discretion available under the PSD program to include as available technologies in Step 1 the most energy efficient options in BACT analyses for both GHG and non-GHG regulated NSR pollutants. While energy efficiency can reduce emissions of all combustion-related emissions, it is a particularly important consideration for GHGs since the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-derived pollutants. Initially, in many instances energy efficient measures may serve as the foundation for a BACT analysis for GHGs, with add-on pollution control technology and other strategies added as they become more available. Energy efficient options that should be considered in Step 1 of a BACT analysis for GHGs can be classified in two categories.

The first category of energy efficiency improvement options includes technologies or processes that maximize the energy efficiency of the individual emissions unit. For example, the processes that may be used in electric generating facilities have varying levels of energy efficiency, measured in terms of amount of heat input that is used in the process or in terms of per unit of the amount of electricity that is produced. When a permit applicant proposes to construct a facility using a less efficient boiler design, such as a pulverized coal (PC) or circulating fluidized bed (CFB) boiler using subcritical steam pressure, a BACT analysis for this source should include more efficient options such as boilers with supercritical and ultra-supercritical steam pressures.[82] Furthermore, combined cycle combustion turbines, which generally have higher efficiencies than simple cycle turbines, should be listed as options when an applicant proposes to construct a natural gas-fired facility. In coal-fired permit applications,

[82] "Supercritical EGUs typically use steam pressures of 3,500 psi (24 MPa) and steam temperatures of 1,075°F (580°C). However, supercritical boilers can be designed to operate at steam pressures as high as 3,600 psi (25 MPa) and steam temperatures as high as 1,100°F (590°C). Above this temperature and pressure the steam is sometimes called 'ultra-supercritcal'[*sic*]." EPA Office of Air and Radiation, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units* (October 2010) at 27.

EPA believes that integrated gasification combined cycle (IGCC) should also be listed for consideration when it is more efficient than the proposed technology.[83] However, these options may be evaluated under the redefining the source framework described above and excluded from consideration at Step 1 of a top-down analysis on a case-by-case basis if it can be shown that application of such a control strategy would disrupt the applicant's basic or fundamental business purpose for the proposed facility.

The second category of energy efficiency improvements includes options that could reduce emissions from a new greenfield facility by improving the utilization of thermal energy and electricity that is generated and used on site. As noted previously, BACT reviews for modified units at existing sources should focus on the emitting unit that is being physically or operationally changed. However, when reviewing a PSD permit application for the construction of a new facility that creates its own energy (thermal or electric) for its own use, EPA recommends that permitting authorities consider technologies or processes that not only maximize the energy efficiency of the individual emitting units, but also process improvements that impact the facility's energy utilization assuming it can be shown that efficiencies in energy use by the facility's higher-energy-using equipment, processes or operations could lead to reductions in emissions from the facility. EPA has long recognized that "a control option [considered in the BACT analysis] may be an 'add-on' air pollution control technology that removes pollutants from a facility's emissions stream, or an 'inherently lower-polluting process/practice' that prevents emissions from being generated in the first instance."[84]

[83] EPA no longer subscribes to the reasoning used by the Agency in a 2005 letter to justify excluding IGCC from consideration in all cases on redefining the source grounds. Letter from Stephen Page, EPA OAQPS to Paul Plath, E3 Consulting, *Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects* (Dec. 13, 2005) (last paragraph on page 2). The Environmental Appeals Board subsequently rejected the application of this reasoning in an individual permit decision, where the record did not demonstrate that IGCC was inconsistent with the fundamental objectives of the permit applicant or distinguish between prior permit decisions that evaluated the technology in more detail. *In re Desert Rock Energy Company*, Slip. Op. at 68-69. Based on this decision, EPA also concluded that a state permit decision following substantially the same reasoning lacked a reasoned basis for excluding further consideration of IGCC. *In the Matter of: American Electric Power Service Corporation,* Order at 8-12. However, EPA continues to interpret the relevant provisions of the CAA, as described in the 2005 letter (pages 1-2), to provide discretion for permitting authorities to exclude options that would fundamentally redefine a proposed source, provided the record includes an appropriate justification in each case *In re Desert Rock Energy Company*, Slip. Op. at 76. Thus, IGCC should not be categorically excluded from a BACT analysis for a coal fired electric generating unit, and this technology should not be excluded on redefining the source grounds at Step 1 of a BACT analysis in any particular case unless the record clearly demonstrates why the permit applicant's basic or fundamental business purpose would be frustrated by application of this process.

[84] *In re Knauf Fiberglass, GMBH*, 8 EAD 121, 129 (EAB 1999) (citing 1990 NSR Workshop Manual at B.10, B.13). In *Knauf Fiberglass* the EPA's Environmental Appeals Board observed that "[t]he permitting authority may require consideration of alternative production processes in the BACT analysis when appropriate." *Id.* at 136. The EAB remanded a PSD permit for a facility that manufactured fiberglass insulation because of several deficiencies in the BACT analysis for the source. One of these deficiencies noted by the Board was the failure to sufficiently consider the possibility of applying an alternative process for producing the fiberglass that was used by another facility in the industry that had lower levels of PM10 emissions using the same add on controls. The source argued that it was unable to reduce its PM10 emissions to levels similar to its competitor because the competitor used a different production process that enabled it to achieve lower PM10 emissions levels. The EAB acknowledged that if the competitor's process was a proprietary trade secret, then such an option might be technically infeasible (not commercially available) for the source under evaluation, but called for the permit record to document this fact and for the applicant to seriously consider pollution control designs for other facilities that were a matter of public record. 8 EAD at 139-144. After the initial remand in 1999, the EAB later upheld a revised permit that was based

For example, an applicant proposing to build a new facility that will generate its own energy with a boiler could also consider ways to optimize the thermal efficiency of a new heat exchanger that uses the steam from the new boiler. Moreover, the design, operation, and maintenance of a steam distribution and utilization system may influence how much steam is needed to complete a specific task. If the steam distribution and utilization is optimized, less steam may be needed. In many cases, lower steam demand could result in lower fuel use and lower emissions at a new facility. Since lower-emitting processes should be considered in BACT reviews, opportunities to utilize energy more efficiently and therefore to produce less of it are appropriate considerations in a BACT review for a new facility. As discussed in the previous section, the evaluation of options in this second category can be facilitated by defining, in the case of new sources, the entity subject to BACT on a basis that encompasses the significant energy-using equipment, processes or operations of the facility.

For the first category of energy efficiency options described above, the number of options available for a given type of emissions unit at an existing or new source will generally be limited in number and not significantly expand the number of options that have traditionally been considered in BACT analyses for previously regulated NSR pollutants. However, the second category of options appropriate for consideration at a new greenfield facility may include equipment or processes that have the effect of lowering emissions because their efficient use of energy means that the facility's energy-producing emitting unit can produce less energy. Evaluation of options in this second category need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of the new facility as a whole (*e.g.,* installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reduction achieved.[85] EPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (*e.g.,* induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions. EPA also recommends that permit applicants at new sources propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks. Comparing the proposed suite of techniques to such benchmarks, which represent a high level of performance within an industry, would demonstrate that the new facility will achieve commensurate levels of energy efficiency using the proposed methods. Such an approach would leave some flexibility for the permit applicant to suggest the precise mix of measures that would meet the desired benchmark, and avoid including in a permit review an assessment of a large number of different combinations of technology choices for smaller pieces of equipment.

While engineering calculations and results from similar equipment demonstrations can often enable the permit applicant or engineer to closely estimate the energy efficiency of a unit,

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on the conclusion that it was not technically feasible for this source to use the lower-polluting process used by its competitor because the process was proprietary and not commercially available to Knauf. *In re Knauf Fiberglass, GMBH*, 9 EAD 1 (EAB 2000).

[85] One federal court has recognized the undesirability of making the BACT analysis into a "Sisyphean labor where there was always one more option to consider." *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007).

we recognize that, in some cases, it may be more difficult to fully and accurately predict the energy efficiency of a unit for BACT purposes. Commonly, the responsible design engineers or vendors will provide both estimated "expected" results and "guaranteed" results. Such estimates can be provided for the permitting authority's consideration. The difference between expected and guaranteed results gives some indication of the uncertainty and risk tolerances included in the guaranteed value. Still, in some cases, the ultimate energy efficiency of the unit may not be accurately known without testing the installed equipment, especially if multiple vendors or multiple design engineers are involved. Of course, this is substantially similar to many current permitting situations, such as when combustion enhancements are installed for controlling emissions of criteria pollutants and the exact effect on energy efficiency is somewhat uncertain until it is operationally tested. Thus, where there is some reasonable uncertainty regarding performance of specified energy efficiency measures, or the combination of measures, the permit can be written to acknowledge that uncertainty. As in the past, based on the particular circumstances addressed in the permitting record, the permitting authority has the discretion to set a permit limit informed by engineering estimates, or to set permit conditions that make allowance for adjustments of the BACT limits based on operational experience.

For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (*e.g.,* hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis. However, for these types of facilities and particularly for new facilities, CCS is an

[86] EPA recognizes that CCS systems may have some unique aspects that differentiate them from the types of equipment that have the traditionally been classified as add-on pollution controls (*i.e.,* scrubbers, fabric filters, electrostatic precipitators). However, since CCS systems have more similarities to such devices than inherently lower-polluting processes, EPA believes that CCS systems are best classified as add-on controls for purposes of a top-down BACT analysis.

[87] As noted above, a control option is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical challenges to implementation. EPA, which participated in the Interagency Task Force, supports the Task Force's recommendations concerning ongoing investment in demonstrations of the CCS technologies based on the report's conclusion that: "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment." See Report of the Interagency Task Force on Carbon Capture and Storage, p.50 (http://www.epa.gov/climatechange/policy/ccs_task_force.html).

option that merits initial consideration and, if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail.

In identifying control technologies in BACT Step 1, the applicant needs to survey the range of potentially available control options. EPA recognizes that dissemination of data and information detailing the function of the proposed control equipment or process is essential if permitting agencies are to reach consistent conclusions on the availability of GHG technology across industries. In the initial phase of PSD permit reviews for GHGs, background information about certain emission control strategies may be limited and technologies may still be under development. For example, alternative technologies are being developed for reusing carbon or sequestering carbon in a form or location other than through injection into underground formations. When these technologies are more developed, they could be included in Step 1 of the top-down BACT process. EPA will add information to the RBLC as it becomes available and supplement the information in the GHG Mitigation Measures Database.[88] EPA may also issue additional white papers for selected stationary source sectors in the future.

C. BACT Step 2 – Eliminate Technically Infeasible Options

General Concepts

Under the second step of the top-down BACT analysis, an available control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, or engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. If a technology has been operated on the same type of source, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered in order for the technology to be eliminated as technically infeasible.[89]

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[88] EPA has developed a new online tool (GHG Mitigation Measures Database) that includes specific performance and cost data on current and developing GHG control measures. It also provides available data on other potential environmental impacts a GHG control measure may have. Currently, the database includes information on GHG controls for electric generating and cement production. This database can be found on EPA's website at http://www.epa.gov/nsr/ghgpermitting.html

[89] *In re Cardinal FG Company*, 12 E.A.D. 153, 166 (EAB 2005); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 199 (EAB 2000).

In the context of a technical feasibility analysis, the terms "availability" and "applicability" relate to the use of technology in a situation that appears similar even if it has not been used in the same industry. Specifically, EPA considers a technology to be "available" where it can be obtained through commercial channels or is otherwise available within the common meaning of the term.[90] EPA considers an available technology to be "applicable" if it can reasonably be installed and operated on the source type under consideration. Where a control technology has been applied on one type of source, this is largely a question of the transferability of the technology to another source type. A control technique should remain under consideration if it has been applied to a pollutant-bearing gas stream with similar chemical and physical characteristics. The control technology would not be applicable if it can be shown that there are significant differences that preclude the successful operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review.

Evaluations of technical feasibility should consider all characteristics of a technology option, including its development stage, commercial applications, scope of installations, and performance data. The applicant is responsible for providing evidence that an available control measure is technically infeasible. However, the permitting authority is responsible for deciding technical feasibility. The permitting authority may require the applicant to address the availability and applicability of a new or emerging technology based on information that becomes available during the consideration of the permit application.

Information regarding what vendors will guarantee should be considered in the BACT selection process with all the other relevant factors, such as BACT emission rates for other recently permitted sources, projected cost and effectiveness of controls, and experience with the technology on similar gas streams. Commercial guarantees are a contract between the permit applicant and the vendor to establish the risk of non-performance the vendor is willing to accept, and they typically establish the remedy for failure to perform and the test methods for acceptance. A permit applicant uses these guarantees to provide its investors and lenders with reasonable assurances that the proposed facility will reliably perform its intended function and consistently meet the proposed permit limits. While permit applicants use these guarantees as protection from overly optimistic vendor claims for new technologies, experience demonstrates that these terms and conditions can also be customized for each circumstance to imply greater or lesser performance, depending on the stringency of the guarantees and associated penalties for nonperformance. The willingness of vendors to provide guarantees and the limits of these guarantees can be an important factor in determining the level of performance specified in a PSD permit. A vendor guarantee of a certain level of performance may be considered by the permitting authority later in the BACT process when proposing a specific emissions limit or level of performance in the PSD permit. However, a control technology should not be eliminated in Step 2 of the top-down BACT process based solely on the inability to obtain a commercial guarantee from a vendor on the application of technology to a source type.

[90] *In re Cardinal FG Company*, 12 E.A.D. at 14; *In re Steel Dynamics, Inc.*, 9 E.A.D. at 199.

Further, a technology should not be eliminated as technically infeasible due to costs. Where the resolution of technical difficulties is a matter of cost, this analysis should occur in BACT Step 4.

GHG-Specific Considerations

EPA's historic approach to assessing technical feasibility that is summarized above and described in the 1990 Workshop Manual and subsequent actions such as EAB decisions is generally applicable to GHGs. The nature of the concerns and remedies arising from identification of available technologies is well-explained in the 1990 Workshop Manual and other referenced documents. However, technologies available for controlling traditional pollutants were, in many cases, well-developed at the time that the 1990 Workshop Manual was drafted. Similarly, we expect the commercial availability of different GHG controls to increase in the coming years. Permitting authorities need to make sure that their decisions regarding technical infeasibility are well-explained and supported in their permitting record, paying particular attention to the most recent information from the commercial sector and other recently-issued permits.

This guidance is being issued at a time when add-on control technologies for certain GHGs or emissions sources may be limited in number and in various stages of development and commercialization. A number of ongoing research, development, and demonstration programs may make CCS technologies more widely applicable in the future.[91] These facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration. When considering the guidance provided below, permitting authorities should be aware of the changing status of various control options for GHG emissions when determining BACT.

In the early years of GHG control strategies, consideration of commercial guarantees is likely to be involved in the BACT determination process. This type of guarantee may be more relevant for certain GHG controls because, unlike other pollutants with available, proven control technologies, some GHG controls may have a greater uncertainty regarding their expected performance. As noted above, the lack of availability of a commercial guarantee, by itself, is not a sufficient basis to classify a technology as "technologically infeasible" for BACT evaluation purposes, even for GHG control determinations.

As discussed earlier, although CCS is not in widespread use at this time, EPA generally considers CCS to be an "available" add-on pollution control technology for facilities emitting CO_2 in large amounts and industrial facilities with high-purity CO_2 streams. Assuming CCS has been included in Step 1 of the top-down BACT process for such sources, it now must be evaluated for technical feasibility in Step 2. CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant

[91] For example, the U.S. Department of Energy has a robust CCS research, development, and demonstration program supported by annual appropriations and $3.4B of Recovery Act funds. See www.fe.doe.gov.

concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.,* space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).

While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.

The level of detail supporting the justification for the removal of CCS in Step 2 will vary depending on the nature of the source under review and the opportunities for CO_2 transport and storage. As with all top-down BACT analyses, cost considerations should not be included in Step 2 of the analysis, but can be considered in Step 4. In circumstances where CO_2 transportation and sequestration opportunities already exist in the area where the source is, or will be, located, or in circumstances where other sources in the same source category have applied CCS in practice, the project would clearly warrant a comprehensive consideration of CCS. In these cases, a fairly detailed case-specific analysis would likely be needed to dismiss CCS. However, in cases where it is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (*e.g.,* sources that emit CO_2 in amounts just over the relevant GHG thresholds and produce a low purity CO_2 stream) a much less detailed justification may be appropriate and acceptable for the source. In addition, a permitting authority may make a determination to dismiss CCS for a small natural gas-fired package boiler, for example, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO_2 given the nature of the project. That finding may be sufficient to dismiss CCS for similar units in subsequent BACT reviews, provided the facts upon which the original finding was made also apply to the subsequent units and are still valid.

D. BACT Step 3 – Ranking of Controls

General Concepts

After the list of all available controls is winnowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top-down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (*i.e.,* the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the top-down BACT selection process in Step 4.[92]

In determining and ranking technologies based on control effectiveness, applicants and permitting authorities should include information on each technology's control efficiency (*e.g.,* percent pollutant removed, emissions per unit product), expected emission rate (*e.g.,* tons per year, pounds per hour, pounds per unit of product, pounds per unit of input, parts per million), and expected emissions reduction (*e.g.,* tons per year). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration. While input-based metrics have traditionally been the preferred ranking format for many BACT analyses, for some source types, particularly combustion sources, it may be more appropriate to rank control options based on output-based metrics that would fully consider the thermal efficiency of the options when determining control effectiveness. In particular, where the output of the facility or the affected source is relatively homogeneous, an output-based standard (*e.g.,* pounds per megawatt hour of electricity, pounds per ton of cement, etc.) may best present the overall emissions control of an array of control options. Where appropriate, net output-based standards provide a direct measure of the energy efficiency of an operation's emission-reducing efforts. However, in the simple case of a new or modified fuel-fired unit, the thermal efficiency of the unit can be a useful ranking metric. Furthermore, when the output of the facility is a changing mix of products, an output-based standard may not be appropriate.

GHG-Specific Considerations

As discussed in earlier sections, the options considered in a BACT analysis for GHG emissions will likely include, but not necessarily be limited to, control options that result in energy efficiency measures to achieve the lowest possible emission level. Where plant-wide measures to reduce emissions are being considered as GHG control techniques, the concept of overall control effectiveness will need to be refined to ensure the suite of measures with the lowest net emissions from the facility is the top-ranked measure. Ranking control options based on their net output-based emissions ensures that the thermal efficiency of the control option, as well as the power demand of that control measure, is fully considered when comparing options in Step 3 of the BACT analysis.

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[92] EPA has previously recommended that Step 3 of a BACT analysis include an assessment of the energy, environmental, and economic impacts of each remaining option on the list. See 1990 Workshop Manual at B.25. However, the energy, environmental, and economic impacts of the control options are not actually compared until Step 4 of the process. See 1990 Workshop Manual at B.26. Thus, the compilation of this information can be accomplished in either Step 3 or Step 4 of the process.

Finally, to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than total mass or mass for the individual GHGs. As explained in the Tailoring Rule, the CO_2e metric will "enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (*e.g.,* flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2).[93]

E. BACT Step 4 – Economic, Energy, and Environmental Impacts

General Concepts

Under Step 4 of the top-down BACT analysis, permitting authorities must consider the economic, energy, and environmental impacts arising from each option remaining under consideration. Accordingly, after all available and technically feasible control options have been ranked in terms of control effectiveness (BACT Step 3), the permitting authority should consider any specific energy, environmental, and economic impacts identified with those technologies to either confirm that the top control alternative is appropriate or determine it to be inappropriate. The "top" control option should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

In BACT Step 4, the applicant and permitting authority should consider both direct and indirect impacts of the emissions control option or strategy being evaluated. EPA has previously referred to BACT Step 4 as the "collateral impacts analysis,"[94] but this term is primarily applicable only to the environmental impact analysis. Overall, the Step 4 analysis is more accurately described as an environmental, economic, and energy impacts analysis that includes both direct and indirect (*i.e.,* collateral) considerations.

The economic impacts component of the analysis should focus on direct economic impacts calculated in terms of cost effectiveness (dollars per ton of pollutant emission reduced). Cost effectiveness should be addressed on both an average basis for each measure and combination of measures, and on an incremental basis comparing the costs and emissions performance level of a control option to the cost and performance of the next most stringent control option.[95] The emphasis should be on the cost of control relative to the amount of pollutant removed, rather than economic parameters that provide an indication of the general affordability of the control alternative relative to the source. To justify elimination of an option on economic grounds, the permit applicant should demonstrate that the costs of pollutant

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[93] 75 FR at 31531-2.
[94] *In re Hillman Power,* 10 E.A.D. at 683; *In the Matter of Columbia Gulf Transmission Co*., 2 E.A.D. 824, 828 n. 5 (Adm'r 1989); *In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17 (EAB 1997).
[95] 1990 Workshop Manual, Section IV.D.2.b (B.36 – B.44).

removal for that option are disproportionately high.[96] Appendix K provides further direction on determining and considering cost effectiveness of control options. As noted in Appendix K, cost estimates used in BACT are typically accurate to within ± 20 to 30 percent.

EPA has traditionally called for the energy impacts analysis to consider only direct energy consumption and not indirect energy impacts, such as the energy required to produce raw materials for construction of control equipment.[97] Direct energy consumption impacts include the consumption of fuel and the consumption of electrical or thermal energy. This energy impacts analysis should include an assessment of demand for both electricity that is generated onsite and power obtained from the electrical grid, and may include an evaluation of impacts on fuel scarcity or a locally desired fuel mix in a particular area. Applicants and permitting authorities should examine whether the energy requirements for each control option result in any significant or unusual energy penalties or benefits.[98] The costs associated with direct energy impacts should be calculated and included in the economic impacts analysis (*i.e.,* cost analysis).[99]

Since a BACT limitation must reflect the maximum degree of reduction achievable for each regulated pollutant, the environmental impacts analysis in Step 4 should concentrate on impacts other than direct impacts due to emissions of the regulated pollutant in question. EPA has previously recommended focusing the BACT environmental impacts analysis in this manner to avoid confusion with the separate air quality impact analysis required under the CAA and PSD regulations for primarily the pollutants that are covered by NAAQS.[100] However, focusing Step 4 of the BACT analysis on increases in emissions of pollutants other than those the technology was designed to control is also justified because the essential purpose of BACT requirement is to achieve the maximum degree of reduction of the particular pollutant under evaluation. In this context, it is generally unnecessary to explicitly consider or justify the environmental benefits of reducing the pollutant subject to the BACT analysis, since these benefits are presumed under the CAA's mandate to reduce emissions of each regulated pollutant to the maximum degree achievable, considering energy, environmental, and economic impacts. Thus, in this context, it is reasonable to interpret the "environmental impact" component of the BACT requirement to focus on the indirect or collateral environmental impacts that may result from selection of control options that achieve the maximum degree of reduction for the pollutant under evaluation.

EPA has recognized that consideration of a wide variety of environmental impacts is appropriate in BACT Step 4, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics.[101] EPA has also recognized that the environmental impacts analysis may examine trade-offs

[96] 1990 Workshop Manual at B.31-32.
[97] *In re Power Holdings*, PSD Appeal No. 09-04 (EAB Aug. 13, 2010), slip op. at 22, n.17 (citing 1990 Workshop Manual at B.30).
[98] 1990 Workshop Manual at B.29.
[99] 1990 Workshop Manual at B.30.
[100] 1990 Workshop Manual at B.46.
[101] 1990 Workshop Manual at B.46; *In the Matter of North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (Adm'r 1986).; *In the Matter of Columbia Gulf Transmission Co.*, 2 E.A.D. at 828.

between emissions of various pollutants resulting from the application of a specific control technique.[102] For instance, in selecting the BACT limit for carbon monoxide (CO) for a facility in an area that is nonattainment for ozone, a permitting authority may need to assess whether it is more important to select a less stringent control for CO emissions to avoid an unacceptable increase in NO_X emissions associated with the CO control technology. EPA has generally not attempted to place specific limits on the scope of the Step 4 environmental impacts analysis, but has focused on "any significant or unusual environmental impacts."[103]

To date, the environmental impacts analysis has not been a pivotal consideration when making BACT determinations in most cases.[104] Typically, applicants and permitting authorities focus on direct economic impacts (*i.e.,* cost effectiveness as measured in annualized cost per tons of pollutant removed by that control) as the reason for not selecting the top-ranked control option as BACT; however, there have been instances where environmental impacts have been a deciding factor in selecting a specific control technology as BACT (*i.e.,* water usage for scrubbers).[105]

Because the Step 4 impacts analysis is intended to help the permitting authority identify and weigh the various beneficial and detrimental impacts of the emissions control option or strategy being evaluated, EPA has recognized that permitting authorities have flexibility in deciding how to weigh the trade-offs associated with emissions control options. However, inherent with the flexibility is the responsibility of the permitting authority to develop a full permit record that explains those decisions given the specific facts of the facility at issue.[106]

GHG-Specific Considerations

There are compelling public health and welfare reasons for BACT to require all GHG reductions that are achievable, considering economic impacts and the other listed statutory factors. As a key step in the process of making GHGs a regulated pollutant, EPA has considered scientific literature on impacts of GHG emissions and has made a final determination that emissions of six GHGs endanger both the public health and the public welfare of current and future generations.[107] Among the public health impacts and risks that EPA cited are anticipated increases in ambient ozone and serious ozone-related health effects, increased likelihood of heat

[102] 1990 Workshop Manual at B.49.
[103] *In re Hillman Power* 10 E.A.D. at 684 (internal quotations omitted).
[104] 1990 Workshop Manual at B.49-50; *In the Matter of Columbia Gulf Transmission Co*., 2 E.A.D. at 828; *In re Hillman Power*, 10 E.A.D. at 688; *In re Kawaihae Cogeneration*, 7 E.A.D. at 117.
[105] Wyoming Dept. of Environmental Quality, Basin Electric Power Cooperative – Dry Fork Station, Permit Application Analysis NSR-AP-3546 (Feb. 5, 2007) at 11 (selecting a dry scrubber as BACT based, in part, on the "negative environmental impact" of the higher water use associated with the wet scrubber); *cf. In re Kawaihae Cogeneration Project*, 7 E.A.D. at 114-119 (upholding permitting decision in which the permitting authority considered the environmental impacts of ammonia used for SCR technology but found the increase in ammonia emissions were not significant enough to warrant use of less stringent NOx control technology)
[106] 1990 Workshop Manual at B.8-9. *See also Alaska Dept. of Environmental Conservation v. EPA*, 540 U.S. 461, 485-495 (2004) (finding EPA has the authority to review state BACT decisions to determine whether they complied with the CAA and upholding EPA's right to issue stop construction orders upon finding a state permitting authority's BACT determination was unreasonable).
[107] *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule*, 74 FR 66496, December 15, 2009.

waves affecting mortality and morbidity, risk of increased intensity of hurricanes and floods, and increased severity of coastal storm events due to rising sea levels. With respect to public welfare, EPA cited numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. The potentially serious adverse impacts of extreme events such as wildfires, flooding, drought and extreme weather conditions also supported EPA's finding.

The energy, environmental, and economic impacts discussed in the section above should be considered for each GHG control technology when conducting a top-down analysis. In conducting the energy, environmental and economic impacts analysis, permitting authorities have "a great deal of discretion" in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration.[108] EPA and other permitting authorities have most often used this analysis to eliminate more stringent control technologies with significant or unusual effects that are unacceptable in favor of the less stringent technologies with more acceptable collateral environmental effects. However, EPA has also interpreted the BACT requirements to allow for a more stringent technology to remain in consideration as BACT if the collateral environmental benefits of choosing such a technology outweigh the economic or energy costs of that selection.[109] In other words, the permitting authority is not limited to evaluating the impacts of only the "top" or most effective technology but can assess the impacts of all technologies under consideration.[110] The same principle applies when assessing technologies for controlling GHGs.

When conducting a BACT analysis for GHGs, the environmental impact analysis should continue to concentrate on impacts other than the direct impacts due to emissions of the regulated pollutant in question. Where GHG control strategies affect emissions of other regulated pollutants, applicants and permitting authorities should consider the potential trade-offs of selecting particular GHG control strategies. Likewise, when conducting a BACT analysis for other regulated NSR pollutants, applicants and permitting authorities should take care to consider how the control strategies under consideration may affect GHG emissions. For example, controlling volatile organic compound (VOC) emissions with a catalytic oxidation system creates GHG emissions in the form of CO_2. Permitting authorities have flexibility when evaluating the trade-offs associated with decreasing one pollutant at the cost of increasing another, and the specific considerations made will depend on the facts of the specific permit at issue. For options that involve improvements in the energy efficiency of a source, EPA does not expect there to be significant trade-offs in emissions of regulated pollutants since energy efficiency improvements should generally reduce emissions of all pollutants resulting from combustion processes.

When weighing any trade-offs between emissions of GHGs and emissions of other regulated NSR pollutants, EPA recommends that permitting authorities focus on the relative levels of GHG emissions rather than the endpoint impacts of GHGs. As a general matter, GHG emissions contribute to global warming and other climate changes that result in impacts on the environment and society. However, due to the global scope of the problem, climate change

[108] *In re Hillman Power*, 10 E.A.D. at 684.
[109] *In the Matter of North County Resource Recovery Assoc.*, 2 E.A.D. at 230-31.
[110] *In re Knauf Fiber Glass,* 8 E.A.D. at 131 n. 15.

modeling and evaluations of risks and impacts of GHG emissions currently is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying these exact impacts attributable to the specific GHG source obtaining a permit in specific places is not currently possible with climate change modeling. Given these considerations, an assessment of the potential increase or decrease in the overall level of GHG emissions from a source would serve as the more appropriate and credible metric for assessing the relative environmental impact of a given control strategy. Thus, when considering the trade-offs between the environmental impacts of a particular level of GHG reduction and a collateral increase in another regulated NSR pollutant, rather than attempting to determine or characterize specific environmental impacts from GHGs emitted at particular locations, EPA recommends that permitting authorities focus on the amount of GHG emission reductions that may be gained or lost by employing a particular control strategy and how that compares to the environmental or other impacts resulting from the collateral emissions increase of other regulated NSR pollutants.

In determining how to value or weigh any trade-offs in emissions for regulated pollutants (including GHGs), permitting authorities should continue to focus on "significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative."[111] Relatively small collateral increases of another pollutant need not be of concern, unless even that small increase would be significant, such as a situation where an area is close to exceeding a NAAQS or PSD increment and the additional increase could push the area into nonattainment. Thus, to assess the significance of an emissions increase or decrease, a permitting authority should give some consideration to the impacts of a given amount of emissions. However, permitting authorities need not consider every possible environmental endpoint impact of every conceivable technology. The top-down BACT process calls for evaluating only those control alternatives that remain under consideration at BACT Step 4 of the analysis. Thus, when a trade-off is present, permitting authorities may limit their consideration of environmental impacts to only to those control options in which the comparison of GHG emissions to other regulated NSR pollutants might actually lead to a different selection of BACT for that facility.

With respect to the evaluation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system. As with all evaluations of economics, a permitting authority should explain its decisions in a well-documented permitting record.

EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in

[111] *In re Hillman Power,* 10 E.A.D. at 684.

Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4. In addition, as a result of the ongoing research and development described in the Interagency Task Force Report noted above, CCS may become less costly and warrant greater consideration in Step 4 of the BACT analysis in the future.

As in the past for criteria pollutant BACT determinations, the final decision regarding the reasonableness of calculated cost effectiveness values will be made by the permitting authority. This decision is typically made by considering previous regulatory and permitting decisions for similar sources. As noted above, to justify elimination of a control option on economic grounds, the permit applicant should demonstrate that the costs of pollutant removal for the particular option are disproportionately high. However, given that there is little history of BACT analyses for GHG at this time, there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT. As the permitting of sources of GHG progresses and more experience is gained, additional data to determine what is cost effective in the context of individual permitting actions will become known and should be included in the RBLC. We note, however, that when looking at pollutants historically regulated under the PSD Program, such as criteria pollutants, the cost effectiveness of a control device is based on a significantly lower volume of emissions than the amount of emissions that are emitted by most sources of GHGs. For example, a new boiler that is subject to the NSPS and emits 250 TPY of NO_X will emit well above 100,000 TPY of CO_2e. As a result, even taking account of the current limited data and consequent uncertainty concerning the costs of GHG BACT, it is reasonable to anticipate that the cost effectiveness numbers (in \$/ton of CO_2e) for the control of GHGs will be significantly lower than those of the cost effectiveness values for controls of criteria pollutants that have evolved over time.[112]

With respect to energy impacts in a BACT analysis for GHGs, the relative energy demands of the options under consideration for reducing emissions from the facility obtaining a permit should be considered when weighing options for reducing direct emissions of GHGs in Step 4 of the analysis, regardless of the location where the thermal or electrical energy for the facility is produced. This analysis should include an assessment of how particular control options for GHGs may impact the amount of energy that must be produced at an offsite location to support the operation of the facility obtaining the permit. Given the potential emissions from generation of electricity, such impacts may also be considered in the context of environmental impacts.[113]

Permitting authorities also have flexibility when evaluating the trade-offs between energy, environmental, and economic impacts. In selecting a technology for GHG control, a

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[112] For consistency purposes, cost effectiveness for GHG control options should be based on dollars per ton of CO_2e removed, rather than total mass or mass for the individual GHGs.

[113] As discussed above in the section on Step 1, energy efficiency improvements that only function to reduce the secondary emissions associated with offsite combustion to produce energy at another location should not be considered as options in the BACT analysis under existing EPA interpretations of its regulations.

permitting authority may find that while a control option with high overall energy efficiency has higher economic costs, those costs are outweighed by the overall reduction of emissions of all pollutants that comes from that higher efficiency. There are no "right" answers to these permitting decisions that can be described in this general guidance, because permitting authorities have a wide range of discretion in their consideration of the various direct and indirect economic, energy, and environmental impacts that might be informative to the top-down BACT analysis for GHG emissions, as well as the BACT determinations for other pollutants. Given the case-by-case nature of the BACT analysis and the importance of considering impacts on the local environment and community (*e.g.,* job loss and the potential movement of production overseas), EPA still believes this flexibility provided for deciding how best to weigh the trade-offs associated with a particular emissions control option continues to be appropriate when evaluating BACT for GHGs. The exact scope and detail of that consideration – including the final decision regarding various trade-offs that may arise in a permitting decision – is dependent on many factors, including the specific facts of the proposed facility, local interests and concerns, and the nature of issues raised in public comments. Accordingly, permitting authorities must ensure that their impacts analysis fully considers the relevant facts and concerns for the facility at issue and that the support for the environmental, economic, and energy choices made during the impacts analysis of the BACT determination is well-documented in the permit record. In so doing, we encourage permitting authorities to use their discretion to consider the full range of impacts from the various controls that could result in facilities that are energy efficient and that lower the overall impact of the GHG emissions from those facilities, while maintaining relatively high levels of controls of other pollutants.

F. BACT Step 5 – Selecting BACT

General Concepts

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit. During Step 3, permitting authorities often consider control alternatives that have a range of potential effectiveness for reducing the pollutant emissions at issue, and thus they must identify an expected emissions reduction range for each technology. In setting the BACT limit in Step 5, the permitting authority should look at the range of performance identified previously and determine a specific limit to include in the final permit. In determining the appropriate limit, the permitting authority can consider a range of factors, including the ability of the control option to consistently achieve a certain emissions rate, available data on past performance of the selected technology, and special circumstances at the specific source under review which might affect the range of performance.[114] In setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue, and thus may consider safety factors unique to those circumstances in setting the limits.[115] EPA has also recognized that in

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[114] *In re Prairie State Generating Company*, 13 E.A.D. at 67-71.
[115] *In re Prairie State Generating Company*, 13 E.A.D. at 71, 73 (and cases cited therein).

some circumstances, it may be acceptable to establish BACT limits that can be adjusted or optimized as the performance of a technology becomes clearer after a period of operation.[116]

The permitting authority is also responsible for defining the form of the BACT limits, and making them enforceable as a practical matter.[117] In determining the form of the limit, the permitting authority should consider issues such as averaging times and units of measurement. For example, a final permit may include a limit based on pounds of emissions on a 24-hour rolling average or a limit representing a percentage of pollutant per weight allowed in the fuel. When making sure the limit is practically enforceable, the permitting authority must include information regarding the methods that will be used for determining compliance with the limits (such as operational parameters, timing, testing methods, etc.) and ensure that there is no ambiguity in the permit terms themselves.[118]

Finally, the permitting authority bears the responsibility in Step 5 to fully justify the BACT decision in the permit record. Regardless of the control level proposed by the applicant as BACT, the ultimate determination of BACT is made by the permitting authority after public review is complete. The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permitting authority to review the documentation and rationale presented in order to: (1) ensure that the applicant has addressed all of the most effective control options that could be applied and; (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permitting authority does not accept the basis for the proposed elimination of a control option, the permitting authority may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permitting authority's satisfaction an adequate demonstration for one or more control alternatives, the permitting authority should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided.

GHG-Specific Considerations

We expect many permits issued after January 2, 2011, to initially place more of an emphasis on energy efficiency, given the role it plays in affecting emissions of GHGs. For energy producing sources, as noted above, one way to incorporate the energy efficiency of a process unit into the BACT analysis is to compare control effectiveness in BACT Step 3 based on output-based emissions of each of the control options. Even in cases where another metric is used in Step 3 to compare options, once an option is selected in Step 5, permitting authorities

[116] *In re AES Puerto Rico, L.P.*, 8 E.A.D. 324, 348-50 (EAB 1999), *In re Hadson Power 14-Buena Vista*, 4 E.A.D. 258, 291 (EAB 1992).
[117] *See generally* EPA Guidance on Limiting Potential to Emit (PTE) in New Source Permitting (June 13, 1989), *available at* http://www.epa.gov/reg3artd/permitting/t5_epa_guidance.htm.
[118] *In re Prairie State Generating Company*, 13 E.A.D. at 83, 120.

may consider converting the BACT emissions limit to a net output basis for the permitted emissions limit. EPA encourages permitting authorities to consider establishing an output-based BACT emissions limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation. Although developed as part of a voluntary program, EPA believes the draft handbook entitled *Output-Based Regulations: A Handbook for Air Regulators* (August 2004) may provide relevant information to assist permitting authorities in establishing limits based on output.[119] Furthermore, since the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages (*e.g.,* 30- or 365-day rolling average) rather than short-term averages (*e.g.,* 3- or 24-hr rolling average).

In addition to a permit containing specific numerical emissions limits established in a BACT analysis, a permit can also include conditions requiring the use of a work practice such as an Environmental Management System (EMS) focused on energy efficiency as part of that BACT analysis. The ENERGY STAR program provides useful guidance on the elements of an energy management program. The inclusion of such a requirement would be appropriate where it is technically impractical to measure emissions and/or energy use from all of the equipment and processes of the plant and apply an output-based standard to each of them. For example, a candidate might be a factory with many different pieces of equipment and processes that use energy. In addition to a BACT emissions limit on the boiler providing energy, the permit could also lay out a requirement to implement an EMS along with a requirement that all suggested actions that result in net savings have to be implemented. Consequently, the plant will operate in the most efficient manner through gradual achievable improvements. However, design, equipment, or work practice standards may not be used in lieu of a numerical emissions limitation(s) unless there is a demonstration in the record that the criteria for applying such a standard are satisfied.

[119] *Output-Based Regulations: A Handbook for Air Regulators* (Draft Final Report) (August 2004), *available at* http://www.epa.gov/chp/documents/obr_final_9105.pdf.

IV. Other PSD Requirements

General Concepts

The PSD requirements include several provisions requiring new and modified major stationary sources to conduct air quality analyses that may involve air quality modeling and ambient monitoring. The applicant must demonstrate that the emissions of any regulated NSR pollutant do not cause or contribute to a violation of any NAAQS or PSD increments.[120] Several months of ambient air quality data must also be collected in some circumstances to support this analysis.[121] In addition, as part of the "additional impacts analysis," the applicant must provide an analysis of the air quality impact of the source or modification, including an analysis of the impairment to visibility, soils, and vegetation (but not vegetation with no significant commercial or recreational value) that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification.[122] Under the federal PSD rules, this analysis may also include monitoring of visibility in any Federal Class I area near the source or modification "for such purposes and by such means as the Administrator deems necessary and appropriate."[123] A demonstration must be made that emissions will not cause or contribute to a violation of any Class I increment and will not have an adverse impact on any air quality related value (AQRV), as defined by the Federal Land Manager, in such area.[124] Under PSD, if a source's proposed project may impact a Class I area, the Federal Land Manager must be notified so this office may fulfill its responsibility for evaluating a source's projected impact on the AQRVs and recommending either approval or disapproval of the source's permit application based on anticipated impacts.

GHG-Specific Considerations

The Tailoring Rule includes the following statement with respect to these requirements:

> "There are currently no NAAQS or PSD increments established for GHGs, and therefore these PSD requirements would not apply for GHGs, even when PSD is triggered for GHGs. However, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the new source emits in significant amounts would be subject to PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements would apply to those pollutants."[125]

Since there are no NAAQS or PSD increments for GHGs,[126] the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or

[120] 42 USC 7475(a)(3); 40 CFR 52.21(k); 40 CFR 51.166(k).
[121] 40 CFR 52.21(m); 40 CFR 51.166(m); 40 CFR 52.21(i)(5); 40 CFR 51.166(i)(5).
[122] 40 CFR 52.21(o); 40 CFR 51.166(o).
[123] 40 CFR 52.21(o)(3).
[124] 40 CFR 52.21(p); 40 CFR 51.166(p).
[125] 75 FR at 31520.
[126] In addition, GHGS have not been designated as a precursor for any criteria pollutant under section 302(g) of the Clean Air Act or in EPA's PSD rules.

contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs.

Monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. However, it should be noted that sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. These provisions call for collection of air quality monitoring data "as the Administrator determines is necessary to assess ambient air quality for that pollutant in any (or the) area that the emissions of that pollutant would affect." In the case of GHGs, the exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) is controlling since GHGs are not currently listed in the relevant paragraph. Nevertheless, EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.

Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

Applicants and permitting authorities should note that, while we are not recommending these analyses for GHG emissions, the incorporation of GHGs into the PSD program does not change the need for sources and permitting authorities to address these requirements for other regulated NSR pollutants. Accordingly, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the source emits in significant amounts would be subject to these other PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements must be satisfied for those pollutants and the applicant and permitting authority are required to conduct the necessary analysis.

V. Title V Considerations

A. General Concepts and Title V Requirements

Under the CAA, major sources (and certain other sources) must apply for, and operate in accordance with, an operating permit that contains conditions necessary to assure compliance with all CAA requirements applicable to the source.[127] The operating permit requirements under title V are intended to improve sources' compliance with other CAA requirements. Title V generally does not add new pollution control requirements, but it does require that each permit contain all air quality control requirements or "applicable requirements" required under the CAA (*e.g.,* NSPS and SIP requirements, including PSD), and it requires that certain procedural requirements be followed, especially with respect to compliance with these requirements. "Applicable requirements" for title V purposes include stationary source requirements, but do not include mobile source requirements. Procedural requirements include providing review of permits by EPA, states, and the public, requiring permit holders to track, report, and annually certify their compliance status with respect to their permit requirements, and otherwise ensuring that permits contain conditions to assure compliance with applicable requirements.

This section discusses title V requirements as they pertain to GHGs. These include the applicability requirement for title V permitting due to GHG emissions (*e.g.*, when a source will become subject to title V for the first time due to its GHG emissions), and requirements for permit applications and permit content. Under Step 1 of the Tailoring Rule, no sources become major sources requiring a title V permit solely as a result of GHG emissions. Sources must address GHGs in a title V permit only if they must address GHGs in their PSD permit (thus, they are a PSD "anyway source" or undergo an "anyway modification"). Beginning in Step 2 of the Tailoring Rule, a stationary source may be a major source subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source exceeds the thresholds established in the Tailoring Rule (discussed below).

Under both Step 1 and Step 2 of the Tailoring Rule, when a source is required to address GHGs in their title V permit, the permit needs to meet the generally applicable title V application and permitting requirements for GHGs, such as describing emissions of GHGs and including in the permit any applicable requirements for GHGs established under other CAA programs (*e.g.*, the PSD program). The source's operating permit application generally must contain emissions-related information for: (1) all pollutants for which the source is major (see the definition of "major stationary source" in 40 CFR 70.2, which incorporates the requirements that a pollutant be subject to regulation, and an emissions threshold for GHG); and (2) all emissions of "regulated air pollutants" (which, under 40 CFR 70.2, includes criteria pollutants, VOCs, and pollutants regulated under CAA Section 111 or 112 standards, but does not currently include GHGs). In addition, the permitting authority shall require sources to provide additional emissions information sufficient to verify which requirements are applicable to the source and

[127] Details of the title V program are addressed in rules promulgated by EPA – 40 CFR 70 addresses programs implemented by state and local agencies and tribes, and 40 CFR 71 addresses programs generally implemented by EPA.

other specific information that may be necessary to implement and enforce other applicable requirements of the CAA or to determine the applicability of such requirements.[128]

Since the Tailoring Rule establishes a phased applicability approach under title V, the pertinent requirements vary somewhat between the first two steps of the Tailoring Rule. The following is a summary of the key requirements and some general examples with respect to title V applicability and title V permitting requirements (including permit application and permit content) with respect to GHGs under Steps 1 and 2 of the Tailoring Rule.

B. Title V Applicability Requirements and GHGs

Applicability requirements for title V permitting as they apply to GHG emissions are summarized in the following table and explained in more detail in subsections V.B.1 and V.B.2 following the table:

Table V-A. Summary of Title V Applicability Criteria for Sources of GHGs

January 2, 2011, to June 30, 2011 (Step 1 of the Tailoring Rule)	**On or after July 1, 2011 (Step 2 of the Tailoring Rule)**
No sources are subject to title V permitting solely as a result of their emissions of GHGs. (Thus, no new title V sources come into the title V program as a result of GHG emissions.) [However, for sources subject to, or that become newly subject to, title V for non-GHG pollutants (*i.e.,* PSD "anyway sources"), sources and permitting authorities need to meet the generally applicable title V application and permitting requirements as necessary to address GHGs, such as including in the permit any applicable requirements for GHGs established under other CAA programs.]*	The following sources are subject to title V permitting requirements as a result of their GHG emissions: • Existing or newly constructed GHG emission sources (not already subject to title V) that emit or have a PTE equal to or greater than: o 100,000 TPY CO_2e, **and** o 100 TPY GHGs mass basis [As with Step 1, for all PSD "anyway sources" subject to title V in Step 2, sources and permitting authorities need to meet the generally applicable title V application and permitting requirements as necessary to address GHGs, such as including in the permit any applicable requirements for GHGs established under other CAA programs]*

* It is expected, at least at the outset, that this will consist primarily of meeting application and permitting requirements necessary to assure compliance with PSD permitting requirements for GHGs. See accompanying text in Section V.C of this guidance for further discussion and examples.

1. *Applicability under Tailoring Rule Step* 1

Under Step 1, no sources are subject to title V permitting solely as a result of their emissions of GHGs. Thus no new title V sources come into the title V program solely as a result of GHG emissions. However, sources required to have title V permits because they are PSD "anyway sources" or undergo PSD "anyway modifications" will be required to address GHGs as

[128] 40 CFR 70.5.

part of their title V permitting to the extent necessary to assure compliance with GHG applicable requirements established under other CAA programs. Section C below describes how sources and permitting authorities should consider addressing GHG requirements in permitting actions.

2. *Applicability under Tailoring Rule Step 2*

Beginning in Step 2 of the Tailoring Rule, a stationary source may be a major source subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source exceeds the thresholds established in the Tailoring Rule. GHG emission sources that emit or have the PTE at least 100,000 TPY CO_2e, and also emit or have the PTE 100 TPY of GHGs on a mass basis will be required to obtain a title V permit if they do not already have one. It is important to note that the requirement to obtain a title V permit will not, by itself, result in the triggering of additional substantive requirements for control of GHG. Rather, these new title V permits will simply incorporate whatever applicable CAA requirements, if any, apply to the source being permitted.

Both of the following conditions need to be met in order for title V to apply under Step 2 of the Tailoring Rule to a GHG emission source:

(1) An existing or newly constructed source emits or has the PTE GHGs in amounts that equal or exceed 100 TPY calculated as the sum of the six well-mixed GHGs on a mass basis (no GWPs applied).

(2) An existing or newly constructed source emits or has the PTE GHGs in amounts that equal or exceed 100,000 TPY calculated as the sum of the six well-mixed GHGs on a CO_2e basis (GWPs applied).

In Step 2, as under Step 1, for all sources otherwise subject to title V for non-GHG pollutants (*i.e.,* anyway sources), sources and permitting authorities will need to meet the generally applicable title V application and permitting requirements as they pertain to GHG applicable requirements established under other CAA programs (*e.g.,* the PSD program). See Section C below for further discussion of permitting requirements.

C. Permitting Requirements

Under both Steps 1 and 2 of the Tailoring Rule, as with other applicable requirements related to non-GHG pollutants, any applicable requirement for GHGs must be addressed in the title V permit (*i.e.,* the permit must contain conditions necessary to assure compliance with applicable requirements for GHGs). EPA anticipates that the initial applicable requirements for GHGs will be in the form of GHG control requirements resulting from PSD permitting actions. It is important to note that GHG reporting requirements for sources established under EPA's final rule for the mandatory reporting of GHGs (40 CFR Part 98: Mandatory Greenhouse Gas Reporting, hereafter referred to as the "GHG reporting rule") are currently not included in the definition of applicable requirement in 40 CFR 70.2 and 71.2. Although the requirements contained in the GHG reporting rule currently are not considered applicable requirements under the title V regulations, the source is not relieved from the requirement to comply with the GHG reporting rule separately from compliance with their title V operating permit. It is the responsibility of each source to determine the applicability of the GHG reporting rule and to comply with it, as necessary. However, since the requirements of the GHG reporting rule are not considered applicable requirements under title V, they do not need to be included in the title V permit.

Under both Steps 1 and 2 of the Tailoring Rule, sources will need to include in their title V permit applications, among other things: citation and descriptions of any applicable requirements for GHGs (*e.g.,* GHG BACT requirements resulting from a PSD review process), information pertaining to any associated monitoring and other compliance activities, and any other information considered necessary to determine the applicability of, and impose, any applicable requirements for GHGs. This is the same application information required under title V for applicable requirements pertaining to conventional pollutants.

As a general matter, all title V permits issued by permitting authorities must contain, among other things, emissions limitations and standards necessary to assure compliance with all applicable requirements for GHGs, all monitoring and testing required by applicable requirements for GHGs, and additional compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with GHG-related terms and conditions of the permit. Permitting authorities will also need to request from sources any information deemed necessary to determine or impose GHG applicable requirements.

It is possible that some sources will need to address GHG-related information in their applications even if they will ultimately not have any GHG-specific applicable requirements (such as a PSD-related BACT requirement for GHGs) included in their permit. This is because, as noted above, permitting authorities would need to request information related to identifying GHG emission sources and other information if they determine such information is necessary to determine applicable requirements. Following is an explanation of the basis for requesting this information and some examples of these types of scenarios under Steps 1 and 2 of the Tailoring Rule.

Under Step 1 of the Tailoring Rule, no source can be major for purposes of title V solely on the basis of its GHG emissions, so the requirement set forth in 40 CFR 70.5 for the source to provide emissions-related information for pollutants for which the source is major does not apply. In addition, as GHGs are not currently considered regulated air pollutants under the title V regulations, the requirement to provide emissions-related information for regulated air pollutants does not apply. However, consistent with the requirements set forth in 40 CFR 70.5, permitting authorities will need to ask for any emissions or other information they deem necessary to determine applicability of, or impose, a CAA requirement.[129] Therefore, during Step 1 of the Tailoring Rule, any source going through a title V permitting action (*i.e.,* applying for a title V operating permit or undergoing a permit revision, reopening or renewal) would need

[129] Note that the phrase "subject to regulation" in the definition of major source in the title V regulations affects when a source may be a major source subject to title V as a result of emissions of a pollutant. If a source is already subject to title V, its application must include any information considered necessary to determine or impose a GHG applicable requirement – this is true even before GHGs become "subject to regulation" for major sources purposes.

to provide GHG emissions or other information if a permitting authority needs the information to determine applicability of a CAA requirement (*e.g.*, PSD).[130] The following is an example of where this request for information might occur:

> *An existing title V source is making a physical change that triggers PSD for NO_X. This change will result in additional applicable requirements for NO_X emissions controls but, according to the applicant, does not trigger BACT review for GHGs. In this case, as part of its analysis of the application for permit revision under its title V program, the permitting authority may determine it necessary to verify that the project did not trigger BACT requirements for GHG emissions, and therefore may need to request the applicant to submit GHG emissions information related to the project sufficient for the permitting authority to determine that PSD did not apply for GHG emissions from the project. This information could include such items as identification and descriptions of any GHG emission units and estimates of GHG emissions associated with the modification project.*

Under Step 2 of the Tailoring Rule, beginning July 1, 2011, a stationary source may be subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source is equal to or greater than the 100,000 TPY CO_2e subject to regulation threshold (as well as the 100 TPY major source mass-based threshold) on a PTE basis. As noted above, sources generally must provide information regarding all emissions of pollutants for which they are major. In many cases, particularly where the source has no applicable requirements for GHGs, emissions descriptions (instead of estimates) may be sufficient. For sources subject to the GHG reporting rule, the emissions description requirements in the title V rules will generally be satisfied by information provided under the reporting rule. Further elaboration on the requirement for emissions data is provided in the White Paper 1 guidance on title V.[131] The following is an example of a permitting scenario under title V during Step 2 of the Tailoring Rule:

> *As of July 1, 2011, an existing facility not previously subject to title V has a GHG PTE over 100,000 TPY CO_2e and over 100 TPY on a mass basis. Therefore, according to the Tailoring Rule applicability criteria for GHG sources, this source becomes subject to title V solely based on its GHG emissions as of July 1, 2011. First, it will need to apply for a title V permit within 12 months of July 1, 2011 (unless an earlier date has been established by the permitting authority). Second, assuming that the facility does not have any applicable requirements for GHG emissions (such as a GHG BACT requirement resulting from a PSD review), the permitting authority may deem it sufficient that the facility simply provide a description of the GHG emission sources at the facility that cause the facility to exceed the applicability criteria threshold for GHGs under title V, rather than a detailed quantification of its GHG emission sources. Lastly, the source would also need to provide other emissions information as necessary for non-GHG emission sources (e.g., information on emissions of regulated air pollutants, information for fee calculation, etc.)*

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[130] 40 CFR 70.5(c)(5).
[131] Office of Air Quality Planning and Standards, *White Paper for Streamlined Development of Part 70 Permit Applications* (July 10, 1995).

It is also important to note that sources that are newly subject to title V solely as a result of their GHG emissions will also need to provide in their title V permit applications required information regarding all other applicable requirements that apply to it under the Act (*e.g.,* SIP regulations). The following is an example of this permitting scenario under Step 2 of the Tailoring Rule:

> *A facility becomes subject to title V permitting requirements solely on the basis of its GHG emissions on July 2, 2011, and, therefore, must apply for a title V permit. The facility has an applicable requirement, such as a SIP requirement imposing an opacity limit on fuel-burning equipment that lacks periodic monitoring and monitoring sufficient to assure compliance. Even if the newly subject title V source did not have any specific GHG-related requirements to include in the title V permit, under this scenario, the facility must propose appropriate monitoring, recordkeeping and reporting (MRR) to assure compliance with the opacity standard in its permit application and the permitting authority must add appropriate MRR to the operating permit for that opacity standard (which may be the MRR proposed by the facility or other requirements) under the authority of the Act.*

D. Title V Fees

EPA rules currently do not require sources to pay any title V fees based on GHG emissions or to otherwise quantify GHG emissions strictly for title V fee purposes. However, throughout Steps 1 and 2 of the Tailoring Rule, the statutory and regulatory requirement to collect fees sufficient to cover all reasonable (direct and indirect) costs required to develop and administer title V programs still applies.[132] Permitting authorities need to review resource needs for GHG-emitting sources and determine if their existing fee structure is adequate. If not, permitting authorities would need to raise fees to cover the direct and indirect costs of the program or develop alternative approaches. EPA will work with permitting authorities that request assistance concerning establishing title V fees related to GHG emissions.

E. Flexible Permits

The final Flexible Air Permitting Rule (74 FR 51418), promulgated on October 6, 2009, reflects EPA's policy and rules governing the use of flexible air permits. A flexible air permit (FAP) is a title V operating permit that by its design authorizes the source owner to make certain types or categories of physical and/or operational changes without further review or approval of the individual changes by the permitting authority. Flexible air permits cannot circumvent, modify, or contravene any applicable requirement and, instead, by their design must assure compliance with each one. Based on our evaluation of State FAP pilots in addition to providing greater operational flexibility, FAPs can result in greater environmental protection, lower administrative costs, pollution prevention and increased energy efficiency.

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[132] 42 USC 7661a(b)(3)(B); 40 CFR 70.9.

FAP approaches can significantly reduce the administrative resources associated with CAA permitting requirements and provide a streamlined path for installing new energy-efficient equipment at industrial facilities. While many energy-efficient equipment upgrades may not trigger air permitting requirements, some changes have the potential to trigger permitting actions or applicability determination activities. The combination of plantwide emissions limits, alternative operating scenarios, and/or advance approvals of categories of operational changes can eliminate the need for case-by-case evaluation (under title V and PSD/NSR) for future energy-efficient equipment upgrades, thereby reducing time delays, uncertainty, and transaction costs in making these changes. In the absence of FAP approaches, air permitting considerations may cause a facility to forego or delay energy-efficient equipment upgrades that have potential to trigger air permitting requirements. FAP approaches can be used to accommodate these types of changes in a streamlined manner that addresses all applicable regulatory requirements up-front.

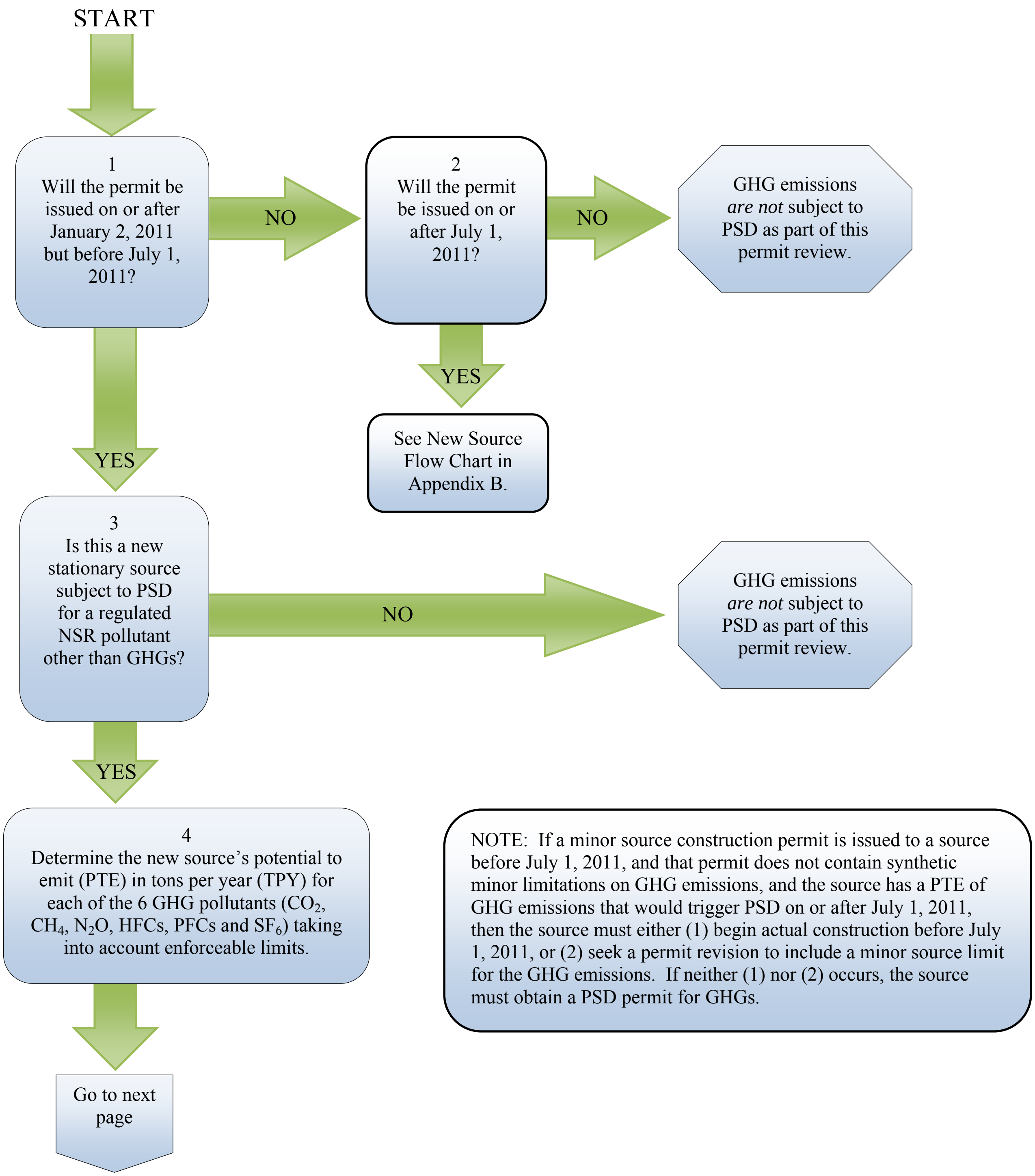
EPA encourages permitting authorities and sources to consider FAPs, particularly in situations where a source is planning to implement an ongoing program designed to improve energy efficiency and reduce GHG over time.

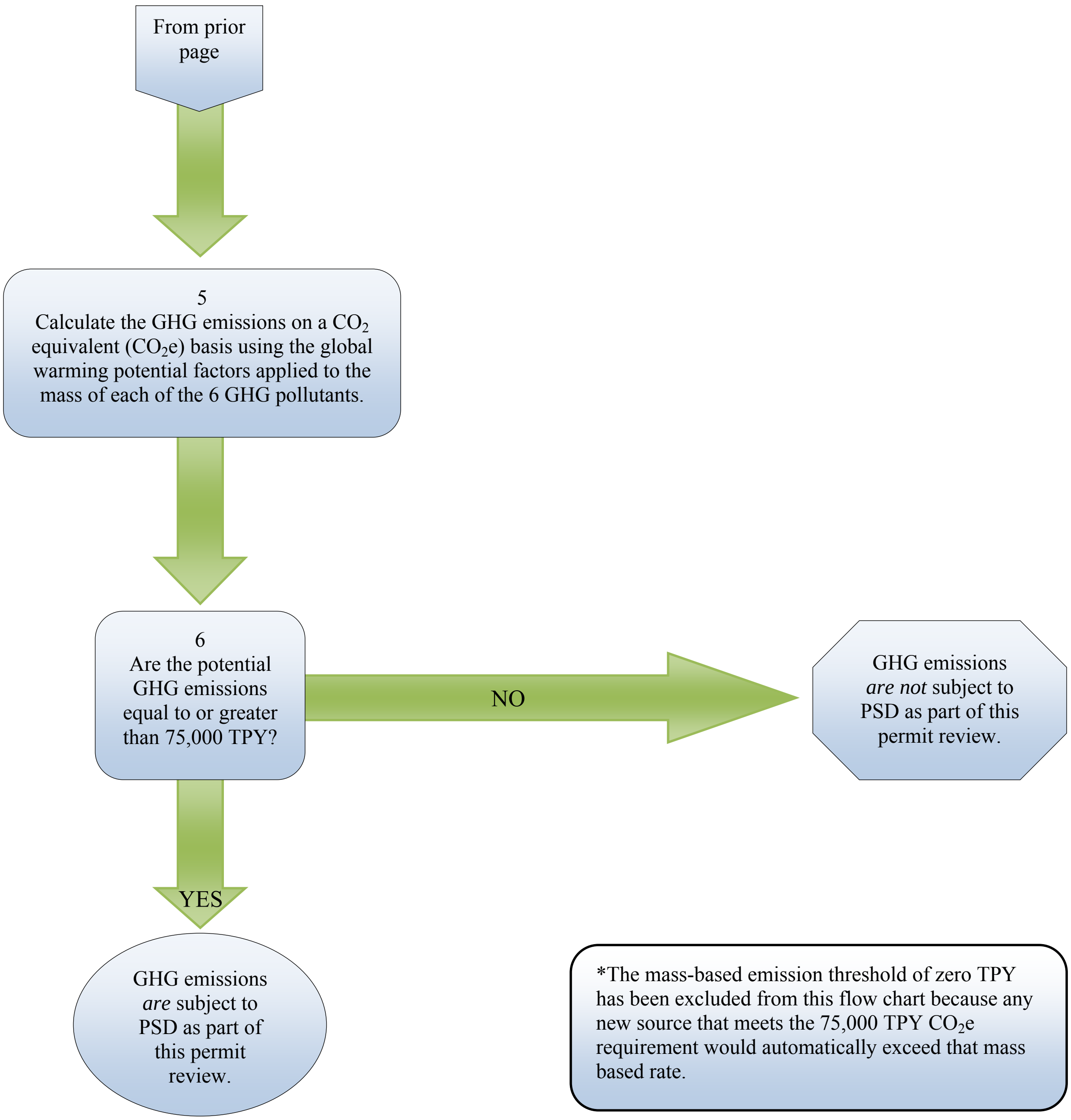
VI. Appendices

Note: The regulatory changes implemented in the Tailoring Rule set forth a two-part applicability process determining the applicability of PSD to GHGs, which first evaluates the sum of the GHG emissions on a CO_2e basis in order to determine whether the source's emissions are a regulated NSR pollutant, and, if so, then evaluates the sum of the GHG emissions on a mass basis in order to determine if there is a major source or major modification of such emissions. However, we noted in the Tailoring Rule preamble that most sources are likely to treat the mass-based analysis as an initial screen from a practical standpoint, since they would not proceed to calculate emissions on a CO_2e basis if they would not trigger PSD or title V on a mass basis.[133] Accordingly, the examples provided in the attached appendices take a variety of approaches for undertaking the required CO_2e and mass-based calculations, and permit applicants and permitting authorities may use the processes identified in this guidance or another process for determining applicability of PSD to GHGs in permits they issue, so long as their process complies with the relevant statutory and regulatory requirements.

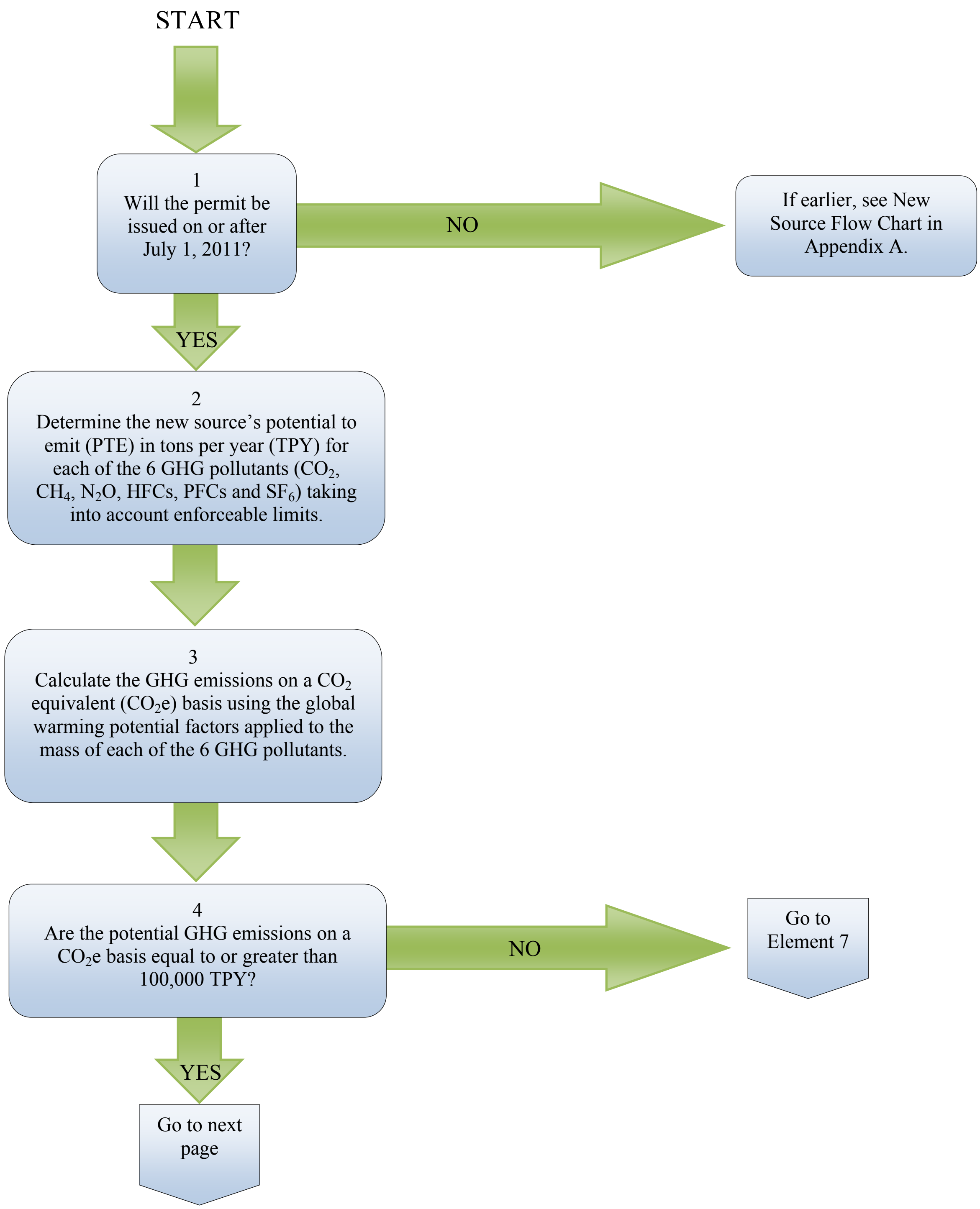
[133] 75 FR 31514, 31522 (June 3, 2010).

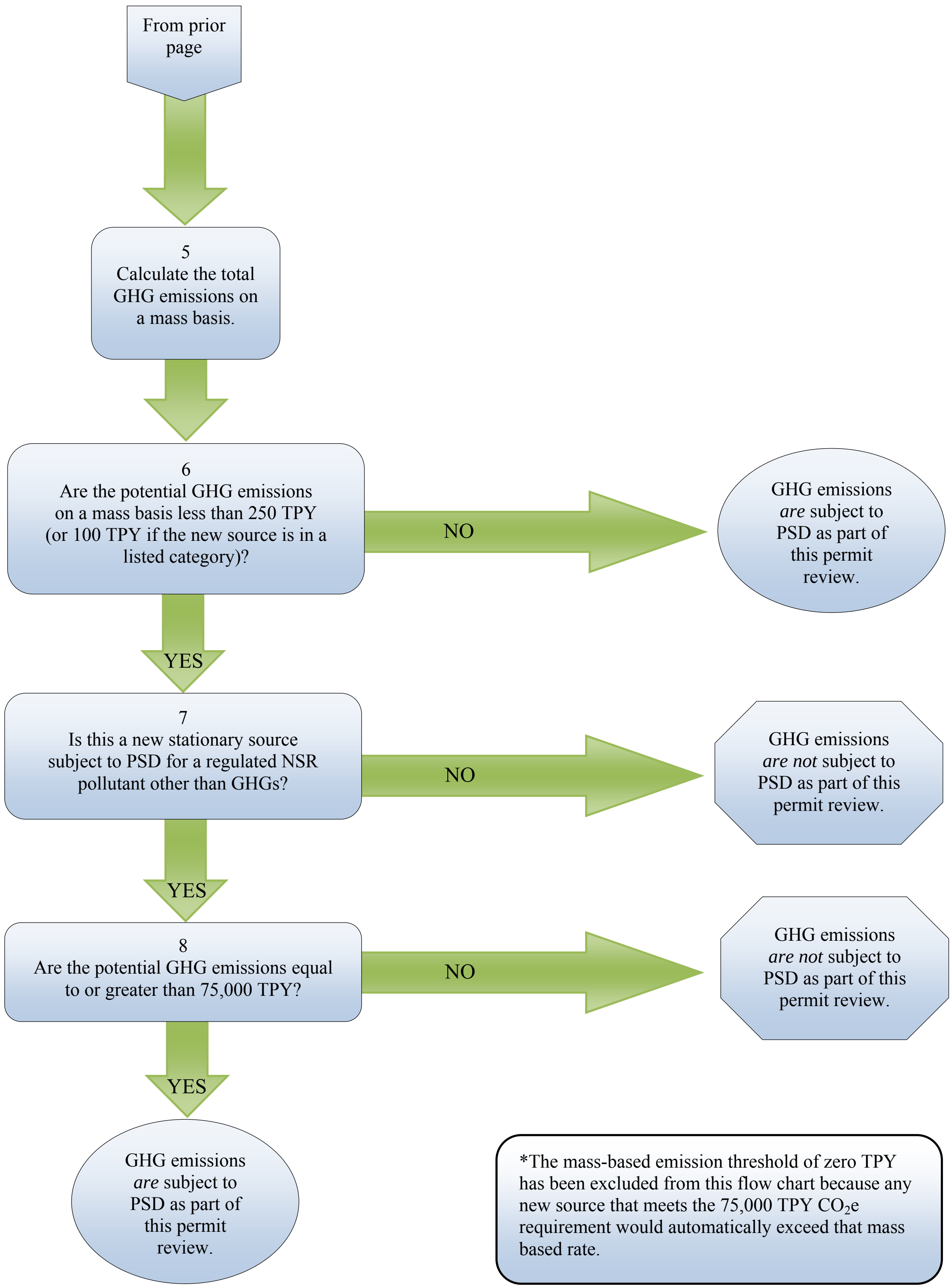
Appendix A. GHG Applicability Flow Chart – New Sources (January 2, 2011, through June 30, 2011)



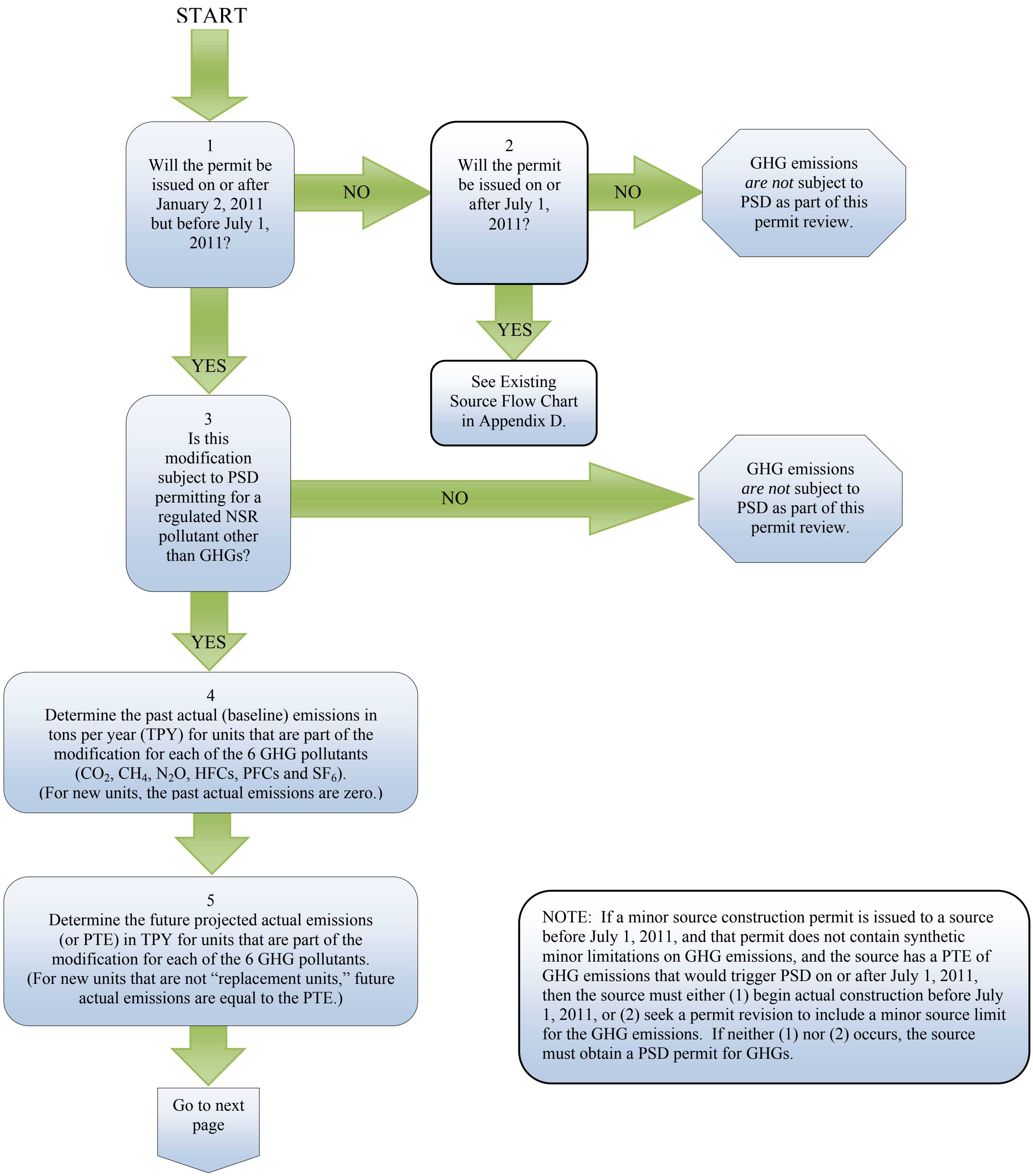

From prior page
5
Calculate the GHG emissions on a CO_2 equivalent (CO_2e) basis using the global warming potential factors applied to the mass of each of the 6 GHG pollutants.
6
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

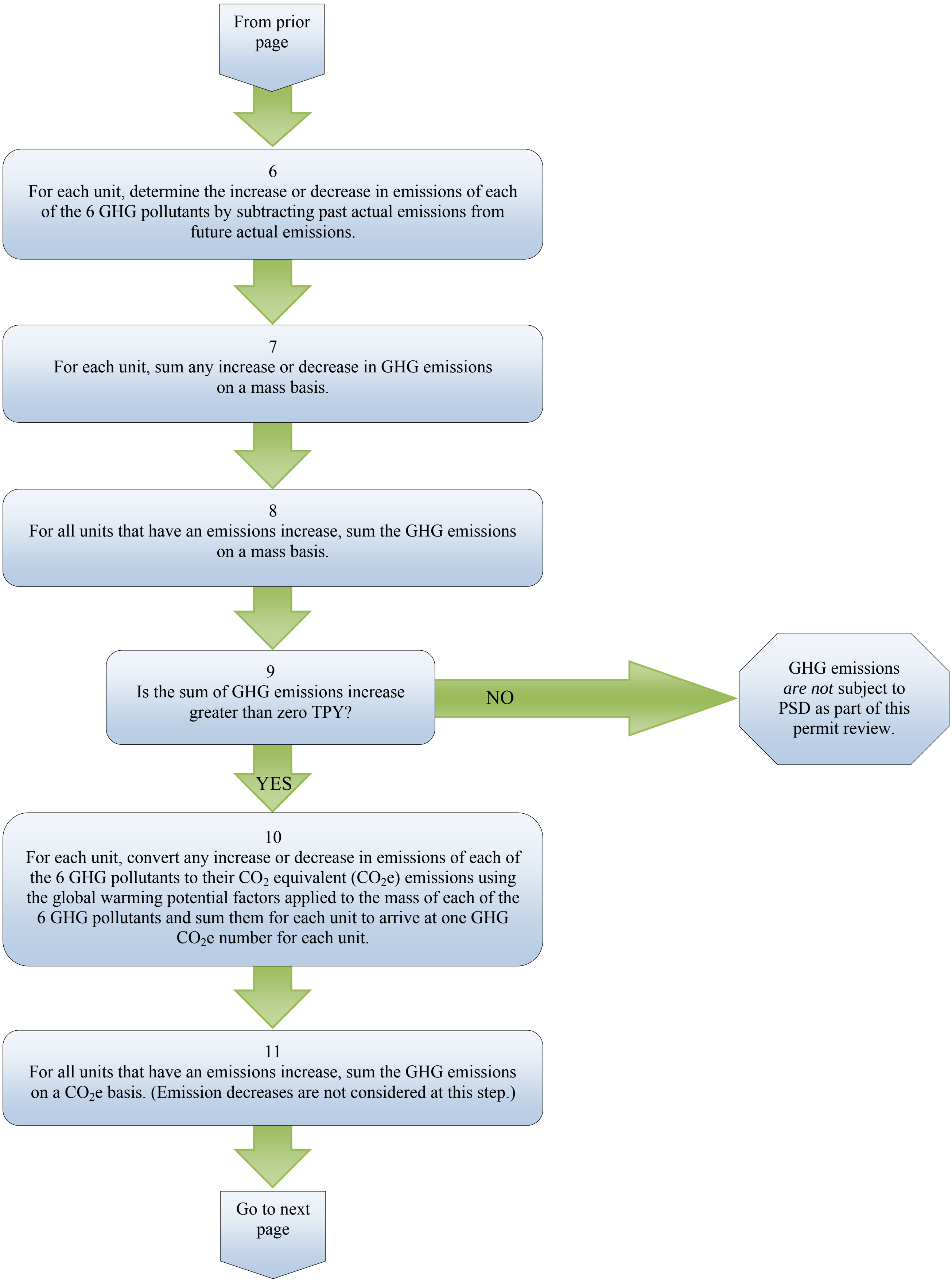
Appendix B. GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)

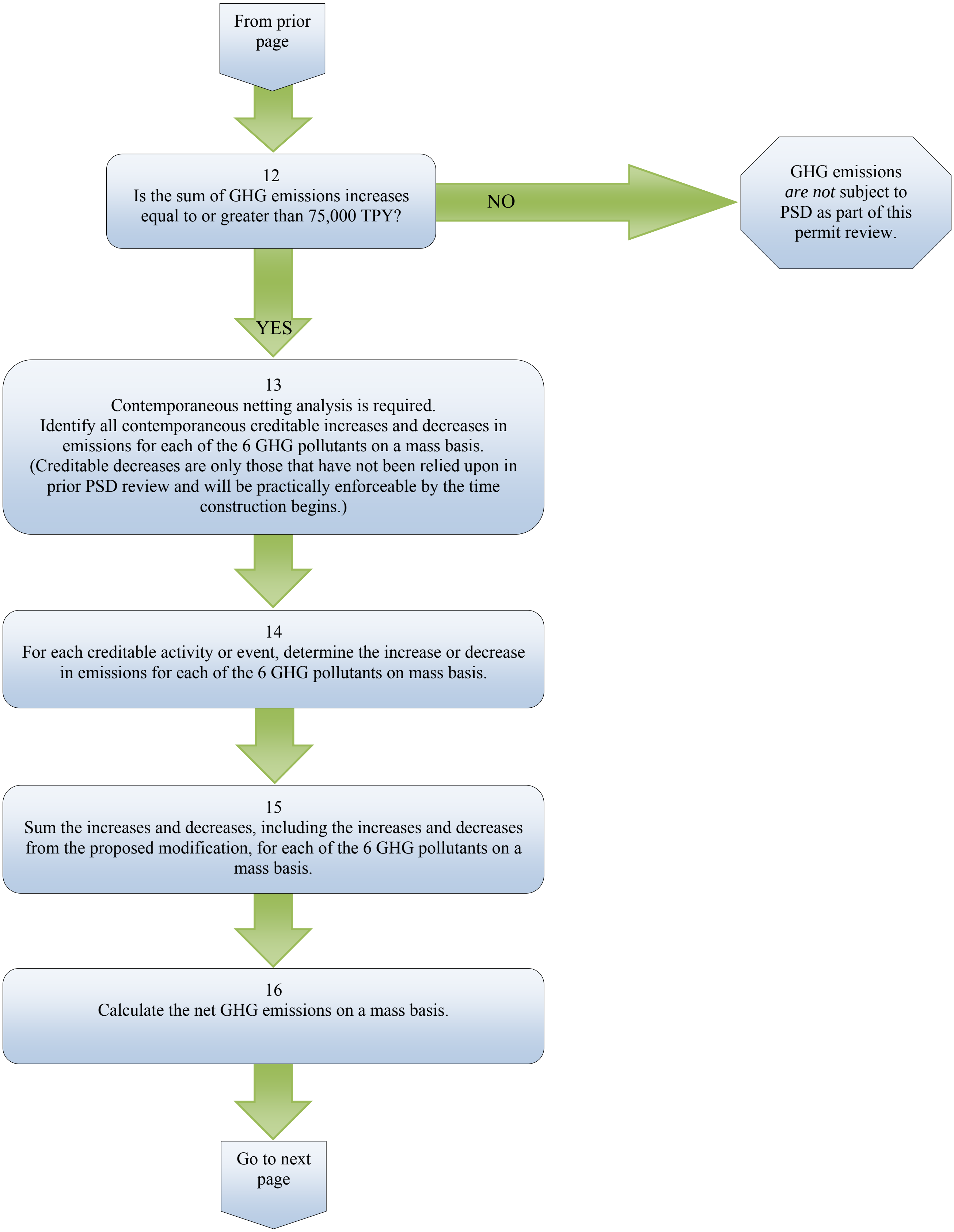


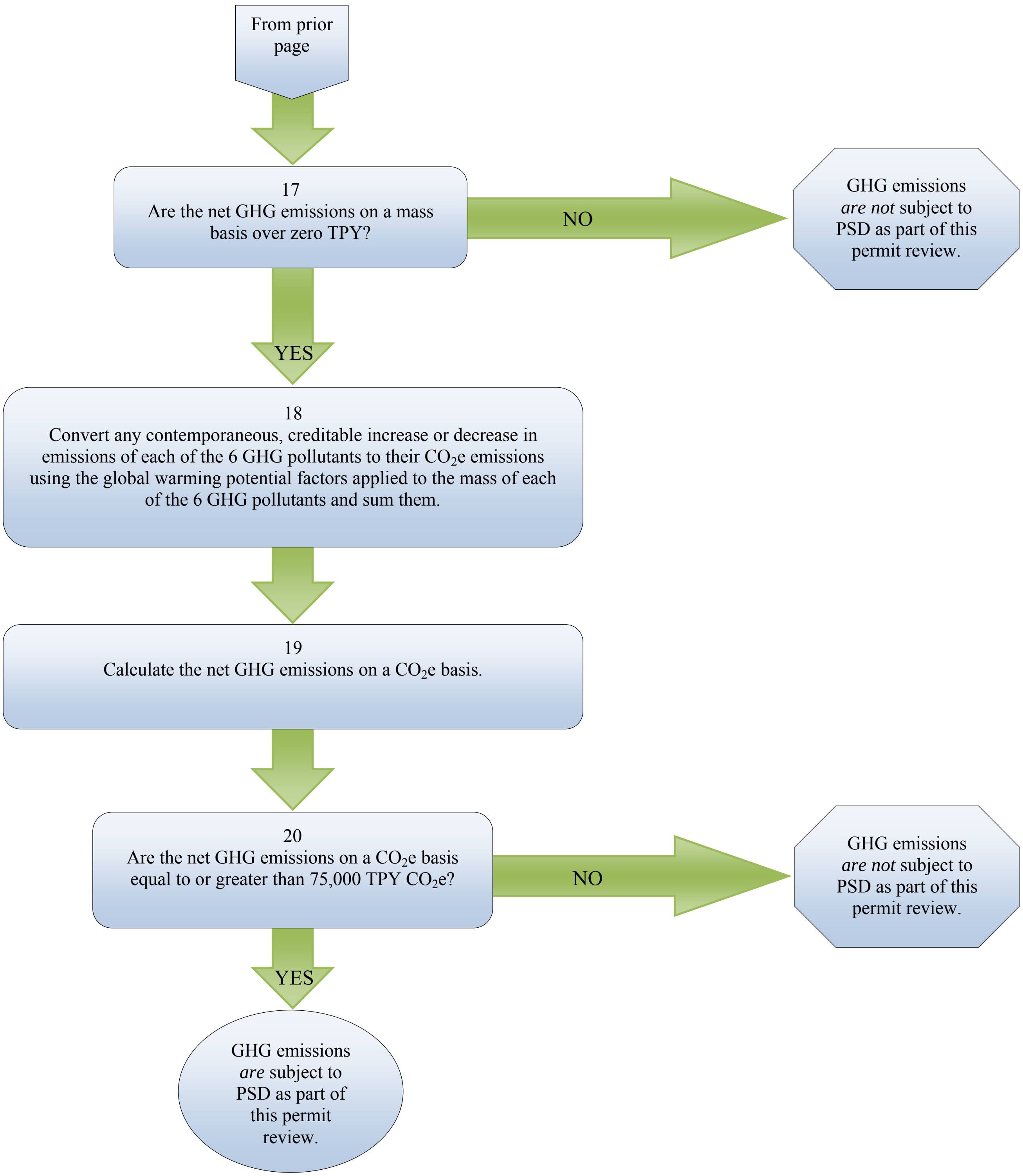

From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

Appendix C. GHG Applicability Flow Chart – Modified Sources (January 2, 2011, through June 30, 2011)

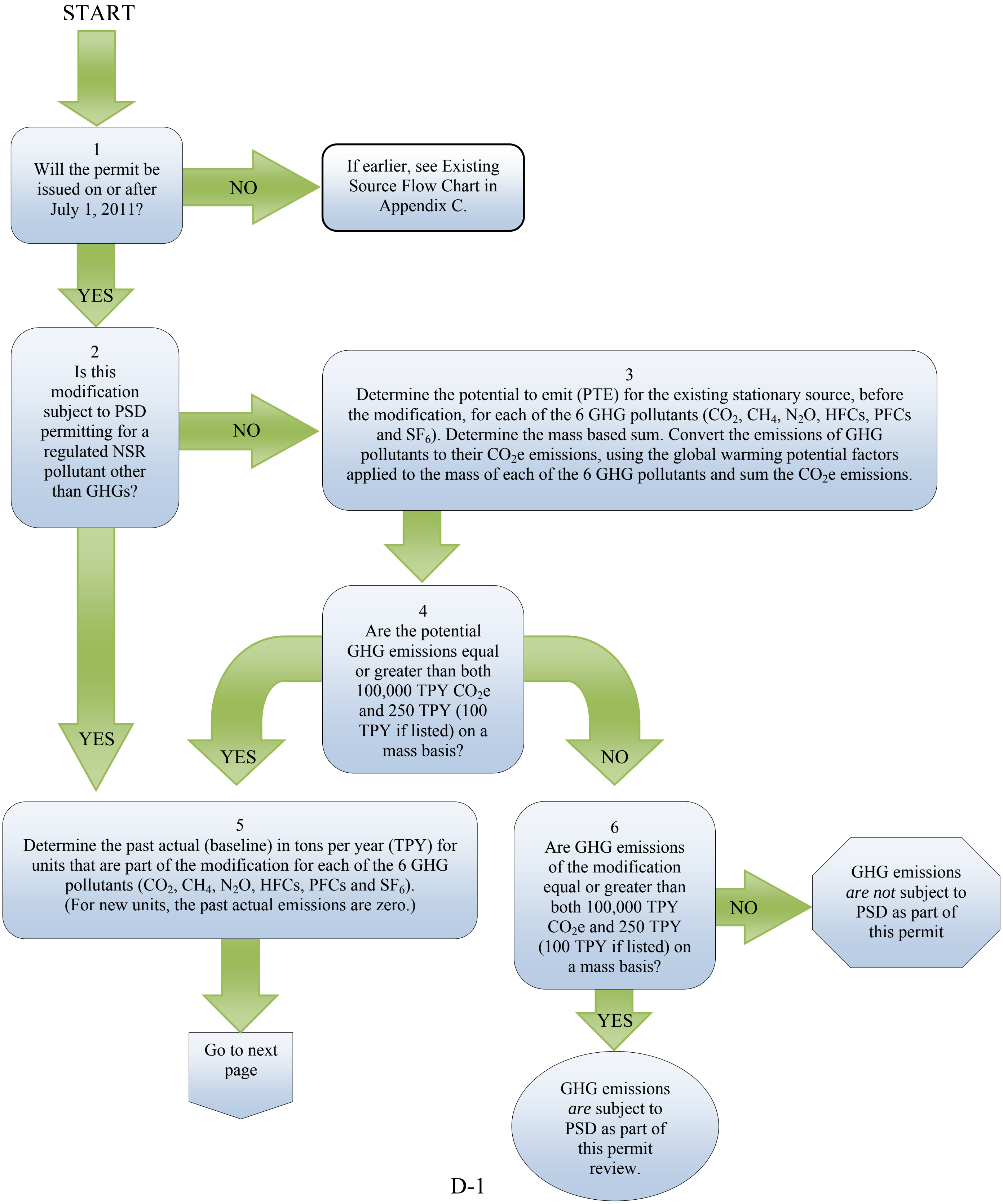


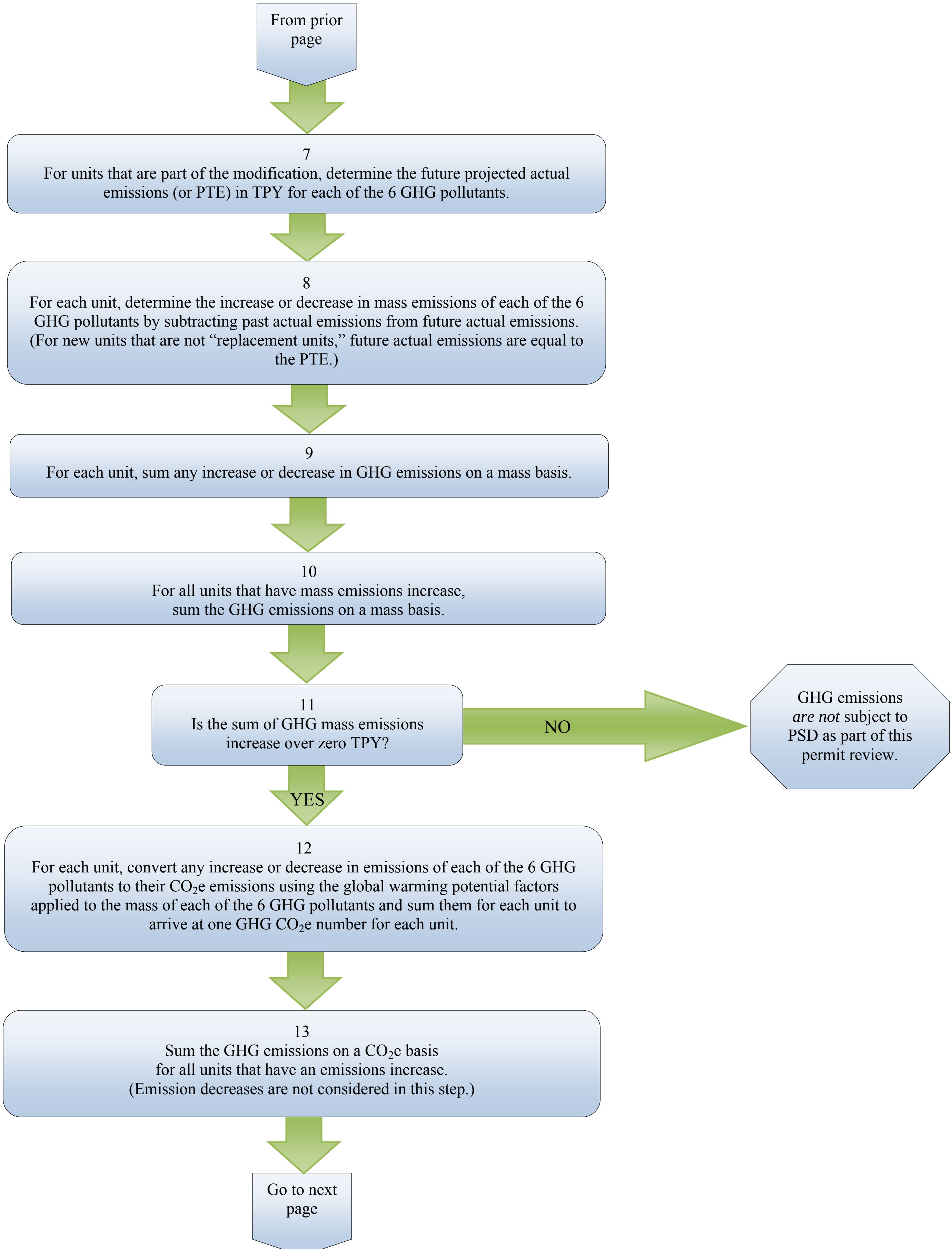

From prior page
6
For each unit, determine the increase or decrease in emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions.
7
For each unit, sum any increase or decrease in GHG emissions on a mass basis.
8
For all units that have an emissions increase, sum the GHG emissions on a mass basis.
9
Is the sum of GHG emissions increase greater than zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
10
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2 equivalent (CO_2e) emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.
11
For all units that have an emissions increase, sum the GHG emissions on a CO_2e basis. (Emission decreases are not considered at this step.)
Go to next page

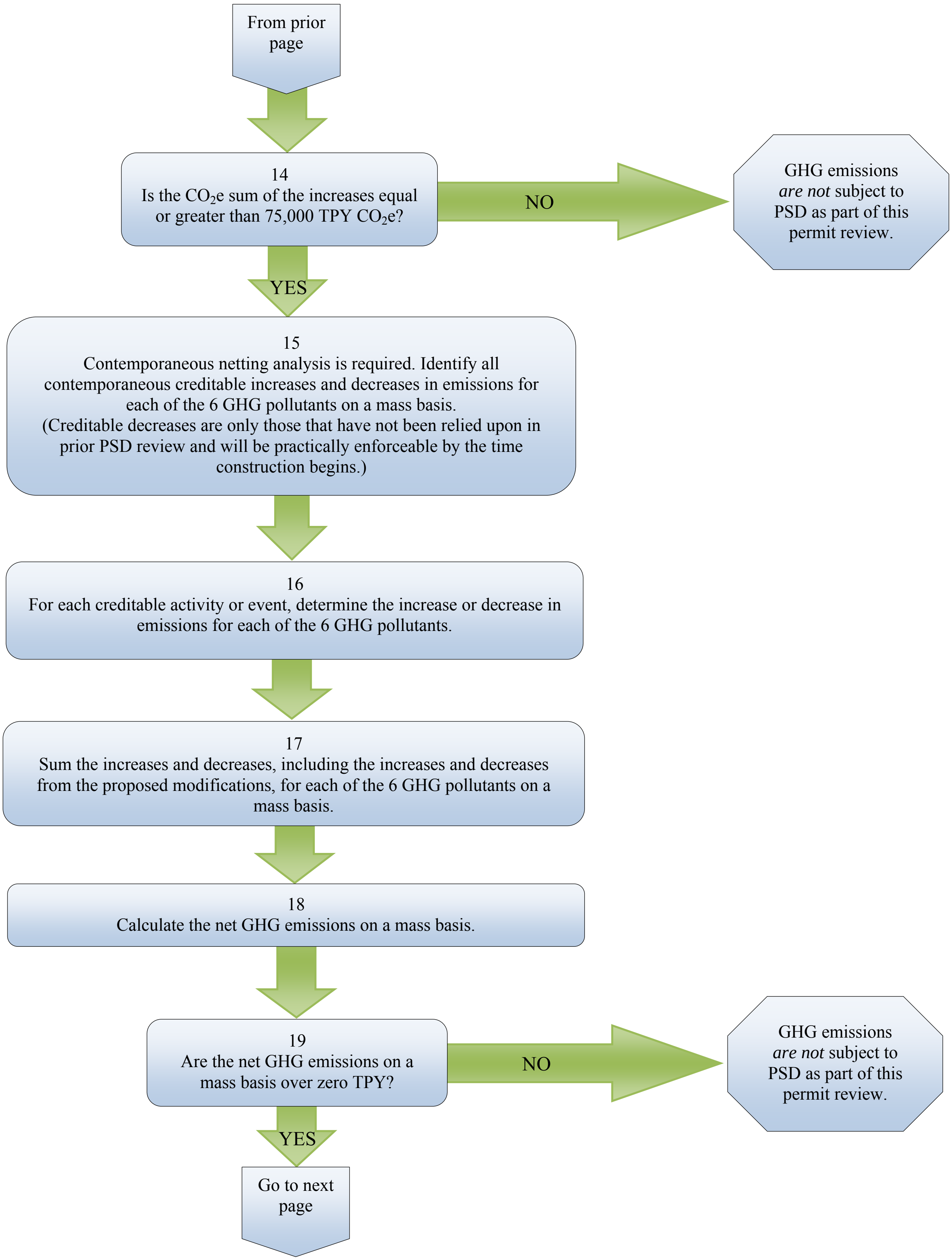

From prior page
12
Is the sum of GHG emissions increases equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
13
Contemporaneous netting analysis is required.
Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
14
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants on mass basis.
15
Sum the increases and decreases, including the increases and decreases from the proposed modification, for each of the 6 GHG pollutants on a mass basis.
16
Calculate the net GHG emissions on a mass basis.
Go to next page

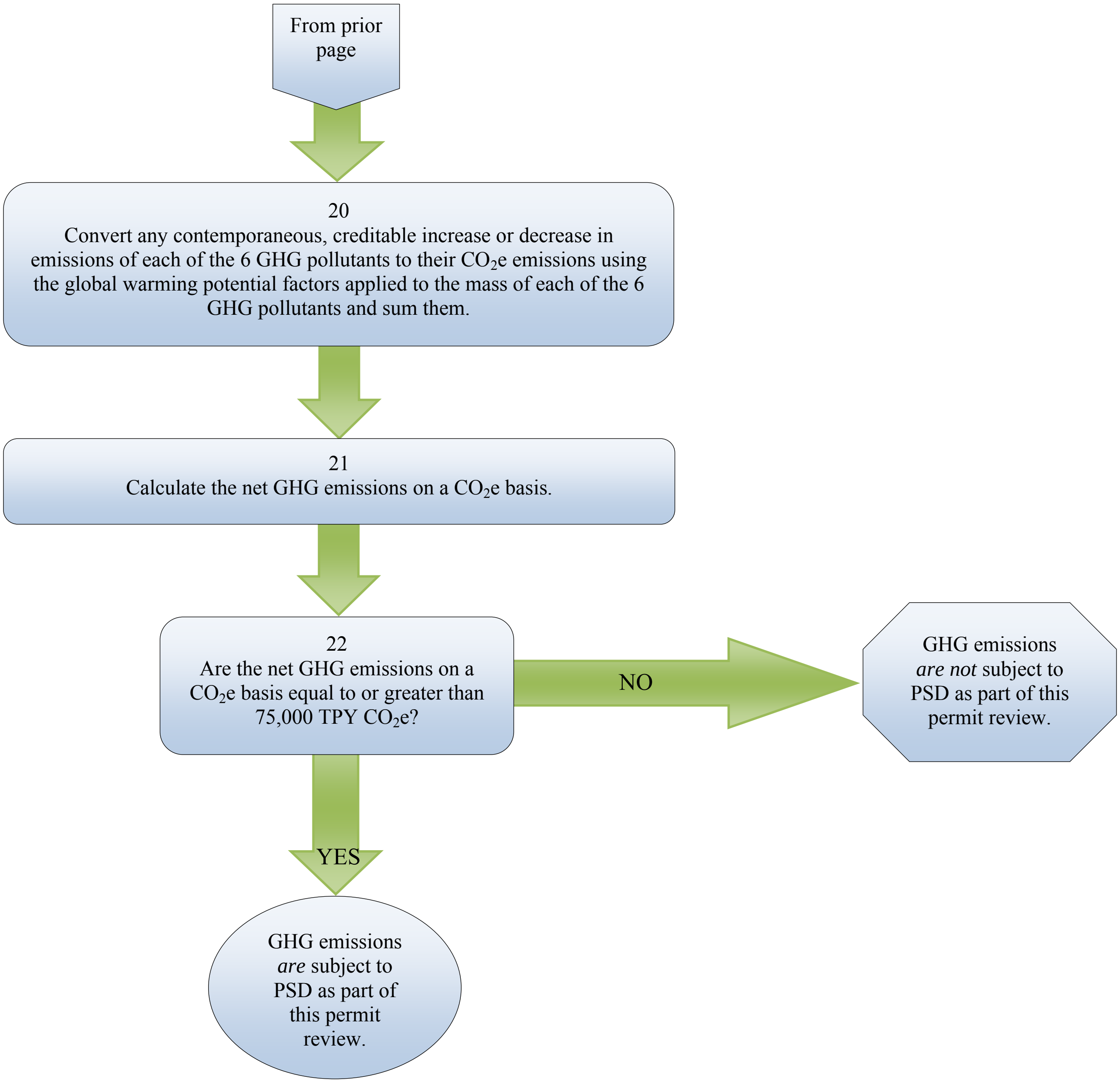

From prior page
17
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
18
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
19
Calculate the net GHG emissions on a CO_2e basis.
20
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.

Appendix D. GHG Applicability Flowchart – Modified Sources (On or after July 1, 2011)




From prior page
7
For units that are part of the modification, determine the future projected actual emissions (or PTE) in TPY for each of the 6 GHG pollutants.
8
For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. (For new units that are not “replacement units,” future actual emissions are equal to the PTE.)
9
For each unit, sum any increase or decrease in GHG emissions on a mass basis.
10
For all units that have mass emissions increase, sum the GHG emissions on a mass basis.
11
Is the sum of GHG mass emissions increase over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
12
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.
13
Sum the GHG emissions on a CO_2e basis
for all units that have an emissions increase.
(Emission decreases are not considered in this step.)
Go to next page


From prior page
14
Is the CO_2e sum of the increases equal or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
15
Contemporaneous netting analysis is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
16
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants.
17
Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 GHG pollutants on a mass basis.
18
Calculate the net GHG emissions on a mass basis.
19
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
Go to next page


From prior page
20
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
21
Calculate the net GHG emissions on a CO_2e basis.
22
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.

Appendix E. Example of PSD Applicability for a Modified Source

Example Scenario:

- An existing stationary source is major for PSD and modifications involving GHGs may be major and possibly subject to PSD.
- The proposed modification consists of the addition of a new emissions unit (Unit #2) and a modification to existing emissions unit (Unit #1). Both units emit one or more compounds identified as a GHG.
- Emissions Unit A was added at the source 3 years ago.
- The GHG emissions used in PSD applicability analyses is a sum of the compounds emitted at the emission unit.

Unit #2 A new emissions unit with a proposed emissions **increase** of 77,000 TPY of CO_2 (1 x 77,000 TPY CO_2 = 77,000 TPY CO_2e).[134]

Unit #1 The modified existing Unit #1 will result in a CO_2 emissions **increase** of 50 TPY (1 x 50 TPY = 50 TPY CO_2e) and a CH_4 emissions **decrease** of 90 TPY (21 x 90 TPY CH_4 = 1890 TPY CO_2e). The pre- and post-change emissions are:

- Baseline actual GHG mass emissions are 400 TPY of CO_2 and 100 TPY of CH_4, which is a total of 500 TPY of GHGs on a mass basis.
- Proposed GHG emissions after the change are 460 TPY (450 TPY from CO_2, 10 TPY from CH_4), which is a 40 TPY decrease from baseline actual emissions on a mass basis.
- Baseline actual CO_2e emissions are 400 TPY CO_2e (1 x 400 TPY of CO_2) plus 2,100 TPY of CO_2e (21 x 100 TPY of CH_4) = 2500 TPY of CO_2e.
- Proposed CO_2e emissions after the change are 450 TPY of CO_2e (1 x 450 TPY of CO_2) plus 210 TPY of CO_2e (21 x 10 TPY of CH_4) = 660 TPY of CO_2e.

Unit A Three years ago, during the contemporaneous period, there was an emissions increase of 10,000 TPY CO_2 (10,000 TPY CO_2e) from the addition of a new emissions unit (Unit A) at the source. There are no other creditable emissions increases or decreases during the contemporaneous period.

Note: The source must calculate emissions changes from existing emissions units being modified (e.g., Unit #1) and in preparing that calculation, the source must compare the emission unit's baseline actual emissions to either (1) a projection of its future actual emissions; or (2) its potential to emit (PTE). See 40 CFR 52.21(b)(41)(ii). Any creditable emissions decreases from existing emissions units must be decreases in baseline actual emissions. The requirements of the PSD rules apply to these calculations and determinations as applicable.

Mass-Based Calculations

(Step 1) *In this step, only consider emissions increases of GHGs from the proposed modification.*

Unit #2 77,000 TPY mass emissions **increase** of GHGs.

[134] For the purposes of this example, the Global Warming Potential values are from the 40 CFR Part 98 Table A-1, as of the date of this document.

Unit #1 The proposed GHG emissions are 460 TPY, which is a 40 TPY GHG mass emissions **decrease** from the baseline actual emissions of 500 TPY. The change at Unit #1 results in a **decrease** in GHG emissions and is therefore not considered in Step 1.

Increases = 77,000 TPY GHG mass emissions increase from Unit #2 is greater than zero TPY, so

Go to Step 2 and conduct contemporaneous netting

(Step 2) *In this step, include the emissions increases and decreases of GHGs from the project and all other contemporaneous and creditable emissions increases and decreases of GHGs.*

Net emissions increase = 77,000 TPY GHG mass emissions from Unit #2 minus a 40 TPY GHG decrease from Unit #1 plus a 10,000 TPY GHG increase from Unit A equals 86,960 TPY GHG mass emissions. This net emissions increase is greater than zero TPY, so

Go to the CO_2e*-based calculations*

CO_2e-Based Calculations

(Step 1) *In this step, only consider CO_2e emissions increases from the modification.*

Unit #2 77,000 TPY CO_2e emissions **increase**

Unit #1 The proposed CO_2e emissions after the modification are 660 TPY CO_2e, which is a 1,840 TPY CO_2e **decrease** from baseline actual emissions of 2,500 TPY CO_2e. Since it is a decrease, ignore the change in CO_2e emissions.

Increases = 77,000 TPY CO_2e emissions increase from Unit #2 is equal to or greater than 75,000 TPY CO_2e, so

Go to Step 2 and conduct contemporaneous netting

(Step 2) *In this step, consider all emissions increases and decreases of CO_2e from the proposed project and all other contemporaneous and creditable emissions increases and decreases of CO_2e.*

Net emissions increase = 77,000 TPY CO_2e emissions increase from Unit #2 minus 1,840 TPY CO_2e emissions decrease from Unit #1 plus a 10,000 TPY CO_2e emissions increase from Unit A equals 85,160 TPY CO_2e emissions. This net emissions increase is equal to or greater than 75,000 TPY CO_2e.

Results: The modification is both a "significant emissions increase" (Step 1) and a "significant net emissions increase" (Step 2) in both the mass and CO_2e-based calculations; therefore, the modification as proposed is major and subject to PSD for GHGs.

Appendix F. BACT Example – Natural Gas Boiler

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope: The permit applicant is proposing to install, at an existing PSD major source, a new 250 MMBtu/hour natural gas-fired boiler. The project's emissions increase is in excess of 75,000 TPY CO_2e and the permit will be issued in March 2011, so the project is subject to BACT for GHGs under Step 1 of the Tailoring Rule. For the sake of simplicity, this example focuses on the section of the BACT analysis for GHG emissions from the project.

The top-down BACT determination is carried out in the following five steps:

Step 1: Identifying all available controls

For purposes of this example, assume that the permit application listed the following available controls in the GHG BACT analysis:

- Boiler Annual Tune-up – Once a year the boiler is tuned for optimal thermal efficiency.
- Boiler Oxygen Trim Control – Stack oxygen level is monitored and the inlet air flow is adjusted for optimal thermal efficiency.
- Use of an Economizer – A heat exchanger is used to transfer some of the heat from the boiler exhaust gas to the incoming boiler feedwater. Preheating the feedwater in this way reduces boiler heating load, increases its thermal efficiency and reduces emissions.
- Boiler Blowdown Heat Recovery – Periodically or continuously, some water in the boiler is removed as a means of avoiding the build-up of water impurities in the boiler. A heat exchanger is used to transfer some of the heat in the hot blowdown water for preheating feedwater. This increases the boiler's thermal efficiency.
- Condensate Recovery – As the boiler steam is used in the heat exchanger, it condenses. When hot condensate is returned to the boiler as feedwater, the boiler heating load is reduced and the thermal efficiency increases.

As would be appropriate under EPA's guidelines for Step 1 of the BACT process, the permitting authority asked the applicant to expand the analysis to consider an air preheater (which recovers heat in the boiler exhaust gas to preheat combustion air). Accordingly, at this stage in this example, the permit applicant and permitting authority identified six control measures.

Further, a public comment was received arguing that the analysis should include a combined cycle natural gas-fired turbine that is more efficient than the proposed boiler. Since the application explains that a boiler is necessary to fulfill the fundamental business purpose of providing process steam (and not generating electricity) and because a varying steam demand requires the ability to startup and shutdown the boiler quickly (due to the fluctuating operational demands of the facility, as substantiated in the application), the permitting authority declined to list the option in Step 1 of the BACT analysis on the grounds it would redefine the source. The permitting authority thoroughly documented this decision in its response to comments.

Step 2: Eliminating technically infeasible options

At this stage of the review, the permit applicant and the permitting authority examine all options for technical feasibility. For this example, the permitting authority determined that the seven controls identified are technically feasible because nothing in the record showed that any of these options was not demonstrated or available or applicable to this type of source.

Step 3: Evaluation and ranking of controls by their effectiveness.

At this step, the permit applicant and permitting authority need to select a measure of effectiveness to compare and rank the options. Assume in this example that the applicant ranked control measures for the boiler based on their impact on the thermal efficiency of the boiler, after finding that thermal efficiency was a useful indicator of CO_2 control efficiency because fuel use is directly related to CO_2 emissions for the boiler and the impact of control measures.

The permit applicant completed the control effectiveness analysis showing that the most effective single measure is oxygen trim control. The applicant's analysis also showed that the use of an air preheater was no more effective than an economizer in recovering exhaust heat, and so the applicant narrowed the review to the economizer only. In this example, the applicant's analysis next considered the effectiveness of the boiler controls in combinations and found that the most effective combination of measures is the use of four measures – oxygen trim control, an economizer, condensate recovery and blowdown heat recovery – which was approved by the permitting authority.

Step 4: Evaluating the most effective controls and documenting results

In this step, the permit applicant completed an analysis of the cost effectiveness of measures and combinations of measures, expressed as $/ton of GHG reduced, as well as an incremental cost effectiveness analysis. In this example, the applicant found that, given the size and other characteristics of this facility, the packages including boiler blowdown heat recovery was not cost effective (as an incremental measure compared to cost born by similar facilities) and the next most effective combination of measures for the boiler was the use of oxygen trim control, an economizer and condensate recovery. The applicant documented this decision in the permitting record and the permitting authority agreed.

Significant energy and environmental impacts are also considered in this step. In this example, the record also showed that the recovery and reuse of condensate would reduce the use of boiler treatment chemicals and the generation of related waste and thus would reduce the amount of water going to wastewater treatment at the site. Since condensate recovery was still in consideration, this information provided additional record support continuing to consider condensate recovery part of the technology option.

Step 5: Selecting BACT

With the analysis and record complete, the permitting authority determines BACT in this last step. In this example, the permitting authority determined, and the record showed, that BACT for GHGs from the proposed facility was the combination of oxygen trim control, an economizer and condensate recovery for the boiler, along with a high transfer efficiency design for the heat exchanger. Accordingly, the permitting authority included the following permit terms in the permit:

- Emission limit expressed in lbs of CO_2e emissions per pound of steam produced, averaged over 30 day rolling periods;
- CO_2e emissions are to be determined based on metered natural gas use and the application of standard emission factors;
- Steam production determined from a gauge on the outlet of the boiler;
- In addition, there would be a requirement to install the boiler as described in the application and BACT determination;
- There would be a requirement to implement a preventive maintenance program for the air to fuel ratio controller of the boiler; and
- A requirement for periodic maintenance and calibration of the natural gas meter and the steam flow analyzer.

Appendix G. BACT Example – Municipal Solid Waste Landfill

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope: The permit applicant proposes to build a new, large municipal solid waste landfill. As the solid waste in a landfill decomposes, landfill gas (composed of methane, carbon dioxide, and trace amounts of organic compounds) is formed. The application shows that the PTE of the landfill expressed as CO_2e emissions is in excess of 100,000 TPY. The permit will be issued after June 2011, so BACT will apply to the GHG emissions under Step 2 of the Tailoring Rule. For the sake of simplicity, this example focuses on the section of the BACT analysis for the capture and control of the landfill gas from the project.

The permit applicant and reviewing authority conduct their BACT determination using the five steps of the top-down processes as follows:

Step 1: Identifying all available controls

The permit applicant and permitting authority agree that the BACT review for a landfill logically has two elements: the capture of the landfill gas and the control of emissions of that gas. In this example, there is an existing NSPS (Part 60 Subpart WWW) applicable to non-methane organic compounds (NMOC) emissions from Municipal Solid Waste (MSW) landfills, which addresses the capture and control of landfill gas. While the NSPS addresses a different component of the emissions than GHGs, the permit applicant and the permitting authority determine that the NSPS is a useful starting point for a GHG BACT determination since it has detailed requirements for the design and operation of the gas collection system.

For capture of the landfill gas, the application uses compliance with the NSPS as the starting point. For control, the applicant identified the following three NSPS options as a starting point for the BACT determination:

- venting to an on-site flare,
- use of the gas in on-site internal combustion engines to generate electricity, or
- treatment of the gas for delivery to a natural gas pipeline.

The applicant did not identify or propose any alternative control options in the application, and none were suggested in public comments. However, the permitting authority did ask the applicant to expand the review to consider two other control measures: (1) a requirement to collect and control landfill gas earlier in the life of the landfill than is specified in the NSPS, and (2) the use of a gas turbine to generate power rather than internal combustion engines.

At this stage, there are two control measures listed for gas capture (NSPS compliant system and a NSPS system with earlier gas collection and treatment) and four control options listed for the control of the landfill gas that is collected (flaring, fueling engines, fueling a gas turbine, and treatment and routing of the gas to a pipeline).

Step 2: Eliminating technically infeasible options

At this stage of the review, the applicant and permitting authority assess the technical feasibility of each option. In this example, the applicant demonstrated that the volume of gas from the proposed facility would be inadequate to fuel a commercially available gas turbine. The permitting authority reviewed the record regarding the technical infeasibility for the gas turbine option, found it was adequate, and accepted elimination of that option from further consideration.

Step 3: Evaluation and ranking of controls by their effectiveness

At this step, the permit applicant and permitting authority need to determine a metric for ranking the control effectiveness of the options under consideration. In this case, the application used total CO_2e emissions over the life of the landfill, based on the current business plan and design, as the effectiveness indicator. The applicant explained that the CO_2e emissions estimates in their application reflected the direct emissions of GHGs and the CO_2 produced for the options where that gas was combusted on site. The application also considered combinations of capture systems and controls for overall effectiveness. The record showed that early capture of gas and conversion of the gas to pipeline quality for export were likely to be the most effective combination, from a PSD perspective, given that the maximum amount of gas would be captured and most of the gas would not be combusted on site. The record also showed that flaring and the use of engines were similar in their control of overall on-site GHG emissions, with both controls reducing methane emissions significantly while generating relatively small on-site CO_2 emissions in the process.

Step 4: Evaluating the most effective controls and documenting results

In this step, the applicant completed an analysis of the cost effectiveness of control measures, expressed as $/ton of GHG reduced, and also determined the incremental cost effectiveness. In this example, the applicant's analysis first found that conversion of gas to pipeline quality was not cost effective, explaining that this control option would more than double the overall cost of the project since the landfill was far from an existing pipeline, and the permitting authority agreed that it should be eliminated for further consideration in the BACT analysis. The record also showed that the NSPS system with early collection was cost effective in both the flare and the engines case. There was also evidence in the record showing that the flare was more cost effective because revenue from the sale of power from use of engines was too little to offset the added cost of the engines and a power transmission line.

The applicant and permitting authority also considered the collateral energy and environmental impacts of the options. In this example, the application noted that there was a positive environmental impact from the use of a flare because NO_X emissions for a flare would be lower than those for the engines. Some public comments identified positive energy and environmental offsite impacts arising from the fact that using landfill gas to generate electricity would displace some other offsite energy generation and associated emissions. In responding to the comments, the permitting authority determined that this benefit outweighed the lower NO_X emissions from the flare. The permit record also demonstrated that the use of engines or a flare would have nearly equal CO_2e control effectiveness. Accordingly, the permitting authority found that the environmental benefits arising from the engines-based system outweighed the flare's cost effectiveness and environmental benefits of lower NO_X emissions.

Step 5: Selecting BACT

The permitting authority determines BACT in this last step. In this example, the permitting authority determined that BACT for the proposed facility was NSPS compliance with early implementation of the capture and control system with engines combusting the landfill gas to generate electricity. Accordingly, the permitting authority included the following permit terms in the permit:

- Compliance with the landfill design and operation requirements of the applicable NSPS with a revised condition for earlier capture and control of the gas.
- A requirement to combust the collected gas in engines with the creation and use of an O&M plan for the engines to assure that they operate efficiently.

Appendix H. BACT Example – Petroleum Refinery Hydrogen Plant

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope:
Petroleum refineries produce and utilize hydrogen in order to convert crude oil to finished products. In this example, a permit applicant proposes a modification project to expand the hydrogen production and hydrotreating capacity of an existing major source refinery. The application submitted by the permit applicant shows that the project has a significant emissions increase and a significant net emissions increase on both a CO_2e basis and a mass basis. The permitting authority will issue the permit in October 2011, so PSD is triggered for GHGs in Step 2 of the Tailoring Rule. For simplicity, this example addresses the GHG BACT analysis for the new hydrogen plant only.

Accordingly to the application, the proposed project utilizes the most common method of producing hydrogen at a refinery, the steam methane reforming (SMR) process. In SMR, methane and steam are reacted via a catalyst to produce hydrogen and CO. The reaction is endothermic and the necessary heat is provided in a gas-fired reformer furnace. The CO generated by the initial SMR reaction further reacts with the steam to generate hydrogen and CO_2. The hydrogen is then separated from the CO_2 and other impurities. In this example, the application shows that the purification is done using a Pressure Swing Adsorption Unit. The permit applicant proposes to use the offgas from that step (containing some hydrogen, CO_2, and other gases) as part of the fuel for the reformer furnace.

The top-down BACT determination is carried out in the following five steps:

Step 1: Identifying all available controls

Assume for purposes of this example that the permit application lists the following control options for GHG emissions:

- Furnace Air/Fuel Control – An oxygen sensor in the furnace exhaust is to be used to control the air and fuel ratio in the furnace on a continuous basis for optimal energy efficiency.
- Waste Heat Recovery – The overall thermal efficiency is to be optimized through the recovery of heat from both the furnace exhaust and the process streams to preheat the furnace combustion air, to preheat the feed to the furnace and to produce steam for use in the process and elsewhere in the refinery.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2. (Some refineries isolate hydrogen reformer CO_2 for sale but that is not a part of this example project.)

The permitting authority did not require the applicant to identify any alternative control options beyond those in the application, and none were suggested in public comments.

Step 2: Eliminating technically infeasible options

At this stage of the review, the permit applicant and the permitting authority examine the control options for technical feasibility. In this example, the permitting record shows that all three controls are technically feasible because there is no evidence that any of these options are not demonstrated or available or applicable to this type of source.

Step 3: Evaluation and ranking of controls by their effectiveness.

At this step, the permit applicant and permitting authority need to select a measure of effectiveness to compare and rank the options. In this example, the applicant ranked control measures for the hydrogen plant based on the GHG emissions per unit of hydrogen produced. The applicant and the permitting authority agreed that such an output-based indicator was a good way to capture the overall effect of multiple energy efficiency measures used in the design of a complex process such as this.

The permit applicant then completed a control effectiveness analysis, in which benchmarking data on the energy efficiency and GHG emissions of recently installed hydrogen plants was provided. The applicant showed that by incorporating various heat recovery measures this hydrogen plant would be a lower emitter (on an output basis) than similar new plants, and the permitting authority concurred in that determination. The applicant's analysis considered the effectiveness of each individual measure and combinations of measures. In this case, the applicant determined that the most effective combination was one in which all three options were included.

Step 4: Evaluating the most effective controls and documenting results

In this step, the permit applicant completed an analysis of the cost effectiveness of measures and combinations of measures, expressed as $/ton of GHG reduced. The applicant also determined the incremental cost effectiveness. In this example, the information supplied by the applicant demonstrated that the transport and sequestration of CO_2 would not be cost effective because the nearest prospective location for sequestration was more than 500 miles away and there was not an existing pipeline or other suitable method for CO_2 transport between the refinery and the sequestration location. Accordingly, the record showed that the cost of transport was significant in comparison to the amount of CO_2 to be sequestered and the cost of the project overall. Although the permitting authority affirmed this determination, in responding to public comments on the issue, the permitting authority did note that in circumstances in which a refinery was located near an oil field that used CO_2 injection for enhanced recovery, the cost for transport and sequestration would likely be in a range that would not exclude the transport control option from the list of technologies that would continue to be considered in the BACT analysis.

Permit applicants and permitting authorities also consider other significant energy and environmental impacts in this step. In this case, none were presented in the application, and the only significant public comment on the issue was addressed by the permitting authority, as noted above.

Step 5: Selecting BACT

With the analysis and record complete, the permitting authority determines BACT. In this example, the permitting authority determined that BACT was a combination of furnace combustion control and integrated waste heat recovery. Accordingly, the permitting authority included the following permit terms in the permit:

- Emission limit in pounds of CO_2e emitted per pound of hydrogen produced, averaged over rolling 30-day periods.
- CO_2e emissions would be determined by metering natural gas sent to the hydrogen plant. With prior approval of the permitting authority, the emissions could be adjusted for excess fuel gas sent to other parts of the refinery. A separate meter and fuel analysis would be needed to get that credit.
- Hydrogen production would be metered.
- The heat recovery systems would need to be installed as described in the application.
- There would need to be a written program for calibration and maintenance of meters.

Appendix I. Resources for GHG Emission Estimation

The following are a number of methods that are traditionally used to estimate PTE from sources and relevant emissions units:

- Federally enforceable operational limits, including the effect of pollution control equipment;
- Performance test data on similar units;
- Equipment vendor emissions data and guarantees;
- Test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111(d) standards for designated pollutants;
- AP-42 Emission Factors;
- Emission factors from technical literature; and
- State emission inventory questionnaires for comparable sources.

These approaches remain relevant for GHG emissions calculations and serve as the fundamental approaches to estimating emissions for permitting applications. For example, direct measurements methods such as continuous emissions monitors (CEMs) would continue to be a preferred means to form the starting point basis for estimating emissions from GHG emissions units. However, because GHG emissions historically have not been subject to regulation under air permitting programs, and there are unique GHG emission source categories, there is not as widespread representation or long-term experience with GHG estimation techniques and measurement methods as there is for conventional pollutants under the above approaches. The purpose of this section is to identify additional references and resources that may be useful when evaluating GHG emission sources and deciding which estimation methods to use.[135]

Mandatory Reporting of Greenhouse Gases. This final rule was issued on October 30, 2009 (74 FR 56260), and established GHG reporting requirements for all sectors of the economy and should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications. The rule includes procedures for estimating GHG emissions from the source categories that are responsible for the majority of stationary source GHG emissions in the U.S. The procedures identify where applications of direct measurement techniques are viable and describes emission factor and mass-balance based approaches where direct measurement techniques are not applicable or available.

[135] The exclusion of a source or emission unit category from these sources does not imply that such sources or emissions units are excluded from permitting requirements. For example, as of the date of this publication CO_2 from biomass combustion is not included in determining applicability under the mandatory reporting rule, but is included in determining applicability under both PSD and title V programs as described in the Tailoring Rule. Also, there are not methods identified for all possible GHG emitting sources and units in the current mandatory reporting rule.

While the GHG reporting rule is focused on estimating and reporting *actual* emissions from source categories, the basic approaches can be used to estimate a source's PTE when correctly adjusted to reflect future conditions and operating parameters. Since many of the affected GHG source categories and emissions units have been or will be subject to permitting requirements for conventional, non-GHG pollutants, sources should use similar adjustments to fuel throughput, activity data, and emissions for determining PTE for GHG that have been used in existing PSD and title V guidance for those units and which are applied on a case-by-case basis depending on specific operating parameters for the affected sources.

Other reference sources that may prove useful to sources and permitting authorities in identifying, characterizing and estimating emissions from GHG emission sources include the following:

- **ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks)**
  http://www.energystar.gov/epis

- **US EPA National Greenhouse Gas Inventory**
  http://epa.gov/climatechange/emissions/usinventoryreport.html

- **EPA's Climate Leaders Protocols**
  http://www.epa.gov/stateply/index.html

- **EPA's Voluntary Partnerships for GHG Reductions:**
  – Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
  – CHP Partnership Program (http://www.epa.gov/chp)
  – Green Power Partnership (http://www.epa.gov/greenpower)
  – Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
  – Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
  – Voluntary Aluminum Industrial Partnership: http://www.epa.gov/highgwp/aluminum-pfc/index.html

- **SF Emission Reduction Partnership for the Magnesium Industry**
  http://www.epa.gov/highgwp/magnesium-sf6/index.html

- **PFC Reduction/Climate Partnership for the Semiconductor Industry**
  http://www.epa.gov/highgwp/semiconductor-pfc/index.html

- **Landfill Gas Emissions Model**
  User's Guide: http://www.epa.gov/ttncatc1/dir1/landgem-v302-guide.pdf

- **Estimation Methodologies for Biogenic Emissions from Solid Waste Disposal, Wastewater Treatment, and Ethanol Fermentation**
  http://www.epa.gov/ttn/chief/efpac/ghg/GHG_Biogenic_Report_revised_Dec1410.pdf

Appendix J. Resources for GHG Control Measures

The following are several information sources to consider when looking for available GHG control measures when conducting a BACT analysis.

- **EPA's GHG Mitigation Measures Database**
  http://www.epa.gov/nsr/ghgpermitting.html

- **EPA's Sector GHG Control White Papers**
  http://www.epa.gov/nsr/ghgpermitting.html

- **EPA's RACT/BACT/LAER Clearinghouse (RBLC)**
  http://cfpub.epa.gov/rblc/

- **ENERGY STAR Guidelines for Energy Management**
  http://www.energystar.gov/guidelines

- **ENERGY STAR Industrial Sector Energy Guides**
  http://www.energystar.gov/epis

- **EPA's Climate Leaders Protocols**
  http://www.epa.gov/stateply/index.html

- **Report of the Interagency Task Force on Carbon Capture and Storage**
  http://www.epa.gov/climatechange/policy/ccs_task_force.html

- **EPA's Lean and Energy Toolkit**
  http://www.epa.gov/lean/toolkit/LeanEnergyToolkit.pdf

- **EPA's Voluntary Partnerships for GHG Reductions:**
  - Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
  - CHP Partnership Program (http://www.epa.gov/chp)
  - Green Power Partnership (http://www.epa.gov/greenpower)
  - Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
  - Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
  - Voluntary Aluminum Industrial Partnership:
    http://www.epa.gov/highgwp/aluminum-pfc/index.html

- **SF Emission Reduction Partnership for the Magnesium Industry**
  http://www.epa.gov/highgwp/magnesium-sf6/index.html

- **PFC Reduction/Climate Partnership for the Semiconductor Industry**
  http://www.epa.gov/highgwp/semiconductor-pfc/index.html

- **DOE's Industrial Technologies Program (Best Practices)**
  http://www1.eere.energy.gov/industry/bestpractices/

Additionally, the following are several information sources that may be helpful when including benchmarking as part of a BACT analysis.

- **EPA Energy Star Industrial Energy Management Information Center**
  http://www.energystar.gov/index.cfm?c=industry.bus_industry_info_center

- **DOE Industrial Technologies Program**
  http://www1.eere.energy.gov/industry/

- **Lawrence Berkeley National Laboratory Industrial Energy Analysis Program**
  http://industrial-energy.lbl.gov/

- **European Union Energy Efficiency Benchmarks**
  http://ec.europa.eu/environment/climat/emission/benchmarking_en.htm

In addition to the above sources of information, once permitting authorities gain experience with GHG BACT determinations, useful information on GHG permitting decisions will be present in EPA's RBLC and Control Technology Center.

Appendix K. Calculating Cost Effectiveness for BACT

The following excerpt is from the Draft 1990 NSR Workshop Manual (pages B.36-B.44)

IV.D.2.b. COST EFFECTIVENESS

Cost effectiveness is the economic criterion used to assess the potential for achieving an objective at least cost. Effectiveness is measured in terms of tons of pollutant emissions removed. Cost is measured in terms of annualized control costs.

Cost effectiveness calculations can be conducted on an average, or incremental basis. The resultant dollar figures are sensitive to the number of alternatives costed as well as the underlying engineering and cost parameters. There are limits to the use of cost-effectiveness analysis. For example, cost-effectiveness analysis should not be used to set the environmental objective. Second, cost-effectiveness should, in and of itself, not be construed as a measure of adverse economic impacts. There are two measures of cost-effectiveness that will be discussed in this section: (1) average cost-effectiveness, and (2) incremental cost-effectiveness.

Average Cost Effectiveness

Average cost effectiveness (total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate) is a way to present the costs of control. Average cost effectiveness is calculated as shown by the following formula:

$$\text{Average Cost Effectiveness (dollars per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emissions rate - Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr) and emissions rates are calculated in tons per year (tons/yr). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

Calculating Baseline Emissions

The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.

Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.

For example, VOC emissions from a storage tank might vary significantly with temperature, volatility of liquid stored, and throughput. In this case, potential emissions would be overestimated if annual VOC emissions were estimated by extrapolating over the course of a year VOC emissions based solely on the hottest summer day. Instead, the range of expected temperatures should be considered in determining annual baseline emissions. Likewise, potential emissions would be overestimated if one assumed that gasoline would be stored in a storage tank being built to feed an oil-fired power boiler or such a tank will be continually filled and emptied. On the other hand, an upper bound case for a storage tank being constructed to store and transfer liquid fuels at a marine terminal should consider emissions based on the most volatile liquids at a high annual throughput level since it would not be unrealistic for the tank to operate in such a manner.

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.

For example, suppose (based on verified historic data regarding the industry in question) a given source can be expected to utilize numerous colored inks over the course of a year. Each color ink has a different VOC content ranging from a high VOC content to a relatively low VOC content. The source verifies that its operation will indeed call for the application of numerous color inks. In this case, it is more realistic for the baseline emission calculation for the source (and other similar sources) to be based on the expected mix of inks that would be expected to result in an upper boundary case annual VOC emissions rather than an assumption that only one color (*i.e.,* the ink with the highest VOC content) will be applied exclusively during the whole year.

In another example, suppose sources in a particular industry historically operate at most at 85 percent capacity. For BACT cost effectiveness purposes (but **not** for applicability), an applicant may calculate cost effectiveness using 85 percent capacity. However, in comparing costs with similar sources, the applicant must consistently use an 85 percent capacity factor for the cost effectiveness of controls on those other sources.

Although permit conditions are normally used to make operating assumptions enforceable, the use of "standard industry practice" parameters for cost effectiveness calculations (but **not** applicability determinations) can be acceptable without permit conditions. However, when a source projects operating parameters (*e.g.*, limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) that are lower than standard industry practice or which have a deciding role in the BACT determination, then these parameters or assumptions must be made enforceable with permit conditions. If the applicant will not accept enforceable permit conditions, then the reviewing agency should use the absolute worst case uncontrolled emissions in calculating baseline emissions. This is necessary to ensure that the permit reflects the conditions under which the source intends to operate.

For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source does not intend to operate more than 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine would not consider limited hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost effective controls. As a consequence of the dissimilar baseline emissions, BACT for the two cases could be very different. Therefore, it is important that the applicant confirm that the operational assumptions used to define the source's baseline emissions (and BACT) are genuine. As previously mentioned, this is usually done through enforceable permit conditions which reflect limits on the source's operation which were used to calculate baseline emissions.

In certain cases, such explicit permit conditions may not be necessary. For example, a source for which continuous operation would be a physical impossibility (by virtue of its design) may consider this limitation in estimating baseline emissions, without a direct permit limit on operations. However, the permit agency has the responsibility to verify that the source is constructed and operated consistent with the information and design specifications contained in the permit application.

For some sources it may be more difficult to define what emissions level actually represents uncontrolled emissions in calculating baseline emissions. For example, uncontrolled emissions could theoretically be defined for a spray coating operation as the maximum VOC content coating at the highest possible rate of application that the spray equipment could physically process, (even though use of such a coating or application rate would be unrealistic for the source). Assuming use of a coating with a VOC content and application rate greater than expected is unrealistic and would result in an overestimate in the amount of emissions reductions to be achieved by the installation of various control options. Likewise, the cost effectiveness of the options could consequently be greatly underestimated. To avoid these problems, uncontrolled emission factors should be represented by the highest realistic VOC content of the types of coatings and highest realistic application rates that would be used by the source, rather than by highest VOC based coating materials or rate of application in general.

Conversely, if uncontrolled emissions are underestimated, emissions reductions to be achieved by the various control options would also be underestimated and their cost effectiveness overestimated. For example, this type of situation occurs in the previous example if the baseline for the above coating operation was based on a VOC content coating or application rate that is too low [when the source had the ability and intent to utilize (even infrequently) a higher VOC content coating or application rate].

Incremental Cost Effectiveness

In addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$\text{Incremental Cost (dollars per incremental ton removed)} = \frac{\text{Total costs (annualized) of control option - Total costs (annualized) of next control option}}{\text{Next control option emission rate - Control option emissions rate}}$$

Care should be exercised in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between **dominant** alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis (see Figure B-1).

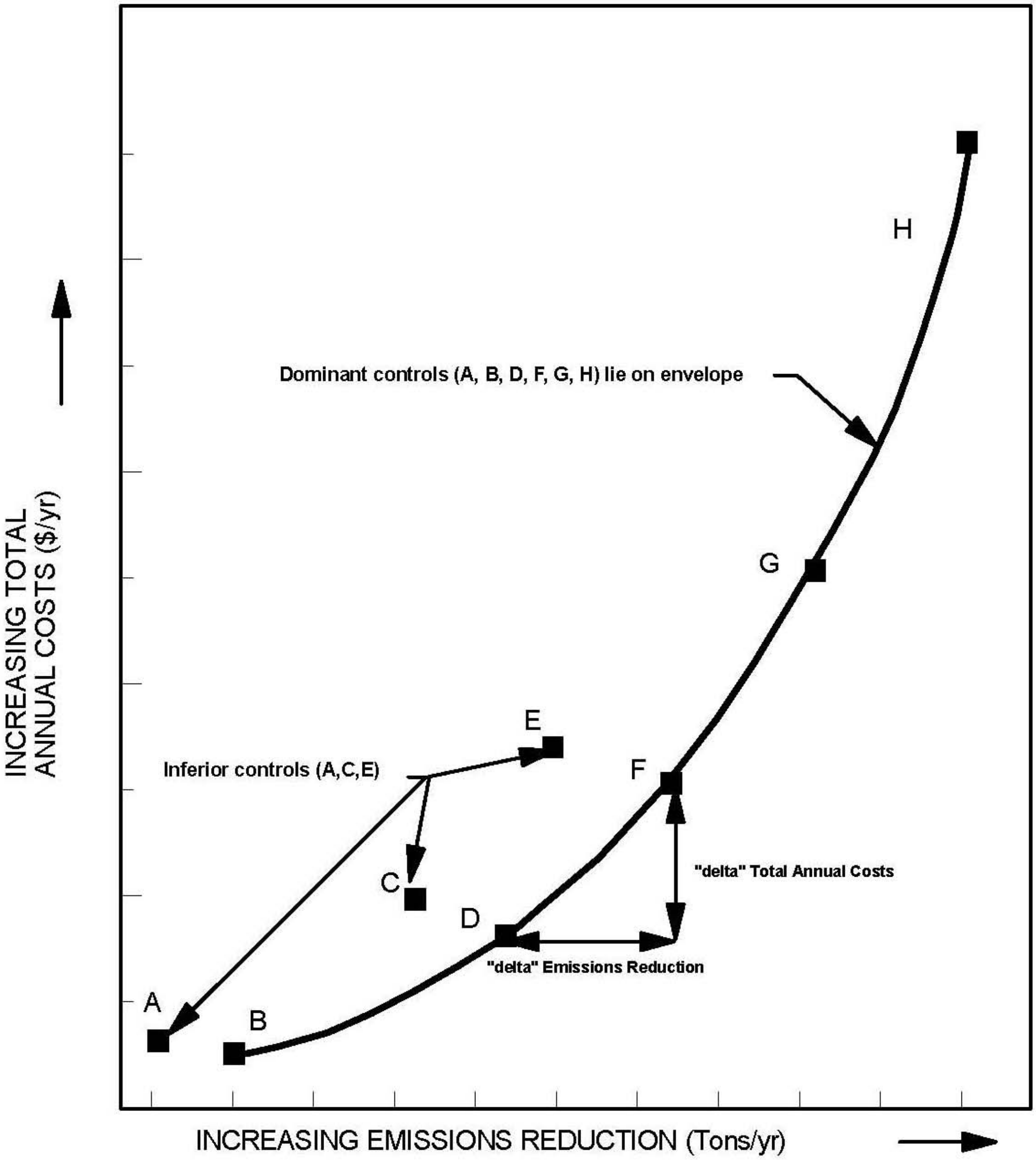


Figure B-1. LEAST-COST ENVELOPE

For example, assume that eight technically available control options for analysis are listed in the BACT hierarchy. These are represented as A through H in Figure B-1. In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options. In Figure B-1, the dominant set of control options, A, B, D, F, G, and H, represent the least-cost envelope depicted by the curvilinear line connecting them. Points C and E are inferior options and should not be considered in the derivation of incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reduction for less money than A; and similarly, D and F will by more reductions for less money than E, respectively.

Consequently, care should be taken in selecting the dominant set of controls when calculating incremental costs. First, the control options need to be rank ordered in ascending order of annualized total costs. Then, as Figure B-1 illustrates, the most reasonable smooth curve of the control options is plotted. The incremental cost effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction. An example is illustrated in Figure B-1 for the incremental cost effectiveness for control option F. The vertical distance, "delta" Total Costs Annualized, divided by the horizontal distance, "delta" Emissions Reduced (TPY), would be the measure of the incremental cost effectiveness for option F.

A comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device.

As a precaution, differences in incremental costs among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another. For example, suppose dominant alternative is preferred to another. For example, suppose dominant alternatives B, D and F on the least-cost envelope (see Figure B-1) are identified as alternatives for a BACT analysis. We may observe the incremental cost effectiveness between dominant alternative B and D is $500 per ton whereas between dominant alternative D and F is $1000 per ton. Alternative D does <u>not</u> dominate alternative F. Both alternatives are dominant and hence on the least cost envelope. Alternative D cannot legitimately be preferred to F on grounds of incremental cost effectiveness.

In addition, when evaluating the total or incremental cost effectiveness of a control alternative, reasonable and supportable assumptions regarding control efficiencies should be made. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures.

The final decision regarding the reasonableness of calculated cost effectiveness values will be made by the review authority considering previous regulatory decisions. Study cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options.

United States Environmental Protection Agency	Office of Air Quality Planning and Standards Air Quality Policy Division Research Triangle Park, NC	Publication No. EPA-457/B-11-001 March 2011

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
9.0	9-1	Provide a copy of the Air Contaminant Discharge Permit Application.	The Air Contaminant Discharge Permit Application is provided in Appendix 9C. The application is in draft format pending inclusion of final data from the Oregon Department of Environmental Quality. Data are anticipated in May 2008.
9.1.2.1	9-6	Indicate which Air Quality Control Region (AQCR) the project falls within.	Air Quality Control Regions are indicated in Sections 9.1.2.1 and 9.1.2.2.
9.1.2.1	9-6	Provide specific Oregon Ambient Air Quality Standards for sulfur dioxide.	Specific Oregon Ambient Air Quality Standards for sulfur dioxide are provided in Table 9.1-1.
9.1.3.1	9-6	Include a table(s) that shows construction emissions of NO_x, CO, SO_2, VOC, PM_{10}, and $PM_{2.5,}$ CO_2 as well as HAPs by year for the LNG terminal and Comrpessor Station. Provide detailed emissions calculations documenting the methodology, emission factors, operating rates, and schedule used to develop the emission rates. The table(s) should include emissions from mobile sources such as delivery vehicles and commuter traffic as well as construction equipment such as earthmoving equipment, marine dredges and barges, welders, etc. The table(s) should also include fugitive emissions from land disturbance and surface preparation (blasting and surface coating) activities.	Construction emissions are provided in Tables 9.1-2 and 9.1-3.
9.1.3.2	9-8	Quantify the amount of ethane and methane that would be released during a blowdown event, estimate the frequency and estimate the total carbon dioxide equivalents of methane released in tons per year.	Ethane and methane emission estimates have been added to Table 9.1-4. The total carbon dioxide equivalent of methane has been added to the text. An estimated frequency of blowdown events of once every five years is stated in Section 9.1.3.2.
9.1.3.2	9-9	It is stated that three natural gas-fired supplemental heaters with a total rating of 140 MMBtu/hr would be	Additional details regarding physical bottlenecks have been added to Section 9.1.3.2.

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
		used at the Terminal. The supporting emission calculations indicate that each supplemental heater are rated at 60 MMBtu/hr for a total of 180 MMBtu/hr. Provide additional details regarding physical bottlenecks that would prevent operations in excess of 140 MMBtu/hr or recalculate emissions based on maximum capacity operations of 180 MMBtu/hr.	
9.1.3.2	9-9	Section 9.1.3.2 includes a statement that emissions from a flare or venting are estimated to be zero. Please clarify whether or not a flare would be constructed as part of the Terminal, and if so, what would the capacity of the flare be.	The construction of the flare has been made more explicit in Section 9.1.3.2. The capacity of the flare has been added. The Terminal is designed such that no venting of boiloff gas (BOG) will occur during normal operation. The Terminal is equipped with a Flare Stack, L-210, which would be used to safely flare boiloff gas during abnormal scenarios only. The bounding abnormal scenario for boiloff gas venting occurs during transfer of LNG from a carrier at or near maximum saturated condition and at or near maximum unloading rates, discharging into on-shore LNG tanks that are operating near maximum operating pressure. Any loss of vapor handling or LNG sendout could result in the LNG tanks approaching maximum allowable operating pressure, necessitating venting of the boiloff gas. Such an event would very quickly result in the reduction or cessation of LNG transfer, thus should venting occur it will be very short lived. The gas venting rate under this scenario is calculated to be a maximum

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
			of 79,000 pounds per hour of boiloff gas. The flare is therefore designed to handle this bounding capacity.
9.1.3.2	9-10	Provide the following for LNG vessels while at the unloading berth: a. Please confirm whether the LNG vessels generate their own electrical power or use shoreside power. b. If the LNG vessel will generate their own electrical power, will the LNG vessels burn natural gas, diesel or bunker fuel? c. If natural gas will be used, provide the source (ship boiloff, vapor return from terminal, on-ship vaporization, etc.). d. If natural gas will be used, how will the company ensure that there is a sufficient supply for the LNG vessel's resident time at berth? e. Clarify the type of fuels used by support vessels. f. Will LNG vessels use boil-off gas prior to, and after berthing? If alternative fuels will be used, update the emission data to reflect this. In addition, what management controls will be in place to assure that boil off gas is used prior to berthing and during unloading of the steam turbine ships.	a. Vessels generate their own power. b. Conventional LNG vessels are powered by boilers burning BOG and/or fuel oil while at berth. The use of fuel oil was used in the calculations. c. Boiloff is the most likely source of the natural gas when used. On-ship vaporization may be used. Vapor return will not be used. d. An adequate supply of fuel is the vessel Captain's responsibility. e. Support vessels will generally use diesel fuel. f. Again, conventional LNG vessels are powered by boilers burning BOG and/or fuel oil while at berth. Alternative fuels will not be used.
9.3.1.2	9-8	Quantify marine-related emission impacts to air quality in the region; discuss the feasibility of emission controls;	Emission impacts and the feasibility of emission controls are presented in Section 9.1.3.3. Compliance with

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
		and demonstrate compliance with associated regulations. Please detail the sources of the emission estimates, whether from manufacturer derived estimates, EPA AP-42 tables or other models. For both the LNG Terminal and Marine emissions, demonstrate that these emissions would not significantly impact air quality in the following class I areas: Mt. Rainer National Park in Washington, Goat Rocks Wilderness in Washington, Mt. Adams Wilderness in Washington, Mt Hood Wilderness in Oregon, and Mt. Jefferson Wilderness in Oregon. Include all correspondence with the Federal Land Manager and the Pacific Northwest Region USDA Forest Service regarding air quality.	associated regulations and air quality impacts are presented in Section 9.1.3.5 and are detailed in a new appendix to the resource report, Appendix 9B.
9.1.3.5	9-13	Based on the information presented in DRAFT RR9, the proposed facility is incorrectly classified as a 100 tpy major source threshold source under PSD rules. The incorrect classification is based on the fact that the Terminal would consist of fossil-fuel fired boilers. The 100 tpy source category under PSD applies to fossil-fuel fired boilers with a combined rating of 250 MMBtu/hr or more. Data in DRAFT RR9 indicates a total combined rating of 140 MMBtu/hr. However, with regard to PSD applicability, please clarify the inclusion (or portion thereof) of vessel emissions when berthed at port. Based on U.S. EPA guidance, emissions from vessels berthed at port that directly serve the purposes of the Terminal must be included in the PSD applicability analysis. The distinction of whether or not this only includes emissions directly	The boilers at the Terminal, as noted, will have a total combined heat input rating of 140 MMBtu/hr. As such the facility will have a 250 ton per year PSD threshold. This has been corrected in the text in Section 9.1.3.5. With regard to the LNGC operations, the emissions associated with vessels when berthed at port have been included in the summary of Terminal emissions. Emissions associated with LNGC unloading and tug emissions associated with the vessel when docked have been included. These emissions have also been included in the dispersion modeling analysis. Emissions associated with marine transport of the vessels while having been estimated have not been included in Terminal operations and modeled as Terminal sources. The heat rating of the docked LNGCs boilers have not

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
		related to pumping LNG to the storage tanks, or also includes idling/hotelling emissions should also consider the fact that U.S. Coast Guard regulations require the LNGCs to be operationally ready due to the type of port. Furthermore, the inclusion of LNGC emissions may impact the combined fossil fuel-fired boiler capacity of the Terminal, thus changing the maximum potential emissions in comparison to PSD major source applicability levels. Should the conclusion result in PSD applicability, an analysis should address ambient impacts of secondary emission sources. References: January 8, 1990 letter to Mr. Ken Waid, Waid and Associates from John Calcagni, Director, Air Quality Management Division. October 28, 2003 letter to Mr. Michael Cathey, El Paso Energy Bridge Gulf of Mexico, LLC from Charles J. Sheehan, EPA Region 6, Regional Counsel	been included in the summation of heat input associated with the Terminal for purposes of determining PSD applicability. Oregon LNG will have no direct control over the size of the boilers and the LNGC will be at the site for only short periods of time. As such, while the LNGC emissions will be considered part of the Terminal operations, the boilers will not be considered part of the Terminal boilers for purposes of PSD threshold determination.
9.2.2.2	9-18	Clarify how OAR 340-035-035(5) is applicable to the proposed project.	Noise from sources identified in OAR 340-035-035(5) is not regulated or limited.
9.2.2.2	9-18	Indicate if there are any "quiet areas" as defined by OAR 340-035-015(50) in the project area.	There are no quiet areas within the Project vicinity. The only quiet area in the state of Oregon is **The Grotto**, *The National Sanctuary of Our Sorrowful Mother* staffed by the Order of Servants of Mary. The Grotto is

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
			located on NE 85th and Sandy Boulevard in Portland, Oregon.
9.2.2.3	9-18	Specifically state the cities and counties that were researched and found not to have noise regulations.	Stated in Section 9.2.2.3.
9.2.3	9-19	Briefly describe major or potential sources of noise near the noise monitoring sites.	Added to Table 9.2-4 and to Appendices 9E and 9F.
9.2.4.1	9-26	Describe the model/formulas used to calculate the noise levels presented in Table 9.2-6.	Description is provided in Appendix 9E, Section 9.3.1, Predicted Construction Noise Levels.
9.2.4.1	9-28	For each HDD location provide the following:(a)identify the nearest NSAs (b)the estimated number of days for drilling or re-completion work that would be required for each well, and whether drilling would be done 24 hours per day;(c)the distance (feet) and direction of the NSAs;(d) the existing Ldn at the NSA(s) and the proposed Ldn at the NSA(s) during and after project well drilling at the well drilling locations; and (e)a description of any noise mitigation that would be implement during and after well drilling activity to reduce noise to 55 dBA Ldn at the NSAs near each HDD location.	Provided in the attachment to Appendix 9E.
9.2.4.1	9-29	Describe the model/formulas used to calculate the noise contour levels presented in Figure 9.2-5.	Provided in Appendix 9F.
9.2.4.1	9-30	Provide a discussion on predicted noise levels associated with all pile driving operations (pier, seawall, berthing area, LNG tanks, etc), including: a. a detailed assessment of the projected pile driving noise and vibration at the nearest NSA as well as potential impacts on NSAs and other structures within 2 miles of the pile driving site; b. the distance (feet) and direction of each NSA and the identified structures from the pile driving	a and b. The nearest NSAs to the general LNG Terminal location are the same as the nearest NSAs to the pile driving locations. No additional NSAs would be affected by the pile driving locations. c. The number of days and the duration are addressed in the main text in Section 9.2.4.1. Impacts to and mitigation of aquatic environment are addressed in Resource Report 3.

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
		site if they are different from those already provided for the general LNG terminal location or if any additional NSAs would be affected from the pile driving locations; c. the estimated number of days that pile driving activities would take place and whether pile driving would be conducted 24 hours per day; d. the existing day-night equivalent sound level (Ldn) at any additional NSAs identified in response to "b" and the proposed Ldn at the identified NSAs (including those initially identified for the terminal) and structures during pile driving activities; and e. evaluate and quantify sound pressure levels in the aquatic environment from pile driving (in dB re: 1μPa) to a distance of 1/2 mile, identify aquatic species affected and discuss impacts to the species; and f. provide a description of any mitigation measures that would be implemented during pile driving activities to reduce noise and/or vibration perceived at the identified NSAs, "Quiet Area," structures, and on the marine/aquatic environment.	d, e, f. Provided in Appendix 9F.
9.2.4.2	9-33	Confirm that the project would not involve other aboveground facilities (e.g., pressure reduction valves) that could be a source of operational noise. If other sources of noise are associated with potation of the project, provide the location of the facilities and the	There will be pressure-reducing valve stations at the terminus of the lateral pipeline and mainline pipeline at Molalla. Distances to nearest NSAs as well as estimates of existing noise levels are provided in Appendix 9E. The closest NSA to the terminus of the lateral pipeline is

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
		distance and direction to the nearest NSA. Additionally, provide an estimate of the existing noise levels at these NSAs.	over 1 mile away while the closest NSA to the terminus of the main pipeline in Molalla is approximately 400 feet away. Given the rural nature of both these areas, the existing levels are anticipated to be similar to those presented for Monitoring Location 5. Mitigation measures such as acoustical lagging, low noise trim, barriers, enclosures or undergrounding will be incorporated during the final design process to ensure the resulting levels from these pressure reducing valves comply with both Oregon's and FERC's noise requirements.
9.2.4.2	9-34	Provide additional information and analysis of noise from the LNG carrier ships and tugboats that would be introduced with proposed docking and unloading operations.	Analysis is provided in Appendix 9F. Tugboats and LNG carrier ships are expected to result in sound levels of 64 and 61 dBA, respectively, at a distance of 300 feet (FEED Expansion, 2005 and Bradwood Landing DEIS, 2007). The proposed dock is approximately 6,500 feet from the closest NSAs. Geometric spreading would provide a 27 dBA reduction and atmospheric attenuation would result in an additional 9 dBA reduction. This would result in levels of less than 30 dBA at the closest NSAs to the Terminal and are therefore not expected to be a significant source of operational noise.
9.2.5	9-35	Describe mitigation measures that Oregon LNG would implement to minimize noise associated with operation of the Terminal.	Oregon LNG anticipates working with vendors to ensure the Terminal complies with the applicable noise limits. Mitigation measures employed may include silencers, barriers, and enclosures.
App 9A		Provide clarification as to why the potential to emit for the emergency electrical generator is not based on the U.S. EPA guideline of 500 hours per year or recalculate potential emissions based on 500 hours per year.	Potential emissions for the emergency generator and the fire pump engines have been recalculated based on 500 hours per year.

Oregon LNG Terminal and Oregon Pipeline Project
FERC Review – Resource Report 9, Air and Noise Quality
Comment/Response Matrix

Section	Page	Question/Comment/Additional Information Needed	Response
App 9B	4	Provide a refined air dispersion analysis for the LNG faciltyfor both Class II and Class I areas. Oregon LNG landing should coordinate with the Oregon DEQ Air Quality Division and the Federal Land Managers for Class I areas within 150 km to develop a protocol acceptable to all agencies. a. Impacts should be evaluated at the Class I areas and near and far field areas for stationary sources and mobile emissions (LNG Ship, support vessels, etc.) originating within the moored safety zone. Specifically, model emissions for stationary sources, stationary combined with hotelling, and stationary combined with offloading and mobile sources within the moored safety zone. b. Results from this modeling should be compared to significant impact levels (SILs) as well as added to the background levels and compared to the NAAQS (Class I, II areas). In addition, please include a Class I visibility and deposition analysis for Class I areas within 150 km	Appendix 9B is now Appendix 9C. The USDA Forest Service and the National Park Service are the Federal Land Managers for the Class I areas within 150 km of the site. Based on guidance from the USDA Forest Service, an evaluation of Air Quality Related Values has been conducted based on a similar analysis done for a nearby major source. This shows small and acceptable impacts to visibility and sulfate and nitrate deposition in the Class I Areas. Emissions from all sources, Terminal, unloading, and marine, associated with Oregon LNG have been included. An analysis has also been conducted for the nearby Class II areas and compared to the ambient air quality standards.
		Provide an analysis of the predicted extent of fog associated with the ambient air vaporizers by season. If appropriate, update the visual impact assessment to include consideration of fog, including revised photo simulations. Also, please note any other potential impacts associated with fog (e.g., traffic impacts).	Analysis has been added to Appendix 9D, the Terminal water vapor plume study. A summary is provided in Section 9.1.3.4

January 8, 1990

Mr. Ken Waid, President
Waid and Associates
8000 Centre Park Drive, Suite 270
Austin, Texas 78754

Dear Mr. Waid:

This is in response to your November 22, 1989 letter to Gerald Emison in which you asked for clarification on two questions concerning "secondary emissions" as defined in the Code of Federal Regulations (CFR) at 40 CFR 52.21(b)(18). First, you asked whether the definition found in the 1988 edition of the CFR was the correct definition. Second, you asked whether any emissions from a vessel are considered secondary emissions.

You are correct in your conclusion that the secondary emissions definition in the 1988 CFR at 40 CFR 52.21(b)(18) is incomplete. The second sentence of the definition in the 1981 CFR apparently was inadvertently omitted when the CFR was revised by the Federal Register of June 25, 1982 (47 FR 27554), which promulgated an amendment to the definition.

Concerning whether any vessel emissions are secondary emissions, the June 25, 1982 revisions to the prevention of significant deterioration (PSD) regulations exempted all vessel emissions from consideration in PSD review of new or modified marine terminals on the basis that vessels are mobile sources and mobile source emissions are excluded by the Clean Air Act from attribution to a stationary source. However, on January 17, 1984 the Court of Appeals for the D.C. Circuit vacated and remanded to the Environmental Protection Agency (EPA) portions of the June 25, 1982 promulgation, including the way in which the Agency treated vessel emissions (Natural Resources Defense Council v. U.S. EPA, 725 F.2d 761). The Court stated that EPA was correct to interpret the term "mobile sources" to include vessels, but that the Agency acted "far too precipitously" in concluding that it therefore had no authority to attribute any vessel emissions to marine terminals. The EPA, the Court went on to say, should have examined the nature of the interactions between a vessel and a terminal to determine specifically which categories of emissions, if any, should be attributed to the terminal.

The Court affirmed the portion of the 1982 promulgation that excluded "to and fro" vessel emissions from attribution to the terminal as secondary emissions, but vacated EPA's 1982 blanket repeal of the dockside vessel emissions component from PSD emissions counting as either primary or secondary emissions. In so doing, the Court acknowledged that, with the exception of to and fro emissions, it implicitly reinstated the PSD regulations promulgated on August 7, 1980 (45 FR 52676). In essence, the Court removed from the CFR the total exclusion of vessel emissions counting which now appears in 40 CFR 52.21 (b) (6) as the phrase " ...except the activities of any vessel," and in

40 CFR 52.21(b)(18) as the phrase "...or from a vessel." Consequently, the August 7, 1980 PSD regulations (with the exception of to and fro emissions counting) shall apply to determinations on how to treat vessel emissions.

The preamble to the 1980 regulations explains that emissions from certain activities of a ship docked at a terminal (i.e., when the vessel is stationary) may be considered emissions of the terminal if the activities would "directly serve the purposes of the terminal and be under the control of its owner or operator to a substantial extent" (45 FR 52696). Vessel emissions which are not to be taken into account in determining whether a marine terminal is subject to PSD review (i.e., they are not primary emissions) are those which result from activities which do not directly serve the purposes of the terminal and are not under the control of the terminal owner or operator. The Court ordered EPA to perform the analyses necessary to distinguish which dockside emissions, if any, should be assigned to the terminal and which should be assigned to the vessel. However, EPA has not yet completed the analyses necessary to define which dockside vessel emissions, and under what conditions, should be assigned to the terminal and whether these would be considered primary or secondary emissions. States with Federally-approved PSD implementation plans are free to develop regulations more stringent than the Federal regulations, and some may have done so already with regard to the treatment of vessel emissions. Thus, I recommend that you check with individual States to learn whether any dockside vessel emissions are considered secondary (or primary) emissions in that particular State.

Finally, as you have noted in your letter, a correction of the Federal PSD regulations is in order. I prefer that any changes to the CFR with respect to vessel emissions not only correct the error of omission cited in your letter, but also carry out the Court's instruction to resolve the issue of dockside emissions attribution for PSD purposes. We hope that our resources will allow us to initiate work on such rulemaking in the near future.

I hope that this has answered your questions. Should you wish to discuss further EPA's policies concerning secondary or vessel emissions, please call Gary McCutchen of my staff at (919) 541-5592.

Sincerely,

John Calcagni
Director
Air Quality Management Division

cc: G. Emison
R. Bartley, Region VI

October 28, 2003

Mr. Michael Cathey
Managing Director
El Paso Energy Bridge Gulf of Mexico, L.L.C.
1001 Louisiana Street
Houston TX 77002

Diana Dutton, Esquire
Akin, Gump, Strauss, Hauer & Feld, L.L.P.
1700 Pacific Avenue, Suite 4100
Dallas TX 75201-4675

Dear Mr. Cathey and Ms. Dutton:

This letter responds to communications from El Paso Energy Bridge Gulf of Mexico, L.L.C. (El Paso), regarding preliminary views the Environmental Protection Agency (EPA) Region 6 expressed in a letter dated March 28, 2003, to the United States Coast Guard, and in several subsequent meetings and telephone calls. El Paso's objections to these views are set forth in an "Analysis of Deepwater Port Permitting Requirements" it provided EPA Region 6 at a meeting on May 9, 2003; in Mr. Cathey's June 16, 2003, letter to Commander Mark Prescott; and in Ms. Dutton's letters of July 18, 2003, and August 18, 2003, to EPA attorneys Patrick Rankin and Michael Boydston. EPA's understanding of the facts in this matter is based on representations in that correspondence, in El Paso's Application to the United States Coast Guard for a Deepwater Port (December 2002) (license application), in National Pollutant Discharge Elimination System (NPDES), Prevention of Significant Deterioration (PSD) and Title V permit applications El Paso filed under protest on September 4, 2003, and in El Paso's statements at a meeting with the Regional Administrator for EPA Region 6 on September 12, 2003.

BACKGROUND

Given the Nation's expanding demand for natural gas, a number of entities are in the process of developing plans and permit applications for deepwater ports through which that commodity may be imported from overseas gasification plants. Typically, such deepwater ports would be located on the outer continental shelf of the United States and use existing natural gas pipelines associated with offshore natural gas production to transport the imported gas ashore. Because the vessels transporting the gas carry it in a liquified state and the pipelines carry it in a gaseous state, the primary industrial process that would occur at offshore natural gas ports is conversion of natural gas from liquified to gaseous state for transport ashore. A major capital expense associated with the ports is generally the construction of offshore fixed facilities on which the re-gasification process will occur. El Paso's proposal, however, is somewhat different.

El Paso proposes to construct and operate a natural gas deepwater port approximately 120 miles off the coast of Louisiana. The proposed port would feature a "submerged turret system" (STS)[1] connected to a short (1.93 miles) pipeline leading to a metering platform. Two other short (3.93 and 1.38 miles) pipelines would convey the natural gas from the metering platform to existing natural gas pipelines operated by other entities for transport ashore. This fixed infrastructure would not include facilities for LNG storage or re-gasification and, under normal circumstances, would not be manned. As explained below, El Paso contends these relatively modest fixed facilities would constitute its entire deepwater port for purposes of federal regulation under the Deepwater Port Act (DPA), Clean Air Act (CAA), and Clean Water Act (CAA).

Only specially designed and equipped liquefied natural gas (LNG) vessels, two of which are now under construction, would be able to deliver natural gas to the fixed infrastructure of the proposed port. Those vessels are identified in El Paso's license application as El Paso Energy Bridge Vessels (EPEBVs). Like most LNG carriers, the EPEBVs would be propelled by steam turbines. The boilers generating the steam would normally be fired with natural gas "boil off" from the cargo on their voyage to the buoy, but by diesel oil while discharging cargo and on the return voyage. Unlike any LNG carrier previously constructed, however, the EPEBVs would be specially outfitted so they could be attached to the STS and re-gasify their LNG cargo before offloading it.

The operator of an EPEBV calling on the port would retrieve the STS, winch it into an opening in the bottom of the vessel's hull, and attach it to the vessel with hydraulically operated locking jacks. It would then ring up "finished with engines" and set a "moored condition" bridge watch. Thereafter, an El Paso representative, a.k.a., "person in charge" (PIC), and "other entities involved in cargo transfer process" would board the vessel. License Application, Appendix M, p. 3. The PIC would inspect the re-gasification system, determine the quantity and quality of the cargo, calibrate metering equipment, assure coordination with the pipeline operators so that maximum operating pressures would not be exceeded, and "issue permission to the vessel operator" to commence the re-gasification and transfer process. *Id,* p. 4.

Onboard re-gasification would be accomplished by warming the LNG until it turned into a gas, a process employing an "open loop" system, "closed loop" system, or a combination of the two. In the open loop mode, warm seawater would be drawn into the EPEBV, then passed through a shell and loop vaporizer, converting the LNG to a gaseous state by heating it, and then

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[1] The proposed STS would be a special purpose buoy equipped with a flexible riser and pipeline manifold and would be affixed to the seabed by chains and anchors. When not in use, it would be submerged, but marked by a smaller lighted buoy on the surface.

would be discharged back to the sea at a reduced temperature. In the closed loop mode, steam from the EPEBV's boilers would be used to heat water circulated through the shell and loop vaporizer in a closed system from which there would be no warming water discharge. El Paso would normally use the open loop system at its proposed Gulf of Mexico facility, but could rely on the closed loop system if necessary. After re-gasification, the natural gas would be conveyed through the buoy, riser, and manifold to the 1.93 mile pipeline leading to the metering platform.

In its letter of March 28, 2003, EPA explained its views on how the CWA would apply to the discharges from the open loop re-gasification system as well as discharges from the metering platform. It also explained its views on how the CAA would apply to emissions associated with both the re-gasification processes and emissions from the metering platform. El Paso objects to regulation of any discharges or emissions originating on the EPEBVs and to the process for authorizing discharges and emissions from the metering platform.

SOURCE OF EPA AUTHORITY TO REGULATE ACTIVITIES ASSOCIATED WITH DEEPWATER PORTS

EPA regards a provision of the DPA, 33 U.S.C. § 1501, *et seq*, as the primary source of its authority to apply the CAA and CWA to activities associated with deepwater ports. In relevant part, 33 U.S.C. § 1518(a)(1) extends the Constitution and laws of the United States "to deepwater ports . . . and to activities connected, associated, or potentially interfering with the use or operation of any such port, in the same manner as if such port were an area of exclusive Federal jurisdiction located within a State." In addition, 33 U.S.C. § 1518(b) "federalizes" consistent laws of the adjacent state and directs that they be applied by federal officials. These statutory provisions are similar to Section 4 of the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. § 1333(a)(1), and serve the same general purpose, i.e., defining the body of law that applies to activities within the purview of the respective acts. *See generally, e.g., Rodrique v. Aetna Casualty & Surety Co.*, 395 U.S. 352 (1969); *Wentz v. Kerr-McGee Corp*., 784 F.2d 699 (5th Cir. 1986); *Village of False Pass v. Clark*, 733 F.2d 605 (9th Cir. 1984). OCSLA § 4 has been long viewed by EPA as the source of its authority to regulate discharges from oil and gas operations on the outer continental shelf. *See* "Outer Continental Shelf Applicability of FWPCA," Opinion of the General Counsel (August 3, 1973), *published at* 2 Gen. Couns. Ops. (Water Pollution) 181, 182 (Environmental Law Publishing Service, 1979).

El Paso contends, however, that the DPA establishes a "one window" licensing process that shifts responsibility for issuing authorizations required by the CWA and CAA from EPA to the Secretary of Transportation. According to El Paso, EPA's role in that unified licensing process is limited to developing conditions implementing those statutes for inclusion in the deepwater port license issued by the Secretary. El Paso further argues that this unified licensing procedure has substantive consequences. According to El Paso, the Secretary's authority to regulate *via* this unified license is circumscribed by the exclusion of "vessels" in the DPA's definition of "deepwater port" and EPA could thus neither recommend nor require the Secretary's imposition of license conditions on vessels, regardless of whether the CWA and CAA authorize EPA to impose such conditions in independent permits. Under that view, only discharges and emissions from the metering platform would be subject to federal regulation.

EPA is informed, however, that the Secretary of Transportation interprets the DPA as requiring a unified application for all necessary federal permits and close coordination between responsible federal agencies, but not as requiring issuance of a single permit. "Federal Agencies with permit responsibilities such as the EPA and MMS will retain all distinct permit issuance authority." USCG Memorandum, "Environmental Planning Aspects of the Deepwater Port Act" (1 April 2003).[2] Because the Secretary has primary responsibility for administration of the DPA, EPA defers to that interpretation and does not address the merits of El Paso's argument. Nor does EPA address the merits of El Paso's argument on the scope of the DPA's vessel exclusion.[3]

INTERNATIONAL LAW

El Paso argues that EPA must interpret the grant of authority under 33 U.S.C. § 1518 in view of constraints imposed by international law, primarily the 1982 United Nations Convention on the Law of the Sea (UNCLOS), which generally prohibits nations from exercising sovereignty over vessels on the high seas.[4] EPA's interpretation is fully consistent with international law, however, as reflected in UNCLOS.

The United States has not acceded to UNCLOS, but it has been U.S. policy since 1983 to act in a manner consistent with the Convention's provisions regarding traditional uses of the ocean. Nothing in UNCLOS III and no general principle of international law, however, limits a nation's sovereignty over its own ports and internal waters, including the authority to impose conditions for entry. *See, e.g., Nevada v. Hall*, 440 U.S. 410 (1979); *United States v. Royal Caribbean Cruises, Ltd.*, 11 F. Supp. 2d 1358 (S.D. Fla. 1998). Assuming that the relevant UNCLOS provisions reflect customary international law and that EPA must interpret §1518 consistently with those provisions, the potential EPA requirements at issue are fully consistent with UNCLOS. Article 60 of UNCLOS explicitly recognizes that coastal States, in their exclusive economic zones (EEZs), "have the exclusive right to construct and to authorize and regulate the construction, operation, and use of . . . installations and structures for the purposes

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[2] Under transition provisions of the Homeland Security Act, the United States Coast Guard remains responsible for processing El Paso's license application, despite its transfer to the recently created Department of Homeland Security. In this context, Coast Guard interpretations of the DPA are attributable to the Secretary of Transportation, who retains ultimate authority for issuance or denial of El Paso's deepwater port license.

[3] The DPA defines "vessel" as "every description of watercraft or other artificial contrivance used as a means of transportation on or through the water." 15 U.S.C. §1506(19).

[4] In addition, El Paso notes the DPA licensing prerequisite that "the deepwater port . . . not unreasonably interfere with international navigation or other reasonable uses of the high seas, as defined by treaty, convention, or customary international law." 33 U.S.C. § 1503(c)(4).

provided for in article 56 [pertaining to the EEZ] and other economic purposes." Deepwater ports fall within this provision.

Moreover, EPA's regulation of discharges and emissions associated with onboard re-gasification performed by ships that are physically attached to El Paso's submerged turret system in no way interferes with the freedom of navigation. There is thus no need for EPA to interpret its authority under the DPA restrictively in order to maintain consistency with international law.

To the extent you contend the re-gasification operations occur on the "high seas" rather than at ports over which the United States is sovereign, your argument appears directed at the authority of Congress to extend U.S. sovereignty to the area in which you propose to locate a deepwater port. EPA notes that Congress was aware of constraints imposed by international law when it enacted the DPA in 1974. It decided that, under the 1958 United Nations Convention on the High Seas, Article 2, "a nation might properly execute jurisdiction on the High Seas in order to license and regulate such [deepwater port] facilities." Senate Report 93-1217, 1974 U.S. Code Congressional and Administrative News 7529, 7536. Of course, UNCLOS further clarifies the authority of a coastal state to establish a deepwater port in its EEZ.

In support of its international law argument, El Paso also relies on Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL). However, El Paso's arguments related to Annex VI are without merit. First, as El Paso acknowledges, Annex VI is not in force and has not yet been ratified by the United States. Second, El Paso claims that regulating emissions of vessels, as proposed by EPA here, "would undermine the international uniformity sought in MARPOL Annex VI," and alleges that EPA has reaffirmed its "deference to emerging international standards" in a recent rulemaking setting standards for Category 3 marine diesel engines. June 16 Cathey letter at 5 (citing 68 Fed. Reg. 9746, at 9759 (Feb. 28, 2003)). But, although EPA endeavors, where possible, to work within international standards, EPA did not "reaffirm[] its deference to emerging international standards" in that rulemaking. The text in question explains EPA's decision to not exercise its discretion to apply the standards contained in that rulemaking to marine diesel engines installed on foreign flag vessels. One of the reasons for that decision was "to facilitate the development of more stringent consensus international requirements" that have the potential of maximizing emission reductions from all vessels that visit U.S. ports. At the same time, EPA clearly noted that it would reconsider this issue in a future rulemaking. In addition, Annex VI does not address air emissions from re-gasification activities. Nor does MARPOL preclude Parties from imposing more stringent conditions on ships entering their ports. Again, EPA does not intend to impose any requirement on vessels exercising their navigational rights on the high seas, but is instead addressing activities conducted at the port. As earlier stated, this regulatory approach is consistent with Article 60 of UNCLOS, which gives "exclusive jurisdiction over . . . artificial islands, installations and structures" in the EEZ to coastal states.

CWA REGULATION OF VESSEL DISCHARGES

CWA § 502(12)(B), 33 U.S.C. § 1362(12), excludes addition of a pollutant from "a vessel or other floating craft" to the ocean or contiguous zone from its definition of "discharge of a pollutant." Based on that statutory exclusion, El Paso argues the CWA provides EPA no authority to regulate discharges from the EPEBVs. Under the 33 U.S.C. § 1518(a)(1), however, discharges from the EPEBVs must be regulated "as if" they occurred "in an area of exclusive Federal jurisdiction located within a State," i.e., in the territorial seas or inland waters. 33 U.S.C. § 1518(a)(1). The statutory exclusion for vessel discharges to the contiguous zone and ocean would not thus apply.

EPA has, however, promulgated a regulatory exclusion for vessel discharges that applies to the territorial seas and inland waters as well as to the contiguous zone and ocean. 40 C.F.R. §122.3 provides in pertinent part:

> The following discharges do not require NPDES permits:
>
> (a) any discharge of sewage from vessels, effluent from properly functioning marine engines, laundry, shower, and galley sink wastes, or any other discharge incidental to the normal operation of a vessel. This exclusion does not apply to rubbish, trash, garbage, or other such materials discharged overboard; nor to other discharges when the vessel is operating in a capacity other than as a means of transportation such as when used as an energy or mining facility, a storage facility or a seafood processing facility, or when secured to the bed of the ocean, contiguous zone or waters of the United States for the purpose of mineral or oil exploration or development . . . .

The first sentence of this regulation describes the fundamental ambit of the exclusion and the second sentence serves two purposes. The second sentence first clarifies that refuse discharged overboard is not excluded from NPDES permit requirements as "discharges incidental to the normal operation of a vessel." Second, it serves as a "recapture clause" for incidental discharges that might otherwise be subject to the exclusion of the first sentence "when the vessel is operating in a capacity other than as a means of transportation." This recapture provision is based on long-standing interpretations that Congress intended to exclude only "vessels or other floating craft" engaged in transportation from CWA permit requirements and that discharges from vessels operating other than as a means of transportation should be regulated under CWA § 402.

El Paso contends the re-gasification process that it would perform aboard EPEBVs is part of those vessels' transportation function, arguing that "[t]he Port [sic], while producing some wastewater pursuant to re-gasification operations, is only conducting those operations in furtherance of its sole purpose – the transportation of natural gas." August 18, 2003, Dutton Letter, pp. 8-9. On this basis El Paso distinguishes the EPEBVs from the seafood processing and drill ships the regulation's recapture provision references as examples, because the primary use of such vessels is not transportation, i.e., they only move to reach the locations in which they will operate in a non-transportation capacity.

There is no need to reach the question of how the recapture provision of the regulation might apply because the warming water discharges from the LNG re-gasification process that EPA would regulate under the port's NPDES permit are not "incidental to the normal operation of a vessel." LNG re-gasification is an industrial process that does not occur as part of the normal operation of a vessel. It is instead an industrial process normally performed at fixed facilities, e.g., onshore terminals, not on vessels delivering the LNG. Moreover, the proposed Port Pelican and Port Cabrillo, subjects of the only other deepwater port applications now pending, would use gravity-based fixed structures on which the LNG would be re-gasified after its delivery. At those facilities, discharges associated with re-gasification would be regulated in the facilities' NPDES permits.

Re-gasification would not even be "incidental to the normal operation" of the EPEBVs themselves. Re-gasification would not occur while the LNG is loaded aboard those vessels nor during their transit of ocean waters. Onboard re-gasification would also not occur should an EPEBV ever offload its cargo at any LNG terminal other than El Paso's. Indeed, the vessel's crew, although it would be fully qualified to transport LNG *via* steam powered vessels to any LNG terminal in the world, would only be allowed to operate the re-gasification system under the direct supervision of El Paso's PIC. Despite its physical location aboard the EPEBVs, the re-gasification process that would occur at this port would be part of El Paso's industrial operation, not part of the vessels' transportation operation. The warming water discharges from this port process should thus be regulated under an NPDES permit in the same fashion as warming water discharges from the same process at competing LNG terminals.

CAA REGULATION OF VESSEL EMISSIONS

El Paso has acknowledged that sources on the port metering platform will produce air emissions of an estimated 9.48 tons per year of NOx, 0.07 tons per year of SO_2, and 0.73 tons per year of PM_{10}. These emissions should be included in the applicability determinations for CAA preconstruction and operating permits. In addition, the much greater vessel emissions associated with the re-gasification process and the transfer of gas to the port should be included. Information submitted by El Paso indicates that these emissions may be as much as 1090 tons per year of NOx.[5] A detailed explanation of our position and a response to your various comments follows.

Fuel Conversion Facility

[5]This figure is derived from El Paso's air permit application, which apparently includes "hotelling" emissions along with re-gasification emissions, and should therefore be viewed as an upper boundary rather than a precise estimate of emissions associated with re-gasification and transfer of gas to the port.

First, in response to your concerns regarding the potential treatment of the port as a "fuel conversion facility," I am attaching a memorandum from EPA's Office of Air Quality Planning and Standards addressing this question. *See* Attachment A, Memorandum from Racqueline Shelton to Guy Donaldson (July 31, 2003). Based on this memorandum and on our current understanding of the nature of the LNG vaporization process at the port, we do not intend to treat the port as a "fuel conversion plant" for new source review (NSR) purposes.

Indirect Source Review

El Paso further asserts that EPA's view that it has permitting jurisdiction over the port "appears to be based on vessels being attracted by the Port, thus making the Port an indirect source of emissions," and that asserting jurisdiction on that basis constitutes a prohibited federally-federally imposed "indirect source review" program under Section 110(a)(5) of the CAA. June 16, 2003, Cathey letter, p. 8. This argument relies on a faulty premise. EPA is not considering the port's potential to attract mobile sources, but is instead examining the activities directly associated with the port and conducted as a part of its operations. This approach is consistent with the CAA:

> it is assuredly not the case that the ban on indirect source review was intended to go so far as to prohibit the attribution to a stationary source of all emissions which happen to emanate from or even merely physically contact a mobile source. Indeed, the statute itself provides that "direct emissions sources or facilities at, within, or associated with, any indirect source shall not be deemed indirect sources for the purpose of this [ban on indirect source review]."

Natural Resources Defense Council, Inc. v. EPA, 725 F.2d 761, 771 (D.C. Cir. 1984) (*NRDC)* (quoting 42 U.S.C. § 7410(a) (5) (C)). All emissions being considered are direct emissions, and are from stationary sources as defined under Section 302(z) of the Act, as further discussed below.[6]

"Stationary Sources" Under the CAA

El Paso maintains that EPA air permitting programs generally cover only stationary sources, and that the CAA defines all vessel emissions as mobile emissions sources. We agree with the first conclusion, but not the second.

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. This

[6]We also note that the CAA's requirement is that EPA not mandate inclusion of an indirect source review program in a State Implementation Plan (SIP) or include it in a Federal Implementation Plan (FIP). CAA Section 110(a)(5)(A), 42 U.S.C. § 7410. EPA's review of the port for permitting purposes is not equivalent to action on a SIP or FIP.

general definition, which is applicable to both preconstruction permits and operating permits, appears at Section 302(z):

> Stationary Source. The term "stationary source" means generally any source of an air pollutant except those emissions resulting directly from an internal combustion engine for transportation purposes or from a nonroad engine or nonroad vehicle as defined in section 216.

42 U.S.C. § 7602(z). In turn, the Section 216 definitions of "nonroad engine" and "nonroad vehicle" are limited to internal combustion engines. 42 U.S.C. § 7550(10), (11). Thus, a vessel powered by external combustion engines would be a "stationary source" for permitting purposes, because only internal-combustion-driven vehicles are excluded from the Section 302(z) definition of stationary source.[7]

El Paso disagrees with this approach, saying that EPA's "rigid" reading of the plain language of the statute would lead to the "illogical result" of treating internal and external combustion engines differently. "A more sensible reading of the CAA," El Paso contends, "is to exempt from permitting the emissions from all nonroad engines and also engines used for propulsion." July 18 Dutton Letter, p. 1. Such an exemption, however, is not present in the CAA. Whether Congress could have used a different approach when it wrote the CAA is not relevant to EPA's decision here, given the plain words of the statute. It is not EPA that has decided to treat external and internal combustion engines differently for purposes of determining what is a stationary source under the CAA. It is instead the express language enacted by Congress.[8]

However, we believe that these statutory definitions do not require EPA to include "to and fro" emissions from marine vessels powered by external combustion engines, or the vessels' "hotelling" emissions not directly associated with the activities of the port as part of the emissions attributable to the port facility. We draw this distinction because under the DPA other U.S. laws apply "to deepwater ports . . . and to activities connected, associated, or potentially interfering with the use or operation of any such port." 33 U.S.C. § 1518(a)(1). The "to and fro" emissions and "hotelling" emissions from the vessels are associated with the normal seagoing activities of the

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[7]As you have informed us, the vessels used in this operation are powered by external combustion engines, not reciprocating internal combustion engines or gas turbines, which generally combust internally. Also, these engines are distinguished from any auxiliary engines on the vessel that may be internal combustion engines.

[8]Whether the Act as a whole would authorize similar treatment of internal-combustion-propelled vessels is not relevant. In this letter we take no position on the applicability of NSR or Title V to emissions from vessels propelled by internal combustion engines. We simply find that the plain language of the Clean Air Act directs that, when making NSR and Title V applicability determinations, EPA is to consider the re-gasification-related emissions from vessels calling at the port.

vessels and not with the industrial activities associated with the port. We thus intend to consider only the emissions from activities in support of the port's function – i.e., those related to processing and transferring gas at the port, regardless of whether they occur on the metering platform or on marine vessels propelled by external combustion engines, as stationary emissions of the port for CAA Title I and Title V purposes. The nature of controls, if any, EPA will propose to impose on those emissions will be reflected in a draft preconstruction/Title V permit.

EPA PSD Regulations and the *NRDC* Decision

El Paso argues that EPA regulations bar consideration of vessel emissions in CAA permitting applicability determinations. July 18 Dutton Letter, p. 3 (citing 40 C.F.R. §§ 51.166(b)(6); 52.21(b)(6)). The cited EPA regulations indeed exclude "the activities of any vessel" from the scope of a regulated stationary source in PSD permitting. EPA promulgated that exemption in 1982, in a rule withdrawing previous regulations that had provided for consideration of vessel emissions on a "control and proximity" basis. See 47 Fed. Reg. 27554 (July 25, 1982). The 1982 rulemaking amended various regulations, including the two cited by El Paso,[9] by adding the phrase "except the activities of any vessel." In the *NRDC* decision, however, the D.C. Circuit Court of Appeals unambiguously vacated the provisions on which El Paso relies:

> [W]e vacate that portion of EPA's revocation [i.e., its 1982 rule withdrawing the previous rules] which "excepts the activities of any vessel" from the emissions attributable to marine terminals, *see, e.g.*, 40 C.F.R. § 51.24(b)(6) (1983), 47 Fed. Reg. 27,560 (1982).

NRDC, 725 F.2d at 775. El Paso correctly notes that the Court also remanded the matter to EPA for further action consistent with its opinion. Nonetheless, the *vacatur* leaves no legally effective regulation that would exempt "the activities of any vessel" from consideration for port permitting purposes. *See Action on Smoking and Health v. Civil Aeronautics Board*, 713 F.2d 795, 797 ("To 'vacate' . . . means 'to annul; to cancel or rescind; to declare, to make, or to render, void; to defeat; to deprive of force; to make of no authority or validity; to set aside.'") El Paso therefore cannot rely on the language added to the regulations by the 1982 rulemaking.

El Paso also asserts that even under EPA's 1980 "control and proximity" regulations, which were withdrawn by the 1982 rule partly vacated in *NRDC*, EPA could still not consider any vessel emissions in permitting the port. Without assessing the merits of El Paso's interpretation of those regulations, we note that the *NRDC* court did not re-promulgate them. Accordingly, the statute rather than these regulations governs our decision here. Our conclusion is reinforced by the fact that the definition of stationary source was added in 1990, after both the rules and the D.C. Circuit opinion had been written. Therefore, nothing in the statute supports the conclusion that re-gasification of LNG occurring at a fixed location using power generated by an external

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[9] 40 C.F.R. § 51.24, which is referenced in the 1983 rulemaking partially vacated in *NRDC*, has since been renumbered as 40 C.F.R. § 166. *See* 51 Fed. Reg. 40656 (Nov. 7, 1986).

combustion engine must be regulated as a mobile source, even when the re-gasification process occurs on a vessel used to transport the LNG and re-gasification equipment to that fixed location.

CONCLUSION

As explained above, EPA Region 6 concludes that:

(1) All discharges from the metering platform and discharges of warming water from the re-gasification process performed aboard EPEBVs are subject to regulation under CWA §402.

(2) Emissions related to the re-gasification and transfer of gas at the port will be included in the CAA operating and preconstruction permit applicability determinations without regard to whether those emissions originate on the metering platforms or EPEBVs. The PSD/Title V permit applications El Paso submitted on September 4, 2003, provide a "worst case" estimate of El Paso's potential to emit. Regional technical staff will be contacting El Paso representatives to discuss potential terms of the draft preconstruction and operating permit.

EPA recognizes and appreciates that El Paso has different views on these matters. Nothing in this letter, however, precludes El Paso from acting on its own interpretation of applicable laws and regulations. The views explained in this letter, if and when applied in a permit, would be subject to administrative review by EPA's Environmental Appeals Board. This letter, therefore, does not constitute "final agency action" for purposes of obtaining judicial review. Final agency action occurs upon completion of the permit appeal processes.

Thank you for your patience in this matter. The views of both El Paso and EPA on these difficult issues of first impression have changed substantially since you originally raised them in May, and substantial time was necessary to provide El Paso full opportunity to express its views and to coordinate this response with various affected programs in EPA and other federal agencies. I assure you that EPA Region 6 will give fair and timely consideration to El Paso's permit applications.

Sincerely yours,

Charles J. Sheehan
Regional Counsel

Enclosure

cc: Commander Mark Prescott
United States Coast Guard