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Alaska LNG Liquefaction Plant Construction Permit Application

Project Information Form Attachment 5:

Appendix D to Alaska LNG Resource Report 9 (Liquefaction Facility Air Quality Modeling Report)

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APPENDIX D LIQUEFACTION FACILITY AIR QUALITY MODELING REPORT

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LIQUEFACTION FACILITY AIR QUALITY MODELING REPORT SUPPORTING RESOURCE REPORT NO. 9

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1.0 INTRODUCTION

The Alaska Gasline Development Corporation (AGDC), BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, and ExxonMobil Alaska LNG LLC (EMALL) (Applicants) plan to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska. The Project includes a Liquefaction Facility in Southcentral Alaska, which is the focus of this document.

As required by FERC, air dispersion modeling was utilized as a tool to demonstrate that the proposed Liquefaction Facility would comply with the National Ambient Air Quality Standards (NAAQS) and Alaska Ambient Air Quality Standards (AAAQS).

The purposes of this FERC Air Quality Modeling Report (Report) are to 1) outline the methodologies, assumptions, and input data used to conduct the air dispersion modeling analysis, and 2) provide the modeling analysis results to support discussions in Resource Report no. 9. The methodologies outlined are generally consistent with:

- Guideline on Air Quality Models, ("Modeling Guideline") (40 CFR Part 51 Appendix W) (USEPA 2005),
- User's Guide for the AMS/EPA Regulatory Model (AERMOD) (USEPA 2004, 2007, 2015a)
- User's Guide for the AERMOD Terrain Preprocessor (AERMAP) (USEPA 2009a).
- Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility. (IWAQM 1993).
- Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts (IWAQM 1998).
- Federal Land Managers' Air Quality Related Values Work Group (FLAG): Phase I Report (USDOI 2010).
- Alaska Department of Environmental Conservation's (ADEC) Modeling Review Procedures Manual (ADEC 2016).

Note that this report is written to address elements required by FERC for an air quality analysis as it relates to the National Environmental Policy Act (NEPA). Air quality impact analyses using dispersion modeling required by USEPA for a Prevention of Significant Deterioration application as it relates to the Clean Air Act (CAA) are generally a subset of those required for a FERC analysis.

1.1 FACILITY DESCRIPTION

The Liquefaction Facility would be a new facility constructed on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula. The proposed Liquefaction Facility would be approximately 921 acres (901 acres onshore and 20 acres offshore) approximately 3 miles from Nikiski and 8.5 miles from Kenai.

While the Liquefaction Facility would be located in a relatively flat area, some higher terrain (approximately 10 to 30 meters (33 to 100 feet) higher than the facility base elevation) exists approximately 5 kilometers (3 miles) to the north. There are also several hills that peak at approximately 40 meters (130 feet) higher than the facility base elevation located about 8 kilometers (5 miles) to the east in the Kenai National Wildlife Refuge.

The coastline is immediately west of the Liquefaction Facility location where there is a bluff that is approximately 40 meters (131 feet) above the water level. Just off the coast there would be a 1,000-meter long trestle where the proposed marine terminal would be located with 2 berths that would receive periodic calls from LNG carriers.

Figure 1-1 shows the proposed location of the Liquefaction Facility on a topographic map.

The Liquefaction Facility would be comprised of the LNG Plant and Marine Terminal. The LNG Plant would include liquefaction processing and storage facilities and necessary utilities and offsite systems, and the Marine Terminal includes the trestle(s), piping, and berthing facilities associated with liquefied natural gas carrier (LNGC) loading and berthing. Equipment at the facility would include gas-fired turbines, liquid fuel-fired reciprocating internal combustion engines, gas-fired auxiliary equipment, and flares. Diesel fuel-fired main and auxiliary engines would be located on LNG carrier vessels docked approximately 1 kilometer (3,300 feet) from the shore. Figure 1-2 provides the proposed Liquefaction Facility plot plan, with notable features indicated. The following types of emission units would be part of the Liquefaction Facility design:

- gas-fired turbines for power generation and compression,
- diesel fuel-fired fire water pumps for supplying water in case of fire
- gas-fired auxiliary air compressor to provide backup air supply in the event of a power or primary system failure,
- thermal oxidizer to control collected hydrocarbon vapors from condensate storage and loading,
- flares for control of excess gas, and
- diesel fuel-fired main and auxiliary engines located on LNG carrier vessels docked approximately 1 kilometer (3,300 feet) from the shore.

Figure 1-1: Location of Proposed Liquefaction Facility

Figure 1-2: Project Proposed Liquefaction Facility Site Plan

2.0 APPLICABLE AIR QUALITY STANDARDS AND EVALUATION CRITERIA

Federal and state air emissions regulations are designed to ensure that new sources do not cause or contribute to an exceedance of ambient standards for criteria air pollutants. The criteria pollutants are as follows:

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

As a major source, as defined under federal New Source Review (NSR) regulations, the Liquefaction Facility would be required to demonstrate by modeling that the cumulative ambient impacts would conform to established regulatory criteria for those pollutants that are emitted above the Significant Emission Rate as defined in 40 CFR 52.21(b)(23)(i). These criteria are described in the following subsections.

2.1 FEDERAL AND STATE AMBIENT AIR QUALITY STANDARDS

The U.S. Environmental Protection Agency (USEPA) has established NAAQS for these seven pollutants. The NAAQS are set at levels the USEPA believes are necessary to protect public health (primary standards) and welfare (secondary standards).

The ADEC has established similar ambient air quality standards referred to as AAAQS. AAAQS are similar to the federal NAAQS for criteria pollutants, except that ADEC has yet to remove the 24 hour and annual standards for SO_2. ADEC also has an eight hour AAAQS for ammonia. **Table 2-1** lists both the federal and state ambient air quality standards.

The federal CAA requires geographic areas that do not meet a particular NAAQS to be designated as “non-attainment” for that individual standard. Other areas can be designated as “in attainment” if data show that the area meets the standard, as “unclassified,” or as “unclassified/attainment” with respect to the standards. An area may also be designated as a “maintenance” area if it has previously been in non-attainment for a pollutant, but has since implemented a State Implementation Plan (SIP) that has brought the area back into attainment for the pollutant.

Alaska has one non-attainment area and four maintenance areas (ADEC 2016b, USEPA 2014a, and 40 C.F.R 81.302). The area surrounding the Liquefaction Facility is currently designated as attainment or unclassified for all criteria pollutants.

Table 2-1: Ambient Air Quality Standards in the Project Vicinity

Air Pollutant	Averaging Period	NAAQS	AAAQS
Sulfur Dioxide	1-Hour[a]	75 ppbv (196 μg/m^3)	196 μg/m^3
	3-Hour[b]	0.5 ppmv (1,300 μg/m^3)	1,300 μg/m^3
	24-Hour[b]	NA	365 μg/m^3
	Annual	NA	80 μg/m^3
Carbon Monoxide	1-Hour[b]	35 ppmv (40 mg/m^3)	40 mg/m^3
	8-Hour[b]	9 ppmv (10 mg/m^3)	10 mg/m^3
Nitrogen Dioxide	1-Hour[c]	100 ppbv (188 μg/m^3)	188 μg/m^3
	Annual	53 ppbv (100 μg/m^3)	100 μg/m^3
Ozone	8-Hour[d]	0.070 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-Hour[b]	150 μg/m^3	150 μg/m^3
Particulate Matter less than 2.5 Microns	24-Hour[e]	35 μg/m^3	35 μg/m^3
	Annual[f]	12 μg/m^3	12 μg/m^3
Lead	Rolling 3-Month Average	0.15 μg/m^3	0.15 μg/m^3
Ammonia	8-Hour[b]	NA	2.1 mg/m^3

Sources: USEPA (https://www.epa.gov/criteria-air-pollutants/naaqs-table); ADEC 2016b

Abbreviations:

NA = not applicable
μg/m^3 = micrograms per cubic meter
mg/m^3 = milligrams per cubic meter
ppbv = parts per billion by volume
ppmv = parts per million by volume

Notes:

[a] Standard is attained when the 3-year average of the 99th percentile of the distribution of daily maximum values is less than 75 ppbv, or 196 μg/m^3.

[b] Second-highest average concentration not to be exceeded more than once in a year.

[c] Standard is attained when the 3-year average of the 98th percentile of the distribution of daily maximum values is less than 100 ppbv, or 188 μg/m^3.

[d] Three-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

[e] Standard is attained when the 3-year average of the 98th percentile of maximum values is less than 35 μg/m^3.

[f] Annual mean, averaged over 3 years.

2.2 PSD CLASS I AND II INCREMENTS

In addition to the NAAQS and AAAQS, air quality is regulated by the CAA through Prevention of Significant Deterioration (PSD) rules implemented in 40 CFR 52.21 and in 18 AAC 50.306. These regulations limit the future increases in ambient air concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$ and establish "minor source baseline dates" for determining the date after which the air quality deterioration must be within the "PSD Increments" to the extent that the NAAQS are not exceeded. Applicable Increments are shown in Table 2-2. While the current dispersion modeling analysis is not in support of PSD permitting, FERC guidance for the preparation of Resource Report No. 9, *Air and Noise Quality*, requires evidence of a project's ability to obtain required permits. In the case of Alaska LNG Project, this means demonstrating that the Liquefaction Facility can satisfy the source impact analysis requirements of the PSD review. As such, the dispersion modeling analysis also compared cumulative impacts to PSD Increments for informational purposes.

Table 2-2: PSD Class I and Class II Increments

Pollutant	Averaging Period	PSD Class I Increments ($\mu g/m^3$)	PSD Class II Increments ($\mu g/m^3$)
Sulfur Dioxide	1-hour	NA	NA
	3-hour [b]	25	512
	24-hour [b]	5	91
	Annual [a]	2	20
Carbon Monoxide	1-hour	NA	NA
	8-hour	NA	NA
Nitrogen Dioxide	1-hour	NA	NA
	Annual [a]	2.5	25
Particulate Matter less than 10 Microns	24-hour [b]	8	30
	Annual [a]	4	17
Particulate Matter less than 2.5 Microns	24-hour [b]	2	9
	Annual [a]	1	4
Lead	3-month rolling average	NA	NA

Abbreviations:
NA = not applicable
Notes:
[a] Never to be exceeded.
[b] Not to be exceeded more than once per year.

2.3 AIR QUALITY RELATED VALUES

Air Quality Related Values (AQRVs) are resources, as defined by Federal Land Managers (FLMs), that may be adversely affected by a change in air quality, and include visibility (either regional haze or plume impairment) and sulfur and nitrogen deposition. The FLMs' AQRV Work Group (FLAG) issued a guidance document (FLAG 2010) for the methodology and AQRV criteria used to evaluate adverse impacts. This guidance and associated screening thresholds were developed primarily for Class I areas.

At the request of the FLMs, additional Class II areas deemed "sensitive" were also evaluated against Class I thresholds. Note that whether these Class II areas are in the near-field (within approximately 50 km) or the far-field (beyond approximately 50 km) changes the applicable model and AQRVs to evaluate, as in the case of visibility.

Because the AQRVs only have screening thresholds below which no concern exists, rather than regulatory standards, AQRV impacts are typically evaluated on a case-by-case basis by FLMs. As part of the impact evaluation, the FLMs consider such factors as magnitude, frequency, duration, location, geographic extent, timing of impacts and current and projected conditions of AQRVs. In practice, this methodology often results in the need to place AQRV impacts into context.

2.3.1 Plume Impairment

Plume impairment is generally defined as the pollutant loading of a portion of the atmosphere such that it becomes visible, by contrast or color difference, against a viewed background such as a landscape feature or the sky. The evaluation criteria for plume impairment are the color difference index (ΔE) and plume contrast (Cp). Plume impairment below the values in **Table 2-3** are considered negligible and no further analysis is warranted. This AQRV is generally applicable for near-field (approximately less than 50 km) source-receptor distances and modeled using the VISCREEN screening model or the PLUVUE II model if more information is required.

According to FLAG 2010, if the screening thresholds are met with VISCREEN, the FLM is likely not to object to the project on the basis of near-field visibility. If screening thresholds are not met, then use of the more refined PLUVUE II model can be implemented. The PLUVUE analysis provides additional information designed to assess the magnitude and frequency of plume impairment.

Table 2-3: Plume Impairment Initial Screening Thresholds

Model	Color Difference Index (ΔE)	Contrast (Cp)
VISCREEN level 1	2.0	0.05
VISCREEN level 2	2.0	0.05
PLUVUE II	1.0	0.02

2.3.2 Regional Haze

Visibility impairment is also manifested by the general alteration in the appearance of landscape features or the sky as the light between the observer and target becomes scattered or absorbed by pollutant loading in the atmosphere. This impairment results in a reduction of contrast between distant landscape features causing features within the landscape to disappear from the view. This AQRV is generally applicable for far-field (greater than approximately 50 km) source-receptor distances or for multiple source analyses. CALPUFF is currently the recommended model to assess regional haze impacts using methodologies and inputs described in FLAG 2010. Regional haze is evaluated by determining the change in light extinction due to pollutant loading. The criteria, shown in **Table 2-4**, represent the incremental increases above a reference background level. According to FLAG 2010, if the 98th percentile change in light extinction is less than 5%, the visibility threshold of concern is not exceeded. Regional haze impacts due to project sources alone that are below this threshold are considered negligible and often no further analysis is warranted.

Cumulative regional haze impacts due to both project and offsite sources are typically compared to a 10% change in light extinction. If this threshold is exceeded at an area being evaluated, the FLM may consider the impacts on a case-by-case basis by taking into account the context when making an adverse impact determination.

Table 2-4: Regional Haze Initial Screening Thresholds

Description	Change in Extinction[a] (%)
Contribute to Visibility Impairment	5
Cause Visibility Impairment	10

Notes:
[a] The 98th percentile value of maximum modeled impacts, by year, for each area of concern.

2.3.3 Acid Deposition

Increased nitrogen (N) or sulfur (S) deposition may result from emissions from new facilities and have a negative impact on AQRVs sensitive to N or S deposition. Dry and wet atmospheric deposition of S and N compounds is also an AQRV that is discussed in FLAG 2010. FLMs have established Deposition Analysis Thresholds (DATs), listed in **Table 2-5**, to use as screening levels for incremental increases in S and N compounds due to a proposed facility. Facility-only deposition below the DAT of 0.005 kg/ha/yr is considered negligible.

The N and S DAT of 0.005 kg/ha/yr for the western Class I areas which are applicable to those located in Alaska is calculated as follows:

DAT = 0.25 kg/ha/yr x 0.5 x 0.04

Where:

- 0.25 kg/ha/yr is the N and S western states natural background deposition value,
- 0.5 is the variability factor, representing the maximum percentage of contribution by all combined anthropogenic sources to the conservative natural background value without triggering concerns regarding impacts, and
- 0.04 is the cumulative factor, representing a four percent safety factor to protect Class I areas from cumulative deposition impacts.

Consistent with FLAG guidance, the modeled deposition flux due to Liquefaction Facility sources alone were compared to the DAT of 0.005 kg/ha/yr. However, because Liquefaction Facility sources and offsite sources were explicitly modeled to evaluate cumulative deposition, it is overly conservative to include a four percent safety factor in the DAT. Therefore, the cumulative factor was removed from the DAT and the modeled cumulative deposition flux due to the Liquefaction Facility and offsite sources was compared to a DAT of 0.125 kg/ha/yr (0.25 x 0.5). **Table 2-5** summarizes the DATs that were used in the acid deposition evaluation (see **Section 7.2.5**).

Table 2-5: Depositio n Analysis Thresholds

Species	Likquefactio n Facility Depositi on (kg/ha/yr)	Cumulativ e Depositi on (kg/ha/yr)
Nitrogen	0.005	0.125
Sulfur	0.005	0.125

2.3.4 Class I and Sensitive Class II Areas for Air Quality Analysis

National Conservation System Lands (NCSLs) that are Class I areas or that are considered to be Sensitive Class II areas warranting AQRV analysis were identified in consultation with the FLMs. For the Liquefaction Facility, NCSLs for AQRV evaluation identified within approximately 50 km (31 miles) for near-field analysis and between approximately 50 km to 300 km for far-field analysis are provided in **Table 2-6** and shown in **Figure 2-1**. The modeling methodology for areas within 50 km of the Liquefaction Facility and those between 50 km and 300 km (186 miles) of the Liquefaction Facility is described in **Section 6.0**.

Table 2-6: Class I and Sensitiv e Class II Areas included in AQRV Evaluat ion

	Class I Areas (approx . distance from LNG Plant)	Sensiti ve Class II Areas Warran tin g[a] AQRV Evaluatio n (approx . distance from LNG Facil ity)
Within approximately 50 km of LNG Facility (near field)	• None	• Kenai National Wildlife Refuge (10 km or 6 mi)
Approximately 50 km – 300 km from LNG Facility (far field)	• Tuxedni National Wildlife Refuge (86 km or 53 mi) • Denali National Park (183 km or 114 mi)	• Lake Clark National Park & Preserve (50 km or 31 mi) • Chugach National Forest (74 km or 46 mi) • Kenai Fjords National Park (92 km or 57 mi) • Kodiak National Wildlife Refuge (256 km or 159 mi)

Notes:
[a] FLMs requested the evaluation of these Sensitive Class II areas.

Figure 2-1: Liquefaction Facility and Nearby Class I and Sensitive Class II Areas

3.0 BACKGROUND AIR QUALITY

In evaluating impacts of the Liquefaction Facility with respect to the NAAQS and AAAQS, the appropriate modeled impacts were added to representative ambient background concentrations shown in **Table 3-1**.

3.1 AMBIENT DATA FOR BACKGROUND DEVELOPMENT

According to USEPA's Guideline on Air Quality Models (USEPA 2005), background concentrations should be representative of the following in the vicinity of the source(s) under consideration:

1. Natural sources,
2. Nearby sources other than the one(s) currently under consideration, and
3. Unidentified sources.

Ambient air quality data that can be demonstrated to meet these criteria and are of PSD-quality should generally be acceptable as the basis for developing background concentrations to support modeling demonstrations.

Background concentrations were developed using data collected as part of the Alaska LNG Project Air Quality Monitoring Program located in Nikiski, Alaska (Alaska LNG, 2015). The primary objective of the monitoring program is to collect PSD-quality ambient air quality data that is representative of the region surrounding the Liquefaction Facility to support future air quality compliance demonstrations. The siting of the air quality monitoring station was approved by the ADEC on March 13, 2014 (Alaska LNG, 2015). **Figure 3-1** depicts the location of the monitoring station and its proximity to the proposed Liquefaction Facility. **Table 3-1** summarizes the full year of data available spanning January 1, 2015 – December 31, 2015.

3.2 1-HOUR NO_2 BACKGROUND DEVELOPMENT

Guidance memos published by the USEPA (2011, 2014b) outline a tiered approach to develop monitored NO_2 background values to assess compliance with the 1-hour NO_2 NAAQS. The following outlines the approaches for each tier:

First Tier Approach

Assume "a uniform monitored background contribution" by "[adding] the overall highest hourly background NO_2 concentration (across the most recent three years) from a representative monitor to the modeled design value." This approach may be applied without further justification (USEPA 2011).

A "Less Conservative" First Tier Approach

Assume "a uniform monitored background contribution based on the monitored design value" by adding the "monitored design value from a representative monitor" to the modeled design value, based on five years of modeling. "The monitored NO_2 design value [is] the 98th-percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data" (USEPA 2011).

Second Tier Approach

"For shorter averaging periods, the meteorological conditions accompanying the concentrations of concern should be identified" (USEPA 2005). Assume a temporally varying background based on "multiyear averages of the 98th-percentile of the available background concentrations by season and hour-of-day, excluding periods when the source in question is expected to impact the monitored concentration" (USEPA 2011). In identifying meteorological conditions of concern, this tiered approach may also encompass approaches where backgrounds vary by wind direction, wind speed, day of week, or month of year as appropriate. This approach is representative “since the monitored values will be temporally paired with modeled concentrations based on temporal factors that are associated with the meteorological variability, but will also reflect worst-case meteorological conditions in a manner that is consistent with the probabilistic form of the 1-hour NO_2 standard” (USEPA 2011).

Third Tier “Paired Sums” Approach

“Combine monitored background and modeled concentrations on an hour-by-hour basis, using hourly monitored background data collected concurrently with the meteorological data period being processed by the model.” This approach is only recommended “in rare cases of relatively isolated sources where the available monitor can be shown to be representative of the ambient concentration levels in the areas or maximum impact from the proposed new source…[or] where the modeled emission inventory clearly represents the majority or emissions that could potentially contribute to the cumulative impact assessment and where inclusion of the monitored background concentration is intended to conservatively represent the potential contribution from minor sources and natural or regional background levels not reflected in the modeled inventory” (USEPA 2011).

The “less conservative” first tier approach was used to develop the1-hour NO_2 background value used in the air quality analyses for the Liquefaction Facility. This representation of the NO_2 background value is consistent with the statistical form of the 1-hour NO_2 NAAQS. USEPA acknowledges that using the maximum hourly NO_2 concentration may be overly conservative and may reflect source-oriented impacts from nearby sources in many cases. Therefore, the agency concludes that the “less conservative” first tier approach “should be acceptable in most cases” (USEPA 2011).

Table 3-1: Background Air Quality Data in the Vicinity of the Liquefaction Facility

Air Pollutant	Averaging Period	Concentration	
		ppbv	µg/m^3
Sulfur Dioxide	1-Hour[a]	1.9	5.0
	3-Hour[b]	1.9	5.0
	24-Hour[b]	0.9	2.4
	Period[b]	0.0	0.0
Carbon Monoxide	1-Hour[b]	1000	1145
	8-Hour[b]	1000	1145
Nitrogen Dioxide	1-Hour[c]	17.2	32.3
	Period[b]	1.4	2.6
Ozone	8-Hour[d]	47	94.0
Particulate Matter less than 10 Microns	24-Hour[b]	NA	40
Particulate Matter less than 2.5 Microns	24-Hour[c]	NA	12
	Period[b]	NA	3.7

Sources: Alaska LNG 2016a (for the period 01/01/2015 – 12/31/2015)

Abbreviations:

NA = not applicable

µg/m^3 = micrograms per cubic meter ppbv = parts per billion by volume

Notes:

[a] Value reported is the 99th percentile of the distribution of measured daily maximum values.

[b] Value reported is the measured maximum average concentration for the period.

[c] Value reported is the 98th percentile of the distribution of measured daily maximum values.

[d] Value reported is the fourth-highest measured daily maximum 8-hour average ozone concentration.

Figure 3-1: Locations of Meteorological and Ambient Air Monitoring Stations

4.0 EMISSION INVENTORIES

This section will provide information regarding the emission inventories used in the dispersion modeling, which serves as an overview of the details incorporated into the emissions calculations which are provided in Appendix A.

4.1 PROJECT EMISSION UNITS

This section describes the emission data used to model Liquefaction Facility sources as well as the modeled scenarios. **Table 4-1** lists the emission units to be installed at the Liquefaction Facility and those that were considered for modeling.

Table 4-1: Equipment to be Installed at the Liquefaction Facility

Description	Number of Units
Turbines	
Gas Compression (simple – cycle)	6
Power Generation (combined – cycle)	4
Reciprocating Internal Combustion Engines (RICE) (Liquid Fired – Ultra Low Sulfur Diesel)	
Firewater Pump	1
Auxiliary Air Compressor	1
Flares	
Low Pressure (LP) Hydrocarbon flare	1
Ground Flares	3 x 50%[a]
Additional Equipment	
Thermal Oxidizer (gas-fired)	1
LNG Carrier auxiliary engines[b] (liquid-fired)	2
Tugboat auxiliary engines[b] (liquid-fired)	4

Notes:

[a] 3 x 50% ground flares (3 enclosures, each capable of handling 50% of the facility flaring requirements) are installed; therefore, only two flares are expected to operate at any one time. The third flare is a back-up.

[b] The main propulsion engines for the LNG carriers and tugboats are part of the Facility emissions inventory and were considered for dispersion modeling. They are not listed here because they were not part of the modeled worst-case scenario that takes place while the ships are within 500 feet of the terminal.

4.1.1 Modeled Scenarios

A conservative normal operations scenario was used to predict impacts from the Liquefaction Facility, including marine terminal activities. This scenario was selected because, when compared to other possible operating scenarios, the total emissions and assumed simultaneous equipment operation for this scenario would yield equivalent or higher modeled impacts than other scenarios. **Table 4-2** lists the operational equipment for the selected scenario alongside the equipment for those scenarios that will not be modeled.

"Normal operations" corresponds to the emissions and stack parameters that are typical for the equipment, on a per unit basis. However, the following conservative assumptions for this scenario should be noted:

- All equipment located at the Liquefaction Facility is assumed to operate concurrently, even intermittently used equipment.

- Power generation turbines were modeled at maximum emissions rates and minimum temperature and velocity stack exit characteristics parameters.
- Even though flare relief events would only occur during maintenance or upset conditions, they were conservatively modeled as part of normal operations.
- For the marine terminal, while it is not possible for two carriers to be simultaneously loading LNG, the normal operations scenario includes the possibility that a second LNG carrier maneuvers into the open berth while one carrier is already docked and loading. While this could occur, typical operation would only include a single vessel at a time.

Modeling of the normal operations scenario was designed to be conservative, even though it is highly unlikely that all sources modeled concurrently would in fact be operating in that manner. The normal operations scenarios for the Liquefaction Facility are detailed below.

Table 4-2: List of Equipment Included in Modeled and Non-Modeled Operational Scenarios

FACILITY EQUIPMENT	SCENARIO TO BE MODELED	NON-MODELED SCENARIOS					
	(Conservative) Normal Operations	Start-up	Early Operations – Phase 1	Early Operations – Phase 2	Early Operations – Phase 3	Maintenance – Turbines & Process System	Maintenance – Flares
LNG Train 1 - 2 Compressor Turbines	Yes	Yes	Yes	Yes	Yes	Offline[(a)]	Yes
LNG Train 2 - 2 Compressor Turbines	Yes	-	-	Yes	Yes	Yes	Yes
LNG Train 3 - 2 Compressor Turbines	Yes	-	-	-	Yes	Yes	Yes
Power Gen. Turbines Set 1 (2 turbines)	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Power Gen. Turbines Set 2 (2 turbines)	Yes	-	-	-	Yes	Yes	Yes
Thermal Oxidizer	Yes	-	Yes	Yes	Yes	Yes	-
Reciprocating IC Engines	Yes	-	-	-	-	-	-
Ground Flares (2) - Pilot/Purge	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ground Flares (spare) - Pilot/Purge (fewer emissions than flare max. relief case)	-	-	-	-	-	-	Yes
Ground Flares (2) - Max. Relief Case	Yes	-	-	-	-	-	-
Ground Flares (2) - Relief Events assoc. with Start-up (fewer emissions than max. relief case)	-	Yes	-	Yes	Yes	-	-
Ground Flares (2) - Relief Events assoc. with Turbine & Process System Maintenance (fewer emissions than max. relief case)	-	-	-	-	-	Yes	-
LP Flare - Pilot/Purge	Yes	-	Yes	Yes	Yes	Yes	Yes
LP Flare - Max. Relief Case	Yes	-	Yes	Yes	Yes	Yes	Yes
LP Flare - Relief Events assoc. with Start-up (fewer emissions than ground flare max. relief case)	-	Yes	-	Yes	Yes	-	-

Notes:

[a] Turbines from Train 1, Train 2, or Train 3 could be offline during maintenance operations. It is likely that only a single turbine would go offline at a time, but no more than 1 full train (2 turbines) would be offline.

4.1.1.1 Normal Operations – Liquefaction Facility

The Liquefaction Facility is designed to process product from the upstream Gas Treatment Plant Facility (GTP), using 3 process trains to compress the full throughput from the GTP. A description of the equipment that was modeled is provided below. Additional details regarding normal operation of the units as well as the development of emissions and exhaust parameters are documented in Appendix A.

Compression Turbines

The compression turbines at the Liquefaction Facility would be arranged with two turbines per train (six turbines total) to compress the refrigerant used to cool the natural gas into liquefied natural gas. The compressors would be located upstream of the refrigerant condensers and would compress the heated refrigerant gas returning from the cross exchangers used to cool the natural gas. It is assumed that the production of LNG would be relatively constant and requires a continuous supply of refrigerant. This would require the compressor turbines to operate near 100% load continuously with little variation. Therefore, modeled emissions and exhaust parameters were based on 100% operating load.

Power Generation Turbines

The Liquefaction Facility main power generation system would consist of four gas-driven turbines which would create a common power supply to all users. The power generation turbine load would fluctuate from 60% to 100%, based on the needs of the process train. Seasonal load variations would be the most common reason for differences in power generation equipment operation. During the summer months, refrigerant condensers would have a much higher energy demand, thus requiring a higher power generation turbine output.

The power generation turbines would all be equipped with Heat Recovery Steam Generators (HRSGs) for steam production at the facility. The HRSGs would operate by using the heat from the hot turbine exhaust gas to produce steam. The steam would be used by steam turbine generators within the power generation plant.

The HRSG would be designed to always accept the full exhaust flow from the compressor turbines. The HRSG would be designed to transfer the heat duty of the exhaust gas that corresponds to a temperature loss of roughly 600°F to 700°F. The typical outlet exhaust temperature of the compressor turbines would be 1000°F. The HRSG would reduce the temperature of the exhaust gas at the stack to 341°F, which was the modeled exhaust temperature.

To ensure maximum model-predicted impacts, emissions rates corresponding to 100% load were conservatively paired with stack exhaust velocities associated with 60% load.

Reciprocating Internal Combustion Engines

The auxiliary air compressor at the Liquefaction Facility would provide backup air supply to the instrument air system in the event of a power failure or primary instrument air compressor failure. It would only be operated in emergencies and for readiness testing. However, it was conservatively included in the modeling as an intermittently operated source, operating for 500 hours per year.

There would be one diesel-driven firewater pump located within the process facilities that would distribute fire water around the facility in the event of an emergency. It would only be operated in emergencies and for readiness testing. However, it was conservatively included in the modeling as an intermittently operated source, operating for 500 hours per year.

Dry and Wet Flare

There would be three separate ground flares located at the Liquefaction Facility, each consisting of a dry and wet flare (six total flares). The 3 x 50% design capacity establishes that during any relief event, two out of the three flares would be operating at maximum capacity. One flare (wet and dry) is a spare and would not regularly operate. As part of normal operations, pilot and purge gas would be continuously combusted at the two wet flares and two dry flares and was included in the dispersion modeling.

Maximum relief events from the flares would occur infrequently and during upset conditions when other daily operating equipment would be shut down. However, air concentration and deposition modeling conservatively included maximum flaring from each of the four operational flares (i.e. two wet flares and two dry flares) in the normal operations scenario as intermittent sources, operating for 500 hours per year. Because the wet and dry flares cannot operate simultaneously, visibility modeling at Class I and Sensitive Class II areas was refined to only include maximum flaring from the dry flares. The dry flare was selected over the wet flare because emissions from the dry flare are much greater than the wet flare.

Low-Pressure Flare

An elevated low-pressure (LP) Flare would be located on land and would take most gas streams from LNG storage and loading systems and the Boiloff Gas (BOG) compression system. The LP Flare would also support marine operations by receiving all gases from warm carriers as well as tank breathing during loading activities. Lastly, if the thermal oxidizer is upset for any reason, gases from condensate storage and loading (typically incinerated by the thermal oxidizer), would be sent to the LP Flare (via blower assist).

The LP flare was modeled as a part of normal operations, assuming continuous emissions for both pilot/purge and maximum relief cases.

Thermal Oxidizer

A thermal oxidizer located at the Liquefaction Facility would combust vented hydrocarbon vapors from condensate storage and loading. The condensate and offspec condensate storage tanks, as well as the equalization tank that would help to separate oil from the facility's wastewater, would send all vent gas from working and flash losses through the thermal oxidizer. The thermal oxidizer was included in the modeling as continuously operating at 100% load.

Point source parameters and emissions rates used to model the normal operations scenario for the Liquefaction Facility are provided in **Table 4-3** and **Table 4-4**. These data were developed based on USEPA emission factors (AP-42) and vendor data, where possible. Detailed calculations are documented in Appendix A. All emission units were modeled as vertical and uncapped point sources, and all point source locations were referenced to NAD83 UTM Zone 5 coordinates.

Table 4-3: Modeled Liquefaction Facility Source Emissions

Model ID	Source Description	NO_x (g/sec)		SO_2 (g/sec)			$PM_{2.5}$ (g/sec)		PM_{10} (g/sec)		CO (g/sec)
		1-hour	Annual	1-hour	3-hour 24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour 8-hour
TURB1	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB2	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB3	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB4	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB5	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB6	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TRB_GEN1	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
TRB_GEN2	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
TRB_GEN3	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
TRB_GEN4	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
AUX_COMP	Auxiliary Air Compressor (RICE)	1.77E-03 [a]	1.77E-03	2.11E-05 [a]	3.69E-04	2.11E-05	1.55E-03	8.87E-05	1.55E-03	8.87E-05	2.72E-01
FPUMP	343 kW Fire Pump 1-2 (RICE)	3.25E-02 [a]	3.25E-02	4.04E-05 [a]	7.08E-04	4.04E-05	2.99E-02	1.71E-03	2.99E-02	1.71E-03	5.19E-01
FLARE_1D	Dry Ground Flare 1 Pilot/Purge	6.13E-02	6.13E-02	2.17E-03	2.17E-03	2.17E-03	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.79E-01
FLARE_2D	Dry Ground Flare 2 Pilot/Purge	6.13E-02	6.13E-02	2.17E-03	2.17E-03	2.17E-03	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.79E-01
FLARE_1W	Wet Ground Flare 1 Pilot/Purge	1.93E-02	1.93E-02	7.09E-04	7.09E-04	7.09E-04	8.00E-03	8.00E-03	8.00E-03	8.00E-03	8.79E-02
FLARE_2W	Wet Ground Flare 2 Pilot/Purge	1.93E-02	1.93E-02	7.09E-04	7.09E-04	7.09E-04	8.00E-03	8.00E-03	8.00E-03	8.00E-03	8.79E-02
DRY_MAX1	Dry Ground Flare 1 Max. Case	2.93E+01	2.93E+01	1.08E+00	3.14E+00	1.08E+00	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.17E+03
DRY_MAX2	Dry Ground Flare 2 Max. Case	2.93E+01	2.93E+01	1.08E+00	3.14E+00	1.08E+00	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.17E+03
WET_MAX1	Wet Ground Flare 1 Max. Case	6.86E+00	6.86E+00	2.51E-01	7.34E-01	2.51E-01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.74E+02
WET_MAX2	Wet Ground Flare 2 Max. Case	6.86E+00	6.86E+00	2.51E-01	7.34E-01	2.51E-01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.74E+02
LP_FLARE	Low Pressure Flare Pilot/Purge	9.00E-02	9.00E-02	6.36E-03	6.36E-03	6.36E-03	3.73E-02	3.73E-02	3.73E-02	3.73E-02	4.10E-01
LP_MAX	Low Pressure Flare (Max. Flow)	1.48E-01	1.48E-01	5.67E-03	3.45E-01	5.67E-03	3.55E+00	5.83E-02	3.55E+00	5.83E-02	3.92E+01
TH_OX	Thermal Oxidizer	7.57E-02	7.57E-02	2.07E-03	2.07E-03	2.07E-03	5.64E-03	5.64E-03	5.64E-03	5.64E-03	6.24E-02

Notes:

[a] Intermittently operating unit, therefore emissions set equal to annual emission rate, per USEPA guidance (USEPA 2011).

Table 4-4: Modeled Liquefaction Facility Source Physical Parameters

Model ID	Source Description	Location [a]			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht. [b]	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
TURB1	Compression turbine	589612.04	6726290.1	38.0	64.0	794	26.2	5.79
TURB2	Compression turbine	589704.73	6726354.0	38.0	64.0	794	26.2	5.79
TURB3	Compression turbine	589477.15	6726485.3	38.0	64.0	794	26.2	5.79
TURB4	Compression turbine	589570.16	6726549.4	38.0	64.0	794	26.2	5.79
TURB5	Compression turbine	589343.13	6726679.9	38.0	64.0	794	26.2	5.79
TURB6	Compression turbine	589435.88	6726744.2	38.0	64.0	794	26.2	5.79
TRB_GEN1	Power generation turbine	589851.09	6726009.6	38.0	45.7	445	14.6	3.05
TRB_GEN2	Power generation turbine	589931.34	6726064.9	38.0	45.7	445	14.6	3.05
TRB_GEN3	Power generation turbine	590011.59	6726120.3	38.0	45.7	445	14.6	3.05
TRB_GEN4	Power generation turbine	590091.83	6726175.8	38.0	45.7	445	14.6	3.05
AUX_COMP	Auxiliary Air Compressor (RICE)	589576.44	6726013.5	38.0	3.05	746	35.1	0.203
FPUMP	343 kW Fire Pump 1-2 (RICE)	590146.73	6726056.2	38.0	3.05	760	47.9	0.203

Notes:

[a] All Coordinates are UTM Zone 5 NAD 83. Modeling assumed the facility was graded at 38 meters, which is the approximate average elevation of the receptors along the fenceline (excluding locations along the immediate shore).

[b] Stack height is above mean sea level.

Table 4-4: Cont. Modeled Liquefaction Facility Source Physical Parameters

Model ID	Source Description	Location [a]			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht. [c]	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
FLARE_1D	Dry Ground Flare 1 Pilot/Purge	589999.69	6725837.1	38.0	2.30 [d]	1,273	20.0	0.446 [d]
FLARE_2D	Dry Ground Flare 2 Pilot/Purge	590097.74	6725906.3	38.0	2.30 [d]	1,273	20.0	0.446 [d]
FLARE_1W	Wet Ground Flare 1 Pilot/Purge	590097.74	6725906.3	38.0	1.32 [d]	1,273	20.0	0.250 [d]
FLARE_2W	Wet Ground Flare 2 Pilot/Purge	589999.69	6725837.1	38.0	1.32 [d]	1,273	20.0	0.250 [d]
DRY_MAX1	Dry Ground Flare 1 Max. Case	589999.69	6725837.1	38.0	172.8 [d]	1,273	20.0	40.8 [d]
DRY_MAX2	Dry Ground Flare 2 Max. Case	590097.74	6725906.3	38.0	172.8 [d]	1,273	20.0	40.8 [d]
WET_MAX1	Wet Ground Flare 1 Max. Case	589999.69	6725837.1	38.0	86.3 [d]	1,273	20.0	19.8 [d]
WET_MAX2	Wet Ground Flare 2 Max. Case	590097.74	6725906.3	38.0	86.3 [d]	1,273	20.0	19.8 [d]
LP_FLARE	Low Pressure Flare Pilot/Purge	589999.69	6725837.1	38.0	63.4 [e]	1,273	20.0	0.541 [e]
LP_MAX	Low Pressure Flare (Max. Flow)	590097.74	6725906.3	38.0	63.4 [e]	1,273	20.0	5.26 [e]
TH_OX	Thermal Oxidizer	589339.8	6726051.8	38.0	14.3	1,255	2.7	1.52

Notes:

[a] All Coordinates are UTM Zone 5 NAD 83. Modeling assumed the facility was graded at 38 meters, which is the approximate average elevation of the receptors along the fenceline (excluding locations along the immediate shore).

[b] Flare stack parameters based on ADEC guidance (ADEC 2016a). ADEC guidance uses flare total heat release to calculate an "effective" stack height and stack diameter. Therefore, different operational phases (e.g. maximum, pilot/purge) will have different “effective" parameters used in the model which will differ from actual physical parameters.

[c] Stack height is above mean sea level.

[d] Effective release height and diameter of ground flares based ADEC guidance (ADEC 2016a). Actual physical release height is at ground level (0.0 meters).

[e] Effective release height and diameter of low pressure flare based ADEC guidance (ADEC 2016a). Actual physical release height is 199 feet (60.7 meters).

4.1.1.2 Normal Operations – Marine Vessels

Normal operations of the Liquefaction Facility would include liquefaction at 100 % production rate. Following FERC guidance, only those emissions occurring from marine vessel operations within 500 meters (0.3 miles) of the LNG carrier berths were explicitly modeled. Modeling marine emissions occurring only in the immediate vicinity of the berths is also the worst-case scenario because it considers the overlap of impacts from the carriers, support vessels, Liquefaction Facility, and other nearby industrial facilities.

Transit emissions from LNG carriers were excluded from the modeling because they occur beyond 500 meters from the LNG carrier berths. Furthermore, the transient nature and short duration of emissions from carriers cruising into port would translate into lower modeled impacts than the worst-case scenario selected for modeling, described in detail below. Note that while carrier transit emissions were excluded from the dispersion modeling analysis, they were included in the overall vessel ton per year emissions inventory as part of the Liquefaction Facility emissions calculations documented in Appendix A.

The modeling analysis included the following operating modes for LNG carriers:

- Maneuvering – vessel moving into or out of port,
- Cool down – stationary phase subsequent to docking,
- Hoteling – vessel is stationary at dock but not loading,
- Loading – loading LNG, and
- Purge lines – stationary phase after loading finishes, just prior to undocking.

Within 500 meters of the berths, four tugs would operate in maneuvering mode while assisting carrier docking and undocking. They were modeled as point sources positioned 50 meters (164 feet) from the carrier, with one at each end of the carrier and two along the side.

After the carrier is docked, two of the four tugs would either idle in standby or be docked, both of which would occur outside the 500 meter perimeter from the terminal. The remaining two tugs would continue in maneuvering mode throughout each call as part of guard operations or, in winter months, performing ice clearing operations. Each of the tugs performing guard/ice clearing operations was modeled as 5 separate point sources to account for the continuous movement of the vessels. One tug (five point sources) was positioned 245 meters (800 feet) to the north of the northern carrier and one tug (five point sources) was positioned 245 meters (800 feet) to the south of the southern carrier.

Because the proposed marine terminal would include two berths, the modeled scenario assumed two LNG carriers could be docked at the same time, though it is not possible for both to be loading at the same time. The narrative below describes the scenario that was modeled. This scenario is conservative because it assumes that two carriers will call at nearly the same time rather than with some lag between the two calls. Note that it is far more likely that only one carrier would call at a time. Based on a sensitivity analysis, loading activities at the northern berth resulted in the highest impacts.

<u>Modeled Marine Scenario Description:</u>

LNG Carrier 1 maneuvers into the southern berth with the assistance of four Tugs positioned around the ship. The carrier then docks and loads LNG while one tug remains in maneuvering mode to guard/clear ice. The other three Tugs are idling or docked beyond 500 meters. While Carrier 1 is loading, LNG Carrier 2 maneuvers into the northern berth with the assistance of four tugs positioned around the ship. Carrier 2 docks and hotels until LNG Carrier 1 is done loading. While Carrier 1 purges lines, Carrier 2 starts loading LNG. Carrier 1 then maneuvers out of the berth and terminal area while Carrier 2 continues to load. After loading, Carrier 2 purges lines. Two tugs continue to guard/clear ice while the other two tugs are idling or docked beyond 500 meters until Carrier 2 is ready to maneuver out of the berth. Carrier 2 maneuvers out of the berth and terminal area with the assistance of four tugs.

Worst-case short-term emissions were based on consideration of the overlapping operations of carriers and tugs for each averaging period, given the sequential order of operations outlined in the above description. The worst-case 1-hour period was determined to be when LNG Carrier 1 is purging lines (after loading) while LNG Carrier 2 is loading LNG. Annual emissions calculations included consideration of all operating modes and the 210 expected calls for a given year. Additional details regarding the development of the worst-case marine modeling scenarios are are documented in Appendix A.

Note that it is expected that LNG carriers loading at the terminal would be powered mostly by internal combustion engines, rather than steam turbine powered generators. Therefore, when calculating annual emissions, it was assumed that 98% of the carriers loading at the facility are powered by Internal Combustion (IC) engines and the rest steam driven.

The short-term emissions rates for the carriers were based on the maximum possible emissions rate from either IC engines or steam turbine power generation. For NO_2 and CO, the short-term emissions from IC engines were higher and were used in the modeling. For SO_2, $PM_{2.5}$, and PM_{10}, short-term emissions from the steam turbines were higher and were used in the modeling.

To calculate emissions from IC engines, assumptions regarding the mix of vessel types that would be arriving at the marine terminal were needed. The types of vessels that would be used affects emissions calculations because emission factors are tied directly to the category of ship. Details regarding the mix of vessels, age of vessels, emission factors and determination of physical stack exit conditions are documented in Appendix A.

Point source parameters and emissions rates used to model normal operations of the Marine Terminal are provided in **Table 4-5** and **Table 4-6**. These data were developed based on USEPA emission factors (AP-42) and vendor data, where possible. Detailed calculations are documented in Appendix A. All emission units were modeled as vertical and uncapped point sources, and all point source locations were referenced to NAD83 UTM Zone 5 coordinates.

Table 4-5: Modeled Marine Source Emissions [a]

Model ID	Source Description	NO_x (g/sec)		SO_2 (g/sec)				$PM_{2.5}$ (g/sec)		PM_{10} (g/sec)		CO (g/sec)
		1-hour	Annual	1-hour	3-hour	24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour 8-hour
LNGCAR1	LNG Carrier (South Berth)	3.08E+00	2.04E+00	9.03E-01	9.03E-01	8.70E-01	1.08E-02	2.38E-01	7.63E-02	2.70E-01	8.45E-02	6.94E+00
LNGCAR2	LNG Carrier (North Berth)	5.29E+00	2.04E+00	9.03E-01	9.03E-01	9.26E-01	1.08E-02	2.54E-01	7.63E-02	2.87E-01	8.45E-02	1.27E+01
TG_MAN1S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN2S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN3S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN4S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN1N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00
TG_MAN2N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00
TG_MAN3N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00
TG_MAN4N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00

Notes:

[a] Worst-case short-term emissions were based on consideration of the overlapping operations of carriers and tugs for each averaging period. Annual emissions calculations were based all operating modes and the number of expected calls for a given year. Thus, there are cases where short-term emission rates for some modes are zero while annual emissions are greater than zero. Additional information regarding the development of the marine emissions can be found in Appendix A.

Table 4-5 Cont.: Modeled Marine Source Emissions [a]

Model ID	Source Description	NOx (g/sec)		SO2 (g/sec)				PM2.5 (g/sec)		PM10 (g/sec)		CO (g/sec)
		1-hour	Annual	1-hour	3-hour	24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour 8-hour
TG_ICE1A	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1B	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1C	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1D	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1E	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE2A	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2B	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2C	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2D	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2E	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00

Notes:

[a] Worst-case short-term emissions were based on consideration of the overlapping operations of carriers and tugs for each averaging period. Annual emissions calculations were based all operating modes and the number of expected calls for a given year. Thus, there are cases where short-term emission rates for some modes are zero while annual emissions are greater than zero. Additional information regarding the development of the marine emissions can be found in Appendix A.

Table 4-6: Modeled Marine Vessel Source Physical Parameters

Model ID	Source Description	Location [a]			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht.	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
LNGCAR1	LNG Carrier (South Berth)	588362.60	6725207.77	0.0	45.0 [b]	589 [c]	4.2 [d]	1.68 [b]
LNGCAR2	LNG Carrier (North Berth)	588176.02	6725657.54	0.0	45.0 [b]	589 [c]	4.2 [d]	1.68 [b]
TG_MAN1S	Tug Maneuvering, assisting South Carrier	588332.80	6725273.48	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN2S	Tug Maneuvering, assisting South Carrier	588308.66	6725140.99	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN3S	Tug Maneuvering, assisting South Carrier	588375.43	6724981.83	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN4S	Tug Maneuvering, assisting South Carrier	588499.33	6724892.38	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN1N	Tug Maneuvering, assisting North Carrier	588149.50	6725723.23	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN2N	Tug Maneuvering, assisting North Carrier	588135.07	6725558.94	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN3N	Tug Maneuvering, assisting North Carrier	588189.67	6725428.53	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]
TG_MAN4N	Tug Maneuvering, assisting North Carrier	588312.47	6725342.39	0.0	10.7 [e]	589 [c]	23.0 [f]	0.460 [e]

Notes:

[a] All Coordinates are UTM Zone 5 NAD 83.

[b] LNG carrier stack height and diameter based on values used for carriers supporting the Corpus Christi Liquefaction project (Cheniere Energy 2013), assuming the vessel stacks will be similarly sized.

[c] Stacks assumed to have an economizer and steady outlet temperature of 600ºF.

[d] LNG carrier stack exhaust velocity based on vendor specifications for a representative engine size for fuel consumption and engine power, and an auxiliary engine load of 53%.

[e] Tug stack height and diameter based on values used for tugs supporting the Corpus Christi Liquefaction project (Cheniere Energy 2013), assuming the vessel stacks will be similarly sized.

[f] Maneuvering tug exhaust velocity based on vendor specifications for a representative engine size for fuel consumption and engine power, and an engine load of 75%.

Table 4-6 Cont.: Modeled Marine Vessel Source Physical Parameters

Model ID	Source Description	Location [a]			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht.	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
TG_ICE1A	Tug guard/ice clearing south of berths	588643.59	6724743.53	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE1B	Tug guard/ice clearing south of berths	588568.69	6724698.67	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE1C	Tug guard/ice clearing south of berths	588468.25	6724675.72	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE1D	Tug guard/ice clearing south of berths	588342.99	6724702.32	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE1E	Tug guard/ice clearing south of berths	588264.51	6724768.63	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE2A	Tug guard/ice clearing north of berths	588166.43	6725931.30	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE2B	Tug guard/ice clearing north of berths	588038.92	6725895.24	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE2C	Tug guard/ice clearing north of berths	587964.45	6725845.46	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE2D	Tug guard/ice clearing north of berths	587909.78	6725743.46	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]
TG_ICE2E	Tug guard/ice clearing north of berths	587890.31	6725642.71	0.0	10.7 [c]	589 [b]	23.0 [d]	0.460 [c]

Notes:

[a] All Coordinates are UTM Zone 5 NAD 83.

[b] Stacks assumed to have an economizer and steady outlet temperature of 600ºF.

[c] Tug stack height and diameter based on values used for tugs supporting the Corpus Christi Liquefaction project (Cheniere Energy 2013), assuming the vessel stacks will be similarly sized.

[d] Maneuvering tug exhaust velocity based on vendor specifications for a representative engine size for fuel consumption and engine power, and an engine load of 75%.

4.1.2 Non-Modeled Scenarios

In addition to normal operations, there are several other reasonably foreseeable operational scenarios that were considered for dispersion modeling of the Liquefaction Facility. However, when compared to the conservative normal operations scenario described above, these scenarios would yield lower modeled impacts due to lower emissions, less equipment operating, and/or fewer operating hours. The subsections below describe these scenarios and why modeled impacts would be lower than that from the normal operations scenario. **Table 4-2** lists the operational equipment that will be included in the modeled normal operations scenario versus equipment associated with those operational scenarios that were not modeled.

4.1.2.1 Plant Start-Up

Start-up of the Liquefaction Facility would initially utilize essential power from nearby substations prior to commissioning the power generation turbines. Initial start-up of LNG Compression Train 1 would require operation of one set of power generation turbines (two turbines total, operating at 60% to 100% load depending on plant needs). Once the power generation turbines are operational, Train 1 would be brought online. Fuel gas for the power generation turbines would be sourced from local sources.

The Refrigeration System would be the first part of the train brought online, which involves purging and filling the system with propane. During this process, propane would be sent to the flare and used to ignite the wet and dry ground flare pilots as well as the LP flare pilot. The Train 1 compressor turbines would be brought online using facility fuel gas and would briefly operate at a load of 10% before quickly ramping up to 100% load.

With the initial turbines online, GTP treated gas, or an equivalent local source, would be introduced to the Gas Dehydration System at the Liquefaction Facility. Until the dehydration system is fully operational, gas produced during purging and conditioning of dehydration media would be sent to the flares. The Cold Section of the plant would be started once dehydrated treated gas is available, with additional off-spec gas sent to the flare.

Finally, once the Refrigeration System of Train 1 and the Cold Section are fully operational, liquefied gas can be produced by the facility and the Liquefied Propane Gas (LPG) Fractionation system can be brought online. The LPG Fractionation system would take the mixed hydrocarbon liquid and separate it into speciated products. The system would include a deethanizer, depropanizer, debutanizer, and an LPG Reinjection system, all of which would produce off-spec gas that would be sent to the flares. The speciated products would then be transferred to their designated storage systems. All vapors produced during the liquid introduction to the storage and loading system would be sent to the flares.

The plant start-up scenario was not included in the dispersion modeling analysis because, if modeled, it would produce lower impacts than the conservative normal operations scenario described in **Section 4.1.1**. As shown in **Table 4-2**, the normal operations scenario includes 4 more compressor turbines and 2 more power generation turbines than the plant start-up scenario. Thus, on both a short-term and long-term basis, total turbine emissions would be far greater from the normal operations scenario than the plant start-up scenario.

Operation of the compressor turbines at a 10% load will be a brief, transient, occurrence before they ramp up to 100% load. Therefore, stack parameters associated with 100% load would be appropriate for modeling either the normal operations scenario or the plant start-up scenario. Because lower load operation will be accounted for in the power generation turbine stack parameters modeled for the normal operations scenario, there would be no difference in stack parameters modeled for the plant start-up scenario. Thus, modeled dispersion of the power generation turbine exhaust would be equivalent between the two scenarios.

The initial plant start-up of the first train scenario includes considerable gas flaring over 6 months. It has been determined that short-term emissions (24 hours or less) from the ground flares would be much less than those occurring from the maximum relief case included in the normal operations scenario. It has also been determined that the total annual emissions from the ground flares during the 6 month startup would also be much less than that from the 500 hours of maximum relief flaring rate conservatively included in the normal operations scenario.

While there would be higher flaring emissions from the LP flare during start-up than during normal operations, the normal operations scenario would still be the worst-case due to the maximum relief flaring from the ground flares conservatively included in that scenario. The maximum relief flaring emissions from the ground flares would far surpass the start-up emissions through these flares and would also surpass the additional flaring through the LP flare during start-up.

Lastly, intermittent IC engines (auxiliary air compressor and fire water pump) are not anticipated to operate for a significant amount of time during plant start-up and thus would not contribute to any modeled impacts. However, emissions from this equipment were conservatively included in the normal operations scenario.

4.1.2.2 Early Plant Operations

Early operation of the Liquefaction Facility would be dependent on the treated gas supplied from the GTP. There would be 3 phases of early operations at the Facility:

> Phase 1: The production of LNG at the Liquefaction Facility would operate at 1/3 of the total capacity through one production train for approximately one year. Therefore, one compression train would be operating at 100% load (two turbines total) and one set of power generation turbines (two turbines total) would be operating. The load of the power generation turbines will depend on the needs of the plant and will range from 60% to 100%. All intermittent equipment (e.g. reciprocating IC engines) will be operational and available if needed. Flaring associated with normal pilot/purge will also occur with early normal operation of Train 1; however no additional flaring scenarios are reasonably foreseeable.
>
> Phase 2: Train 2 start-up would commence after approximately the first year of facility operation, and would be similar to the start-up of Train 1. With Train 1 fully operational, Train 2 would come online with the 2 compressor turbines briefly operating at 10% load, then quickly ramping up to 100% load. Again, the power generation turbines would be operating according to the needs of the plant (from 60% to 100% load). All intermittent equipment (e.g. reciprocating IC engines) would be operational and available if needed, though not anticipated to be used. Flaring of relief events similar to the start-up of Train 1 will also occur, however this will not include the initial start-up of utility or common system, only flaring associate with the Refrigeration Trains.
>
> Phase 3: After Train 2 is fully operational and the facility is processing 2/3 of normal facility throughput, start-up of Train 3 would commence, with the 2 compressor turbines at 10% load, and power generation turbines at 60% to 100%, based on plant needs. All intermittent equipment (e.g. reciprocating IC engines) would be operational and available if needed, though not anticipated to be used. Flaring of relief events associated with equipment start-up would also occur.

No scenario specific to early plant operation was included in the dispersion modeling analysis because, if modeled, it would produce lower impacts than the conservative normal operations scenario described in **Section 4.1.1**. Considering the compressor and power generation turbines, **Table 4-2** shows that all phases of the early plant operations scenario include fewer turbines and/or lower turbine loads than the normal operations scenario which would result in lower emissions and lower modeled impacts on both a short-term and long-term basis.

Similar to the plant start-up scenario, there would be no difference in turbine stack parameters between the normal operations and early plant operations scenarios, thus modeled dispersion of the exhaust would be equivalent between the two scenarios. Furthermore, the early operations scenario includes a lower amount of flared gas than the normal operations scenario. Lastly, intermittent IC engines are not anticipated to operate during early plant operations and thus would not contribute to any modeled impacts. However, emissions from this equipment were conservatively included in the normal operations scenario.

4.1.2.3 Early Marine Terminal Operations

Both marine terminals would be commissioned during the initial startup of the facility and Train 1 however, the first LNG Carrier vessels would not arrive to the Facility until LNG has been produced and sent to the LNG Storage Tanks which would occur during Phase 1 of early operation. Once LNG carrier calls begin, normal marine operations would commence. At that point, there is no difference in source assumptions from what is included in the normal operations scenario. The only difference is in the annual number of calls. With the plant operating at less than a 100% production rate, there would be fewer annual carrier calls during the early operations scenario than during normal operations and thus fewer annual emissions. Therefore, on a short-term and long-term basis, the normal operations scenario for marine vessels described above is the worst-case for dispersion modeling. There are no other reasonably anticipated marine scenarios that would deviate from normal operations and require a separate air quality dispersion modeling assessment.

4.1.2.4 Maintenance Operations

Turbines and Process Systems

The LNG train compressor turbines and power generation turbines would need maintenance roughly every 3 years. The duration of the maintenance event would range between 2 to 8 weeks. Process system maintenance and shutdown (heat exchangers, columns, air coolers, etc.) would coincide with turbine maintenance. During maintenance events, the equipment would be purged of gas and opened to the atmosphere for operator inspection. Once the equipment can come back online, the equipment would need to be purged of the air by an inert gas before feed gas can be reintroduced to the system. The purge gas and the initial feed gas will be sent to the flare while the equipment is brought back online.

While a turbine is being shut down, there would be an increase in uncontrolled emissions when the turbine drops below the load where the control technology functions on its way to zero load. The control technology will stop functioning somewhere below approximately 50% turbine load. Turbine operation outside of the control technology functional range would be a brief, transient occurrence that would not be explicitly modeled.

Because maintenance of equipment systems and trains would be staggered to maintain as high of the facility capacity as possible, it is likely that only one turbine would be taken offline at a time. Therefore, it is anticipated that not more than one train (2 turbines) would go offline at any time. Note that maintenance at the Liquefaction Facility may be synchronized with maintenance at the GTP to keep the treated gas and LNG production coordinated.

The maintenance operations scenario for the turbines and process systems would not produce higher modeled impacts than the normal operations scenario because there would be less equipment operating as shown in **Table 4-2**. While relief flaring would occur, the amount of gas would not be greater than from the maximum relief scenario that is included in the normal operations scenario. Therefore, the maintenance operations scenario for turbines will not be modeled.

Flares

The flare configuration is 3 x 50%, where each flare would be capable of handling 50% flaring capacity from the entire facility. The third flare would be completely offline when not in use, meaning no fuel gas supplied for line purging and no fuel gas supplied for pilot gas. When maintenance or shutdown of one of the operating flares is required (every 5 to 10 years), the spare flare would need to come online before the other flare is shut down. This overlap would result in purge/pilot emissions from all three flares for a day or two. The operations for the remainder of the equipment at the facility would not deviate from the Normal Operations scenario.

Maintenance operations for the flares were not explicitly modeled because impacts would be less than that for the normal operations scenario. While maintenance operations include pilot/purge operation from an additional flare over the normal operations scenario, there are no emissions due to maximum relief flaring during flare maintenance. On both a short-term and long-term basis, the emissions due to the maximum relief flaring from two ground flares (conservatively included during normal operations) are far greater than pilot/purge emissions from a single flare.

4.1.2.5 Seasonal Effects on Emissions

Power Generation Turbines

Winter operation of the facility requires less power than the summer operation due to reduced demand from the Air Coolers within all systems. During the winter, operation of the power generation turbines may be at a decreased load, or even result in one of the power plants (two turbines) being taken offline. A power plant would be taken offline if the load required by the facility drops to a level that would require all four turbines to operate outside of the stable operation load range. The power generation turbines are designed to be operating in a load range from 60% to 100%, with optimal design being 85% on all turbines. The number of turbines would be reduced until the outlet power required by the facility could be produced from the remaining turbines within their stable operation load range. The normal operations scenario includes all four turbines at their maximum emission rates throughout the year. Therefore, the scenario that was modeled is more conservative than this reduced operating scenario and these seasonal effects do not need to be explicitly modeled.

4.1.3 Construction Emissions

Construction of the Liquefaction Facility would occur over an estimated eight year span, beginning in the second year following project authorization. Construction activities begin with site clearing and stabilization, roadway and surface preparation and construction, and include heavy equipment associated with scrapers, dozers, trenching, and stockpiling soil and bedrock. A worker camp would be constructed and operated during most of this construction period, and could include sources related to power generation, incineration, food preparation and refrigeration, heating, ventilation, and air conditioning. Site construction would include use of heavy equipment such as cranes and heavy transport vehicles, concrete and asphalt batch plants, additional excavation, welding, seasonal heaters, and the use of power equipment such as engines associated with pneumatic systems, power generation, and support of construction camp activities.

Construction of the Marine Terminal operations would begin at the same time as the Liquefaction Facility, but would span a four-year period. Many construction activities would take place from barges and tugs, and would include cranes, loaders, pile drivers and other support vehicles and operations.

Depending on the type of activity, construction of the Liquefaction Facility and Marine Terminal would occur on different temporary time scales from several months to several years and would be spread over multiple locations around the proposed site. Given these complexities, it is not possible to predict with precision which of these activities will actually overlap in time, or to know the relative locations of the associated equipment for different activities when they do overlap. These limitations would pose great difficulties for any attempt to predict ambient air quality impacts due to emissions from such equipment by means of standard dispersion models. Such models have been designed to estimate impacts from stationary sources, and the usefulness of their predictions is substantially diminished when detailed information on emission source geometry and temporal patterns cannot be provided.

The only recourse for modeling with incomplete emission source data is to resort to hypothetical worst-case assumptions that produce the highest possible predicted impacts for each of the averaging times covered in the ambient air quality standards. This approach is very likely to over-predict actual impacts by a wide margin, which is contrary to the purpose of the impact analysis. Also, by providing only absolute maximum impact estimates, such results are particularly unsuitable for comparison with several of the short-term NAAQS/AAAQS that are based on multiple-year averages of certain percentile concentrations.

The difficulties described above, in addition to the fact that construction emissions are not subject to the same federal and state permitting rules as operational emissions, help to explain why dispersion modeling has not been used to characterize construction air quality impacts in any of the recent NEPA documents that have been prepared by the FERC for other LNG projects across the U.S. Following the same logic, construction activities were not modeled but rather to propose mitigations and best management practices (BMPs) for controlling construction emissions. Some BMPs that will be developed and submitted for FERC review include:

- Construction emission control plan
- Fugitive dust control plan
- Open burning control plan.

While construction activities were not included in the dispersion modeling analyses, the construction operations and construction camp activities were included in the criteria pollutant emissions documented in one of the other appendices to Resource Report no. 9.

4.2 OFFSITE SOURCES

4.2.1 Near-Field Existing Sources

In addition to modeling sources associated with the Liquefaction Facility, the dispersion analysis also addressed the cumulative ambient air quality impacts from the proposed facility and nearby offsite sources. The following lists the offsite sources included in the analysis; **Figure 1-1** shows their locations:

- Tesoro Refinery
- Existing ConocoPhillips Company (COP) Kenai LNG Facility (including ships)
- Tesoro Kenai Pipe Line (KPL) Marine Loading Terminal (including ships)
- Homer Electric Association (HEA) Bernice Lake Power Plant
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships) (Agrium)
- Homer Electric Association (HEA) Nikiski Generation Plant

No other sources were explicitly modeled because they were either not expected to produce a significant concentration gradient in the impact area or were included as part of the background concentration.

Table 4-7 lists the data sources used to develop modeling inputs for the offsite sources.

4.2.2 Far-Field Existing Sources

In addition to the above near-field sources, the far-field modeling analysis also included existing sources not close enough to cause a significant concentration gradient in the near-field, but which could create such gradients within the far-field modeling domain. **Figure 4-1** lists the sources included in the modeling and displays their proximity to Class I and Sensitive Class II areas as well as the proposed Liquefaction Facility. Table 4-7 lists the data sources used to develop the modeling inputs for the far-field existing offsite sources. Additional details regarding the development of modeled emissions and parameters can be found in Appendix A.

4.2.3 Reasonably Foreseeable Development

In order to ensure that potential impacts in the Class I and Sensitive Class II areas would be fully addressed, the ADEC was contacted regarding other new projects throughout the state that are currently engaged in the permitting process or in construction, and may become operational over the next several years. Lists of such projects were developed following review of Resource Report No. 1 and in consultation with ADEC for the modeling domain containing the Liquefaction Facility. **Figure 4-1** lists the Reasonably Foreseeable Development (RFD) sources included in the modeling and displays their proximity to Class I and Sensitive Class II areas as well as the proposed facility. Table 4-7 lists the data sources used to develop the modeling inputs for the far-field existing offsite sources. Details regarding the development of modeled emissions and parameters can be found in Appendix A.

Note that compressor and heater stations associated with the Project pipeline were not included as RFD sources and were not modeled as part of the cumulative impact analysis. This is because emissions from these Project sources would not be large enough to significantly contribute to maximum far-field impacts dominated by the Liquefaction Facility nor are impacts from these sources likely to be collocated in space and time with those from the Liquefaction Facility. Furthermore, the Project is submitting a separate near-field air quality analysis to specifically address impacts from those compressor and heater stations that are close enough to Class I and Sensitive Class II areas to warrant modeling obviating the need to address them in this analysis.

Figure 4-1: Locations of Far-Field Existing and Reasonable Foreseeable Development Sources

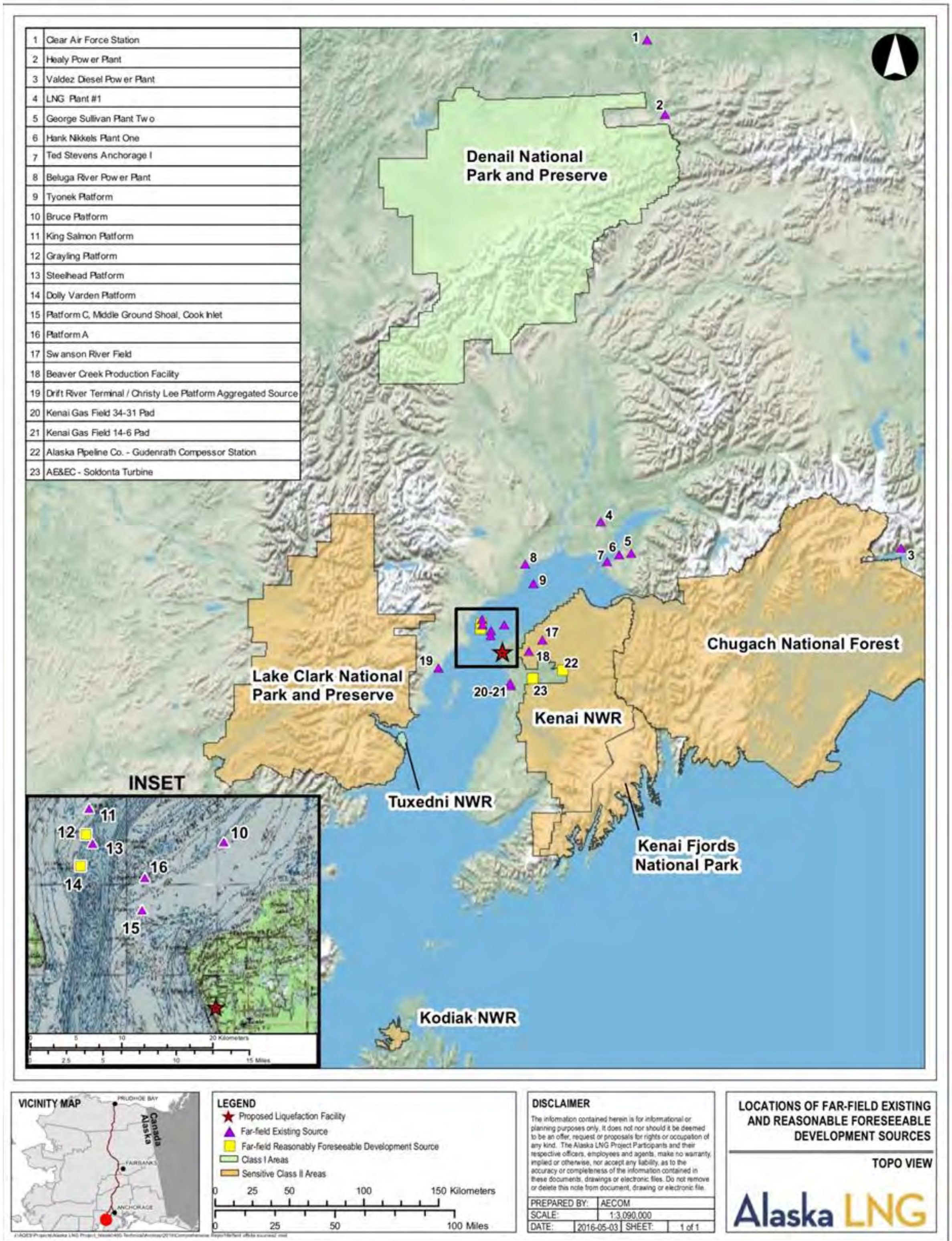


Table 4-7: Source of Modeling Inputs for Offsite Facilities

Facility	Source of Data Used in Dispersion Modeling			PSD Increment Consumption
	Stack Locations	Emissions	Stack Parameters	
Tesoro Refinery	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004), with some adjustments based on Google Earth aerial photography and elevations.	Vessel: "Cook Inlet Vessel Traffic Study" (Cape International 2012) and "Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories Final Report "(USEPA 2009b). All other sources: 2011 National Emissions Inventory (NEI 2011), except maximum permitted emissions for those sources not found in the NEI.	Vessel: Parameters equivalent to Alaska LNG carrier due to lack of additional information. All other sources: Information reported to ADEC and posted to their website for public use. (http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory).	NO_2: Partial SO_2: Partial PM_{10}: Partial $PM_{2.5}$: Partial
Kenai LNG Facility	Plot plans approved for use on the Alaska LNG project in 2014.	Vessel: Emissions equivalent to Alaska LNG carrier due to lack of additional information. All other sources: 2011 National Emissions Inventory (NEI 2011).	Vessel: Parameters equivalent to Alaska LNG carrier due to lack of additional information. All other sources: Dispersion modeling submitted to ADEC in March 2004 (Tesoro Refinery 2004), stack orientations determined by site photography.	NO_2: Partial SO_2: Partial PM_{10}: Partial $PM_{2.5}$: No
KPL Marine Loading Terminal	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	2011 National Emissions Inventory (NEI 2011).	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	NO_2: Partial SO_2: Partial PM_{10}: Partial $PM_{2.5}$: No
Bernice Lake Power Station	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	2011 National Emissions Inventory (NEI 2011).	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	NO_2: No SO_2: Yes PM_{10}: Yes $PM_{2.5}$: No
Agrium	Dispersion modeling information submitted to ADEC supporting the Agrium permit application (Agrium 2014).			NO_2: Yes SO_2: Yes PM_{10}: Yes $PM_{2.5}$: Yes
Nikiski Generating Station	Dispersion modeling information submitted to ADEC supporting the Agrium permit application (Agrium 2014).			NO_2: No SO_2: No PM_{10}: No $PM_{2.5}$: No

Table 4-7 Cont. Source of Modeling Inputs for Offsite Facilities

Facility	Source of Data Used in Dispersion Modeling			PSD Increment Consumption
	Stack Locations	Emissions	Stack Parameters	
Far-Field Existing Facilities	Primary Data Source: 2011 National Emissions Inventory (NEI 2011). Secondary Data Source: For facilities not in the NEI, the ADEC point source database (ADEC 2011) was used.	Primary Data Source: 2011 National Emissions Inventory (NEI 2011). Secondary Data Source: For facilities not in the NEI, the ADEC point source database (ADEC 2011) was used.	All facilities modeled as volume sources with release height of 10 m, sigma-y of 2.33 m and sigma-z of 2.33 m.	Appendix A lists the PSD consumption status for each facility.
Reasonably Foreseeable Development Facilities	Permit documents available at: http://dec.alaska.gov/Applications/Air/airtoolsweb/AirPermitsApprovalsAndPublicNotices	Permit documents available at: http://dec.alaska.gov/Applications/Air/airtoolsweb/AirPermitsApprovalsAndPublicNotices	All facilities modeled as volume sources with release height of 10 m, sigma-y of 2.33 m and sigma-z of 2.33 m.	NO_2: Yes SO_2: Yes PM_{10}: Yes $PM_{2.5}$: Yes

5.0 NEAR-FIELD MODELING METHODOLOGY

This section describes the methodology used to model the Liquefaction Facility and background source emissions with the purpose to assess ambient concentrations to a distance of 20 kilometers (12.5 miles).

5.1 MODEL SELECTION

Selection of the appropriate dispersion model for use in the required ambient air quality impact analysis is based on the available meteorological input data, the physical characteristics of the emission units that are to be simulated, the land use designation in the vicinity of the source under consideration, and the complexity of the nearby terrain. The USEPA-approved American Meteorological Society/USEPA Regulatory Model (AERMOD) modeling system was used to assess the potential ambient impacts from the proposed Liquefaction Facility. AERMOD is recommended for use in modeling multi-source emissions, and can account for plume downwash, stack tip downwash, and point, area, and volume sources (USEPA 2004, 2007). AERMOD also has the ability to simulate impacts at both flat and complex terrain receptors.

The version numbers of the AERMOD model and pre-processors that were used include:

- AERMAP version 11103
- AERMET version 15181
- AERMOD version 15181
- Building Profile Input Program, PRIME version (BPIPPRM) version 04274

5.2 MODEL OPTIONS

AERMOD model input options for Liquefaction Facility sources were set to their regulatory default values (USEPA 2015a) with the exception of the NO_2 modeling methodology, discussed below in **Section 5.7**.

The BETA AERMOD model option was used for all averaging periods and pollutants in the cumulative modeling to apply USEPA-recommended adjustments to buoyancy and dispersion for the horizontal firewater pump stacks and capped boiler stacks located at the Kenai LNG offsite facility. These adjustments were invoked in AERMOD through the use of the POINTHOR and POINTCAP keywords.

The use of these non-default BETA options currently requires case-by-case approval from USEPA. However, ADEC prefers applicants use these options as it ensures correct adjustments are made to stack characteristics and prevents any errors that could be made by manually implementing the stack adjustments (ADEC 2016a). Note that USEPA has proposed these options be adopted as regulatory defaults options in their recently proposed revisions to the Modeling Guideline (USEPA 2015b).

5.3 METEOROLOGICAL DATA

Hourly meteorological data used for air quality dispersion modeling must be spatially and climatologically representative of the area of interest and should be both laterally and vertically representative of the plume transport and dispersion conditions. The Modeling Guideline recommends a minimum of one year of site-specific meteorological data or five consecutive years of representative data collected at the nearest National Weather Service (NWS) station. Required surface meteorological data inputs to the AERMOD meteorological processor (AERMET) include, at a minimum, hourly observations of wind speed, wind direction, temperature, and cloud cover (or solar radiation and low-level vertical temperature difference data in lieu of cloud cover). Morning upper air sounding data from a representative NWS station are also required to generate daytime convective parameters and a complete meteorological dataset.

AERMOD-ready meteorological input files for Kenai, Alaska for 2008-2012 are pre-approved for use by ADEC for projects located in Nikiski. However, because the data are observed at a single 8-meter level, a separate study was conducted to assess whether the data are representative of the transport and dispersion conditions at the level of plumes released from the tallest stacks that would be installed at the Facility (e.g. 64 meters). The study focused on the tallest stacks since it is widely accepted that 8-meter, National Weather Service surface data can be used to represent releases from levels up to about 30 meters (100 feet).

For stacks higher than 30 meters, the study compared modeled impacts using the 8-meter Kenai meteorological data versus multi-level (up to 60 meters, 200 feet) meteorological data collected at Nikiski as input to AERMOD. The multi-level data used in the study were recorded at a tall tower located adjacent to the northern Facility fenceline (Alaska LNG, 2015). Due to the similarity in modeled impacts, the study concluded that transport and dispersion conditions for tall stacks can be adequately characterized by AERMOD using the single level 8-meter Kenai data and that the Kenai data were appropriate to use for dispersion modeling of the Liquefaction Facility sources.

Additional information regarding the processing of the Kenai 2008-2012 dataset is available at http://dec.alaska.gov/air/ap/AERMOD_Met_Data.htm. Prior to use in dispersion modeling, the files were reprocessed using the current version of the AERMET processor (version 15181), as the files were originally developed using an older version of AERMET.

5.3.1 Surface Data

AERMOD-ready meteorological files were developed using surface data from the Kenai National Weather Service (NWS) station located near the Kenai Airport. Hourly surface data for Kenai NWS that were input to AERMET were supplied by ADEC. **Table 5-1** lists the joint data capture for each of the five years. **Figure 3-1** shows that the Kenai NWS station is approximately 12 kilometers (7.5 miles) to the southeast of the Liquefaction Facility location. **Figure 5-1** shows a wind rose for the model-ready 2008-2012 meteorological data.

Table 5-1: Meteorological Input Data Percent Missing Hours after Processing with AERMET

Modeled Period	Year, % Missing				
	2008	2009	2010	2011	2012
Quarter 1	0	0.32	0.05	0.05	0.05
Quarter 2	0	0.05	0.05	0.18	0.14
Quarter 3	7.65	0	1.18	1.13	0
Quarter 4	0.41	0.45	0.41	0.95	1.09
Annual	2.03	0.21	0.42	0.58	0.32

5.3.2 Upper Air Data

The temperature structure of the atmosphere prior to sunrise is required by AERMET to estimate the growth of the convective boundary layer for the day. AERMET uses the 1200 Greenwich Mean Time upper air sounding from the nearest NWS upper air observing station for this purpose. The nearest NWS station to the proposed facility that collects upper air sounding data is in Anchorage located approximately 94 kilometers (58 miles) northeast of the proposed facility. Upper air data from Anchorage concurrent with the surface data were supplied by ADEC and used as input to AERMET.

5.3.3 Surface Characteristics

Surface characteristics, including surface roughness length, Bowen ratio, and albedo, must be provided to AERMET. A summary of the surface characteristics used as input to AERMET is provided in **Table 5-2**. These data were included in the AERMOD-ready data files supplied by ADEC. **Figure 5-2** shows the land cover in the vicinity of the proposed facility and the Kenai NWS station.

5.3.4 Use of Vertical Wind Speed Standard Deviation (sigma-w) Measurements

Additional data processing is performed for site-specific sigma-w measurements that are extremely low (near or at zero and below instrument threshold values). Following recommendations provided by USEPA's AERMOD modeling contractor, any reported values of site-specific sigma-w below 0.1 m/s are set to missing so as to avoid an anomalous problem in the model that can be caused by inappropriate input data.

This processing is generally only applicable to site specific data, if collected. Sigma-w is an optional parameter that was not collected at Kenai NWS. Therefore, the additional data processing was not required for the Liquefaction Facility air quality analyses.

Table 5-2: Surface Characteristics for AERMET Processing

Surface Parameter	Spring Value[a]	Summer Value[a]	Autumn Value[a]	Winter Value[a]
Albedo	0.143	0.145	0.152	0.406
Bowen Ratio	0.509	0.395	0.658	0.426
Surface Roughness Length (meters)				
Sector 1 (30 - 60)	0.071	0.112	0.071	0.005
Sector 2 (60 - 90)	0.138	0.197	0.138	0.022
Sector 3 (90 - 120)	0.140	0.176	0.140	0.045
Sector 4 (120 - 150)	0.141	0.177	0.141	0.046
Sector 5 (150 - 180)	0.073	0.109	0.073	0.008
Sector 6 (180 - 210)	0.050	0.069	0.050	0.008
Sector 7 (210 - 240)	0.036	0.060	0.036	0.002
Sector 8 (240 - 270)	0.078	0.104	0.078	0.019
Sector 9 (270 - 330)	0.034	0.050	0.034	0.004
Sector 10 (330 - 30)	0.045	0.065	0.045	0.005

Notes:

[a] Winter is defined as November through, spring is defined as April through May, summer is defined as June through August, and autumn is defined as September through October.

Figure 5-1: Wind Rose for 2008-2012 Kenai Meteorological Data

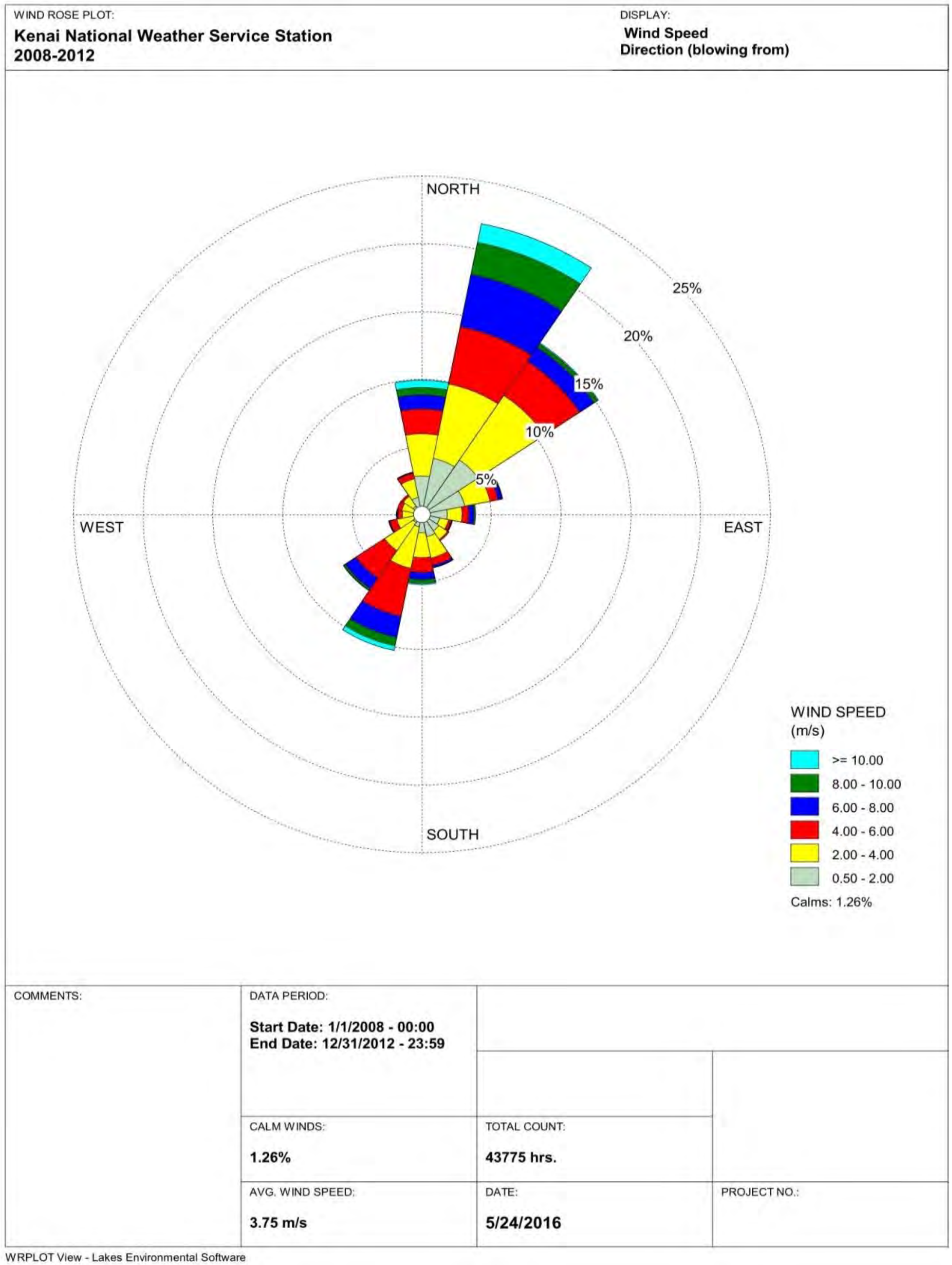
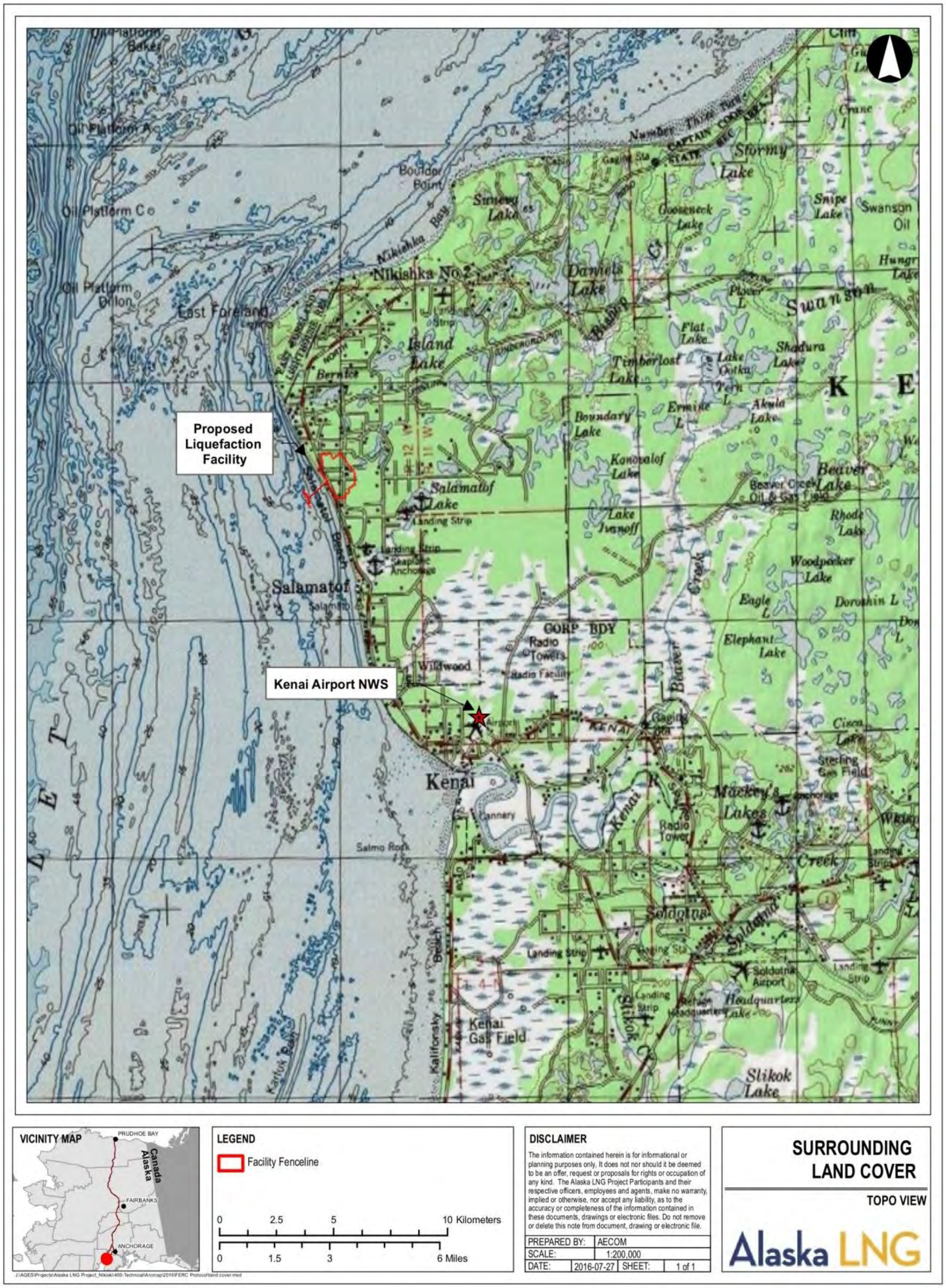


Figure 5-2: Land Cover Surrounding the Kenai NWS Location



5.4 RECEPTORS

USEPA regulations define ambient air is as "that portion of the atmosphere, external to buildings, to which the general public has access" (40 CFR 50.1(e)). For the purposes of dispersion air quality modeling, the ambient air quality boundary is typically set around an area to which a source has the ability and right to exclude public access.

There would be a physical barrier (fenceline) that the Liquefaction Facility will control that would limit public access. Therefore, that fenceline identified on the facility site plan (Alaska LNG 2016b) was used as the ambient air quality boundary around the facility. Additionally, there is a need to exclude the public from the immediate area surrounding the trestle and LNG carrier berths during loading/unloading operations for safety reasons including:

- avoidance of collisions with LNG carriers,
- the risk of LNG leak and consequent pool fire, and
- the risk of fire and explosion on board the LNG carriers.

The regulatory process that determines the dimensions of a marine safety and security zone has not been completed. As a proxy, a 500-foot (152-meter) buffer zone was used as an ambient air quality boundary in the air dispersion modeling analysis. Receptors were also excluded in the immediate vicinity (100 feet) of offsite marine vessels. The ambient air boundaries surrounding the on-shore Liquefaction Facility and the LNG carriers and trestle, as well as ambient boundaries around offsite sources, are shown in **Figure 5-3**.

Receptor locations developed in accordance with ADEC modeling guidance (ADEC 2016a) as a Cartesian grid centered on the Liquefaction Facility were spaced as follows:

- 25-meter spacing along the Liquefaction Facility fenceline as well as offsite facility fencelines.
- 25-meter spacing along boundary of the 500-foot exclusion zone around the LNG carriers and trestle.
- 25-meter spacing extending from the Liquefaction Facility fenceline and the 500-ft exclusion zone out to a minimum distance of 200 meters.
- 50-meter spacing extending out to 500 meters from the Liquefaction Facility fenceline, and extending over areas where an overlap in impacts between the facility and offsite sources is possible.
- 100-meter spacing out to 1 kilometer from the Liquefaction Facility fenceline.
- 250-meter spacing out to 2.5 kilometers from the Liquefaction Facility fenceline.
- 500-meter spacing out to 5 kilometers from the Liquefaction Facility fenceline.
- 1,000-meter spacing out to 10 kilometers from the Liquefaction Facility fenceline.
- 2,000-meter spacing out to 20 kilometers from the Liquefaction Facility fenceline.

Additionally, preliminary modeling indicated an area of elevated concentrations due to hilly terrain located 4-5 kilometers (2.5 to 3 miles) north of the facility. Therefore, a small 50-meter spaced receptor grid was placed over each of three hills to ensure the maximum concentrations on the terrain were predicted.

When conducting cumulative modeling, impacts from an offsite source are not included on totals at receptors within that source's fenceline. Therefore the cumulative modeling was separated into the following analyses:

- The main cumulative modeling analysis determined impacts at receptors along and outside the Liquefaction Facility fenceline and offsite source fencelines, where all facility and offsite sources are modeled. (See **Figure 5-3**).

- Several separate analyses determined impacts at receptors within an offsite source's fenceline, where that source is excluded from the modeling but the remainder of all facility and offsite sources are included.

The maximum of the impacts determined between the analyses described above was reported as the overall cumulative impact.

Modeling for the Liquefaction Facility alone included all receptors along and outside the facility fenceline, including those receptors within offsite source fencelines. **Figure 5-3** depicts the near-field receptor grid (for cumulative modeling) out to 1 kilometer. **Figure 5-4** depicts the near-field receptor grid out to 20 kilometers.

5.5 ELEVATION DATA

The terrain data to determine receptor and source elevations were obtained from the United States Geological Survey National Elevation Dataset (NED) (http://ned.usgs.gov). The highest possible resolution data (1/9th arc second) was used and processed with the AERMAP processor to assign elevations to the receptor locations.

Additionally, the proposed facility was assumed to be graded at an elevation of 38 meters (125 feet) above sea level, which is the approximate average elevation of the receptors along the fenceline (excluding locations along the immediate shore). Therefore, all emission unit stacks and structures at the facility were assigned a base elevation of 38 meters.

5.6 BUILDING DOWNWASH AND STACK HEIGHT

Building structures that obstruct wind flow near emission points may cause stack discharges to become entrained in the turbulent wakes of these structures leading to downwash of the plumes. Wind blowing around a building creates zones of turbulence that are more intense than if the building were absent. These effects generally can cause excessive ground-level pollutant concentrations, from elevated stack discharges. For this reason, building downwash algorithms are considered an integral component of the selected model.

The modeling analysis followed the guidance provided in the USEPA Guidelines for Determination of Good Engineering Practice (GEP) Stack Height (USEPA 1985). The USEPA GEP guidelines specify that the GEP stack height is calculated in the following manner:

$H_{GEP} = H_B + 1.5L$
H_B = the height of adjacent or nearby structures
L = the lesser dimension (height or projected width) of the adjacent or nearby structures)

The effects of plume downwash were considered for all emission units. Direction-specific building dimensions were calculated using the current version of the USEPA-approved Building Profile Input Program (BPIPPRM Version 04274). The BPIPPRM program also calculates the Good Engineering Practice (GEP) stack heights for all modeled emission units.

Building dimensions developed for the Liquefaction Facility were input to BPIPPRM where possible. Where heights were not available, single-story building heights containing process equipment or emission units were assigned a height of 8 meters (26 feet, 1.5 times the height of a typical single story building). Modeled source locations were based on the facility site plan.

Dimensions for the LNG carriers were set to those developed for the Corpus Christi Liquefaction project (Cheniere Energy 2013). Dimensions corresponding to a 217,000 cubic meter vessel were used, as that size is the upper limit of the range of ship sizes expected to visit the Marine Terminal. Selecting the largest ship size is conservative as it maximizes potential stack downwash.

The modeled layout of the proposed Liquefaction Facility is shown in **Figure 5-5** which details the structure locations and heights, as well as the emission unit stack locations and heights that were included in the building downwash analysis.

5.7 NO_2 MODELING APPROACH

The NAAQS and AAAQS for nitrogen oxides (NO_x) are expressed in terms of NO_2. For modeling purposes, additional calculations and modeling approaches are used to determine NO_2 impacts from modeled NO_x emissions. The USEPA Modeling Guideline presents a three-tiered approach that may be applied to modeling 1-hour and annual NO_2 impacts. These three tiers are:

- Tier 1: assume full conversion of NO to NO_2. In other words, it assumes that all NO_x is emitted as NO_2.
- Tier 2: multiply the Tier 1 result by an empirically derived ambient NO_2/NO_x ratio, with 0.80 as the 1-hour national default and 0.75 as the annual national default.
- Tier 3: detailed screening methods may be considered on a case-by-case basis, with the Ozone Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM) identified as detailed screening techniques.

Preliminary modeling indicated that assuming full conversion of NO_X to NO_2 (Tier 1) was too conservative for this analysis. Therefore, consistent with recent USEPA guidance (USEPA 2014b), Tier 2 was implemented using the Ambient Ratio Method 2 (ARM2).

The ARM2 option applies an ambient ratio to the modeled NO_x concentrations based on a formula derived empirically from ambient measurements of NO_2/NO_x ratios. ARM2 was implemented with default upper and lower limits (of 0.9 and 0.2, respectively) on the ambient ratio applied to the modeled concentration. The lower limit of 0.2 is appropriate for this analysis because an ambient in-stack NO_2/NO_x ratio of 0.2 is representative of in-stack ratios of the sources dominating the impacts. While a few sources may have in-stack ratios above 0.2, those most culpable for the maximum 1-hour NO_2 impacts, such as the Project's LNG carriers, are at 0.2 or below. Furthermore, USEPA guidance recommends that if the total conversion results (Tier 1) from primary source are within 150 – 200 ppbv, that impacts are likely to be appropriately conservative when using ARM2, regardless of the ISR of the primary source (USEPA 2014b). In the current case, the primary source is the Liquefaction Facility. The Tier 1 total 1-hr NO_2 impact due to the Liquefaction Facility is approximately 134 ppbv, thus it is likely that results obtained using ARM2 are appropriately conservative.

ARM2 is currently a non-default BETA AERMOD option that requires case-by-case approval from USEPA. However, USEPA has proposed adoption of this option as a regulatory default option in their recently proposed revisions to the Guideline (USEPA 2015b).

Figure 5-3: Near-Field Receptor Grid and Ambient Air Quality Boundaries out to 1 Kilometer

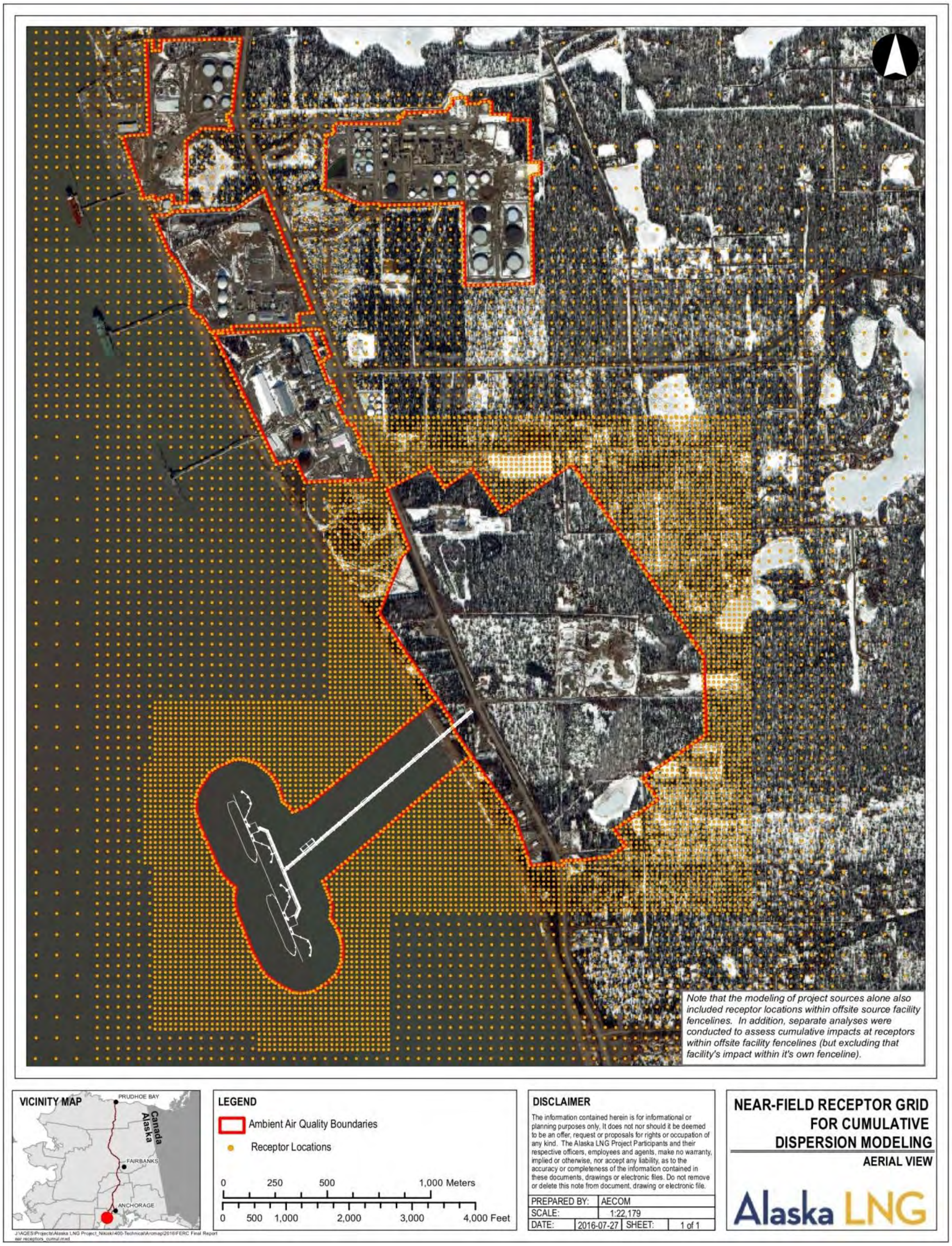


Figure 5-4: Near-Field Receptor Grid out to 20 Kilometers

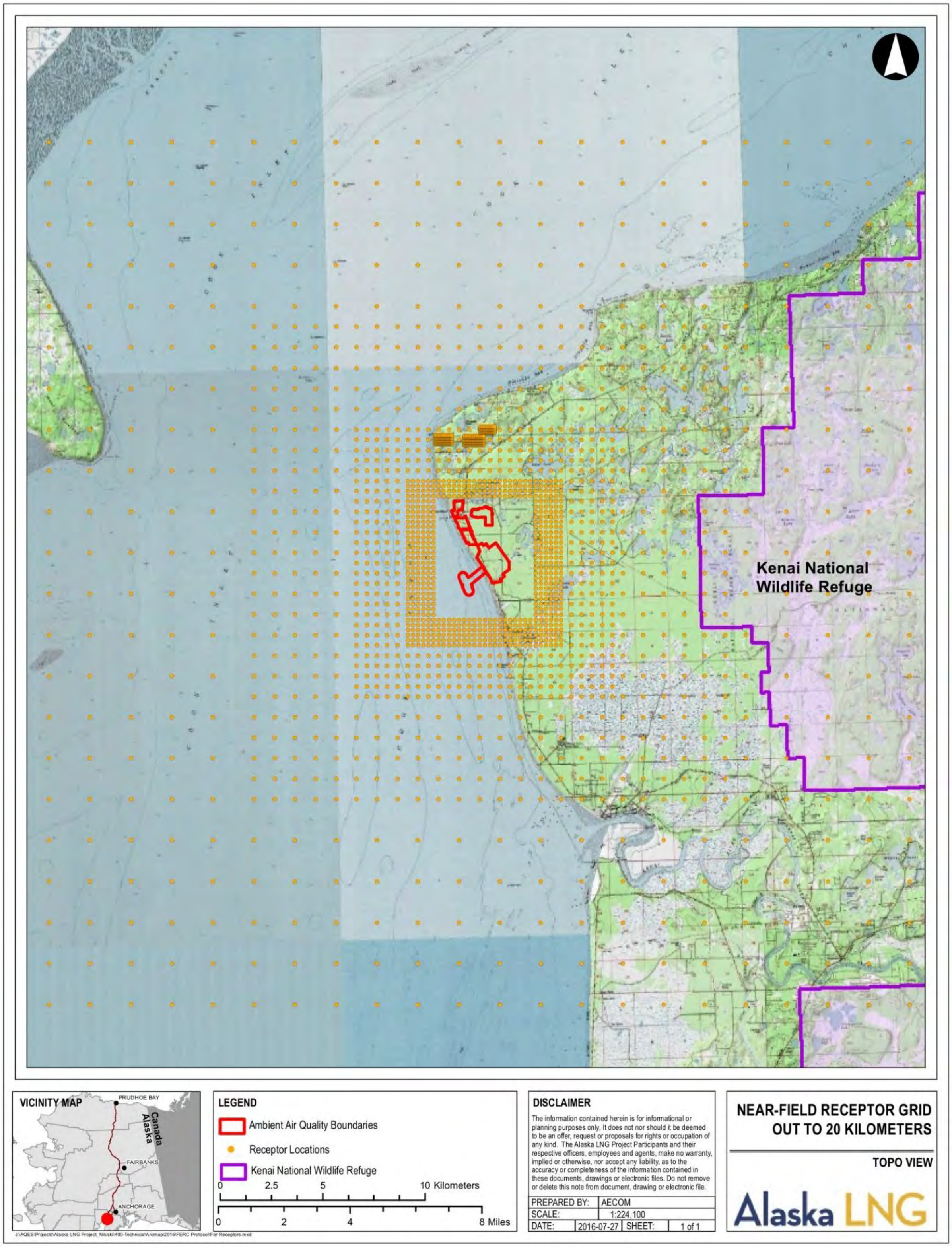
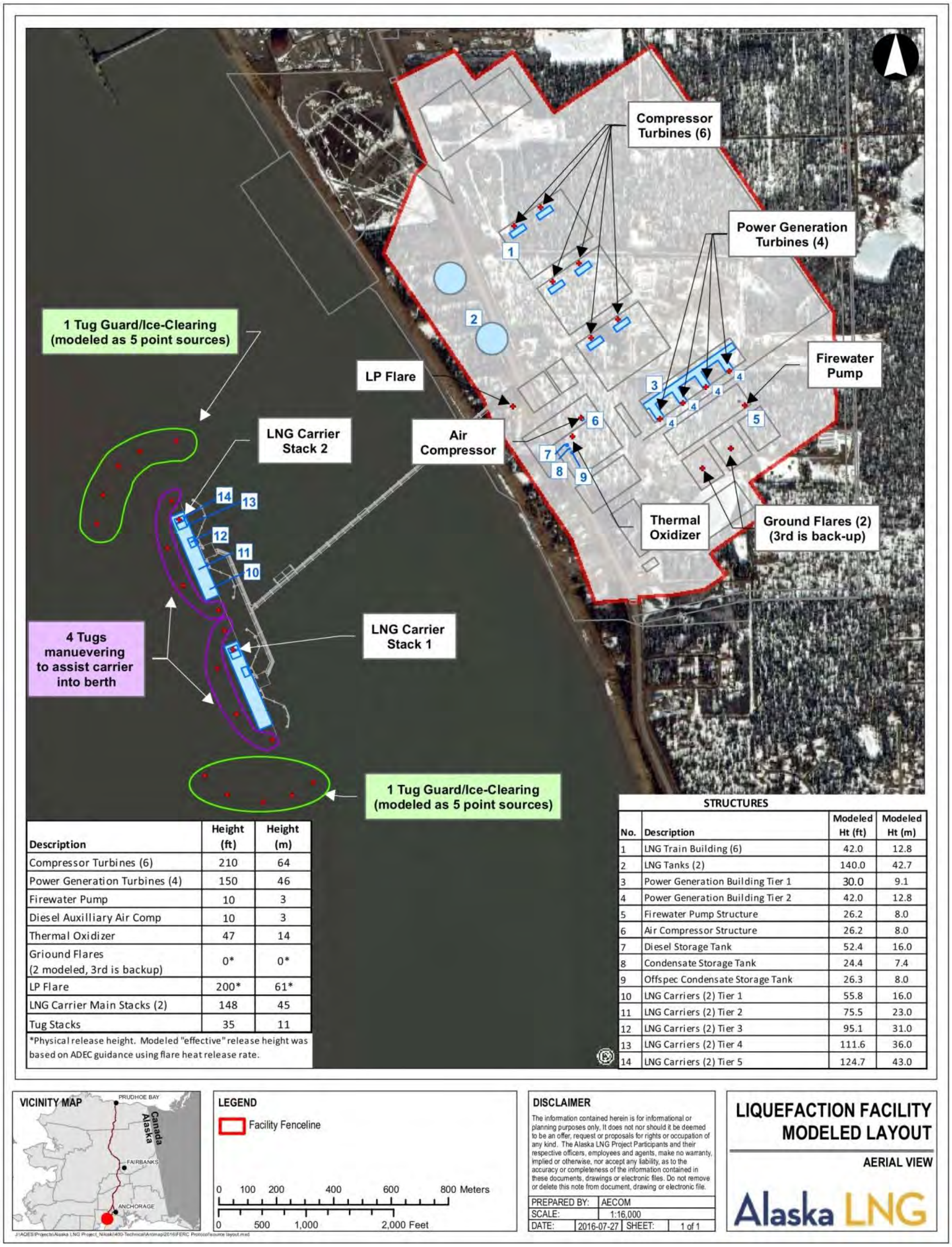


Figure 5-5: Liquefaction Facility Modeled Layout



Description	Height (ft)	Height (m)
Compressor Turbines (6)	210	64
Power Generation Turbines (4)	150	46
Firewater Pump	10	3
Diesel Auxilliary Air Comp	10	3
Thermal Oxidizer	47	14
Grround Flares (2 modeled, 3rd is backup)	0*	0*
LP Flare	200*	61*
LNG Carrier Main Stacks (2)	148	45
Tug Stacks	35	11

*Physical release height. Modeled "effective" release height was based on ADEC guidance using flare heat release rate.

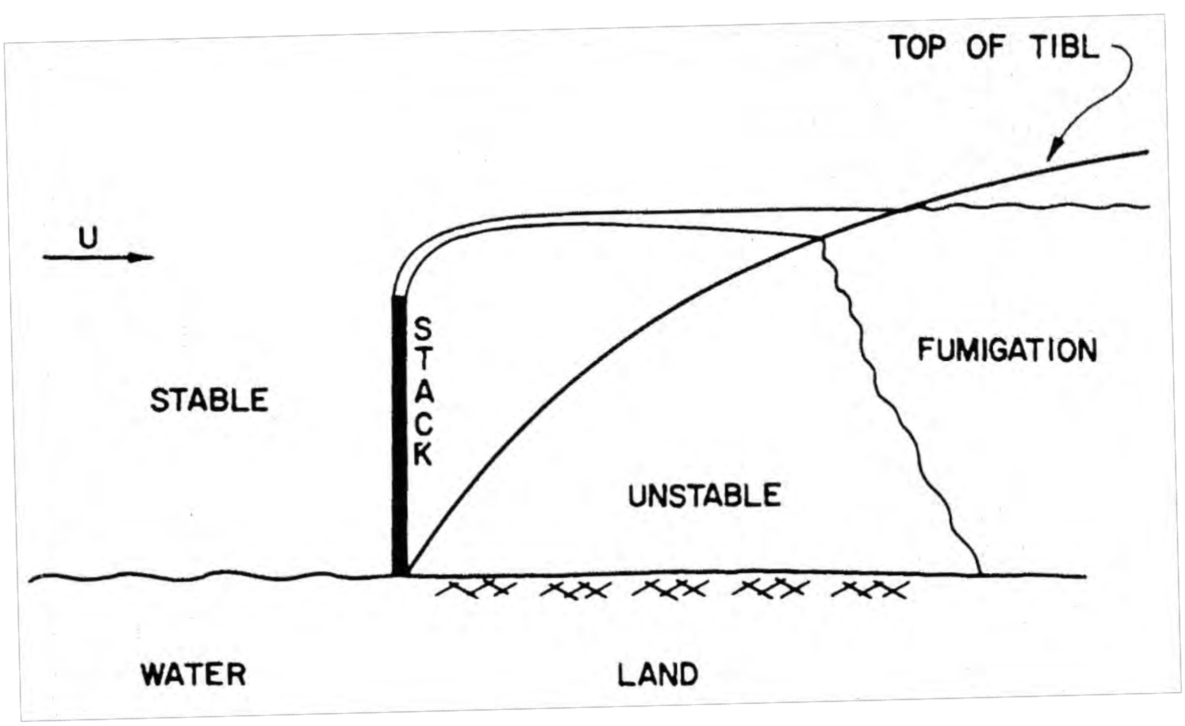
STRUCTURES

No.	Description	Modeled Ht (ft)	Modeled Ht (m)
1	LNG Train Building (6)	42.0	12.8
2	LNG Tanks (2)	140.0	42.7
3	Power Generation Building Tier 1	30.0	9.1
4	Power Generation Building Tier 2	42.0	12.8
5	Firewater Pump Structure	26.2	8.0
6	Air Compressor Structure	26.2	8.0
7	Diesel Storage Tank	52.4	16.0
8	Condensate Storage Tank	24.4	7.4
9	Offspec Condensate Storage Tank	26.3	8.0
10	LNG Carriers (2) Tier 1	55.8	16.0
11	LNG Carriers (2) Tier 2	75.5	23.0
12	LNG Carriers (2) Tier 3	95.1	31.0
13	LNG Carriers (2) Tier 4	111.6	36.0
14	LNG Carriers (2) Tier 5	124.7	43.0

5.8 SHORELINE FUMIGATION

Shoreline fumigation can occur when a plume is emitted from offshore sources or tall onshore emissions sources, such as a power plant stack, under unique meteorological conditions along a coastal boundary. When a plume is emitted in a stable offshore boundary layer with flow onto the shore, fumigation occurs when the plume impacts an unstable onshore boundary layer, known as the thermal internal boundary layer (TIBL). As shown below in **Figure 5-6**, when the plume in the stable air layer interacts with the TIBL, that layer is mixed to the ground and can result in elevated concentrations of ground-level pollutants from both near-shoreline plumes and other regional sources of emissions.

Figure 5-6: Depiction of Typical Shoreline Fumigation (Stunder et al. 1986)



USEPA's Modeling Guideline advises that air quality modeling analyses should address conditions when fumigation is expected to occur from sources near or just inland of the shoreline. Though impacts from fumigation events should be addressed, most onshore near-field air quality models, including AERMOD, are not equipped to characterize shoreline fumigation events. In rare cases, a conservative screening analysis using AERSCREEN can be used to address shoreline fumigation; otherwise, the Guideline on Air Quality Models cites the Shoreline Dispersion Model (SDM) as a refined means to account for air quality conditions when shoreline fumigation is expected to occur.

The SDM model is a hybrid model that can estimate ground level concentrations for both fumigation and non-fumigation conditions. The SDM model first uses the following criteria to determine whether fumigation events are expected:

- Wind direction at the shoreline sources must be onshore (airflow at an angle of at least 20 degrees).
- Wind speed must be greater than 2 m/sec.

- Daytime with overland stability class A, B, or C.
- Stable overwater lapse rate (positive potential temperature gradient).

If all of the above criteria are met, the SDM uses the Shoreline Fumigation Model (SFM) to determine concentrations. For the remaining hours when there is no fumigation expected, the SDM uses the MPTER model (multiple point source dispersion algorithm with terrain) to determine concentrations. Note that the MPTER model was selected because it was the USEPA-preferred regulatory model for estimating ground-level concentrations at the time of the SDM model development (USEPA1988).

5.8.1 Meteorological Data

The SDM model requires two sets of meteorological data:

- Surface data – wind speed, wind direction, temperature, stability class, and mixing height.
- Tower data – wind speed within the TIBL, wind speed at stack height, surface sensible heat flux, potential temperature over land, potential temperature over water, and vertical potential temperature gradient over water.

Surface Data

To develop the surface data, USEPA's PCRAMMET program was used to process 2008-2012 data observed at Kenai NWS station with concurrent twice daily mixing height data for Anchorage, AK. For input to PCRAMMET, Kenai surface data were obtained from Trinity Consultants in CD-144 format. Twice daily mixing height data were developed by inputting upper air sounding data and surface temperatures from Anchorage into USEPA's Mixing Height Program (version 98340). Note that the SDM model only uses mixing height values for non-fumigation hours when the MPTER model is invoked. For fumigation hours, the SDM model does not use the mixing height but instead develops a TIBL height based on surface sensible heat flux, potential temperature gradient over water, wind speed, and downwind distance. As described below, the current analysis only used the SDM model for fumigation hours. Therefore, the actual mixing height values input to the model were irrelevant.

Tower Data

The tower data were developed using a combination of surface data from Kenai NWS and buoy data collected at the National Data Buoy Center (NDBC) station located in Nikiski (Station NKTA2). The wind speed within the TIBL was developed for input to SDM by estimating the winds at 60 meters (200 feet) using Kenai surface winds scaled by the power law according to stability category, using wind speed profile exponents used in the USEPA's ISCST3 model (predecessor of AERMOD). Wind speed at the stack height was also calculated in this manner such that the wind speed within the TIBL was set equal to the wind speed at stack height.

Potential temperature is defined as the temperature that would be measured at an air pressure of 1000 millibars (mb). Given that the typical air pressure at Kenai NWS is approximately 1010 mb, the potential temperature is nearly equivalent to the surface temperature measured at Kenai and thus the Kenai surface temperature was used. Surface sensible heat flux at Kenai NWS, as calculated by the AERMET processor, was also used as part of the "tower data" file.

Similar to potential temperature over land, the potential temperature over water was set equal to the air temperature observed over water recorded at the Nikiski buoy for 2008-2012. The vertical potential temperature gradient over water was also developed from the buoy data. First, the difference between the air temperature above the water surface and the temperature of the surface water was determined. This temperature difference was then divided by 3.4 meters, the measurement height of the buoy air temperature sensor. The potential temperature gradient in an isothermal atmosphere is about 10 ^{o}C per km or 0.01 ^{o}C/m. This gradient, often referred to as the adiabatic lapse rate, was added to the measured temperature gradient to obtain the potential temperature gradient.

Note that water temperature data were not available for some of the colder months, generally when ice was present. However, fumigation is far more likely to occur during warmer months when the temperature over land easily becomes warmer than the nearby cooler air over water. Therefore, even if data were available for those missing periods it isn't likely the outcome of the modeling analysis would be affected.

Also note that the shallow depth of the water temperature sensor of the Nikiski buoy causes it to occasionally be located out of the water during very low tide events. These periods only occurred occasionally for 1-2 hours at a time and were removed from the dataset. **Table 5-3** indicates that there are valid air and water temperatures for greater than 98% of the period of available data, even after removing those water temperatures affected by low tide.

Table 5-3: Data Capture for Nikiski Buoy Data

Year	Water Temperature Data Availability		% Missing During Period Available	
	Begin (MM/DY)	End (MM/DY)	Air Temperature	Water Temperature
2008	03/09	12/13	0.8%	0.8%
2009	05/01	12/18	0.2%	0.2%
2010	04/06	12/03	2.0%	2.0%
2011	04/20	11/24	1.2%	1.3%
2012	04/23	11/17	0.8%	0.8%

5.8.2 Fumigation Analysis

The shoreline fumigation analysis for the Liquefaction Facility used the SDM model to determine the maximum hourly fumigation concentration, which was then added to cumulative AERMOD modeling results to account for fumigation. Rather than relying solely on SDM, this approach was used because 1) adding the maximum hourly concentration due to fumigation to AERMOD results regardless of averaging period is highly conservative, and 2) this approach primarily relies upon USEPA's preferred model, AERMOD, rather than the decades-old SDM. If this approach was found to be too conservative, then AERMOD was run using hourly fumigation concentrations in a background file to determine the overall impacts.

Note that only fumigation concentrations output by the SDM model were used. Concentrations resulting from non-fumigation hours were not used as the MPTER model invoked by SDM is no longer a USEPA-approved model.

The procedure for the fumigation analysis is described in detail below.

1. *Determine the maximum 1-hour concentration predicted for fumigation hours with the SDM model.*

   The SDM model was run with all sources associated with the Liquefaction Facility with the exception of the tugs. It is unlikely that tug operations would realistically contribute to any potential shoreline fumigation due to the transient and mobile nature of the tug operations.

   Also, because the SDM model is limited to land-based source locations, the LNG carriers were located at the shoreline for the fumigation simulation. This is conservative because realistically, the actual offshore location of the carriers allows for more time for plume rise and dispersion prior to any potential intersection with the TIBL when compared to the modeled shoreline location. A higher plume would intersect with the TIBL at a higher point and thus fumigate to the ground farther downwind than a similar but lower plume. Impacts occurring farther downwind are expected to be less than those occurring closer to the source.

2. *Add maximum 1-hour fumigation concentrations to cumulative AERMOD modeling results.*

As a conservative "first tier" analysis, the maximum 1-hour fumigation concentration found with the SDM model was added to cumulative AERMOD results, regardless of averaging period. For the 1-hour NO_2 NAAQS analysis, annual NO_2 PSD Increment analysis, and 24-hour $PM_{2.5}$ PSD Increment analysis, this proved to be too conservative, thus those analyses were refined using the AERMOD model.

As a refinement to the first tier analysis, an hourly varying background file was used in AERMOD to add the fumigation concentration to cumulative modeling results for Liquefaction Facility and offsite sources. The background file used the SDM maximum 1-hour fumigation concentration for hours where fumigation is expected (based on the above criteria) and a zero for hours where fumigation is not expected.

While not as conservative as the first tier analysis above, this "second tier" analysis still overestimates the contribution from potential fumigation. For every hour that fumigation occurs, this procedure adds the maximum fumigation concentration to every impact predicted within the modeling domain and not just at that location where the maximum fumigation impact is predicted to occur. This will overestimate impacts on the largest part of the modeling domain. Furthermore, combining the impact from fumigating and non-fumigating conditions also leads to overestimation of cumulative impacts because sources culpable for fumigation in the SDM model are also modeled in AERMOD. Thus, there is inherently some "double-counting" of impacts.

The results of the above analyses are incorporated into the summary tables presented in **Section 7.1**.

6.0 CLASS I AND SENSITIVE CLASS II AREA MODELING METHODOLOGY

This section describes the methodology of modeling the Liquefaction Facility and background sources emissions with the purpose to assess ambient concentration, visibility, and acidic deposition in Class I (Tuxedni National Wildlife Refuge (NWR) and Denali National Park (NP)) and Sensitive Class II areas (Kenai NWR, Chugach National Forest (NF), Lake Clark National Park & Preserve (NPR), Kenai Fjords NP, and Kodiak NWR).

6.1 MODEL SELECTION

Air quality impacts predicted at Class I and sensitive Class II areas for comparison to the NAAQS and PSD increments were determined using the USEPA-approved version of the CALPUFF modeling system (Version 5.8). This modeling system includes the following processors:

- CALMET – Version 5.8 – Level 070623
- CALPUFF – Version 5.8.4 – Level 130731
- POSTUTIL – Version 1.56 – Level 070627
- CALPOST – Version 6.221 – Level 082724

At the time that this analysis was complete, with the exception of CALMET, these were the most current USEPA-approved versions of the CALPUFF modeling system. Since that time USEPA released updated versions of CALPUFF and CALMET. Version 5.8.5 (Level 151214) replaces Version 5.8.4 (Level 130731). The USEPA-approved version of CALPOST remains at Version 6.221 (Level 080724). CALPUFF and CALMET were updated to incorporate minor bug fixes. For this analysis, these new versions will result in negligible differences from those predicted with the previous versions; hence they were not incorporated into this analysis which would delay submittal.

Both the near-field and far-field deposition analyses were performed using the CALPUFF modeling system. While there is accepted FLM guidance for near-field deposition modeling using the AERMOD model, it is considered a conservative screening technique. The CALPUFF modeling system is a more refined method that is an accepted technique following FLAG 2010, particularly when the modeling domain contains receptors both in the near-field and far-field.

Note that because the majority of receptors for the Class I and sensitive Class II areas are beyond 50 kilometers and for consistency with the deposition analysis, CALPUFF was used to determine ambient air quality at both near-field and far-field receptors located in these areas.

The near-field visibility analysis was conducted with the USEPA-approved visibility screening model VISCREEN (Version 13190).

The near-field ambient concentration assessment was conducted with the USEPA-approved dispersion model, AERMOD as described in **Section 5.0**.

6.2 MODEL INPUTS

Point source parameters and emissions rates that were used to model the Liquefaction Facility are provided in **Table 4-3** and **Table 4-4**. Point source parameters and emissions rates used to model Marine Terminal sources are provided in **Table 4-5** and **Table 4-6**. In addition to the above sources, the far-field modeling analysis also included existing sources and reasonably foreseeable development sources. **Table 4-7** lists the data sources used to develop the modeling inputs for these sources.

For visibility modeling, particulate matter emissions were speciated into filterable (elemental carbon) and condensable (secondary organic aerosol) according to the AP-42 for each source type. Detailed emissions calculations are documented in Appendix A.

All source locations are referenced to Lambert Conformal Conic coordinate system, centered at 59ºN, 151ºW, with standard latitudes of 30ºN and 60ºN. Building downwash parameters were used for Liquefaction Facility sources as described in **Section 5.6** and modeled with the PRIME algorithm.

6.3 MODEL OPTIONS

All CALPUFF model options that were used conform to the USEPA guidance (USEPA 2006) or defaults ("MREG = 1" option in CALPUFF). Ammonia-limiting method in POSTUTIL program was used to repartition nitric acid and nitrate on a receptor-by-receptor and hour-by-hour basis to account for over prediction due to overlapping puffs in CALPUFF. It was accomplished by turning on the option "MNITRATE" to 1 and "NH3TYP" to 3.

The CALPOST model options and inputs followed the FLAG 2010 guidance and inputs (USDOI 2010). Visibility modeling used "MVISBK = 8" and "M8_MODE= 5" options to compute background extinction. The extinction coefficients for the modeled Sensitive Class II areas are not provided in the FLAG 2010 document. Due to the proximity of Tuxedni NWR to these modeled Sensitive Class II areas, Tuxedni extinction coefficients (from FLAG 2010) were used for visibility modeling of these Sensitive Class II areas.

The annual average concentrations, Rayleigh scattering coefficient, and sea salt concentrations were taken from FLAG 2010 Table 6. The monthly relative humidity adjustment factors for large sulfate and nitrate particles were obtained from FLAG Table 7 and for small particles from FLAG Table 8. The sea salt relative humidity adjustment factors were obtained from FLAG Table 9.

6.4 MODELING DOMAIN

The modeling domain is limited by the gridded meteorological input data obtained for use on this project (see **Section 6.7**). However, the modeling domain is 540 km by 650 km, which is large enough to encompass the Liquefaction Facility, background sources, and receptors at Class I and Sensitive Class II areas within 300 kilometers (186 miles) of the Liquefaction Facility. The domain is based on a Lambert Conformal Conic coordinate system centered at 59ºN, 151ºW, with standard latitudes of 30ºN and 60ºN and a 2-km grid size. Where possible, the edge of the domain extended at least 50 km from the nearest receptor to ensure the model captures potential puff recirculation effects. The modeling domain is shown in **Figure 6-1**.

The horizontal resolution, geographic projection and datum were based on the CALMET prognostic meteorological data grid. The following vertical layers were used:

0, 20, 40, 65, 120, 200, 400, 700, 1,200, 2,200, and 4,000 meters

6.5 OZONE AND AMMONIA DATA

Representative ozone and ammonia data are required for use in the chemical transformation of primary pollutant emissions. Hourly ozone is used by CALPUFF to account for the oxidation of NO_x and SO_2 emissions to nitric acid and sulfuric acid, respectively. The predicted nitric acid and sulfuric acid are then partitioned in CALPUFF between the gaseous and particulate nitrate and sulfate phases based on the available ammonia, as well as ambient temperature and relative humidity.

Hourly ozone data for 2002-2004 from Denali National Park were used in CALPUFF. This dataset was developed and approved for use in the Best Achievable Retrofit Technology (BART) regional haze modeling for this area (ADEC 2014). The ozone station location is depicted in **Figure 6-1**.

The ammonia data input to CALPUFF has a direct effect on the amount of visibility degradation predicted by the model. Typically, a smaller ammonia background concentration results in less secondary particle formation from a modeled source's SO_2 and NO_x emissions and would produce less visibility degradation at modeled areas. The Western Regional Air Partnership (WRAP)[1] and USEPA (BART rule[2]) have acknowledged the limitations of CALPUFF chemistry for predicting wintertime nitrates. This is especially true for the very cold Alaskan winters, in which the temperatures are often well below the 50ºF (or higher) that the CALPUFF MESOPUFF-II chemistry is based upon. The independent evaluations[3] of just nitrate formation show an over-prediction factor ranging from 2 to 4 for just this issue unless very low ammonia background concentrations are input to CALPUFF. Despite its importance in atmospheric chemistry and CALPUFF model sensitivity to ammonia levels, ammonia is not routinely measured by any national monitoring network.

To determine the appropriate ammonia concentration for input to CALPUFF, a review of available guidance and literature was conducted. The Federal Land Managers' Air Quality Related Values Work Group (FLAG 2010) document suggests using 10 ppbv for grassland, 0.5 ppbv for forests, and 1 ppbv for arid lands, unless better data is available for a specific modeling domain. The "CALMET/CALPUFF Modeling Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States" (WRAP 2006) recommends a much smaller background NH_3 value of 0.1 ppbv for Alaska (WRAP 2006). This recommendation was used for the WRAP Regional Modeling Center (RMC) BART modeling for sources Alaska as well as for the BART determination modeling for Golden Valley Electric Association (GVEA) Healey Plant[4].

Table 6-1 summarizes the findings of the literature review, noting measured and modeled ammonia concentrations in the western United States and Alaska. Although the values listed represent many different assumptions (models, resolution, time frame, averaging period) they all indicate a generally low ammonia background value in Alaska with concentrations consistently much lower than 1 ppbv during cold months and higher concentrations during warmer months (note that CALPUFF is not sensitive to ammonia concentrations during warmer temperatures). Ammonia levels are affected by changes in temperature because vegetation acts as a main source of atmospheric ammonia (besides relatively constant source of livestock waste and fertilizers). An analysis of the satellite data over Alaska conducted for this project also found a clear indication of seasonality in measured ammonia levels.

These findings, in conjunction with an understanding of CALPUFF's inherent limitations and conservatisms regarding ammonia and in-transit chemistry, support the use of seasonal rather than annual uniform concentrations of ammonia in the model. As shown in **Table 6-2**, 30 years of normal temperature data collected from the stations in the Kenai area suggests that the growing season starts in May and lasts through October based on temperatures above freezing. The remaining months have freezing temperatures with dormant vegetation providing negligible ammonia. As

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[1] See slide # 9 at http://www.wrapair.org/forums/ssjf/meetings/050907/WRAP_Regional_Modeling_SSJF2.pdf.

[2] Federal Register, July 6, 2005, Volume 70, pages 39121 and 39123.

[3] See Figure 1 and Figure 2 http://mycommittees.api.org/rasa/amp/CALPUFF%20Projects%20and%20Studies/CALPUFF%20Evaluation%20with%20SWWYTAF,%202009,%20Kharamchandani%20et%20al.pdf

[4] See page 30 https://dec.alaska.gov/air/ap/docs/GVEA%20BART%20Final%20Determination%20Report%202-5-10.pdf

shown in **Table 6-3,** the colder months of November to April, were assigned an ammonia value of 0.1 ppbv in CALPUFF, based on the WRAP BART modeling discussed above. While CALPUFF is not sensitive to ammonia concentrations during warmer temperatures, the months of May to October were assigned an ammonia value of 1.0 ppbv in the model, which is likely conservative for the region.

Table 6-1: Summary of Ambient Ammonia Levels Literature Review

Source of Estimate	NH_3 (ppbv)	Description	Location	Year(s)
Adams et al. (1999) Plate 3	0.003-0.01	Modeled annual average	North Slope, Alaska	1990s
Chen at al. (2011) Figure 1	Lowest at Yellowstone, WY (monthly average of 0.1-0.4 ppbv) and highest at Cedar Bluff, KY (1.7-4.6 ppbv) and Bondville, IL (1.2-5.2 ppbv)	Collected NH_3 concentrations at 9 existing IMPROVE monitoring sites	Rocky Mountains region in the western US	2010-2012
Osada et al. (2011)	<0.224	Suggested conclusion from marine modeling studies	"Remote" Marine Regions	2000s
Dentener and Crutzen (1994) Figure 2a and Fig. 3a	0.06-0.1	Modeled annual average	North Slope, Alaska	1980/1990s
Schirokauer et al. (2014) Table 3 and Figure 12	0-14 ppmv in May-August, 14-95 ppbv during May-October	Measured NH_3 at 7 sites during May-October	Southeast Alaska	2008-2009
Shephard et al. (2011) Figure 2	0.0-1.25	Modeled monthly average for most months	North Slope, Alaska	2000s
Xu and Penner (2012) Fig. 2 and Fig. 5	0.001-0.01	Modeled annual average	North Slope, Alaska	1990/2000s

Table 6-2: 30-Year (1981-2010) Climatological Normal Temperatures in degrees Fahrenheit

Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BIG RIVER LAKES	19.9	23.2	28.1	37.5	48.0	56.2	59.4	57.9	50.3	37.9	26.0	22.0
INTRICATE BAY	17.8	20.7	24.8	33.9	44.5	52.5	56.6	55.0	47.7	35.8	26.2	21.5
KASILOF 3 NW	17.2	19.6	24.1	33.6	42.4	49.5	53.7	52.4	45.9	34.6	23.1	19.1
KENAI 9N	16.3	19.4	24.9	34.6	44.8	52.4	55.9	54.5	47.3	35.0	23.3	18.8
KENAI AP	16.4	19.7	25.7	36.2	46.0	52.5	56.3	55.0	48.1	35.2	23.2	19.0
SOLDOTNA 5SSW	13.4	17.4	24.8	34.6	44.4	51.2	55.2	53.3	45.6	33.3	19.2	16.2
Temperature data obtained from the National Climatic Data Center												

Table 6-3: Ambient Ammonia Background Concentrations for Use in CALPUFF

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Ammonia Concentration (ppbv)	0.1	0.1	0.1	0.1	1.0	1.0	1.0	1.0	1.0	1.0	0.1	0.1

6.6 VISIBILITY MODELING APPROACH

6.6.1 Near-field Analysis

The near-field plume visibility analysis was conducted using USEPA's VISCREEN model to evaluate the extent of visibility of plumes associated with the Liquefaction Facility in Kenai NWR which is the only Class I or Class II area close enough to be reasonably modeled with a near-field model. VISCREEN is a screening-level plume visibility model recommended in USEPA's Workbook for Plume Visual Impact Screening and Analysis (the Visibility Workbook, USEPA 1992). This model simulates the dispersion and optical characteristics of an elevated emission source plume. It incorporates the straight-line Gaussian dispersion of primary particulate as well as the transformation of primary pollutants (NO_x). It then computes the scattering of direct sunlight due to air-borne pollutants. For a given time of day, wind speed, atmospheric stability, background visual range, and ozone concentration, the model computes light intensity at various visible wavelengths for lines-of-sight through the plume centerline. By comparing the light intensity reaching an observer both with and without the source present, the model computes visibility parameters that can be used to gauge whether or not a plume might be visible against a background sky or terrain.

Inputs which are required by VISCREEN include:

- Emission rates of NO_x and primary particulate (elemental carbon and primary sulfate are optional emission rates),
- Observer distance from source,
- Meteorological conditions (wind speed and atmospheric stability),
- Background visual range, and
- Background ozone concentration.

The two visibility parameters that VISCREEN estimates are specified in the Visibility Workbook and include:

- Plume contrast (Cp) - a measure of the fractional reduction or increase in light intensity at the 0.55 μm wave length due to the presence of a plume. This (green) wave length is used because it is at the center of the visible spectrum. According to the Workbook, plume contrast values exceeding 0.05 in absolute value should be used as a screening criterion, inferring that a 5% change in intensity is likely to be noticed by a casual observer.
- Plume perceptibility parameter (ΔE) - an integral measure that incorporates differences in light intensity over all visible wavelengths incorporating human perception. ΔE evaluates the degree to which a plume can be seen either against a sky or terrain background. The Visibility Workbook establishes a ΔE threshold of 2.0 to indicate the presence of a visible plume against a background sky or terrain.

Observer locations chosen for the VISCREEN analysis included the closest Class II sensitive area: Kenai NWR (the most conservative observer location as suggested by the Visibility Workbook) and Skilak Lake (a popular visitor destination within the refuge). Kenai NWR is located approximately 10 kilometers (6 miles) from the Liquefaction Facility and Skilak Lake is located approximately 52 kilometers (32 miles) from the Facility. Both were assessed using a Level II assessment methodology (as described the Workbook). Unless otherwise mentioned, default VISCREEN settings were utilized.

According to FLAG (USDOI 2010), VISCREEN is usually applied for lines of sight that are within 50 kilometers of a source. While a small section of the northeast border of Lake Clark National Park is approximately 50 kilometers from the Liquefaction Facility, that portion of the part of the park is not frequently visited and does not likely contain scenic vistas, and by far the largest majority of the park lies well beyond 50 kilometers. Furthermore, 50 kilometers is at the extreme limit of near-field model applicability. All of these issues should be considered together when decided to use a near-field or far-field model to estimate visibility impacts. Following careful consideration, a near-field visibility analysis was not performed at Lake Clark National Park. Instead, a regional haze assessment within Lake Clark National Park was performed using CALPUFF and is described below in **Section 6.6.2**.

The USEPA Visibility Workbook indicates that the highest modeled plume visibility impairment is associated with plume-observer geometry where the wind vector carries the plume centerline 11.25° on either side of the line between the plant and the observer. Thus, one wind vector to left and one to the right of the observer location were simulated. Following the methods described in the Visibility Workbook, the wind speed and atmospheric stability class for the 22.5° wind direction sector for each observer that corresponds to the one percentile worst-case probability will be applied. Wind speed and stability class categories and frequencies were based on the same meteorological data set used for the near-field modeling analyses described in Section 5: 2008-2012 meteorological data from the nearby Kenai NWS station.

Background visual range was determined by averaging the 12 months of average monthly visual range values measured in nearby Tuxedni NWR. This information was found in Table 10 of FLAG 2010.

Emission rates used as inputs for each source included primary NO_x, primary particulate matter, and primary elemental carbon. Note that VISCREEN assumes that 10% of NO_x emissions are initially converted to NO_2, either within the source stack or within the first kilometer of plume transport. In addition, the default VISCREEN ozone background value of 40 ppbv was assumed and is consistent with measurements collected at Denali National Park and used for the long-range assessment with CALPUFF and the near-field NO_2 chemical transformation in AERMOD.

There would be several emission source types at the Liquefaction facility, and many would have different stack parameter characteristics. Some sources would also be large distances apart. For a VISCREEN analysis, it is reasonable to assume that the plumes from many of these sources would not combine into a single plume. Thus, an assessment of which plumes would and would not likely combine was performed. Stack velocities, heights, temperatures and distances were considered in this analysis. A total of 5 separate plumes were conservatively identified. The sources that were combined into each of these plumes are shown in **Table 6-4** with justifications. A specific VISCREEN analysis was performed on each of these plumes to obtain more representative visibility degradation estimations at the observer locations.

Note that only emission rates associated with the pilot/purge operations were modeled in the near-field visibility analysis. Maximum flaring emission rates (which may occur during upset and startup scenarios) associated with the flares were not modeled. Maximum flaring scenarios are expected to be extremely rare and short lived (occurring less than an hour at a time). The probability that these very short-lived maximum flaring events would coincide with the stability classes, wind directions, worst case solar/scattering angles necessary for visibility degradation is very low. In addition, VISCREEN does not consider the extreme dispersion and thermal buoyancy from plumes associated with maximum flaring events. For these reasons, the inclusion of maximum flaring emissions in a VISCREEN analysis would create predicted impacts that are not representative of reasonable foreseeable operations associated with normal operations of the facility.

Table 6-4: Combined Plume Emission Sources

VISCREEN Analysis	Source Emissions Included in Plume	Justification for Combining Sources
Compressor Turbines	6 Compressor Turbine	Identical source types. Distances apart range from approximately 0.1 to 0.5 km
Power Generator	4 Power Generators + Firewater Pump + Aux Compressor	The Power Generators are located in the same general vicinity of each other. The Firewater Pump and Aux Compressors are also nearby and have stack parameters which suggest potential for combining with Power Generator plumes.
LP Flare	2 LP Flares + Thermal Oxidizer	The two LP flares are nearby each other. The Thermal Oxidizer is also conservatively included with the LP Flares as it is nearby source
Wet/Dry Flare	2 Wet Flares + 2 Dry Flares	All four of these flares are nearby each other and have similar stack parameters
Marine Sources	North Carrier + South Carrier + Support Tugs	Though exact locations of these sources is unknown, they were conservatively combined into a single plume

6.6.2 Far-field Analysis

As noted in **Section 6.5** above, CALPUFF uses measurements of background ammonia concentrations to estimate secondary particulate formation which contributes to the amount of regional haze and visibility degradation predicted by the model. CALPUFF simulates each modeled source individually; thus, the background ammonia concentration is assumed by the model to be fully available to react with emissions from each source. This can lead to the model overestimating secondary particulate formation and regional haze impacts because, in reality, the total emissions from the combination of emission units compete for the available ammonia. Therefore actual secondary particulate formation would be less due to less background ammonia availability. Despite the inherent conservatism in the model, far-field cumulative regional haze impacts were determined by conventional utilization of CALPUFF.

Regional haze impacts due to the Liquefaction Facility were refined by subtracting the offsite regional haze impact from the cumulative regional haze impact, as shown below. This was accomplished by conventional utilization of CALPUFF for the cumulative and existing source groups noted below and post-processing using the POSTUTIL program.

This refined method better accounts for the fact that the available background ammonia is partially consumed by the background emission source inventory.

Project Regional Haze Impact **(Liquefaction Facility Sources Only)**	**=**	**Cumulative Regional Haze Impact** **(Offsite Sources + Liquefaction Facility Sources)**	**-**	**Background Sources Regional Haze Impact** **(Offsite Sources Only)**

6.7 METEOROLOGICAL DATA

6.7.1 Prognostic Meteorological Data

The most recent available prognostic meteorological data that exists for the modeling domain is the three-year (2002-2004) Fifth Generation Penn State/NCAR Mesoscale Model (MM5) dataset developed for the Alaska BART Coalition and was used as the gridded, domain-wide prognostic meteorological dataset. This dataset was developed and approved and used in the BART regional haze modeling for this area (ADEC 2014).

The model performance evaluation for the MM5 dataset showed that the wind field depicted within the grid met the specifications for bias and accuracy and was confirmed for use in the CALPUFF modeling (Geomatrix 2007).

6.7.2 CALMET

The MM5 meteorological data was processed using CALMET to develop a meteorological wind field. The performance evaluation of the processed dataset was acceptable to regulatory agencies for BART modeling and therefore was used by the Alaska BART Coalition for Cook Inlet CALPUFF modeling (ADEC 2014). The CALMET/CALPUFF modeling domain is shown by the blue line in **Figure 6-1**.

6.8 RECEPTORS

Receptor locations and their elevations for Tuxedni and Denali were obtained from the National Park Service databases (http://www.nature.nps.gov/air/maps/receptors/download/ClassIData.zip).

Receptor placement for Sensitive Class II areas was designed similar to the Denali receptors spacing, with receptors placed every 6 kilometers (3.7 miles) vertically and every 3 kilometers (2 miles) horizontally. Receptors beyond 300 kilometers of the Liquefaction Facility were not modeled since they are beyond the accepted regulatory limit of the model.

Note that the CALMET domain does not extend all the way to the Kodiak NWR, a Sensitive Class II area. Therefore, a surrogate data point to represent Kodiak NWR impacts was placed at the Barren Islands. Also note that receptors shown at the Kenai NWR are located less than 50 km from the Liquefaction Facility.

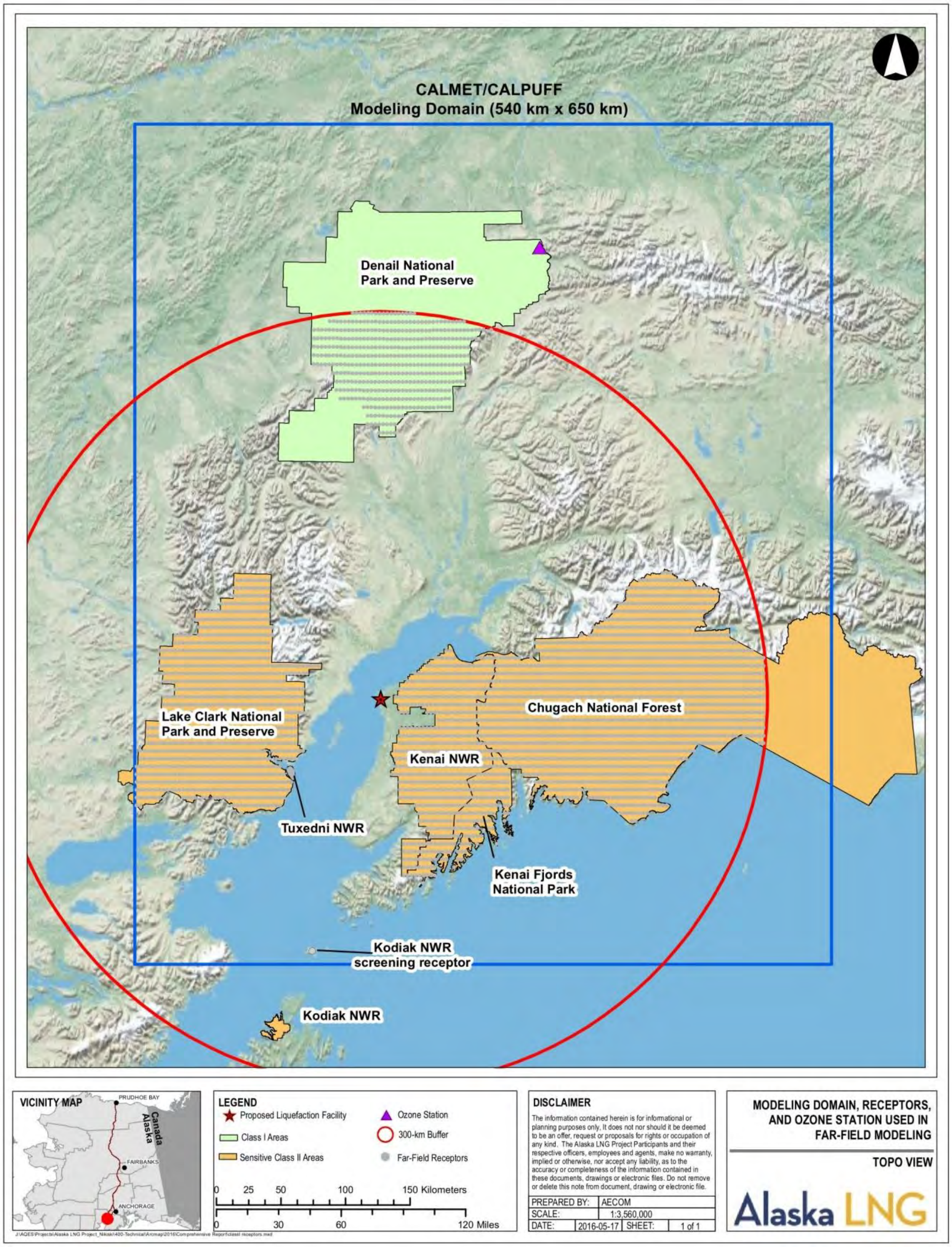
6.9 ELEVATION DATA

The terrain data was extracted from the provided CALMET geo.dat file to assign elevations to the Sensitive Class II receptors using Lakes Environmental CALPUFF View program (available at https://www.weblakes.com/products/calpuff/).

6.10 NO_2 MODELING APPROACH

Section 5.7 discusses the three-tiered approach that may be applied to modeling 1-hour and annual NO_2 impacts. Preliminary modeling indicated that assuming full conversion of NO to NO_2 (Tier 1) was too conservative for the Class I and Sensitive Class II Area modeling analysis. Therefore, consistent with recent USEPA guidance (USEPA 2014b), Tier 2 (ARM) was implemented whereby Tier 1 results were multiplied by the default 1-hour and annual NO_2/NO_x ratios of 0.80 and 0.75, respectively.

Figure 6-1: Far-Field Modeling Domain and Receptors



7.0 MODELING RESULTS

The results of the ambient air quality modeling analyses for the Liquefaction Facility are presented in this Section. Both near-field and Class I and Sensitive Class II area analyses are discussed below. The analyses were conducted according to the technical approaches, source emission rates, and stack parameters presented in **Sections 4, 5**, and **6**. Electronic input and output files for all model runs used to develop the results in the tables that follow are transmitted digitally with this report (Doc. No. USAL-P1-SRZZZ-00-000001-001).

7.1 NEAR-FIELD DISPERSION MODEL IMPACTS

This section presents AERMOD results for modeled receptors within approximately 50 kilometers of the Liquefaction Facility. Visibility impacts for near-field sensitive Class II areas are presented in **Section 7.2.4.**

7.1.1 Criteria Pollutant Project Only Impacts

Model-predicted concentrations resulting from normal operations at the Liquefaction Facility alone (no offsite sources) are compared to the NAAQS and AAAQS in Table 7-1 and compared to PSD Class II increments in Table 7-2. These model results are provided for information purposes only since it is more appropriate to compare cumulative impacts to these criteria. All model-predicted impacts are below the applicable standards and increments listed in **Section 2.0**.

7.1.2 Criteria Pollutant Cumulative Impacts

Cumulative model-predicted concentrations from the Liquefaction Facility, existing and proposed offsite sources, and other non-modeled sources (represented by ambient background concentrations) are compared to the NAAQS and AAAQS in Table 7-3. Cumulative model-predicted concentrations are also compared to PSD Class II increments in Table 7-4. While all model-predicted impacts are below the applicable standards and increments listed in **Section 2.0**, it is highly conservative to add the maximum 1-hour fumigation impacts to all cumulative AERMOD impacts, regardless of averaging period. Realistically, any potential impacts due to fumigation would be far less, particularly for 24-hour and annual averaging periods.

Note that lead and ammonia emissions are either negligible or not emitted at all from the Liquefaction Facility; therefore, they were not addressed as part of the dispersion modeling analysis.

Table 7-1: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	57.5	5.0	62.5	196	196
	3-Hour [b]	39.6	5.0	44.6	1,300	1,300
	24-Hour [b]	17.1	2.4	19.5	NA	365
	Annual [d]	0.11	0.0	0.11	NA	80
Carbon Monoxide	1-Hour [b]	2,721	1,145	3,866	40,000	40,000
	8-Hour [b]	1,071	1,145	2,216	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	140.1	32.3	172.4	188	188
	Annual [d]	8.4	2.60	11.0	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	5.1	40	45.1	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	3.6	12	15.6	35	35
	Annual [g]	0.38	3.70	4.1	12	12

Abbreviations:

NA = not applicable

μg/m³ = micrograms per cubic meter

Notes:

[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[b] Value reported is the highest, second highest concentration of the values determined for each of the 5 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[d] Value reported is the maximum annual average concentration for the 5-year period.

[e] Value reported is the 98th percentile averaged over the 5-year period.

[f] Value reported is the highest, 6th highest concentration over the 5-year period.

[g] Value reported is the annual mean concentration, averaged over the 5-year period.

Table 7-2: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	39.6	512
	24-Hour [b]	17.1	91
	Annual [c]	0.11	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	8.4	25
Particulate Matter less than 10 Microns	24-Hour [b]	5.4	30
	Annual [c]	0.43	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	4.8	9
	Annual [c]	0.43	4

Abbreviations:

NA = not applicable

μg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-3: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (µg/m³)	Maximum 1-Hour Fumigation Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)
Sulfur Dioxide	1-Hour [a]	63.4	5.7	5.0	74.1	196	196
	3-Hour [b]	50.6	5.7	5.0	61.3	1,300	1,300
	24-Hour [b]	32.0	5.7	2.4	40.1	NA	365
	Annual [d]	0.6	5.7	0.0	6.3	NA	80
Carbon Monoxide	1-Hour [b]	2,721	78.3	1,145	3,945	40,000	40,000
	8-Hour [b]	1,071	78.3	1,145	2,294	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	149.5	Included [h]	32.3	181.8	188	188
	Annual [d]	20.4	34.1	2.60	57.1	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	23.9	5.0	40	68.9	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	6.4	5.0	12	23.4	35	35
	Annual [g]	2.8	5.0	3.7	11.4	12	12

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[b] Value reported is the highest, second highest concentration of the values determined for each of the 5 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[d] Value reported is the maximum annual average concentration for the 5-year period.

[e] Value reported is the 98th percentile averaged over the 5-year period.

[f] Value reported is the highest, 6th highest concentration over the 5-year period.

[g] Value reported is the annual mean concentration, averaged over the 5-year period.

[h] Hourly fumigation concentration was modeled in AERMOD through use of background concentration file. Thus, the resulting AERMOD concentration includes fumigation.

Table 7-4: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (µg/m³)	Maximum 1-Hour Fumigation Concentration (µg/m³)	Total Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA	NA	NA
	3-Hour [b]	39.6	5.7	45.4	512
	24-Hour [b]	17.5	5.7	23.3	91
	Annual [c]	0.6	4.9	5.5	20
Carbon Monoxide	1-Hour [a]	NA	NA	NA	NA
	8-Hour [a]	NA	NA	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA	NA	NA
	Annual [c]	12.5	Included [d]	12.5	25
Particulate Matter less than 10 Microns	24-Hour [b]	24.7	5.0	29.7	30
	Annual [c]	2.7	5.0	7.7	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	8.7	Included [d]	8.7	9
	Annual [c]	1.3	Included [d]	1.3	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

[d] Hourly fumigation concentration was modeled in AERMOD through use of background concentration file. Thus, the resulting AERMOD concentration includes fumigation.

7.2 CLASS I AND SENSITIVE CLASS II MODEL-PREDICTED IMPACTS

This section presents results for modeled receptors within selected Class I and Sensitive Class II areas.

7.2.1 Criteria Pollutant Project Only Impacts

Modeled impacts resulting from normal operations for the Liquefaction Facility are compared to applicable standards discussed in **Section 2.0**. Model-predicted concentrations from the Liquefaction Facility only are compared to the NAAQS and AAAQS for each of the selected Class I and Sensitive Class II areas in **Table 7-5** through **Table 7-10**. Model–predicted concentrations from the Liquefaction Facility alone are compared to PSD increment in Table 7-11 through Table 7-16. These model results are provided for information purposes only since it is more appropriate to compare cumulative impacts to these criteria. All model-predicted impacts due to the Liquefaction Facility alone are well below all standards and increments at all modeled Class I and Sensitive Class II areas.

7.2.2 Criteria Pollutant Cumulative Impacts

Cumulative CALPUFF-predicted concentrations from the Liquefaction Facility, existing offsite sources, RFD sources, and other non-modeled sources (represented by ambient background concentrations) are compared to the NAAQS and AAAQS for each far field Class I and Sensitive Class II area in Table 7-17 through Table 7-22. The results indicate that the cumulative air quality impacts, combined with representative background air quality data, are well below the NAAQS and AAAQS at all areas of concern.

Cumulative modeling was also performed for increment-consuming sources only for comparison to PSD Class I and Class II increments. Table 7-23 through Table 7-28 present the results, which indicate impacts are less than the PSD increment at all areas of concern.

7.2.3 Secondary $PM_{2.5}$ and PM_{10} Formation

CALPUFF simulates simple, in-transit transformation of SO_2 emissions to ammonia sulfate and NO_x emissions to ammonium nitrate. $PM_{2.5}$ and PM_{10} impacts due to Liquefaction Facility sources were calculated using IWAQM guidance and the POSTUTIL processor to include both direct PM impacts along with the modeled ammonia sulfate and ammonium nitrate concentrations. These total PM concentrations are included in the $PM_{2.5}$ and PM_{10} concentrations in the NAAQS and PSD increment results tables.

7.2.4 AQRV Visibility Assessment

This section describes the results of the AQRV visibility analysis. As suggested by FLAG, two assessments were performed:

- A near-field assessment to determine the near-field impact of non-collocated plumes as compared to a viewing background, and
- A distance/multi-source (far-field) assessment to determine how the general appearance of the overall scene in the region would be affected.

7.2.4.1 Near-field Analysis

Plume visibility at Kenai NWR, which is the only Class I or Class II Area located within 50 kilometers of the Liquefaction Facility, was assessed with the VISCREEN model, as described in **Section 6.6.1**. The plume visibility results of plume perceptibility (ΔE) and plume contrast (Cp) against both a sky and terrain background for each source/observer location combination are shown Table 7-29 and Table 7-30.

As can be seen, all Cp and ΔE screening criteria were met by large margins for all plumes except for the combined plume associated with the compressor turbines. For the turbines, ΔE and Cp slightly above screening levels were noted at the Closest Park Boundary when viewing both a Sky and Terrain Background. ΔE was also slightly above screening levels at Skilak Lake when viewing a Terrain Background. The highest ΔE occurred at the Closest Park Boundary when viewing a Terrain Background.

While a few results were not less than the Class I screening levels, VISCREEN is by nature a conservative screening model. Results shown are for absolute worst case scattering angles (10 and 140 degrees) based on sun position, and therefore, will only occur for certain portions of year and day, depending on season. The Cp and ΔE terrain background calculations are also based on the assumption that the terrain object being viewed is black. This is also likely conservative considering much of the terrain in reality will be colorful or white.

Finally, it is important to consider that the modeled compressor turbines plume consisted of emissions from six separate turbines. Each of these turbines is separated by a distance of 0.1 to 0.5 kilometer of each other, so instances where these separated turbine plumes would potentially combine into a single plume as modeled are likely rare. ΔE and Cp criteria would be met for all locations and viewing backgrounds if one assumes no more than two of the turbine plumes would ever realistically combine.

7.2.4.2 Far-field Analysis

As shown in **Table 7-31**, predicted visibility impacts (reported as the 8th highest percent change in light extinction) from the Liquefaction Facility alone are below the 5% threshold at nearly all Class I and Sensitive Class II areas. With some additional modeling refinements, it would be below thresholds at all areas of concern, thus the visibility impacts are below de minimis thresholds. The modeled change in light extinction at Lake Clark is 5.1% and 5.3% for 2003 and 2004, respectively; these results are conservative and could be refined as described below:

- A background ammonia value of 1 ppbv was conservatively selected for the growing season. This value is considerably higher than the 0.1 ppbv used for historical BART modeling in Alaska. The actual background ammonia value is likely somewhere in between 0.1 and 1 ppbv, which would reduce visibility impacts, potentially reducing the impact at Lake Clark to below the 5% de minimis threshold.
- Refinement of the conservative assumptions included in the Liquefaction Facility simulation would also lead to lower visibility impacts and likely reduce the impact at Lake Clark NP to below 5%. Refinements could include modeling a more realistic normal operating scenario that does not include operations such as maximum relief flaring combined with all other sources operating normally.

As shown in **Table 7-32**, the cumulative change in light extinction exceeds the 10% threshold at all far-field areas. Because cumulative impacts show potential issues where the source-only impacts do not, it is evident that the elevated impacts are attributable to offsite sources.

Note that existing visibility extinction measurements reported through the IMPROVE program at Tuxedni NWR and Denali NP are much lower than cumulative model-predicted impacts at these locations. Thus, it is clear the model is over-predicting cumulative impacts and likely over-predicting Liquefaction Facility-only impacts as well, which are already essentially below 5%. Note that the CALPUFF model includes the conservative assumption of a steady background visibility condition that only slightly varies monthly. In reality, there is daily variation of measured aerosols, which is not accounted for in the model. If the model were able to be refined to account for daily visibility variation it is likely that model-predicted visibility impacts would be lower.

7.2.5 AQRV Deposition Modeling Results

As shown in **Table 7-33**, the sulfur deposition flux from the Liquefaction Facility alone is slightly above the DAT at Tuxedni NWR, Kenai NWR, and Lake Clark NP. The onshore sources located at the Liquefaction Facility most culpable for these impacts. It is worth noting that the upper limit of pipeline quality natural gas sulfur content (16 ppmv) was assumed in the calculations of emissions for these sources and that the actual fuel sulfur content will likely be much lower (by as much as half), which would mitigate sulfur deposition impacts.

Table 7-34 shows that the nitrogen deposition flux from the Liquefaction Facility also exceeds the DAT at Tuxedni NWR, Kenai NWR, Lake Clark NP, as well as Denali NP. However, it is believed that refinements to the conservative assumptions included in the normal operations scenario for the facility would reduce deposition impacts to below the DAT for all areas. Refinements could include modeling a more realistic normal operating scenario which does not include operations such as maximum relief flaring, and/or modeling the turbines at a more realistic load instead of the conservative 100% that was assumed. These refinements would also reduce the sulfur deposition impacts.

Cumulative deposition modeling results are shown in **Table 7-35** and **Table 7-36** and indicate that modeled nitrogen and sulfur deposition fluxes all within the cumulative DAT

Note that DATs for both the Liquefaction Facility-only and cumulative deposition assessments are screening thresholds developed to be conservatively protective of all Class I areas regardless of location-specific natural background and buffering capacity. If park-specific studies were available, there may be an opportunity to refine and increase the acceptable thresholds. For example, because the natural background is directly related to the calculation of the DATs (shown in **Section 2.3.3**), an elevated natural background at a particular location would result in a higher DAT.

7.3 MODELING CONCLUSIONS

- The following are conclusions based on the results discussed above for near-field receptors and receptors at the modeled Class I and Sensitive Class II areas. Considering the following conservative assumptions, the modeling results indicate there is no concern the Liquefaction Facility would cause adverse air, deposition, or visibility impacts at near-field, Class I, or Sensitive Class II areas:
  - All equipment located at the Liquefaction Facility is assumed to operate concurrently, even intermittently used emergency equipment.
  - Short-term turbine emissions are based on worst-case, rather than average, ambient temperatures. Average temperature would result in lower emissions.
  - The turbines are assumed to operate at 100% load, even though it is more likely they will operate at near 90% load, which would result in lower emissions.
  - 500 hours per year of maximum relief flaring is included in the modeling demonstration in addition to continuous pilot purge and all other equipment operating. While maximum relief flaring is inevitable, it is unlikely to occur as much as 500 hours per year and with all other equipment operating.
  - The modeled marine scenario assumes that two carriers will call within a few hours of one another, with both docked concurrently for a period of time, though it is far more likely that only one carrier would call at any time.
- Despite the aforementioned conservative assumptions:
  - At near-field locations, model-predicted impacts are below all air quality standards and increments.
  - At far-field locations, model-predicted impacts are below all air quality standards and increments at all Class I and Sensitive Class II areas.
- While some results of the near-field visibility assessment were above Class I screening levels, they are likely attributable to:

  - The worst-case meteorological conditions included in the screening-level VISCREEN model, which are infrequent and unlikely to occur simultaneously with the wind direction required for an observer to notice the plume.
  - The conservative assumption that emissions from all six turbines combine into a single plume, which is also highly unlikely.
- Visibility impacts due to the Liquefaction Facility alone are below the 5% de minimis threshold at all Class I and Sensitive Class II areas except Lake Clark NP. Refinements to the ammonia background and the modeled facility normal operating scenario would mitigate modeled visibility impacts at all areas, and could easily reduce the impact at Lake Clark NP to below 5%.
- Cumulative predicted visibility impacts exceed the 10% threshold at all far-field Class I and Sensitive Class II areas, however:
  - The elevated impacts are attributable to offsite sources based on a comparison of impacts with and without the Liquefaction Facility.
  - Impacts due to the Liquefaction Facility are a negligible portion of the cumulative impact.
  - A comparison of existing visibility measurements to cumulative modeled impacts at Tuxedni NWR and Denali NP indicates the model is over-predicting cumulative impacts. Impacts due to the Liquefaction Facility alone are also likely overly conservative (which are already generally below the source-only de minimis threshold).
- Deposition impacts due to the Liquefaction Facility alone are above the DAT at several Class I and Sensitive Class II areas, however:
  - The actual fuel sulfur content of pipeline quality gas used at the facility would likely be less (by as much as half) than the 16 ppmv that was assumed in the modeling, which would mitigate modeled sulfur deposition impacts.
  - Refinements to the modeled facility normal operating scenario would likely reduce both sulfur and nitrogen deposition impacts to below the DAT for all areas.
  - If park-specific studies were available, there would be an opportunity to refine and increase the acceptable DATs, as current thresholds were designed to be protective of all Class I areas.
- Cumulative deposition impacts are within the DAT at all far field Class I and Sensitive Class II areas.

Table 7-5: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	0.11	5.0	5.11	196	196
	3-Hour [b]	0.12	5.0	5.12	1,300	1,300
	24-Hour [b]	0.05	2.3	2.35	NA	365
	Annual [d]	0.00	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	5.67	1,145	1,151	40,000	40,000
	8-Hour [b]	3.04	1,145	1,148	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.78	32.3	33.08	188	188
	Annual [d]	0.02	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.34	40.0	40.34	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.13	12.0	12.13	35	35
	Annual [d]	0.02	3.7	3.72	12	15

Table 7-6: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	0.10	5.0	5.10	196	196
	3-Hour [b]	0.10	5.0	5.10	1,300	1,300
	24-Hour [b]	0.04	2.3	2.34	NA	365
	Annual [d]	0.002	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	4.90	1,145	1,150	40,000	40,000
	8-Hour [b]	2.64	1,145	1,148	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.63	32.3	32.93	188	188
	Annual [d]	0.02	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.31	40.0	40.31	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.10	12.0	12.10	35	35
	Annual [d]	0.01	3.7	3.71	12	15

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:
[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[d] Value reported is the maximum annual average concentration for the 3-year period.
[e] Value reported is the 98th percentile averaged over the 3-year period.
[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-7: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	0.03	5.0	5.03	196	196
	3-Hour [b]	0.06	5.0	5.06	1,300	1,300
	24-Hour [b]	0.02	2.3	2.32	NA	365
	Annual [d]	0.0005	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	4.65	1,145	1,150	40,000	40,000
	8-Hour [b]	1.87	1,145	1,147	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.39	32.3	32.69	188	188
	Annual [d]	0.003	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.09	40.0	40.09	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.03	12.0	12.03	35	35
	Annual [d]	0.006	3.7	3.71	12	15

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:
[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[d] Value reported is the maximum annual average concentration for the 3-year period.
[e] Value reported is the 98th percentile averaged over the 3-year period.
[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-8: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	0.07	5.0	5.07	196	196
	3-Hour [b]	0.07	5.0	5.07	1,300	1,300
	24-Hour [b]	0.03	2.3	2.33	NA	365
	Annual [d]	0.0008	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	4.60	1,145	1,150	40,000	40,000
	8-Hour [b]	2.08	1,145	1,147	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.44	32.3	32.74	188	188
	Annual [d]	0.004	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.07	40.0	40.07	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.07	12.0	12.07	35	35
	Annual [d]	0.008	3.7	3.71	12	15

Table 7-9: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	0.13	5.0	5.13	196	196
	3-Hour [b]	0.13	5.0	5.13	1,300	1,300
	24-Hour [b]	0.06	2.3	2.36	NA	365
	Annual [d]	0.003	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	6.80	1,145	1152	40,000	40,000
	8-Hour [b]	3.36	1,145	1148	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.78	32.3	33.08	188	188
	Annual [d]	0.02	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.38	40.0	40.38	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.14	12.0	12.14	35	35
	Annual [d]	0.02	3.7	3.72	12	15

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:
[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[d] Value reported is the maximum annual average concentration for the 3-year period.
[e] Value reported is the 98th percentile averaged over the 3-year period.
[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-10: Liquefaction Facility-Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	5.01	5.0	10.01	196	196
	3-Hour [b]	5.01	5.0	10.01	1,300	1,300
	24-Hour [b]	2.35	2.3	4.65	NA	365
	Annual [d]	0.0002	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	1.10	1,145	1,146	40,000	40,000
	8-Hour [b]	0.61	1,145	1,146	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.05	32.3	32.35	188	188
	Annual [d]	0.001	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.02	40.0	40.02	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.01	12.0	12.01	35	35
	Annual [d]	0.002	3.7	3.70	12	15

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:

[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

[d] Value reported is the maximum annual average concentration for the 3-year period.

[e] Value reported is the 98th percentile averaged over the 3-year period.

[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-11: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class I Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.12	25
	24-Hour [b]	0.05	5
	Annual [c]	0.003	2
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.02	2.5
Particulate Matter less than 10 Microns	24-Hour [b]	0.34	8
	Annual [c]	0.02	4
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.38	2
	Annual [c]	0.02	1

Table 7-12: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class I Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.10	25
	24-Hour [b]	0.04	5
	Annual [c]	0.002	2
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.02	2.5
Particulate Matter less than 10 Microns	24-Hour [b]	0.31	8
	Annual [c]	0.01	4
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.34	2
	Annual [c]	0.01	1

Abbreviations:
NA = not applicable
µg/m³ = micrograms per cubic meter
Notes:
[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.
[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.
[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-13: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.06	512
	24-Hour [b]	0.02	91
	Annual [c]	0.0005	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.003	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.09	30
	Annual [c]	0.01	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.10	9
	Annual [c]	0.01	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-14: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.07	512
	24-Hour [b]	0.03	91
	Annual [c]	0.001	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.004	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.12	30
	Annual [c]	0.01	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.15	9
	Annual [c]	0.01	4

Table 7-15: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.13	512
	24-Hour [b]	0.06	91
	Annual [c]	0.00	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.02	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.38	30
	Annual [c]	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.42	9
	Annual [c]	0.02	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-16: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.01	512
	24-Hour [b]	0.005	91
	Annual [c]	0.0002	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.02	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.02	30
	Annual [c]	0.002	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.02	9
	Annual [c]	0.003	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the three modeled years.

[c] Value reported is the maximum annual average concentration for the 3-year period.

Table 7-17: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)
Sulfur Dioxide	1-Hour [a]	0.70	5.0	5.70	196	196
	3-Hour [b]	0.68	5.0	5.68	1,300	1,300
	24-Hour [b]	0.32	2.3	2.62	NA	365
	Annual [d]	0.03	0	0.03	NA	80
Carbon Monoxide	1-Hour [b]	14.66	1,145	1,160	40,000	40,000
	8-Hour [b]	7.80	1,145	1,153	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	4.79	32.3	37.09	188	188
	Annual [d]	0.22	2.6	2.82	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	2.25	40.0	42.25	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.93	12.0	12.93	35	35
	Annual [d]	0.12	3.7	3.82	12	15

Table 7-18: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)
Sulfur Dioxide	1-Hour [a]	22.21	5.0	27.21	196	196
	3-Hour [b]	15.45	5.0	20.45	1,300	1,300
	24-Hour [b]	4.05	2.3	6.35	NA	365
	Annual [d]	0.258	0	0.26	NA	80
Carbon Monoxide	1-Hour [b]	46.63	1,145	1,192	40,000	40,000
	8-Hour [b]	17.34	1,145	1,162	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	9.65	32.3	41.95	188	188
	Annual [d]	0.15	2.6	2.75	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	2.22	40.0	42.22	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.83	12.0	12.83	35	35
	Annual [d]	0.10	3.7	3.80	12	15

Abbreviations:
NA = not applicable
µg/m³ = micrograms per cubic meter

Notes:
[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[d] Value reported is the maximum annual average concentration for the 3-year period.
[e] Value reported is the 98th percentile averaged over the 3-year period.
[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-19: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	0.13	5.0	5.13	196	196
	3-Hour [b]	0.14	5.0	5.14	1,300	1,300
	24-Hour [b]	0.06	2.3	2.36	NA	365
	Annual [d]	0.0040	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	5.29	1,145	1,150	40,000	40,000
	8-Hour [b]	2.62	1,145	1,148	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.79	32.3	33.09	188	188
	Annual [d]	0.016	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.49	40.0	40.49	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.17	12.0	12.17	35	35
	Annual [d]	0.025	3.7	3.72	12	15

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter
Notes:
[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[d] Value reported is the maximum annual average concentration for the 3-year period.
[e] Value reported is the 98th percentile averaged over the 3-year period.
[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-20: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	1.95	5.0	6.95	196	196
	3-Hour [b]	1.74	5.0	6.74	1,300	1,300
	24-Hour [b]	0.64	2.3	2.94	NA	365
	Annual [d]	0.0633	0	0.06	NA	80
Carbon Monoxide	1-Hour [b]	73.08	1,145	1,218	40,000	40,000
	8-Hour [b]	32.53	1,145	1,178	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	17.45	32.3	49.75	188	188
	Annual [d]	0.687	2.6	3.29	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	1.35	40.0	41.35	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	1.35	12.0	13.35	35	35
	Annual [d]	0.182	3.7	3.88	12	15

Table 7-21: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)
Sulfur Dioxide	1-Hour [a]	1.31	5.0	6.31	196	196
	3-Hour [b]	1.10	5.0	6.10	1,300	1,300
	24-Hour [b]	0.42	2.3	2.72	NA	365
	Annual [d]	0.062	0	0.06	NA	80
Carbon Monoxide	1-Hour [b]	46.98	1,145	1,192	40,000	40,000
	8-Hour [b]	23.27	1,145	1,169	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	11.97	32.3	44.27	188	188
	Annual [d]	0.54	2.6	3.14	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	2.54	40.0	42.54	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	1.44	12.0	13.44	35	35
	Annual [d]	0.19	3.7	3.89	12	15

Abbreviations:
NA = not applicable
µg/m³ = micrograms per cubic meter

Notes:
[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
[d] Value reported is the maximum annual average concentration for the 3-year period.
[e] Value reported is the 98th percentile averaged over the 3-year period.
[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-22: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)
Sulfur Dioxide	1-Hour [a]	0.01	5.0	5.01	196	196
	3-Hour [b]	0.01	5.0	5.01	1,300	1,300
	24-Hour [b]	0.05	2.3	2.35	NA	365
	Annual [d]	0.0002	0	0.00	NA	80
Carbon Monoxide	1-Hour [b]	1.10	1,145	1,146	40,000	40,000
	8-Hour [b]	0.61	1,145	1,146	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.05	32.3	32.35	188	188
	Annual [d]	0.001	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.02	40.0	40.02	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.01	12.0	12.01	35	35
	Annual [d]	0.002	3.7	3.70	12	15

Abbreviations:
NA = not applicable
µg/m³ = micrograms per cubic meter

Notes:

[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

[b] Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

[d] Value reported is the maximum annual average concentration for the 3-year period.

[e] Value reported is the 98th percentile averaged over the 3-year period.

[f] Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-23: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration ($\mu g/m^3$)	Class I Increments ($\mu g/m^3$)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.64	25
	24-Hour [b]	0.30	5
	Annual [c]	0.03	2
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.18	2.5
Particulate Matter less than 10 Microns	24-Hour [b]	1.74	8
	Annual [c]	0.10	4
Particulate Matter less than 2.5 Microns	24-Hour [b]	1.78	2
	Annual [c]	0.10	1

Table 7-24: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration ($\mu g/m^3$)	Class I Increments ($\mu g/m^3$)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	15.45	25
	24-Hour [b]	4.05	5
	Annual [c]	0.26	2
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.12	2.5
Particulate Matter less than 10 Microns	24-Hour [b]	1.67	8
	Annual [c]	0.08	4
Particulate Matter less than 2.5 Microns	24-Hour [b]	1.76	2
	Annual [c]	0.08	1

Abbreviations:
NA = not applicable
$\mu g/m^3$ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-25: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.13	512
	24-Hour [b]	0.05	91
	Annual [c]	0.004	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.02	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.40	30
	Annual [c]	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.42	9
	Annual [c]	0.03	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-26: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	1.74	512
	24-Hour [b]	0.64	91
	Annual [c]	0.06	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.68	25
Particulate Matter less than 10 Microns	24-Hour [b]	2.37	30
	Annual [c]	0.18	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	2.46	9
	Annual [c]	0.19	4

Table 7-27: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	1.10	512
	24-Hour [b]	0.42	91
	Annual [c]	0.06	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.52	25
Particulate Matter less than 10 Microns	24-Hour [b]	2.15	30
	Annual [c]	0.19	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	2.36	9
	Annual [c]	0.20	4

Abbreviations:

NA = not applicable

$\mu g/m^3$ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

Table 7-28: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	2.62	512
	24-Hour [b]	0.63	91
	Annual [c]	0.07	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.03	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.40	30
	Annual [c]	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.50	9
	Annual [c]	0.03	4

Abbreviations:

NA = not applicable

$\mu g/m^3$ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hour NO_2, 1-hour SO_2, 1-hour CO, or 8-hour CO.

[b] Value reported is the maximum of the highest-second-high values from each of the three modeled years.

[c] Value reported is the maximum annual average concentration for the 3-year period.

a

Table 7-29: VISCREEN Predicted Impacts Inside Kenai National Wildlife Refuge (Sky Background)

Source Plume[a]	Observer Location	Scattering Angle (deg)	Perceptibility (ΔE)		Contrast (Cp)	
			Criteria	Modeled	Criteria	Modeled
Forward Scatter						
Compressor Turbine	Closest Park Boundary	10	2.00	1.30	±0.05	-0.02
	Skilak Lake	10	2.00	0.39	±0.05	-0.01
Power Generators	Closest Park Boundary	10	2.00	0.38	±0.05	-0.01
	Skilak Lake	10	2.00	0.12	±0.05	0.00
LP Flare + TH Oxidizer	Closest Park Boundary	10	2.00	0.01	±0.05	0.00
	Skilak Lake	10	2.00	0.00	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	10	2.00	0.01	±0.05	0.00
	Skilak Lake	10	2.00	0.01	±0.05	0.00
Marine	Closest Park Boundary	10	2.00	0.91	±0.05	-0.01
	Skilak Lake	10	2.00	0.33	±0.05	-0.01
Backward Scatter						
Compressor Turbine	Closest Park Boundary	140	2.00	**2.39**	±0.05	**-0.067**
	Skilak Lake	140	2.00	0.86	±0.05	-0.03

Power Generators	Closest Park Boundary	140	2.00	0.66	±0.05	-0.02
	Skilak Lake	140	2.00	0.24	±0.05	-0.01
LP Flare + TH Oxidizer	Closest Park Boundary	140	2.00	0.01	±0.05	0.00
	Skilak Lake	140	2.00	0.01	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	140	2.00	0.02	±0.05	0.00
	Skilak Lake	140	2.00	0.01	±0.05	0.00
Marine	Closest Park Boundary	140	2.00	0.78	±0.05	-0.02
	Skilak Lake	140	2.00	0.24	±0.05	-0.01

Notes:

[a] See Table 6-4 for discussion regarding how individual sources were combined into these 5 separate plume impact assessments.

Table 7-30: VISCREEN Predicted Impacts Inside Kenai National Wildlife Refuge (Terrain Background)

Source Plume [a]	Observer Location	Scattering Angle (deg)	Perceptibility (ΔE)		Contrast (Cp)	
			Criteria	Modeled	Criteria	Modeled
Forward Scatter						
Compressor Turbine	Closest Park Boundary	10	2.00	**5.63**	±0.05	0.02
	Skilak Lake	10	2.00	**2.15**	±0.05	0.03
Power Generators	Closest Park Boundary	10	2.00	1.61	±0.05	0.01
	Skilak Lake	10	2.00	0.60	±0.05	0.01
LP Flare + TH Oxidizer	Closest Park Boundary	10	2.00	0.04	±0.05	0.00
	Skilak Lake	10	2.00	0.01	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	10	2.00	0.07	±0.05	0.00
	Skilak Lake	10	2.00	0.03	±0.05	0.00
Marine	Closest Park Boundary	10	2.00	0.68	±0.05	0.00
	Skilak Lake	10	2.00	0.46	±0.05	0.01
Backward Scatter						
Compressor Turbine	Closest Park Boundary	140	2.00	0.46	±0.05	0.00
	Skilak Lake	140	2.00	0.75	±0.05	0.02
Power Generators	Closest Park Boundary	140	2.00	0.12	±0.05	0.00
	Skilak Lake	140	2.00	0.21	±0.05	0.01
LP Flare + TH Oxidizer	Closest Park Boundary	140	2.00	0.00	±0.05	0.00
	Skilak Lake	140	2.00	0.00	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	140	2.00	0.01	±0.05	0.00
	Skilak Lake	140	2.00	0.01	±0.05	0.00
Marine	Closest Park Boundary	140	2.00	0.11	±0.05	0.00
	Skilak Lake	140	2.00	0.20	±0.05	0.01

Notes:

[a] See Table 6-4 for discussion regarding how individual sources were combined into these 5 separate plume impact assessments.

Table 7-31: Liquefaction Facility-Only Regional Haze Results

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
Tuxedni NWR	2002	2	0	2.9	5.0
	2003	1	0	3.5	5.0
	2004	5	0	4.5	5.0
Denali NP	2002	2	0	2.8	5.0
	2003	2	0	3.1	5.0
	2004	3	0	3.7	5.0
Kenai Fjords NP	2002	0	0	1.6	5.0
	2003	0	0	2.0	5.0
	2004	0	0	1.5	5.0
Chugach NF	2002	2	0	2.9	5.0
	2003	0	0	2.8	5.0
	2004	1	0	2.9	5.0
Lake Clark NP	2002	7	0	4.9	5.0
	2003	8	0	**5.1**	5.0
	2004	13	0	**5.3**	5.0
Kodiak NWR	2002	0	0	0.5	5.0
	2003	0	0	0.4	5.0
	2004	0	0	0.4	5.0

Table 7-32: Cumulative Regional Haze Results

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Cumulative Visibility Extinction Threshold (%)
		5%	10%		
Tuxedni NWR	2002	144	70	**24.5**	10.0
	2003	136	67	**28.5**	10.0
	2004	142	75	**25.3**	10.0
Denali NP	2002	194	100	**46.7**	10.0
	2003	198	102	**53.3**	10.0
	2004	208	127	**47.8**	10.0
Kenai Fjords NP	2002	35	9	**11.3**	10.0
	2003	35	8	**10.2**	10.0
	2004	26	2	7.5	10.0
Chugach NF	2002	214	121	**34.8**	10.0
	2003	220	136	**38.2**	10.0
	2004	206	113	**43.9**	10.0
Lake Clark NP	2002	261	157	**40.2**	10.0
	2003	243	138	**40.3**	10.0
	2004	261	153	**50.8**	10.0
Kodiak NWR	2002	29	10	**11.2**	10.0
	2003	46	9	**10.3**	10.0
	2004	32	11	**13.2**	10.0

Table 7-33: Liquefaction Facility-Only Sulfur Deposition Results

Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	**5.188E-03**	0.005	104
Denali NP	3-Year Max	3.701E-03	0.005	74
Kenai NWR	3-Year Max	**5.796E-03**	0.005	116
Kenai Fjords NP	3-Year Max	2.943E-04	0.005	6
Chugach NF	3-Year Max	9.726E-04	0.005	19
Lake Clark NP	3-Year Max	**5.931E-03**	0.005	119
Kodiak NWR	3-Year Max	2.238E-04	0.005	4

Table 7-34: Liquefaction Facility-Only Nitrogen Deposition Results

Class I/II Area	Year	Nitrogen Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	**1.359E-02**	0.005	272
Denali NP	3-Year Max	**1.433E-02**	0.005	287
Kenai NWR	3-Year Max	**3.135E-02**	0.005	627
Kenai Fjords NP	3-Year Max	1.953E-03	0.005	39
Chugach NF	3-Year Max	4.775E-03	0.005	95
Lake Clark NP	3-Year Max	**1.966E-02**	0.005	393
Kodiak NWR	3-Year Max	2.096E-03	0.005	42

Table 7-35: Cumulative Sulfur Deposition Results

Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	5.42E-02	0.125	43
Denali NP	3-Year Max	7.95E-02	0.125	64
Kenai Fjords NP	3-Year Max	2.44E-03	0.125	2
Chugach NF	3-Year Max	3.00E-02	0.125	24
Lake Clark NP	3-Year Max	5.28E-02	0.125	42
Kodiak NWR	3-Year Max	2.70E-02	0.125	22

Table 7-36: Cumulative Nitrogen Deposition Results

Class I/II Area	Year	Nitrogen Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	1.19E-01	0.125	95
Denali NP	3-Year Max	9.34E-02	0.125	75
Kenai Fjords NP	3-Year Max	1.37E-02	0.125	11
Chugach NF	3-Year Max	7.31E-02	0.125	58
Lake Clark NP	3-Year Max	1.22E-01	0.125	98
Kodiak NWR	3-Year Max	1.82E-02	0.125	15

8.0 ASSESSMENT OF OZONE AND SECONDARY PARTICULATE IMPACTS

8.1 UNDERSTANDING OZONE CONCENTRATIONS

8.1.1 Ozone Chemical Processes

Ozone is not directly omitted from the Liquefaction Facility, therefore, any impacts to ambient ozone as a result of Liquefaction Facility precursor emissions requires an understanding of conditions resulting in ozone formation and destruction in the project area and the possible role that source emissions could play in that formation.

8.1.1.1 Conditions for Ozone Formation

Ground level ozone is more accurately referred to as tropospheric ozone. Tropospheric ozone is formed from the chemical reaction between Volatile Organic Compounds (VOC) and NO_x. In general ozone concentrations tend to peak near urban-suburban areas, where there are higher amounts of VOC and NO_x emissions. Ozone concentrations tend to decrease in rural locations and more remote locations. Since ozone is formed in the atmosphere, rather than directly emitted, VOC and NO_x emissions are referred to as ozone precursor emissions or 'ozone precursors'.

Energy is required to initiate the chemical reactions that form ozone. Commonly this energy is provided by solar radiation. The chemical reaction is initiated by a process called photolysis, which is when molecules are separated by the action of light. Since the reactions that form ozone are driven by solar radiation, ozone is formed more rapidly on sunny days. In the northern hemisphere available solar energy peaks during the summer, although during other times of the year if the surface is highly reflective (such as when there is snow cover) the solar energy can be high enough to form ozone in the presence of ozone precursors.

8.1.1.2 Ozone Formation Chemical Mechanisms

Tropospheric ozone formation is initiated by photolysis of NO_2. This step begins a series of complex and highly diverse chemical reactions that both produce and destroy ozone in the atmosphere. The exact chemical reactions depend on the presence of multiple chemical compounds in the atmosphere. At the heart of the ozone formation process is the hydroxyl radical (OH). The OH radical can react with either VOC or NO_x. When there is more VOC in the atmosphere than NO_x (which is referred to as a high VOC-to-NOx ratio) the OH radical will mainly react with VOC, at low VOC-to-NO_x ratios the OH radical predominately reacts with NO_x.

At a given VOC-to-NOx ratio, the OH will react equally with both compounds. This given value represents the maximum ozone formation, for ratios of VOC-to-NO_x less than this optimum ratio, OH reacts predominantly with NO_2 removing radicals and retarding ozone formation. Under these conditions a reduction of NO_x favors ozone formation. On the other hand, under very low NO_x concentrations (high VOC-to-NO_x ratios) a decrease in NO_x favors certain reactions among peroxy radicals which retard ozone formation.

This complex chemistry implies that ozone production is not simply proportional to the amount of NO_x present. At a given level of VOC, there is a NO_x concentration that will maximize ozone production that is an optimum VOC-to-NO_x ratio. For ratios less than this optimum ratio NO_x increases lead to ozone decreases. Urban centers and areas immediately downwind of recently emitted NO_x (which is predominately emitted in the form of nitrogen oxide [NO]) tend to have sufficiently low VOC-to-NO_x ratios that ozone is destroyed rather than formed. In contrast, rural environments tend to have higher VOC-to-NO_x ratios due to the predominance of natural VOC emissions from plants (referred to as "biogenic" sources). In effect in most areas, except in areas with fresh NO_x emissions, the availability of NO_x governs ozone production.

8.1.1.3 Ozone Destruction Processes

Ozone formation has a non-linear relationship with its precursors. In particular for NO_x, a process called NO_x titration occurs in the immediate vicinity of NO sources. Fresh NO emissions are emitted from combustion sources such as power plants and mobile sources. When NO_x titrates ozone, ozone is removed by reaction with NO to regenerate nitrogen dioxide (NO_2) following this reaction:

$O_3 + NO \rightarrow NO_2 + O$

During the daytime this reaction is normally balanced by the photolysis of NO_2 that produces atomic oxygen and subsequent ozone. However in the vicinity of large NO emissions during nighttime, the result is the net conversion of ozone to NO_2. This process can be considered as an ozone sink. In addition, high NO_2 concentrations deflect the initial oxidation step of VOCs by forming other products such as nitric acid (HNO_3) which prevent the net formation of ozone.

In addition to the destruction paths indicated above, in Polar Regions during the springtime unique photochemistry converts inert halide salt ions into reactive halogen species that deplete ozone in the boundary layer to near zero levels (Simpson et al. 2007, Oltmans et al. 2012, Helmig et al. 2012, Thompson et al. 2015). These ozone depletion events (ODEs) were first discovered in the 1980s and great advances have been made to understand their dynamics, but many key processes remain poorly understood. It is known that the ODEs are caused by active halogen photochemistry resulting from halogen atom precursors emitted from snow, ice or aerosol surfaces. The role of bromine has been generally accepted, but much less is known about the roles of chlorine and iodine radicals in the ozone depletion chemistry (Simpson et al. 2007, Thompson et al. 2015). The main source of reactive bromine species is bromide from sea salt that is released via a series of photochemical and heterogeneous reactions known as the bromine explosion. ODEs can influence the chemistry in the polar troposphere as it leads to a shift in oxidants and oxidation products. In particular, ozone depletion and halogen chemistry have a significant impact on VOC photochemistry by leading to the rapid destruction of alkanes, alkenes and most aromatics.

8.1.2 Ozone Lifetimes

8.1.2.1 Ozone Lifetime

Tropospheric ozone has two main sources: transport from upper levels of the atmosphere (stratospheric ozone) and photochemical production near the surface. The two main processes involved in the loss of tropospheric ozone are: chemical destruction and uptake of ozone at the surface of the earth (dry deposition). Ozone lifetimes in the troposphere vary significantly depending on altitude, latitude and season. Ozone lifetimes could easily vary between 5 to 30 days. Stevenson et al. (2006) analyzed global tropospheric ozone distributions and lifetimes using an ensemble of 26 atmospheric chemistry models and found a mean ozone lifetime of 22 days. These values imply that once formed, ozone could be subjected to meteorological transport over significant regional scales.

Stohl (2006) developed a climatology of transport in and to the Artic based on a Lagrangian particle dispersion model. Stohl found that the time spent by air masses continuously north of 70°N or Artic Age is highest near the surface in North America. North of 80°N, near the surface the mean Artic age is 1 week in winter and 2 weeks in summer. For ozone in particular, sunlight fuels photolysis reactions and plays an important role in the atmospheric chemistry. In the Arctic winter, however its absence completely inhibits the photochemistry and is then important to estimate how long Arctic air is exposed to continuous darkness and how frequently it travels south escaping polar night. Stohl found that the time in complete darkness spent by an air mass in North America is about 10 to 14 days during December. Importantly Stohl also was able to determine three major pathways in which air pollution can be transported into the Arctic: low-level transport followed by ascent in the Arctic, low-level transport alone, and uplift outside the Arctic, followed by descent in the Arctic. Sensitivities of Arctic masses to air pollutant emissions indicate that they are the highest over Siberia and Europe in winter and over the oceans in summer. Stratospheric intrusion was found to be much slower in the Arctic than in midlatitudes.

8.1.2.2 Source and Distance Relationship on Ozone Concentrations

Typically as an air mass moves away from an urban center, the VOC-to-NO_x ratio changes due to further photochemical reactions, meteorological processes and the influence of fresh emissions. Usually the concentrations of NO_x decrease faster than that of VOC because of the presence of fresh biogenic emissions. Thus the VOC-to-NO_x ratios increase as one moves away from urban centers and in more suburban, rural, and remote regions the formation of ozone becomes mainly NO_x limited. The photochemistry in urban plumes proceeds relatively fast as the oxidation of VOCs leads to increased ozone over a short period of time and to a faster removal of NO_x. Hence the regime where ozone formation is controlled by the concentration of NO_x is reached sooner.

Baker et al. (2016) performed photochemical modeling simulations of 24 hypothetical single sources in the continental United State to estimate their impacts in ozone concentrations. The modeling showed that downwind impacts varied directionally from each source due to differences in meteorology and chemical environment near the source. An aggregate analysis of maximum daily 8-hour ozone impacts as a function of the distance from the source shows that maximum impacts are not located in close proximity to the modeled emissions sources, but after the peak impact is reached, the ozone concentrations decrease as the distance increases.

8.1.3 Existing Ozone Concentrations

At remote locations, natural background ozone concentrations can range between 20 and 40 ppbv. Sources of natural ozone include stratospheric intrusions, wildfires, lightning and vegetation (a.k.a. biogenic sources). Also it is recognized that even sites located in remote regions can measure ozone which originated from manmade sources. Detailed analysis on the sources contributing to background ozone using a combination of measurements and photochemical grid modeling does not exist for the state of Alaska; however, observations (Vingarzan 2004) show that hourly median ozone concentrations in Denali National Park range between 29 and 34 ppbv, while the ozone annual means range between 23 and 29 ppbv at Point Barrow, AK.

8.2 UNDERSTANDING SECONDARY PARTICULATE CONCENTRATIONS

Aerosols also known as particulate matter (PM) are solids or liquids suspended in the atmosphere that have diameters that range from 0.001 up to 100 micrometers (µm). Although aerosols could have multiple sizes, generally those that have diameters less than 2.5 µm are classified as “fine”, while anything larger than 2.5 µm would be known as “coarse”. The sources and chemical compositions of fine and coarse particles are different. In general coarse particles are produced by mechanical processes and consist of soil dust, sea salt, fly ash, etc. Fine particles consist of both primary particles from combustion and secondary particles that are formed in the atmosphere as the results of various chemical reactions and gas-to-particle conversion; it consists of sulfates, nitrates, ammonium, secondary organics, etc. USEPA has developed standards for particulate with a diameter less than 10 µm (PM_{10}) and those with a diameter less than 2.5 µm ($PM_{2.5}$). This Section focuses on secondary particles since these cannot be modeled in the near-field using models approved in the Modeling Guideline.

8.2.1 Particle Formation and Lifetimes

Fine particles undergo a series of complex processes that ultimately lead to their formation and establish their atmospheric lifetimes. Generally, fine particles are subject to the general formation and removal pathways:

Nucleation. This process describes the rate at which a transformation of phase occurs as the very first small nuclei appear. The nucleation of trace substances and water from the vapor phase to the liquid or solid phase is of primary concern in the atmosphere. Heterogeneous nucleation is the nucleation on a foreign surface or substance and it readily allows the formation in air of water droplets when the relative humidity is only slightly above 100%.

Chemical reactions. A significant amount of chemical reactions occur between gas phase precursors that eventually lead to the formation of particulate matter in the atmosphere. Generally hundreds to thousands of chemical reactions occur depending on the chemical species involved. The ultimate compositions of these particulates in the atmosphere include sulfate, nitrate, ammonium, elemental carbon, organic compounds, water, and metals.

Condensation. This process involves particle populations and it refers to vapor that condenses on particles or when material evaporates from the aerosol to the gas phase. This process tends to change the size of the particles; usually the growth of the particles is governed by the diffusion coefficient for each species as well as the vapor pressure difference between chemical species and the equilibrium vapor pressure.

Coagulation. This process involves particle growth as the result of one or more particles suspended in the atmosphere colliding as a result of Brownian motion or other hydrodynamic, electrical, gravitational or other forces.

Cloud processing and removal. Aerosols can activate under supersaturation conditions and lead to the formation of cloud droplets, in other words they act as cloud condensation nuclei. Once processed in this manner they could be removed from the atmosphere following precipitation events or they could also undergo aqueous phase chemistry. Finally, precipitation can also remove a significant number of particles from the atmosphere as the cloud droplets interact with aerosols.

Fine particles are usually the result of the processes mentioned above and in many instances they are formed in the atmosphere. $PM_{2.5}$ generally is composed of particles that had multiple sources such as combustion (coal, oil, gasoline, diesel, wood, etc.) and gas to particle conversion of precursors such as NO_x, SO_2 and VOCs.

8.2.2 $PM_{2.5}$ Lifetimes

8.2.2.1 $PM_{2.5}$ Lifetime

The estimated lifetime of $PM_{2.5}$ in the troposphere varies significantly depending on altitude, latitude and season. $PM_{2.5}$ lifetimes could easily vary between a few days up to several weeks. Once formed, particles could be subjected to meteorological transport over significant regional scales that range from hundreds to thousands of miles.

A summary of the characteristics of atmospheric transport of precursors into the Artic troposphere was presented in Section 8.1.2.1 above. Those same characteristics affect the lifetime of particulates in the Arctic. An important consideration in the lifetime of particulate nitrate and sulfate, which are PM components usually associated to anthropogenic sources, is the availability of ammonia. Ammonia is the dominant alkaline gas in the atmosphere and plays and important role in the formation of ammonium nitrate or sulfate, thus is important to quantify its magnitude and location. In midlatitudes major sources of ammonia include agriculture, vegetation, transport and industry, but these are expected to contribute minimally in the Arctic Circle. Ammonia is short lived in the atmosphere so is unlikely that long range transport would bring significant amounts of ammonia from lower latitudes. Biomass burning could inject important amounts of ammonia, so wildfires could play an important episodic role. In remote marine environments, the ocean is the dominant source of ammonia by remineralization of organic matter by bacteria and phytoplankton excretion (Carpenter et al. 2012). During the summertime, it is expected that this also will be the most important source of ammonia in the Arctic. Wentworth et al. (2016) have been able to determine that ammonia concentrations in the Arctic could range between 0.03 and 0.6 µg/m^3 (0.040 – 0.870 ppbv) during the summer, which is 1 to 2 orders of magnitude lower than typical ammonia concentrations over the continental U.S (0.1 to 10 ppbv).

8.2.2.2 Source and Distance Relationship on $PM_{2.5}$ Concentrations

The spatial distribution of $PM_{2.5}$ over large distances from a single source is in part a function of the chemical species involved. For instance particles that contain significant amounts of sulfate will be longer lived in the atmosphere than those with only nitrate, because nitrate is semi-volatile and thus able to convert back into the gas phase. Other more inert species like fine dust will be subjected to dispersion and gravitational settling without their lifetimes being significantly affected by chemical processes.

Baker et al. (2016) performed photochemical modeling simulations of 24 hypothetical single sources in the continental United State to estimate their impacts in ozone and $PM_{2.5}$ concentrations. The modeling showed that downwind impacts varied directionally from each source due to differences in meteorology and chemical environment near the source. An aggregate analysis of daily maximum 24-hour average $PM_{2.5}$ impacts as a function of the distance from the source shows that maximum impacts from secondary formation are not located in close proximity to the modeled emissions sources, but after the peak direct $PM_{2.5}$ impact is reached but somewhere less than 50 kilometers downwind, the $PM_{2.5}$ concentrations decrease as the distance increases.

8.2.3 Existing $PM_{2.5}$ Concentrations

There is no typical or uniform ambient background concentration of $PM_{2.5}$ given that it could be composed by multiple chemical species. Urban environments' in the continental U.S. typically have some of the highest $PM_{2.5}$ concentrations that could exceed more than 12 µg/m^3 on an annual average. Rural and remote environments will usually show both different compositions and lower annual concentrations that could range from 5 to 10 µg/m^3. However some areas might be influenced by desert aerosols, which originate in deserts from wind disturbance but could extend considerably over adjacent regions. It is well documented that dust storms from the Sahara could transfer material across the Atlantic Ocean and affect the east coast of the United States. Also coastal areas might be influenced by marine aerosols.

The Liquefaction Facility is located close to Anchorage, Alaska. Kim and Hopke (2008) performed a characterization of ambient fine particles using source apportionment techniques in the Northwestern U.S. and Anchorage. They found that gasoline vehicles, secondary sulfates, and wood smoke were the largest sources of $PM_{2.5}$ in the region. Secondary sulfates showed an April peak in Anchorage which they linked to increased photochemical reactions and long range transport. Ward et al. (2012) performed a source apportionment study in the subarctic air shed of Fairbanks, Alaska. They found that $PM_{2.5}$ concentrations average between 22 and 26 µg/m^3 with frequent exceedances to the 24-hour NAAQS. Their analysis using Chemical Bass Balance indicated that wood smoke from residential combustion was the major source of $PM_{2.5}$ contributing between 60% and 80% of the measured PM.

Wang and Hopke (2014) also performed a source apportionment study in Fairbanks, Alaska. This analysis shows similar results with wood smoke being the highest contribution (~40%) to $PM_{2.5}$ concentrations, followed by secondary sulfates and gasoline. Wang and Hopke conclude that winter heating is the most important factor affecting the air quality in Fairbanks.

8.3 A DESCRIPTION OF REGIONAL OZONE AND $PM_{2.5}$ PRECURSOR EMISSIONS

Emissions of ozone precursors from the region surrounding the Liquefaction Facility are summarized in **Table 8-1** based on the most recent NEI (USEPA 2016) which was compiled for 2011. The NEI is a comprehensive and detailed estimate of air emissions of criteria pollutants, criteria precursors, and hazardous air pollutants from air emissions sources. Among all the emission sectors Kenai Peninsula Borough, the combustion processes related to electrical utilities and other industrial processes are among the largest contributors to NO_x emissions, followed by mobile emissions. The petroleum and related industries are the largest contributors to VOC emissions in the Kenai Peninsula Borough, followed by the VOC emissions from mobile sources. The NO_x emission totals are very similar between the Municipality of Anchorage and the Kenai Peninsula Borough, but the VOC total emissions are about 67% larger in Anchorage. Matanuska-Susitna Borough shows the lowest total emissions of both NO_x and VOC from the three areas around the project.

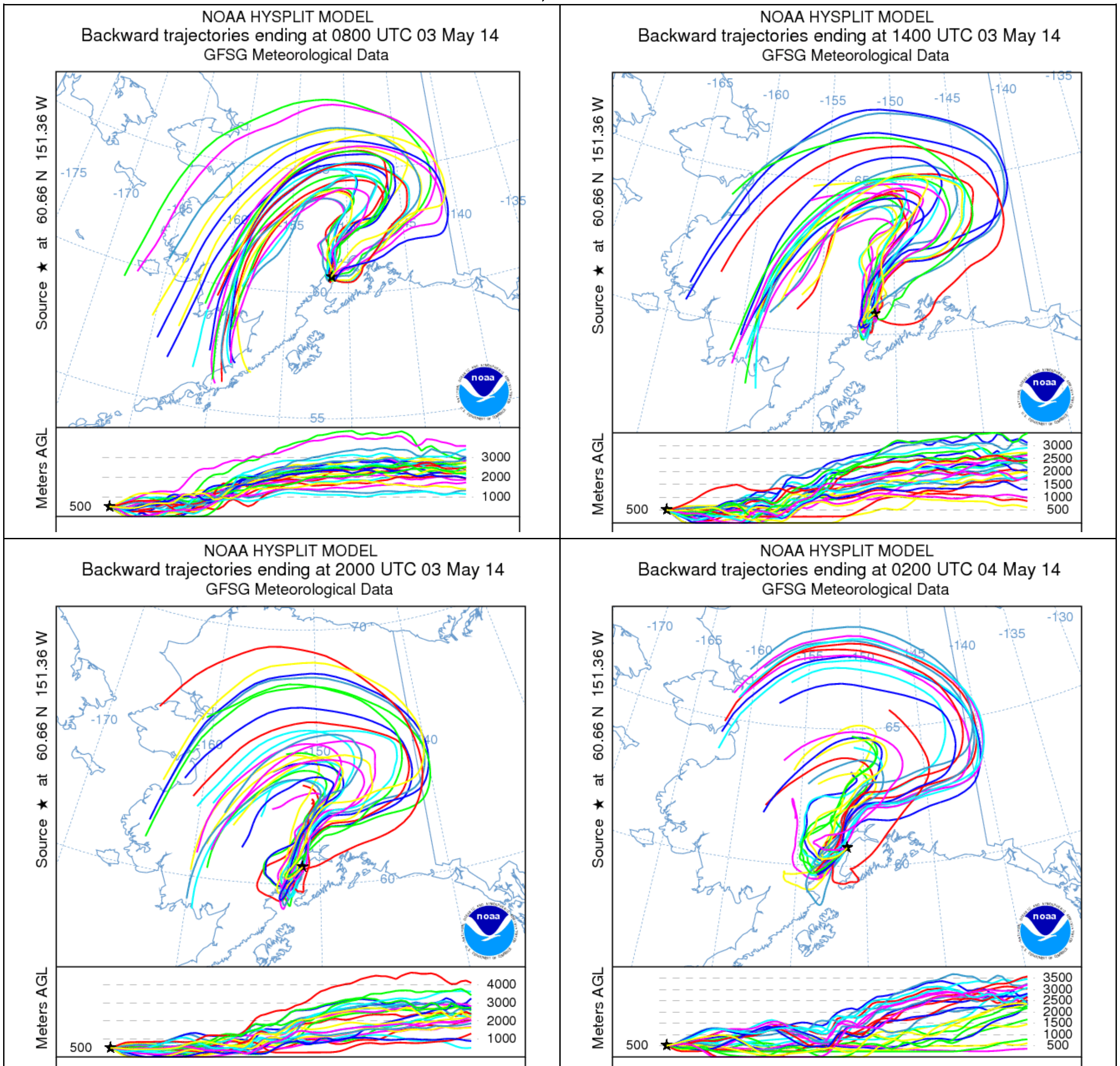
Table 8-1: Anthropogenic Emissions in the Region Surrounding the Liquefaction Facility

Emission Inventory Sector	Municipality of Anchorage			Kenai Peninsula Borough			Matanuska-Susitna Borough		
	NOx (TPY)	VOCs (TPY)	Primary $PM_{2.5}$ (TPY)	NOx (TPY)	VOCs (TPY)	Primary $PM_{2.5}$ (TPY)	NOx (TPY)	VOCs (TPY)	Primary $PM_{2.5}$ (TPY)
FUEL COMB. ELEC. UTIL.	1,966	14	43	4,098	331	111	--	--	--
FUEL COMB. INDUSTRIAL	236	40	28	4,187	170	116	285	9	5
FUEL COMB. OTHER	843	474	356	238	122	93	172	139	108
PETROLEUM & RELATED INDUSTRIES	0	2	0	464	3,809	11	26	99	1
OTHER INDUSTRIAL PROCESSES	--	62	122	--	3	32	--	3	32
SOLVENT UTILIZATION	--	2,000	0	--	353	--	--	552	--
STORAGE & TRANSPORT	2	1,629	0	--	565	--	--	433	--
WASTE DISPOSAL & RECYCLING	13	9	1	15	28	82	14	25	81
HIGHWAY VEHICLES	5,158	3,263	184	1,688	1,148	64	1,972	1,485	79
OFF-HIGHWAY	4,057	6,521	312	1,853	1,887	131	616	1,692	68
MISCELLANEOUS	22	413	870	13	207	1,465	3	56	1,471
Total	**12,298**	**14,428**	**1,916**	**12,556**	**8,622**	**2,105**	**3,088**	**4,494**	**1,844**

Notes:
Data based on USEPA's 2011 NEI available at
https://www.epa.gov/air-emissions-inventories/2011-national-emissions-inventory-nei-data

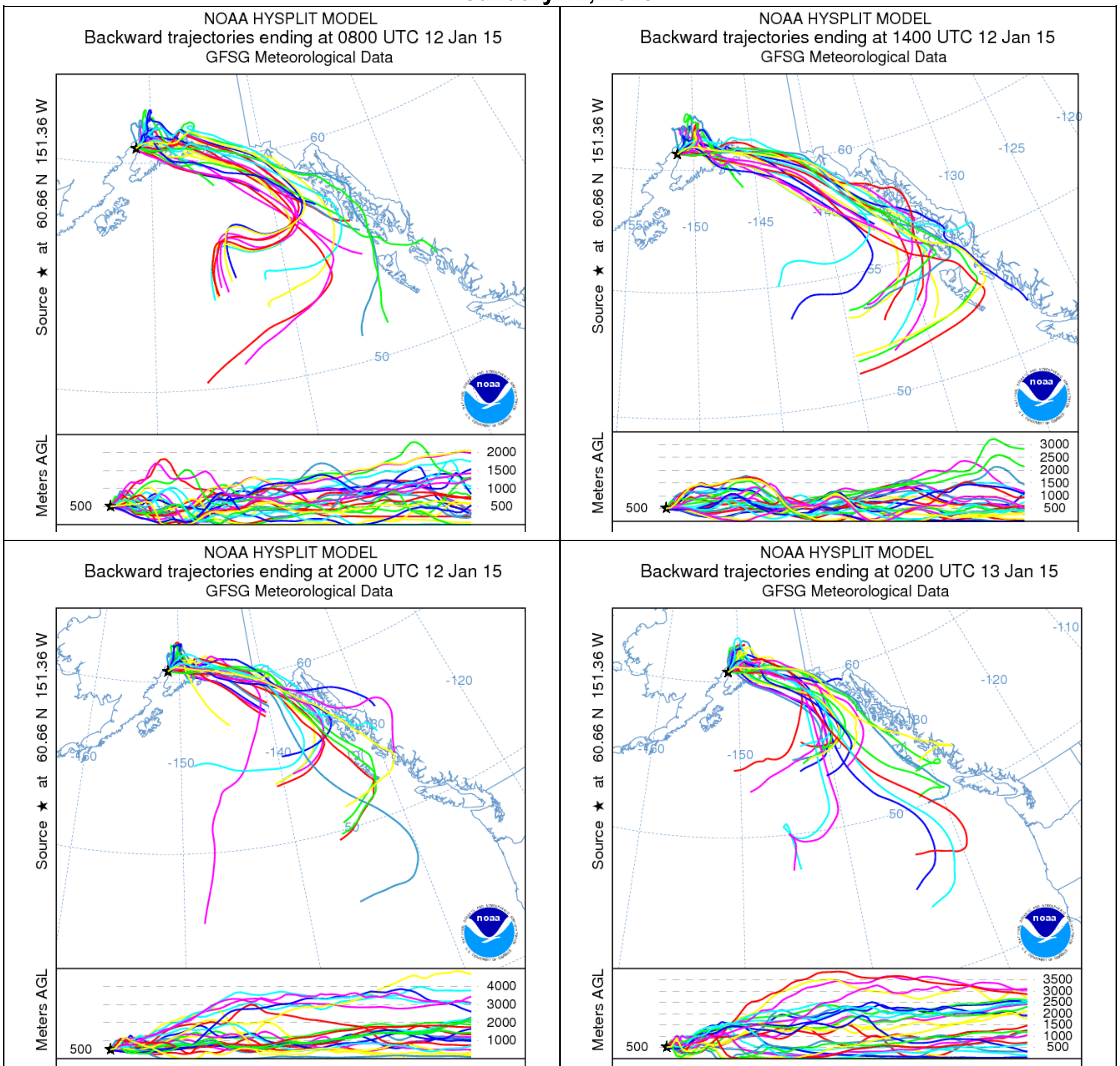
The table also presents the level of primary $PM_{2.5}$ emissions associated to different sectors on the three counties. In general, the largest source of $PM_{2.5}$ on the Kenai Peninsula is the combined contribution of multiple sources. The $PM_{2.5}$ total among all the areas is very similar.

Figure 8-1: 72-Hour Back trajectories Arriving at the Project Location at (**60.664 N, 151.362 W**) May 14, 2014



Notes:
Top row shows hours 0:00 and 6:00 AKT, while the bottom row shows hours 12:00 and 18:00 AKT. Global Data Assimilation System (GDAS) meteorological data was used to derive the HYSPLIT back trajectories results.

Figure 8-2: 72-Hour Back Trajectories Arriving at the Project Location at **(60.664N, 151.362 W) January 12, 2015**



Notes:

Top row shows hours 0:00 and 6:00 AKT, while the bottom row shows hours 12:00 and 18:00 AKT. Global Data Assimilation System (GDAS) meteorological data was used to derive the HYSPLIT back trajectories results.

8.4 OZONE AND $PM_{2.5}$ ASSESSMENT

Currently, there is insufficient guidance to assess both ozone and $PM_{2.5}$ impacts for this project. The most recent guidance is the "Proposed Approach for Demonstrating Ozone PSD Compliance" (USEPA 2015c) (referred to hereafter as the "Guidance"), which is currently a proposed approach that has not been formally accepted. In this current stage of uncertainty regarding ozone assessment, the following section describes a variety of approaches to understand potential project impacts to existing ambient ozone. From this analysis it is clear that regional ozone concentrations are low, well below the NAAQS/AAAQS. The small increase in regional precursor emissions that occur as a result of the project will have a negligible effect on existing ozone and $PM_{2.5}$ concentrations and therefore, regional pollution levels will still remain well below the NAAQS/AAAQS.

8.4.1 Regional Modeling

8.4.1.1 Overview of PGM models

Photochemical grid models (PGM) describe atmospheric concentrations in an array of fixed computational grid cells; PGMs are also called Eulerian models. Eulerian models are formulated to solve the pollutant continuity equation, where the pollutants concentrations enter and leave each of the modeling cells species concentrations are estimates as function of space and time. The continuity equation is numerically solved and calculates the changes to the concentrations by the following major processes: advection, turbulent and molecular diffusion, emissions, chemistry and removal (wet and dry). The two state-of-the-science grid models currently used are USEPA's CMAQ and RAMBOLL ENVIRON's CAMx.

The USEPA Community Multiscale Air Quality (CMAQ) modeling system is designed for applications ranging from regulatory and policy analysis to understanding the complex interactions of atmospheric chemistry and physics. It is a three-dimensional Eulerian atmospheric chemistry and transport modeling system that simulates ozone, particulate matter (PM), toxic airborne pollutants, visibility, and acidic and nutrient pollutant species throughout the troposphere. Designed as a "one-atmosphere" model, CMAQ can address the complex couplings among several air quality issues simultaneously across spatial scales ranging from local to hemispheric.

The Comprehensive Air Quality Model with Extensions (CAMx) modeling system is a publicly available multi-scale photochemical/aerosol grid modeling system developed and maintained by RAMBOLL ENVIRON (2014). CAMx was developed with new codes during the late 1990s using modern and modular coding practices. This has made the model an ideal platform to treat a variety of air quality issues including ozone, condensable PM, visibility, and acid deposition. The flexible CAMx framework also makes it a convenient and robust host model for the implementation of a variety of mass balance and sensitivity analysis techniques.

A number of studies have been performed since 2008 using both CMAQ and CAMx to estimate the impacts on ozone and $PM_{2.5}$ from single source emissions and also other types of applications. Both models are capable of providing a more realistic chemical and physical environment to evaluate these impacts. These studies show that PGMs are appropriate to establish the impacts from secondary formed pollutants for single sources but also from a vast array of emissions. One recent analysis presented by Baker et al. (2016) provides a more robust range of impacts covering a diverse set of sources, chemical environments and time scales. Baker et al. used CAMx to simulate the evolution of 24 hypothetical sources added to a baseline and evaluated the corresponding perturbation to ozone and $PM_{2.5}$ concentrations. The analysis contributes more information about the downwind effects of single sources, but concludes that further investigation would be needed to fully assess the variability in single source impacts from a range of chemical and physical conditions. Also the analysis performed by Baker et al. focuses exclusively on the potential impacts in the continental U.S and a similar effort would be important to establish impacts in regions like Alaska; however this study serves as an important point of reference.

8.4.1.2 PGM Model limitations

Although PGMs can evaluate the impacts of secondary formed pollutants, there are several factors that limit their applications. For instance depending on the spatial resolution of the modeling grid cells, the plumes from the sources could get immediately diffused through the cell and this could impact ozone peak impacts and their spatial distribution. Also there are known limitations and uncertainties in the performance of these models, which require additionally analysis to characterize the potential biases of the pollutants predictions. PGMs usually require adequate modeling platforms and inputs (emissions and meteorology) which could be costly to develop if none exist in the area or region of interest. Also PGM simulations are computationally intensive and require significant amounts of time to complete depending on the application. Finally depending on the magnitude of emissions, estimating the ozone and $PM_{2.5}$ impacts from an individual source may not be appropriate for a PGM application. Also, neither CAMx nor CMAQ include any of the halogen chemistry resulting in ozone depletion events in polar regions previously described.

8.4.2 Analysis of the Contribution of Liquefaction Facility Emissions

8.4.2.1 Liquefaction Facility Emissions

The total potential Liquefaction Facility project emissions of ozone precursors from stationary sources would be approximately 1,600 tons per year (TPY) of NO_x and 330 TPY of VOC. The potential Liquefaction Facility emissions would represent approximately 13% of the total NO_x and about 4% of the total VOC emissions in the Kenai Peninsula Borough (**Table 8-1**). These values reflect the potential to contribute to ozone formation by the Liquefaction Facility, but as has been shown in this analysis most of the observed concentrations near the project are more likely to be the result of long range transport.

8.4.2.2 Potential Impacts

Ozone

Determination of ozone and $PM_{2.5}$ impacts due to emissions from single sources is a very active area of research and model development. Information obtained from a PGM is appropriate to consider since they include a representation of the physical and chemical processes undergone by the atmospheric pollutants. Importantly they account for the photochemical reactions that lead to ozone formation. PGMs have been typically used to investigate the impacts from NO_x sources larger than 1,000 TPY. Another consideration is the lack of representative modeling platforms to be used for specific applications and the elaborate and computationally more expensive needs to perform PGM simulations. For this particular project, the direct application of PGM would not be appropriate given that is not expected that the precursor emissions would lead to the formation of ozone and $PM_{2.5}$ concentrations that contribute to any exceedances of the NAAQS/AAAQS. This section reviews some of the available PGM applications and shows the approximate peak ozone impacts that would be expected from the Liquefaction Facility based on applying the PGM model based on single source analyzes.

Baker et al. (2016) provide the most comprehensive up-to-date evaluation and application of PGMs for single source impacts on ozone and $PM_{2.5}$. Baker et al. present a compilation of 8-hour ozone impacts from NO_x emissions as reported in the literature from multiple studies in addition to their own modeling. It should be expected that given the differences among modeling studies and different geographic areas that similar NO_x emissions would not necessarily lead to identical ozone impacts. However, Baker et al. are able to show consistently that single source NO_x emissions less than 2,000 TPY will not lead to ozone impacts larger than approximately 3 ppbv as illustrated in **Figure 8-3**. **Table 8-2** (adapted from Baker et al. 2016 shows the ozone concentrations predicted from studies in which single sources emitted less than 2,000 TPY of NO_x.

Table 8-2 shows that it can be expected that for NO_x sources in the range of 1,000 to 2,000 TPY, the peak ozone impacts estimated by PGM have ranged from 0.9 to 7.5 ppbv. This range of information provides an approximate estimate of the potential ozone impact associated with the emissions from the Liquefaction Facility. Furthermore, Baker et al. found that peak impacts for the sources included in their assessment and from other studies are typically closer than 50 kilometers downwind from the source but rarely in the same grid cell as the source. Based on this information, peak ozone impacts associated with the Liquefaction Facility are unlikely to occur near the neighboring areas of the project and will not result in attainment issues.

$PM_{2.5}$

$PM_{2.5}$ concentrations are more difficult to evaluate as particulates are formed by multiple chemical species. However Baker et al. investigated the model peak 24-hour $PM_{2.5}$ sulfate and nitrate concentrations response to the emissions of SO_2 and NO_x. Baker et al. found that the 24-hour $PM_{2.5}$ nitrate concentrations would increase between 0.1 and 0.8 μg/m^3 when the emissions of a single source range between 0 and 500 TPY. The potential to emit NO_x from the Liquefaction Facility is less than 2,000 TPY. Baker et al. also found that for SO_2 emissions in the range of 500 to 1,000 TPY, would result in sulfate ion 24-hour $PM_{2.5}$ concentrations range between 0 and 2 μg/m^3. The potential to emit SO_2 from the Liquefaction Facility is less than 100 TPY. Baker et al. also show that typical impacts for sulfate $PM_{2.5}$ tend to peak at a distance of approximately 10 kilometers (6 miles) from the source with values of 5 to 8 μg/m^3 and then rapidly decrease with distance with almost no impacts after 20 or 30 kilometers (12 to 19 miles) from the source. Nitrate impacts are the largest at a distance of about 5 to 10 kilometers (3 to 6 miles) from the source with values of 0.6 to 1.2 μg/m^3 and decrease with distance but impacts could be as large as 0.2 μg/m^3 at a distance of 100 kilometers (62 miles) from the source.

Figure 8-3: Relationship Between the Change in Daily Maximum 8-Hour Average O_3 and Change in NO_x Precursor Emissions (TPY) (Baker et al. 2016)

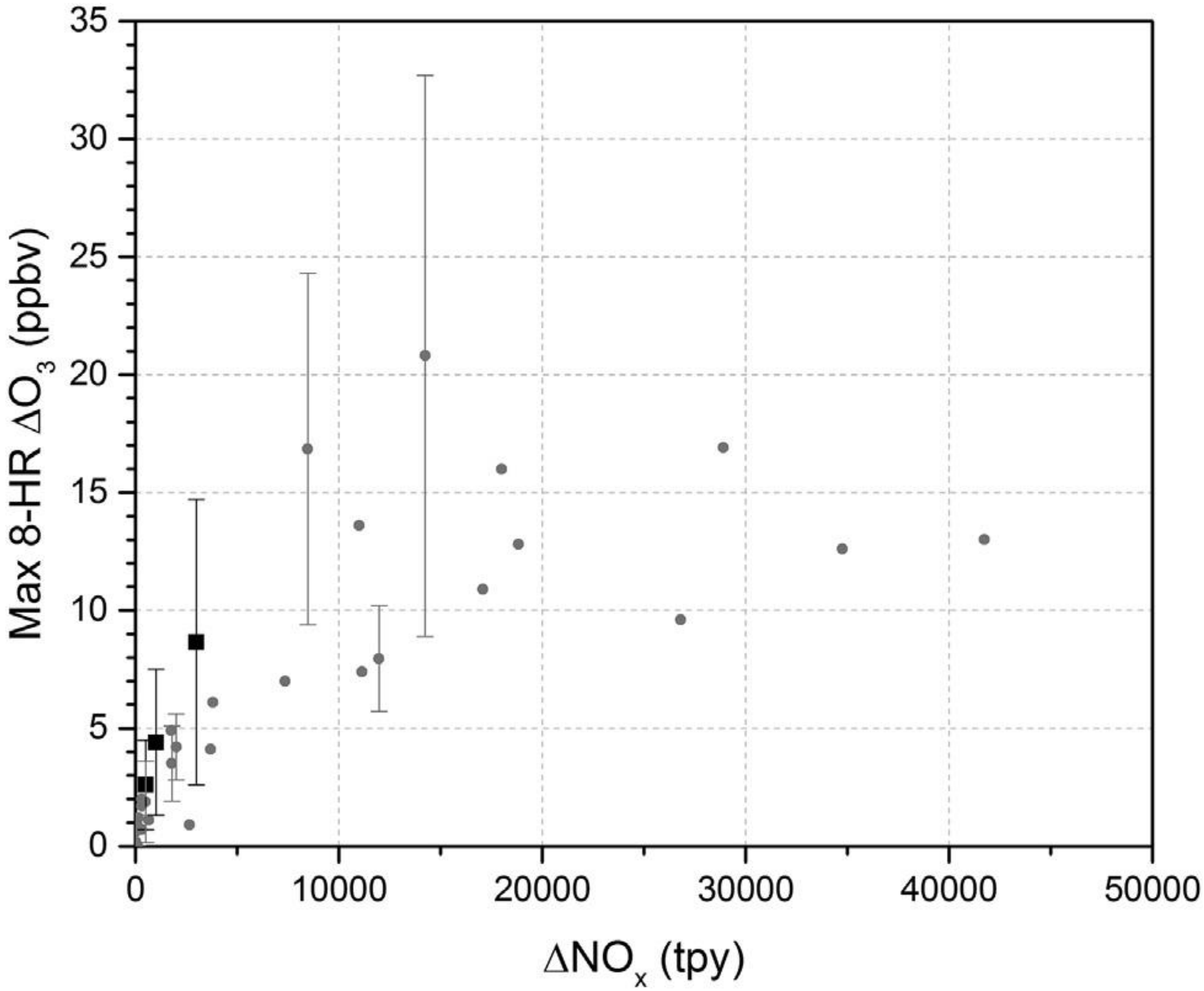


Table 8-2: Compilation of 8-Hour Ozone Impacts (ppbv) from NO_x Emission s (TPY) Reported in Literature (Baker et al. 2016)

Reference	Location	Time Period Modeled	Year Modeled	Type of Source	Method Used	Model Resolution (km)	Stack Height (m)	Annual NO_x Emissions (TPY)	8-hr O_3 delta (ppbv)
ENVIRON, 2005	Houston, TX	Summer episodes	1999	Single EGU	CAMx brute force	4	Not known	2,665	0.9
Castell et al., 2010	Spain	Summer episodes	2003 & 2004	Single EGU	CAMx brute force	2	65	1,789	1.9-5.1
ENVIRON, 2012a	Utah and Colorado	Full year	2006	Single EGU	CAMx APCA	12	65.5	1,751	4.9
This work	Eastern US	Full year	2011	Hypothetical Source	CAMx OSAT	12	1 and 90	1,000	1.3-7.5
Kelly et al., 2015	California	Summer and winter episodes	2007	Hypothetical Source	CMAQ brute force & DDM	4	90	2,000	2.8-5.6

Notes:

EGU: Electric Generating Units
APCA: CAMx Anthropogenic Precursor Culpability Assessment
OSAT: CAMx Ozone Source Apportionment Technology
DDM: Decoupled Direct Method

8.5 SUMMARY OF LIQUEFACTION FACILITY OZONE AND SECONDARY $PM_{2.5}$ IMPACTS

This analysis reviewed the processes involved in the formation and loss of ozone and secondary $PM_{2.5}$. This information is presented to help with the understanding of these processes in general but also in relation to the specific characteristics of the sub-arctic atmosphere. A review of available monitoring data near the project area showed that neither ozone nor $PM_{2.5}$ current concentrations are or have been in exceedance of the NAAQS/AAAQS despite continual development in the region. Furthermore, back trajectory analysis for selected episodes identified from the monitoring data suggests that observed concentrations could be at least in part the result of pollution transported from Anchorage and midlatitude regions.

Using available tools, a conservative quantification of the potential regional impact of the Liquefaction Facility in both ozone and $PM_{2.5}$ was developed. The information provided in this analysis is very conservative as it relies on photochemical modeling performed for the continental U.S, which does not account for the chemical complexities (halogen chemistry), the seasonal pattern (photochemical shutdown in the winter), and the global boundary influences (long range transport contribution to pollution from Asia and Europe) known to occur in Alaska.

The analysis presented indicates that emissions from the Liquefaction Facility would at most lead to ozone increments of about 3 ppbv. Notice that this increase is not additive, otherwise the cumulative effect of existing sources would have already affected the monitoring record. Also, the location of peak impact is likely to be variable in space and time. This maximum increase of 3 ppbv in a region where ozone design values currently range around 0.045 ppmv would not lead to nonattainment issues in the region.

For $PM_{2.5}$, the analysis presented indicates that emissions from the Liquefaction Facility would at most lead to nitrate increments of about 1 $\mu g/m^3$ and sulfate increments of less than 2 $\mu g/m^3$ for the 24-hour averaging period. These would be the estimated $PM_{2.5}$ impacts that are not expected to occur near the source, but downwind as the result of secondary formation. Just as with ozone this increase is not additive and the location of peak impact likely to be variable in space and time. This maximum increase of less than 3 $\mu g/m^3$ in a region where $PM_{2.5}$ concentrations range around 10 $\mu g/m^3$ would not lead to nonattainment issues in the region. Furthermore, the formation of ammonium sulfate and nitrate would be significantly limited by the availability of ammonia as previously discussed.

9.0 ACRONYMS AND TERMS

AAAQS	Alaska Ambient Air Quality Standards
ADEC	Alaska Department of Environmental Conservation
AERMAP	AERMOD terrain preprocessor
AERMET	AERMOD meteorological processor
AERMOD	American Meteorological Society/USEPA Regulatory Model
AERSCREEN	Screening-level air quality model base on AERMOD
AKT	Alaska Time
APCA	Anthropogenic Precursor Culpability Assessment
AQRVs	Air Quality Related Values
ARM	Ambient Ratio Method
ARM2	Ambient Ratio Method 2
BART	Best Available Retrofit Technology
BMP	Best Management Practices
BOG	Boiloff gas
BPIPPRM	Building Profile Input Program
CAA	Clean Air Act
CALMET	CALPUFF meteorology preprocessor
CALPOST	CALPUFF post-processor
CALPUFF	Gaussian puff dispersion model used for far-field modeling
CAMx	Comprehensive Air Quality Model with Extensions
CMAQ	Community Multiscale Air Quality model
CO	Carbon Monoxide
COP	ConocoPhillips Company
DATs	Deposition Analysis Thresholds
DDM	Decoupled Direct Method
EMALL	ExxonMobil Alaska LNG LLC
EGU	Electric Generating Unit
FERC	Federal Energy Regulatory Commission
FLAG	Federal Land Manager's Air Quality related Values Work Group
FLMs	Federal Land Managers
GDAS	Global Data Assimilation System
GEP	Good Engineering Practice
GTP	Gas Treatment Plant
GVEA	Golden Valley Electric Association
HEA	Homer Electric Association
HNO_3	Nitric Acid
HRSG	Heat Recovery Steam Generator
HYSPLIT	Hybrid Single Particle Lagrangian Integrated Trajectory Model
IC	Internal Combustion
ISCST3	Predecessor of AERMOD
KPL	Tesoro Kenai Pipe Line Marine Loading Terminal
LNG	Liquefied Natural Gas
LNGC	Liquefied Natural Gas Carrier
LP	Low pressure
LPG	Liquefied Propane Gas
MM5	NCAR Mesoscale Model
MPTER	Multiple point source Gaussian dispersion model with terrain
N	Nitrogen
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 1983

NCSLs	National Conservation System Lands
NDBC	National Data Buoy Center
NED	National Elevation Dataset
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
NO_2	Nitrogen Dioxide
NOAA	National Oceanic and Atmospheric Administration
NO_X	Nitrogen Oxides
NP	National Park
NSR	New Source Review
NWR	National Wildlife Refuge
NWS	National Weather Service
O_3	Ozone
ODE	Ozone Depletion Event
OH	Hydroxl
OLM	Ozone Limiting Method
OSAT	Ozone Source Apportionment Technology
Pb	Lead
PBU	Prudhoe Bay Unit
PGM	Photochemical Grid Model
PLUVUE II	Plume visibility model used for near-field visual impact modeling
PM	Particulate Matter
PM_{10}	Particulate matter having an aerodynamic diameter of 10 microns or less
$PM_{2.5}$	Particulate matter having an aerodynamic diameter of 2.5 microns or less
POSTUTIL	CALPUFF Post-Processor
ppbv	Parts per billion by volume
ppmv	Parts per million by volume
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTU	Point Thomson Unit
PVMRM	Plume Volume Molar Ratio Method
Report	FERC Air Quality Modeling Report
RFD	Reasonable Foreseeable Development
RICE	Reciprocating Internal Combustion Engine
RML	Regional Modeling Center
S	Sulfur
SDM	Shoreline Dispersion Model
SFM	Shoreline Fumigation Model
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TIBL	Thermal Internal Boundary Layer
TPY	Tons per year
USDOI	US Department of the Interior
USEPA	U.S. Environmental Protection Agency
UTM	Universal Transverse Mercator
VISCREEN	A screening model used for near-field visual impact modeling
WRAP	Western Regional Air Partnership

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8.3.1 Back Trajectories Analysis on Days with Elevated Ozone Concentrations

To better characterize periods of elevated ozone concentrations, it is helpful to understand the history of these air masses. Back trajectories derived using the HYSPLIT model (NOAA: http://www.arl.noaa.gov/hysplit) were used to further analyze periods with elevated ozone concentrations near the project area as indicated by available monitoring data. **Figure 8-1** shows back trajectories displaying a 72-hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for May 3, 2014 when the monitor located at the Agrium facility indicates 8-hour average daily maximum concentrations could be as high as 0.0609 ppmv. The figures show that for most of the day, air masses are transported to the Liquefaction Facility area from the north. These trajectories are important as it seems to suggest that for this particular event a significant contribution of the ozone concentrations observed at Agrium could be transported downwind from Anchorage. The spatial extent of the trajectories suggests that, for the most part, the observed concentrations are the result of transported ozone into the region more than locally formed ozone.

8.3.2 Back Trajectories Analysis on Days with Elevated $PM_{2.5}$ Concentrations

To better characterize periods of elevated $PM_{2.5}$ concentrations, it was also determined to understand the history of these air masses. Back trajectories derived using the HYSPLIT model (NOAA: http://www.arl.noaa.gov/hysplit) were used to further analyze periods with elevated $PM_{2.5}$ concentrations near the project area as indicated by available monitoring data. **Figure 8-2** shows back trajectories displaying a 72-hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for January 12, 2015 when the Butte monitor (located 158 kilometers away from the project) indicates $PM_{2.5}$ concentrations could be as high as 61.5 µg/m^3. The figures show that for most of the day, air masses are transported to the Liquefaction Facility area from the north passing by Anchorage. The figures also illustrate the prevalent travel of air masses along the western coast of Canada, potentially transporting particulates from these regions to the project area. The spatial extent of the trajectories suggests that, for the most part, the observed concentrations are the result of transported particles into the region more than from local emissions.

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11.0 APPENDICES

APPENDIX A – LIQUEFACTION FACILITY AIR EMISSIONS INVENTORY

Public

EMISSIONS CALCULATION REPORT FOR THE ALASKA LNG LIQUEFACTION FACILITY

USAL-P1-SRZZZ-00-000001-000

APPENDIX A

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1.0 OBJECTIVE OF EMISSIONS CALCULATION REPORT

The Alaska Gasline Development Corporation, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, and ExxonMobil Alaska LNG LLC (Applicants) plan to construct one integrated liquefied natural gas (LNG) Alaska LNG Project (Project). The project contains two separate facilities, the Gas Treatment Plant (GTP) and the Liquefaction Facility.

The purpose of this Emissions Calculation Report (Report) is to present the methodologies that were used to calculate the air pollutant emissions from sources at the Liquefaction Facility. Quantitative emissions data is needed to demonstrate that these facilities would adhere to the applicable Clean Air Act (CAA) requirements as administered by the Environmental Protection Agency (USEPA) and the Alaska Department of Environmental Conservation (ADEC), and to support the assessment of air quality impacts for the Federal Energy Regulatory Commission (FERC) application and the associated National Environmental Policy Act (NEPA) process. Specifically presented are the methods proposed for developing emissions data to support the following analyses:

- Determining applicable permitting requirements triggered by the proposed facilities
- Assessment of the facilities' air quality impacts for the project's FERC application and in the subsequent NEPA analyses
- Dispersion modeling to evaluate the project's compliance with applicable state and federal ambient air quality standards and related thresholds
- Additional modeling to evaluate the facility's impacts to air quality-related values (AQRVs), including visibility, acid deposition, and impacts to soils, flora and fauna

This document explains the emission calculations located in the sections at the end of this report. The explanations located in this report provide a basis for the values and methods used within the calculations, both items should be reviewed simultaneously. The facility emission calculations are represented by the document sections prefixed with EC (Emission Calculation). The marine terminal emission calculations are represented by the document sections prefixed with MEC (Marine Emission Calculation). The tables located within this report reference both the summary tables and the individual equipment calculation pages.

2.0 DESCRIPTION OF THE LIQUEFACTION FACILITY

The Liquefaction Facility, which would consist of the LNG Plant and the Marine Terminal, would receive North Slope natural gas via the Project Mainline, liquefy the gas, and store the liquefied natural gas (LNG) on-site until the LNG would ship from the adjacent Marine Terminal by LNG carrier vessels.

The LNG Plant is designed to produce 20 million metric tons (tonnes) per annum of liquefied natural gas, and includes liquefaction, processing and storage facilities, and necessary utility systems. It would include three identical trains comprised of compression and refrigeration equipment to liquefy the compressed natural gas from the GTP to salable LNG. Major equipment at the facility would include gas-fired turbines, liquid fuel-fired reciprocating internal combustion engines, gas-fired auxiliary equipment, and flares.

The Marine Terminal would include the trestle(s), flare, piping, and berthing facilities associated with LNG carrier loading and berthing. The carrier vessels that would call at the Marine Terminal would be equipped with either diesel engines or steam systems for the main propulsion and auxiliary equipment to assist in the loading of the LNG into onboard compartments for transit. They would be assisted in berthing, loading and unberthing operations by tugboats and other support vessels.

The fuel gas to be used at the Liquefaction Facility was assumed to have 16 ppmv sulfur in accordance with the pipeline specification of 1 grain sulfur/100 standard cubic feet of gas.

Table 2-1 lists the major emissions emitting equipment at the Liquefaction Facility. Mobile and non-road equipment associated with facility operations and the methods used to quantify the associated emissions are described in **Section 9.0** of this Report. **Table 2-2** shows ambient temperature data for Nikiski that was used in developing emissions data for equipment of the Liquefaction Facility (see **Sections 4.0** through **8.0**).

Ambient temperature data was obtained from the Cooperative Observer Network (COOP) Summaries for Alaska from the Western Regional Climate Center (WRCC 2006). Regional temperatures are based on measurements from Nikiski Terminal (1967-1978), and Kenai FAA Airport (1949-2006). Temperatures at these locations were assumed to be representative for the Liquefaction Facility location. The COOP information (WRCC 2006) from all locations shows annual average temperatures close to 40°F; the average at Nikiski Terminal is 42.2°F, and the Kenai Airport mean value is 42.2°F. The value of 40°F was selected after rounding to one significant digit. The listed lowest and highest ambient temperatures were selected to represent the maximum and minimum probable temperatures during normal operation at the site, rather than extreme temperature values that have rarely been recorded. A representative low ambient temperature of -30°F was selected based on the very small reasonably foreseeable probability of the ambient temperature being below -30°F for any extended period of time. The regional temperature data indicates one instance of a temperature below -30°F in the past 15 years. Similarly, 70°F, was selected, for the representative highest ambient temperature, based on a review of the regional temperature data showing that ambient values higher than 70°F have not occurred in almost 45 years.

Table 2-1 Liquefaction Facility Emitting Equipment Type and Count

Equipment Type	Facility Count
Compressor Turbines	6
Power Generation Turbines	4
Reciprocating Internal Combustion Engines (Emergency/Non-Emergency)	2
Fuel Gas Heaters/Boilers	0
Flares (Including Thermal Oxidizer)	8
Marine Equipment (Site Specific Vessels, excluding LNG carrier vessels)	4

Table 2-2 Ambient Temperatures Used for Liquefaction Facility Calculations

	Temperature (°F)
Lowest Ambient	-30
Highest Ambient	70
Annual Average Ambient	40

3.0 DESCRIPTION OF EMISSIONS DATA NEEDS

3.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) APPLICABILITY AND REVIEW

The federal PSD permitting program applies to major new stationary sources and major modifications of existing sources that are proposed to be located in areas that are in compliance with the National Ambient Air Quality Standards (NAAQS). A source is “major” for a given pollutant if the maximum expected facility-wide emissions of that pollutant from a new facility will exceed 250 tons per year (tpy), or 100 tpy for 28 named facility categories. New sources with potential emissions in excess of the 100/250 thresholds are subject to PSD review. If a facility is major for at least one pollutant, then other pollutants emitted in amounts above their respective Significant Emission Rates (SERs) are also subject to the PSD process. The SERs are 40 tpy for NO_x, SO_x, and VOCs, 15 tpy for PM_{10}, and 10 tpy for $PM_{2.5}$.

The Project would be required to apply for PSD permit reviews for the Liquefaction Facility at Nikiski (see **Section 2.0**). Maximum possible annual emissions for all criteria pollutants were calculated for individual equipment and then summed to provide facility-wide emissions for comparison with the major source thresholds and applicable Significant Emission Rate (SER) limits.

Assumed maximum hourly emission rates and the maximum foreseeable facility operating hours per year were used to calculate maximum annual emissions for these applicability determinations. The calculated annual pollutant rates from each stationary source should be conservative enough that they would never be exceeded during normal operations. Emission factors derived from vendors, source tests for comparable equipment or from standard references, such as the USEPA’s *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009), may be used for certain pollutants if suitable vendor data are not available.

3.2 FEDERAL ENVIRONMENTAL REGULATORY COMMISSION (FERC) IMPACT ASSESSMENT

The Federal Energy Regulatory Commission (FERC) requires a full assessment of all emissions sources associated with the proposed facilities, including sources that are not normally included in the PSD review, such as mobile sources and construction emissions[1].

Inasmuch as the focus of the FERC environmental review is on assessing a proposed Project’s anticipated actual impacts, it might be assumed that only expected actual emissions data would be required. However, FERC guidance for the preparation of Resource Report No. 9, *Air and Noise Quality*, also requires evidence of a Project’s ability to obtain required permits. In the case of the Project, this includes showing that the Liquefaction Facility can satisfy the requirements of the PSD review, which mostly evaluates impacts for maximum potential facility emissions. Thus, the emissions data required for preparation of the Project FERC submittal will rely primarily on the same assumptions as that for PSD permitting.

Assumed maximum emission rates and the maximum foreseeable facility operating hours per year were used to calculate maximum annual emissions for the FERC submittal. The calculated annual pollutant rates from each stationary source should be conservative enough that they would never be exceeded during normal operations. Emission factors derived from source tests for comparable equipment or from standard references, such as the USEPA’s *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009), may be used if suitable vendor data are not available.

[1] The development of construction emissions estimates for the Project is not addressed in this Report.

Emission rates required for the dispersion modeling analyses presented in the Project submittals to FERC were calculated using the same methodology as described for PSD modeling in the next section.

3.3 PSD Dispersion Modeling

Under the PSD program, a proposed new major stationary source or major modification must complete a series of air quality impact analyses that includes a comprehensive, cumulative air quality impact analysis to demonstrate that the source's emissions will not cause or contribute to a modeled violation of any NAAQS. This means the applicant will need to model its own source's emissions, as well as those from other existing facilities in the area near the proposed Project facilities, to show compliance with the NAAQS and PSD increments.

The modeling analyses described above is required to evaluate maximum potential impacts for comparison with the NAAQS and PSD increment thresholds. In general, this means that the corresponding modeling analyses must use maximum emission rates for short and long--term averaging times corresponding to these ambient criteria. However, for some types of equipment, most notably gas-fired turbines, pollutant emissions vary for different loads and ambient temperature conditions. For these sources, peak impacts may be predicted to occur at other than peak load operations.

Emissions rates to support the PSD modeling analyses were derived from equipment vendor data, where possible. Such data may be available from manufacturers of turbines, reciprocating engines and boilers/heaters, but may not be forthcoming for flares. Where necessary, source test data from comparable equipment or emission factors from established reference compilations, like USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009) were used.

3.4 Air Quality Related Values (AQRV) Modeling (Evaluating Impacts to Visibility and Deposition)

Emission rates to support the AQRV modeling analysis for the new facilities were based on the same methodology as those used in the PSD dispersion modeling assessment. The assumed maximum hourly emission rates and the maximum foreseeable facility operating hours per year were used to calculate maximum annual emissions for the AQRV Analysis. There is an additional requirement to speciate the particulate matter for these analyses into the filterable or elemental carbon (EC) portion, as well as the condensable or secondary organic aerosols (SOA). The PM emissions for each type of equipment were speciated based on the USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009). The calculated PM_{10} and $PM_{2.5}$ rates from each stationary source should be conservative enough that they would never be exceeded during normal operations.

Visibility modeling is based on the maximum 24-hour NO_x, SO_x and PM emission rates from the proposed new facility of interest. To ensure that the resulting impacts are conservative, it is common for these simulations to assume 24 consecutive hours of operation at the maximum possible hourly emission rates for these pollutants. The deposition modeling is based on reasonably foreseeable annual NO_x and SO_x emission rates from the proposed facility.

The impacts to the region's air quality and AQRVs in Class I PSD areas and sensitive Class II areas were developed using the actual emissions from the existing sources, as provided by ADEC. These actual emissions data on existing facilities were augmented with maximum allowable emissions for reasonably foreseeable future sources that are currently undergoing permitting or construction in the areas potentially impacted by emissions of the Project's Liquefaction Facility.

4.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS: COMPRESSION TURBINES

4.1 OPERATIONS DESCRIPTION

The compression turbines at the Liquefaction Facility would be arranged with two turbines per train (six turbines total), to compress the refrigerant used to cool the natural gas into liquefied natural gas. The compressors would be located upstream of the refrigerant condensers and would compress the heated refrigerant gas returning from the cross exchangers used to cool the natural gas. The production of LNG would be relatively constant and require a continuous supply of refrigerant. This would require the compressor turbines to operate near 100% continuously with little variation.

4.2 EMISSIONS DATA SOURCES

The turbine vendor provided performance estimates (fuel usage, exhaust gas properties) and emission concentration estimates for certain pollutants in the exhaust for the compression turbines currently proposed for the Liquefaction Facility. See **Section 2.0** and **Table 2-2** for a discussion on selection of a representative ambient temperature range at the Liquefaction Facility site. The vendor created the operating and emissions profiles based on the design specifications of the fuel gas to be utilized at the Liquefaction facility, as well as the ambient temperatures and typical ambient pressure at the proposed facility location.

Table 4-1 lists the sources of the emission factors that were used to calculate turbine emissions, including a mix of vendor estimates and factors from public sources.

Table 4-1 Data Sources for Liquefaction Facility Compression Turbines Emissions Estimation

Pollutant	Data Source Description
NO_x	Vendor Data
CO	Vendor Data
VOC	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
PM_{10}[1]	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
$PM_{2.5}$	Assumed same value as PM_{10} for the most conservative estimate
SO_2	Mass balance assuming all sulfur in the fuel becomes SO_2 (H_2SO_4 emissions included in SO_2)
Lead[2]	Negligible
Total GHG	40 CFR Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
NO_2/NO_x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

4.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility potential to emit (PTE). Calculating the annual tons per year per pollutant was needed for PSD Applicability determination and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual ton per year and emissions for other appropriate averaging times as required for modeling.

4.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were quantified in the same manner used to quantify emissions for comparison to New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the compression turbines include the assumed operating load, ambient temperature, and supplemental firing.

Operating Load and Ambient Temperature Selection

Table 4-2 provides the assumed operating hours, as well as the assumed turbine loads and ambient temperatures corresponding to the maximum annual pollutant emission rates. The selected emissions and operating conditions provided a conservative estimate of the compression turbines PTE values for PSD Applicability and FERC Impact Assessment because of the following:

- Operation at maximum load was assumed for a full year, without any variations that would typically result in lower emissions.
- Use of emission rates corresponding to the annual average ambient temperature provided the best annual estimate across all operating temperatures that would affect the turbine operation and therefore the emissions.

Table 4-2 Assumed Liquefaction Facility Compression Turbine Annual Operations

Pollutant	Annual Operating Hours	Selected Load	Selected Ambient Temperature
NO_x	Continuous Full-Time Operation (8,760 hours)	Maximum Operating Load (100%)	Annual Average Temperature (40°F)
CO			
VOC			
PM_{10}			
$PM_{2.5}$			
SO_2			
Total GHG			
Total HAPs			

Supplemental Firing Considerations Annual Emissions Calculations

Supplemental firing was not utilized in the design of the Liquefaction Facility compression turbines.

Final Calculated Annual Emissions

The annual emissions calculated for the compression turbines to be included in the facility's PTE summary are shown in **Table 4-3**.

Table 4-3 Liquefaction Facility Compression Turbines PTE Summary

Pollutant		Compressor Turbine (per turbine)	Reference to Calculation
NO_x	ton/year	157	Sections EC-1 and EC-4
CO	ton/year	265	
VOC	ton/year	10.9	
PM_{10}	ton/year	34.3	
$PM_{2.5}$	ton/year	34.3	
SO_2	ton/year	12.2	
GHG	tonnes/year	517,860	
HAPs	ton/year	5.01	

4.3.2 Criteria Pollutant Modeling

Conservative estimates of maximum short-term and long-term emissions were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term annual emissions were calculated using the same methodology used to determine the PTE emissions, as previously described.

Operating Load and Ambient Temperature Selection

Table 4-4 shows the operational loads and ambient temperatures used to determine the compression turbine emission rates and stack parameters that were assumed in the dispersion modeling to evaluate short-term criteria pollutant impacts (averaging times of 1 to 24 hours). The following conventions were used to provide this information to support the modeling analyses:

- The exhaust velocity used was the minimum velocity across the range of turbine loads and ambient temperatures, this corresponded to operation at the maximum ambient temperature.
- The exhaust temperature used was the minimum temperature across the range of turbine loads and ambient temperatures, this corresponded to operation at the minimum ambient temperature.
- Maximum impacts were predicted conservatively by the model using the maximum emission rates in combination with the minimum exhaust velocities and exhaust temperatures.

Table 4-5 provides similar information relating to the emission rates and stack parameters assumed for modeling long-term (i.e., annual average) turbine impacts.

Table 4-4 Short-Term Modeling Parameters for Liquefaction Facility Compression Turbines

Pollutant	Emission Type	Maximum Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
		Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO_x	1-Hour	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)	Maximum Operating Load (100%)	Maximum Ambient Temperature (70°F)	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)
CO	1-Hour						
	8-Hour						
PM_{10}	24-Hour						
$PM_{2.5}$	24-Hour						
SO_2	1-Hour						
	3-Hour						
	24-Hour						

Table 4-5 Long-Term Modeling Parameters for Liquefaction Facility Compression Turbines

Pollutant	Annual Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO_x	Maximum Operating Load (100%)	Annual Average Temperature (40°F)	Maximum Operating Load (100%)	Maximum Ambient Temperature (70°F)	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)
CO						
PM_{10}						
$PM_{2.5}$						
SO_2						

Supplemental Firing Considerations Modeling Emissions Calculations

Supplemental firing was not utilized in the design of the Liquefaction Facility compression turbines. Accordingly, no consideration of potential effects of supplemental firing on the emission rates and stack parameters of these turbines were needed.

Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the compression turbines to be included in the facility's modeling compliance demonstration are shown in **Table 4-6**.

Table 4-6 Modeling Emissions Summary for Liquefaction Facility Compression Turbine

Pollutant		Compressor Turbine (per turbine)			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	4.74	794	26.21	Sections EC-2 and EC-4
	Long-Term	4.51			
CO	Short-Term	8.02			
PM_{10}	Short-Term	1.04			
	Long-Term	0.99			
$PM_{2.5}$	Short-Term	1.04			
	Long-Term	0.99			
SO_2	Short-Term	0.37			
	Long-Term	0.35			

4.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling in that it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the short-term impact modeling described in **Section 4.3.2**. The short-term particulate matter emissions were speciated for the AQRV analyses as described in the following subsection.

PM Speciation Breakdown

Table 4-7 shows the assumed breakdown and basis for the short-term compression turbine emissions of the PM_{10} and $PM_{2.5}$ into filterable and condensable fractions, as required for AQRV modeling.

Table 4-7 AQRV PM Speciation for Liquefaction Facility Compression Turbine AQRV

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}	
Gas	0	29%	29%	71%	71%	AP-42 Table 3.1-2a (USEPA 2009)

5.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS: POWER GENERATION TURBINES

5.1 OPERATIONS DESCRIPTION

The Liquefaction Facility main power generation system would consist of four gas-driven turbines which would create a common power supply to the facility. The power generation turbine load would fluctuate based on the needs of the process trains; the turbine load can range from 60% to 100%. Seasonal load variations would be the most common reason for differences in power generation equipment operation. At the Liquefaction Facility, the air cooler fans in the refrigerant condensers would have a much higher energy demand during the summer months, than in winter, thus requiring a higher power generation turbine output.

The power generation turbines at the Liquefaction Facility would all be equipped with HRSGs for steam production at the facility. The HRSGs would operate by transferring the heat from the hot turbine exhaust gas to water, causing a phase change into steam. The steam would then be used by steam turbines within the facility's power generation plant.

The HRSG would be designed to always accept the full exhaust flow from the power generation turbines. Downstream of the HRSG is an exhaust stack that would be the actual emission point. The HRSG would be designed to transfer the heat duty of the exhaust gas that corresponds to a temperature loss of roughly 600°F to 700°F. The typical outlet exhaust temperature of the power generation turbines would be 1,000°F. The HRSG would reduce the temperature of the exhaust gas at the stack to 341°F and would not cause an increase in pollutant emissions at the turbine stack.

5.2 EMISSIONS DATA SOURCES

The turbine vendor provided performance estimates (fuel usage, exhaust gas properties) and emission concentration estimates for certain pollutants in the exhaust for the power generation turbines currently proposed for the Liquefaction Facility. See **Section 2.0** and **Table 2-2** for a discussion on selection of a representative ambient temperature range at the Liquefaction Facility site. The vendor created the operating and emissions profiles based on the design specifications of the fuel gas to be utilized at the Liquefaction Facility, as well as ambient temperatures and typical ambient pressure for the proposed facility location.

Table 5-1 lists the sources of the emission factors that were used to calculate turbine emissions, including a mix of vendor estimates and factors from public sources.

Table 5-1 Data Sources for Liquefaction Facility Power Generation Turbine Emissions Estimation

Pollutant	Data Source Description
NO_x	Vendor Data
CO	Vendor Data
VOC	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
PM_{10}[1]	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
$PM_{2.5}$	Assumed same value as PM_{10} for the most conservative estimate
SO_2	Mass balance assuming all sulfur in the fuel becomes SO_2 (H_2SO_4 emissions included in SO_2)
Lead[2]	Negligible
Total GHG	40 CFR Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
NO_2/NO_x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

5.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility PTE. Calculating the annual tons per year per pollutant was needed for PSD Applicability and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual tons per year and emissions for other appropriate averaging times as required for modeling.

5.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were estimated in the same manner used to quantify emissions for comparison with New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the power generation turbines include operating load and ambient temperature.

<u>Operating Load and Ambient Temperature Selection</u>

Table 5-2 provides the assumed operating hours, as well as the assumed turbine loads and ambient temperatures corresponding to the maximum annual pollutant emission rates. The selected emissions and operating conditions provided a conservative estimate of the power generation turbines PTE for PSD Applicability and FERC Impact Assessment because of the following:

- Operation at maximum load was assumed for a full year without any variations in load, that would typically result in lower emissions.
- Use of the emission rates corresponding to the annual average ambient temperature provided the best annual estimate across all operating temperatures that would affect the turbine operation and therefore the emissions.

Table 5-2 Assumed Liquefaction Facility Power Generation Turbine Annual Operations

Pollutant	Annual Operating Hours	Selected Load	Selected Ambient Temperature
NO_x	Continuous Full-Time Operation (8,760 hours)	Maximum Operating Load (100%)	Annual Average Temperature (40°F)
CO			
VOC			
PM_{10}			
$PM_{2.5}$			
SO_2			
Total GHG			
Total HAPs			

Supplemental Firing Considerations Annual Emissions Calculations

The Liquefaction facility power generation turbines would be equipped with Heat Recovery Steam Generation units: however, a supplemental firing capability was not provided in the design of these turbines and no additional emissions from such activity were need to be accounted for.

Final Calculated Annual Emissions

The annual emissions calculated for the power generation turbines to be included in the facility's PTE summary are shown in **Table 5-3**.

Table 5-3 Liquefaction Facility Power Generation Turbines PTE Summary

Pollutant		Power Generation Turbine (per turbine)	Reference to Calculation
NO_x	ton/year	52.9	Sections EC-1 and EC-4
CO	ton/year	17.9	
VOC	ton/year	3.76	
PM_{10}	ton/year	11.8	
$PM_{2.5}$	ton/year	11.8	
SO_2	ton/year	4.19	
GHG	tonnes/year	178,670	
HAPs	ton/year	1.73	

5.3.2 Criteria Pollutant Modeling

Conservative estimates of maximum short-term and long-term emissions were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term annual emissions were calculated with the same methodology used to determine the PTE emissions, as previously described.

Operating Load and Ambient Temperature Selection

Table 5-4 shows the operational loads and ambient temperatures used to determine the power generation turbine emission rates and stack parameters for dispersion modeling to evaluate short-term impacts (averaging times of 1 to 24 hours). The following conventions were used to provide this information to support the modeling analyses:

- The exhaust velocity used for modeling was the minimum velocity across the range of turbine loads and ambient temperatures.
- The exhaust temperature was determined by considering the range of temperatures for each turbine load and ambient temperature as well as the exhaust temperature due to operation of the HRSG. An exhaust temperature of 341°F was selected for use in the dispersion modeling because it is the minimum of all temperatures considered as limited by the HRSG.
- Maximum impacts were predicted conservatively by the model by using the maximum emission rates in combination with the minimum exhaust velocities and exhaust temperatures.

Table 5-5 provides similar information relating to the emission rates and stack parameters assumed for modeling long-term (i.e., annual average) turbine impacts.

Table 5-4 Short-Term Modeling Parameters for the Liquefaction Facility Power Generation Turbines

Pollutant	Emission Type	Maximum Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
		Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO_x	1-Hour	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Constant for all Turbine Loads and Ambient Temperatures (Based on Process Steam Needs, Minimum Exhaust Temperature of 341°F considered)	
CO	1-Hour						
	8-Hour						
PM_{10}	24-Hour						
$PM_{2.5}$	24-Hour						
SO_2	1-Hour						
	3-Hour						
	24-Hour						

Table 5-5 Long-Term Modeling Parameters for the Liquefaction Facility Power Generation Turbines

Pollutant	Annual Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO_x	Maximum Operating Load (100%)	Annual Average Temperature (40°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Constant for all Turbine Loads and Ambient Temperatures (Based on Process Steam Needs, Minimum Exhaust Temperature of 341°F considered)	
CO						
PM_{10}						
$PM_{2.5}$						
SO_2						

<u>Supplemental Firing Considerations Modeling Emissions Calculations</u>

The Liquefaction Facility power generation turbines would be equipped with Heat Recovery Steam Generation units, however, a supplemental firing capability was not considered in the design.

Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the power generation turbines to be included in the facility's modeling compliance demonstration are shown in **Table 5-6**.

Table 5-6 Modeling Emissions Summary for Liquefaction Facility Power Generation Turbine

Pollutant		Power Generation Turbine (per turbine)			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	1.84	445	14.6	Sections EC-2 and EC-4
	Long-Term	1.52			
CO	Short-Term	1.00			
PM_{10}	Short-Term	0.38			
	Long-Term	0.34			
$PM_{2.5}$	Short-Term	0.38			
	Long-Term	0.34			
SO_2	Short-Term	0.14			
	Long-Term	0.12			

5.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling, as it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the short-term impact modeling described in **Section 5.3.2**. The short-term particulate matter emissions were speciated for the AQRV analyses as described in the following subsection.

PM Speciation Breakdown

Table 5-7 shows the assumed breakdown and basis for the short-term power generation turbine emissions of the PM_{10} and $PM_{2.5}$ into filterable and condensable fractions, as required for AQRV modeling.

Table 5-7 AQRV PM Speciation for Liquefaction Facility Power Generation Turbines

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}	
Gas	0	29%	29%	71%	71%	AP-42 Table 3.1-2a (USEPA 2009)

6.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS : RECIPROCATING INTERNAL COMBUSTION ENGINES (EMERGENCY/NON-EMERGENCY)

6.1 OPERATIONS DESCRIPTION

The reciprocating diesel internal combustion engines listed below are expected to be installed at the Liquefaction Facility.

Auxiliary Air Compressor

The Auxiliary Air Compressor would be provided as a backup air supply to the instrument air system in the event of a power failure or primary instrument air compressor failure. The instrument air system controls all pneumatic instrumentation and valving. In the event of a failure, the facilities valving may require some additional air supply to move into the valve specific fail setting (open or closed).

Diesel Firewater Pump Engine

The Firewater Pump would be diesel-driven and located within the process facilities. There would be one firewater pump designed to distribute 5,000 gallons per minute (gpm) of fire water around the facility in the event of an emergency.

6.2 EMISSIONS DATA SOURCES

Common industry standards for specific equipment types were used to provide emission factors that may be used with engine operating data to estimate the maximum criteria pollutant emission rates allowable under these standards. The tiered engine standards have been provided to vendors as a way to characterize average emissions, rather than “not to exceed” emissions. Because of this, an additional 25% margin was added to the emission factors derived from the standards in order to represent conservative, “not to exceed” emission rates.

Non-Emergency Diesel-Fired Generators

40 CFR Part 60 Subpart IIII (USEPA 2013) was the applicable standard for stationary emergency engines. Per the directions in 40 CFR Part 60 Subpart IIII Section 60.4201 Rule (a) based on the size and build date of the equipment, 40 CFR Part 1039 Subpart B, 1039.102: Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines was the applicable standard for non-emergency engines. The Tier 4 level of emission control was assumed for these units since the equipment would not be installed until 2025. (See **Table 6-1**)

Emergency Diesel-Fired Fire Water Pumps

40 CFR Part 60 Subpart IIII, Appendix Table 4: Emission Standards for Stationary Fire Pump Engines (USEPA 2013) was the applicable standard for fire water pumps. The Tier 2 level of emission control was assumed since the equipment would not be installed until 2025. (See **Table 6-2**)

Table 6-1 Data Sources for Liquefaction Facility Non-Emergency Diesel Equipment Emissions Estimation

Pollutant	Data Source Description
NO_x	40 CFR Part 1039 Subpart B, 1039.102 (95% of NO_x+NMHC) (USEPA 2010)
CO	40 CFR Part 1039 Subpart B, 1039.102 (USEPA 2010)
VOC	40 CFR Part 1039 Subpart B, 1039.102 (5% of NO_x+NMHC) (USEPA 2010)
PM_{10}[1]	40 CFR Part 1039 Subpart B, 1039.102 (USEPA 2010)
$PM_{2.5}$	Assumed same value as PM_{10} for the most conservative estimate
SO_2	Mass balance assuming all sulfur in the fuel becomes SO_2 (H_2SO_4 emissions included in SO_2)
Lead[2]	Negligible
Total GHG	40 CFR 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.3 (USEPA 2009)
NO_2/NO_x Ratio	USEPA's default accepted ratio of 0.5 (USEPA 2011)

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

Table 6-2 Data Sources for Liquefaction Facility Diesel-Fired Fire Water Pump Emissions Estimation

Pollutant	Data Source Description
NO_x	40 CFR Part 60 Subpart IIII, Appendix Table 4 (95% of NO_x+NMHC) (USEPA 2013)
CO	40 CFR Part 60 Subpart IIII, Appendix Table 4 (USEPA 2013)
VOC	40 CFR Part 60 Subpart IIII, Appendix Table 4 (5% of NO_x+NMHC) (USEPA 2013)
PM_{10}[1]	40 CFR Part 60 Subpart IIII, Appendix Table 4 (USEPA 2013)
$PM_{2.5}$	Assumed same value as PM_{10} for the most conservative estimate
SO_2	Mass balance assuming all sulfur in the fuel becomes SO_2 (H_2SO_4 emissions included in SO_2)
Lead[2]	Negligible
Total GHG	40 CFR Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.3 (USEPA 2009)
NO_2/NO_x Ratio	USEPA's default accepted ratio of 0.5 (USEPA 2011)

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

6.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility PTE. Calculating the annual tons per year per pollutant was needed for PSD Applicability and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual tons per year and emissions for other appropriate averaging times as required for modeling.

6.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were estimated in the same manner used to quantify emissions for comparison to New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the diesel-driven engines include annual operating hours and operating load.

Operating Hours and Operating Load

Diesel firewater pump engines and auxiliary emergency equipment typically would operate only during short periodic tests to ensure their operability in an emergency. Recognizing that modeled impacts from such sources would be greatly overestimated if they were assumed to operate continuously at maximum capacity, USEPA has issued guidance (USEPA 2011) that allows a less conservative approach for modeling the impacts from such sources against the short-term ambient standards. Accordingly, the modeling impacts for these sources may use “annualized” emissions, i.e., total annual emissions could be assumed to be spread over all hours of the year to calculate a much lower equivalent hourly rate.

Table 6-3 provides the assumed operational characteristics chosen for the calculation of the intermittent diesel equipment annual emission rates. These assumptions provided a conservative estimate of PTE values for PSD Applicability and FERC Impact Assessment because of the following:

- 500 hours of operation per year was assumed and is much higher than the projected actual operation per year for this equipment (more likely less than 100 hours of operation per year).
- Maximum load for full duration of operation without any variations in load that would typically result in lower emissions.

The emission factor standards used for these diesel-fired equipment are not ambient temperature dependent.

Table 6-3 Assumed Liquefaction Facility Intermittent Diesel Equipment Annual Operations

Pollutant	Annual Operating Hours	Selected Load
NO_x	Maximum Intermittent Operating Hours (500)	Maximum Operating Load (100%)
CO		
VOC		
PM_{10}		
$PM_{2.5}$		
SO_2		
Total GHG		
Total HAPs		

Final Calculated Annual Emissions

The annual emissions calculated for the intermittent diesel equipment to be included in the facility's PTE summary are shown in **Table 6-4**.

Table 6-4 Liquefaction Facility Intermittent Diesel Equipment PTE Summary

Pollutant		Auxiliary Air Compressor	Diesel Firewater Pump	Reference to Calculation
NO_x	ton/year	0.06	1.13	Sections EC-1 and EC-5
CO	ton/year	0.54	1.03	
VOC	ton/year	0.03	0.06	
PM_{10}	ton/year	3.08E-03	0.06	
$PM_{2.5}$	ton/year	3.08E-03	0.06	
SO_2	ton/year	7.33E-04	1.40E-03	
GHG	tonnes/year	77.9	149	
HAPs	ton/year	2.12E-03	4.07E-03	

6.3.2 Criteria Pollutant Modeling

Conservative estimates of the short-term and long-term emissions from the intermittent diesel equipment were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term annual emissions were calculated with the same methodology used to determine the PTE emissions, as previously described. Also, the short-term emissions for NO_x and SO_2 were annualized in accordance with USEPA modeling guidance (USEPA 2011) for intermittent sources of these pollutants.

Operating Load Selection

Table 6-5 shows the diesel equipment operating load assumptions that were used in determining short-term emission rates for the criteria pollutant dispersion modeling analyses to evaluate NAAQS compliance for all pollutants and averaging times. However, as discussed in **Section 6.3.2,** and allowed by USEPA guidance (USEPA 2011), the "hourly" emission rates used in the modeling for 1-hour NO_2 and 1-hour SO_2 was determined by spreading the annual emissions over the 8,760 hours of the year (annualized). This practice removed the unreasonable conservatism associated with assuming continuous operation for emission units that actually operate only a few hundred hours per year. The annualized emission rates were based on the maximum hourly emission rate derated by a factor of 500 hours/8,760 hours.

The exhaust velocity and exhaust temperature were based on data for a representative combustion engine. Parameters corresponding to the maximum load operation were selected to represent exhaust velocities and temperatures for dispersion modeling, because this is the best understood and most readily available information for diesel engine operation. Although the exclusive use of stack parameters for maximum load operation does not necessarily yield the most conservative possible result for modeling purposes, the exhaust velocity and temperature would not be expected to change appreciably with load during normal equipment testing. Additionally, stack parameters for these engines are almost entirely independent of ambient temperature conditions.

Table 6-6 shows the selection of modeling parameters for evaluating annual average impacts. All annual emission rates were based on the maximum hourly emission rate derated by a factor of 500 hours/8,760 hours.

Table 6-5 Short-Term Modeling Parameters for Liquefaction Facility Intermittent Diesel Equipment

Pollutant	Emission Type	Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load	Selected Load
NO_x	1-Hour	100% (Annualized)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO	1-Hour	100%		
	8-Hour	100%		
PM_{10}	24-Hour	100%		
$PM_{2.5}$	24-Hour	100%		
SO_2	1-Hour	100% (Annualized)		
	3-Hour	100%		
	24-Hour	100%		

Table 6-6 Long-Term Modeling Parameters for Liquefaction Facility Intermittent Diesel Equipment

Pollutant	Annualized Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load	Selected Load
NO_x	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO			
PM_{10}			
$PM_{2.5}$			
SO_2			

Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the intermittent diesel equipment to be included in the facility's modeling compliance demonstration are shown in **Table 6-7**.

Table 6-7 Modeling Emissions Summary Liquefaction Facility Intermittent Diesel Equipment

Pollutant		Auxiliary Air Compressor			Diesel Fire Water Pump			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	1.77E-03 (Annualized)	746	35.1	0.03 (Annualized)	760	47.9	Sections EC-2 and EC-5
	Long-Term	1.77E-03			0.03			
CO	Short-Term	0.27			0.52			
PM_{10}	Short-Term	1.55E-03			0.03			
	Long-Term	8.87E-05			1.71E-03			
$PM_{2.5}$	Short-Term	1.55E-03			0.03			
	Long-Term	8.87E-05			1.71E-03			
SO_2	Short-Term (Hourly)	2.11E-05 (Annualized)			4.04E-05 (Annualized)			
	Short-Term (Daily)	3.69E-04			7.08E-04			
	Long-Term	2.11E-05			4.04E-05			

6.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling as it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the other short-term impact modeling described in **Section 6.3.2**. The short-term particulate matter emissions used for the AQRV analysis were speciated as described in the following subsection.

PM Speciation Breakdown

Table 6-8 shows the assumed breakdown and basis for the short-term Liquefaction Facility diesel equipment emissions of the PM_{10} and $PM_{2.5}$ into filterable and condensable fractions, as required for AQRV modeling.

Table 6-8 AQRV PM Speciation for Liquefaction Facility Intermittent Diesel Engines

Equipment Type	Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
			$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}	
Generator	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2[1] (USEPA 2009)
Compressor	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2[1] (USEPA 2009)

Note 1: The diesel engines at the Liquefaction Facility would be less than 600 hp, Since no filterable/condensable PM information is provided for engines of this size in AP 42 Section 3.3, the data provided in AP-42 Section 3.4: Large Stationary Diesel Equipment (greater than 600 hp), was used to support the AQRV PM Speciation

7.0 DEVELOPMENT OF EMISSIONS AND STACK PARAMETERS: FUEL GAS HEATERS

The Liquefaction Facility design does not currently include any gas-fired heaters.

8.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMTERS: FLARES

8.1 OPERATIONS DESCRIPTION

Dry and Wet Flare

There would be 2 sets of 3 x 50% Ground Flares, one specifically for dry reliefs and the other for wet reliefs (six total flares), at the Liquefaction Facility. The ground flares would be divided into three different enclosures. The 3 x 50% capacity designation means that during any relief event, two of the three flares would be operating at maximum capacity handling 100% (2 x 50%) of the facility relief stream. The different enclosures would be surrounded by wind and radiation fencing to provide adequate distance from the flare to ensure that the radiation outside of the fence would not exceed 500 BTU/hr/ft^2 at grade. The flares would be designed for smokeless operation up to 100% of all flow rates.

The Dry Flare would be used for the majority of the relief events from all around the Liquefaction Facility during normal operations. The Wet Flare would receive relief events from the dehydration system regeneration equipment, downstream of the debutanizer system, and from the steam heat medium system. These locations within the facility would potentially be subject to entrainment of water within the gas or liquid which could freeze and form hydrates within the piping.

LP Flare

A Low Pressure Flare would be provided on land to support the arrival of the warm LNG carriers (e.g. full of warm inert gas rather than small amounts of cold LNG), which must be purged of inert gas prior to loading. This elevated sonic LP Flare would not be used for emergency reliefs. It is understood that multiple LNG Carriers a year would call at the marine facility in this warm condition. The warm carriers would have to be purged of gases (potentially remaining hydrocarbon boil-off gas and inert gases), cooled, and pressurized in order to proceed with LNG loading. The LP Flare would receive all gases from warm carriers as well as the Boil-Off Gas Compressor seal gas located in the LNG storage/loading area. Steam would be available as an assist medium for this flare.

Thermal Oxidizer

A Thermal Oxidizer would be located at the Liquefaction Facility as an emissions reduction technique for the hydrocarbon tanks downstream of the fractionation train. The condensate and off-spec condensate storage tanks, as well as the equalization tank that would help to separate oil from the facility's wastewater, would send all vent gas, from working and flash losses, through the Thermal Oxidizer. The Thermal Oxidizer would be sized to provide a required amount of residence time to ensure maximum destruction of VOCs.

8.2 EMISSIONS DATA SOURCE

Common industry references were used to provide emission factors, which were applied with operating data to calculate pollutant emission rates.

Table 8-1 and **Table 8-2** show the references for these emission factors for criteria pollutants, hazardous air pollutants and greenhouse gases.

Table 8-1 Data Sources for Liquefaction Facility Flare Equipment Emissions Estimation

Pollutant	Data Source Description
NO_x	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
CO	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
VOC	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
PM_{10}[1]	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
$PM_{2.5}$	Assumed same value as PM_{10} for most conservative estimate
SO_2	Mass balance assuming all sulfur in the fuel becomes SO_2 (H_2SO_4 emissions included in SO_2)
Lead[2]	Negligible
Total GHG	40 CFR 98 Subpart C (USEPA 2011)
Total HAPs	Ventura County Air Pollution Control District, AB 2588 Combustion Emission Factors (VCAPD 2001)
NO_2/NO_x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: PM emissions were included in the analysis for conservatism. It was understood that the smokeless flare design would have low particulate matter emissions. The PM mass emissions were calculated conservatively based on an assumed soot concentration of 40 µg/L for lightly smoking flares as cited in USEPA's AP 42 Compilation of Air Pollutant Emission Factors.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

Table 8-2 Data Sources for Liquefaction Facility Thermal Oxidizer Equipment Emissions Estimation

Pollutant	Data Source Description
NO_x	TCEQ Vapor Oxidizer emission factor (TCEQ 2008)
CO	TCEQ Vapor Oxidizer emission factor (TCEQ 2008)
VOC	TCEQ Vapor Oxidizer emission factor (Same as AP-42 equipment emission factors, Section 1.4) (TCEQ 2008)
PM_{10}	TCEQ Vapor Oxidizer emission factor (Same as AP-42 equipment emission factors, Section 1.4) (TCEQ 2008)
$PM_{2.5}$	Assumed same value as PM_{10} for most conservative estimate
SO_2	Mass balance assuming all sulfur in the fuel becomes SO_2 (H_2SO_4 emissions included in SO_2)
Lead[1]	Negligible
Total GHG	40 CFR 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 1.4 (USEPA 2009)
NO_2/NO_x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

8.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility PTE. Calculating the annual tons per year per pollutant was needed for PSD Applicability determination and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual tons per year and emissions for other appropriate averaging times as required for modeling.

8.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were estimated in the same manner used to quantify emissions for comparison with New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the flares and the thermal oxidizer include annual operating hours and emergency/normal operating relief rates.

Operating Hours and Operating Load

Emissions from the flare systems were calculated uniquely because they would normally operate continuously at a low throughput, with only a few non-routine events per year during which the flares would operate at a much higher maximum throughput. Purge gas through the headers and pilot gas to keep the flare pilots lit would be combusted by the flares 8,760 hours/year (continuously), while the maximum flaring conditions for the Dry and Wet Flares was conservatively assumed to occur 500 hours/year. The emissions from the 500 hours/year maximum case were annualized over the entire year (500/8,760) and then added to the emissions for the continuous purge/pilot fuel gas feed. The maximum flaring condition for the LP Flare, were based on a specific operating schedule, and were assumed to occur 144 hours/year (6 vessels per year arriving warm, with each requiring 24 hours of flaring). The emissions from the 144 hours/year maximum case were annualized over the entire year (144/8,760) and then were added to the emissions for the continuous purge/pilot fuel gas feed.

The flare PM emission factor in USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009) is based on the exhaust flow rate, not the fuel feed rate. An additional calculation was required to determine the full exhaust flow rate from the flare based on the fuel flow mixing with atmospheric air and combusting. The methodology described in 40 CFR 60 Method 19: Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates (USEPA 1991) was used to develop the exhaust flow rate based on an assumed dry oxygen concentration in the exhaust. Equation 19-1 of Method 19 was employed to determine the exhaust flow using an Fd factor, fuel flow heat duty, and the O_2 concentration. An Fd factor of 8,710 dscf/MMBtu was used since only gaseous fuel would be combusted in the flares. The Fd factor only accounts for gas with butane (C4 and lower) as the heaviest component. While other components may be sent to the flares, the majority of hydrocarbon streams at the facility would be natural gas (C1). The oxygen and water concentrations of the flare exhaust gas were assumed to be similar to standard values used for other external combustion devices (boilers/heaters). Specifically, an oxygen concentration of 3% and a water concentration of 10% were used in the calculation.

The thermal oxidizer would operate continuously with a steady input flow rate of gas sufficient to keep the burner operational and the oxidizer hot, to ensure destruction of VOCs for any variation in gas that may occur.

Table 8-3 and **Table 8-4** provide the assumed operational characteristics selected for the calculation of maximum annual pollutant emissions, based on continuous pilot/purge operation, and intermittent maximum relief operation (flares only).

The flare purge/pilot and thermal oxidizer emissions were conservative because of the following:

- Operation at constant load was assumed for a full year without any variations, which would typically result in lower emissions.

The flare maximum/routine operation emissions were conservative because of the following:

- 500 hours of operation per year was assumed, which is much higher than the projected actual operation (most likely less than 1 hour of operation per year).

- 144 hours of operation per year was based on the LP Flare handling all warm carrier calls that may occur throughout the year. Six warm calls were assumed with 24 hours of inert gas purging per call.
- Maximum load for full duration of each event, without any variations in load which would typically result in lower emissions.

The emission factors standards that were used for the flares are not ambient temperature dependent.

Table 8-3 Assumed Liquefaction Facility Flare Annual Operations

Pollutant	Annual Operating Hours (Purge/Pilot) All Flares	Annual Operating Hours (Maximum) Dry and Wet Flares	Annual Operating Hours (Routine Operations) LP Flare	Selected Load All Flares
NO_x	Maximum Operating Hours (8,760 hours)	Intermittent Operating Hours (500 hours)	Routine Required Operating Hours (144 hours)	Pilot/Purge: Pilot/Purge Flare Tip Operation Rate (100%) Maximum: Maximum Flare Operation Rate (100%)
CO				
VOC				
PM_{10}				
$PM_{2.5}$				
SO_2				
Total GHG				
Total HAPs				

Table 8-4 Assumed Liquefaction Facility Thermal Oxidizer Annual Operations

Pollutant	Annual Operating Hours	Selected Load All Flares
NO_x	Maximum Operating Hours (8,760 hours)	Maximum Operating Load (100%)
CO		
VOC		
PM_{10}		
$PM_{2.5}$		
SO_2		
Total GHG		
Total HAPs		

Final Calculated Annual Emissions

The annual emissions calculated for the flares and the thermal oxidizer to be included in the facility's PTE summary are shown in **Table 8-5**.

Table 8-5 Liquefaction Facility Flare and Thermal Oxidizer PTE Summary

Pollutant		Dry Flare (Per Flare)		Wet Flare (Per Flare)		LP Flare (Per Flare)		Thermal Oxidizer	Reference to Calculation
		Purge/ Pilot	Max	Purge/ Pilot	Max	Purge/ Pilot	Max		
NO_x	ton/year	2.13	1,020	0.67	238	3.13	5.14	2.63	Section EC-1 and EC-6/EC-7
CO	ton/year	9.71	4,650	3.06	1,090	14.3	22.4	2.17	
VOC	ton/year	17.9	8,550	5.62	2,000	26.2	40.9	0.14	
PM_{10}	ton/year	0.88	423	0.28	98.9	1.3	2.03	0.20	
$PM_{2.5}$	ton/year	0.88	423	0.28	98.9	1.3	2.03	0.20	
SO_2	ton/year	0.08	37.4	0.02	8.74	0.22	0.20	0.07	
GHG	tonnes/year	3,330	1,593,200	1,050	372,300	4,890	7,630	2,800	
HAPs	ton/year	0.09	43.5	0.03	10.2	0.13	0.21	0.05	

8.3.2 Criteria Pollutant Modeling

Conservative estimates of the short-term and long-term emissions from the flares and thermal oxidizer were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term (annual) emissions were calculated with the same methodology used to determine the PTE emissions, as previously described. Also, the short term emissions for NO_x and SO_2 were annualized in accordance with USEPA guidance (USEPA 2011) on calculating emissions for modeling of intermittent sources.

Operating Load Selection

The flares required two separate emissions calculations: one for the purge/pilot emissions that would occur continuously for 8,760 hours/year, and another for the emergency and routine maximum flaring cases that were assumed to occur 500 hours per year for the Dry and Wet flares and 144 hours per year for the LP Flare. Emissions for the maximum flaring cases were annualized over the entire year (derated by a factor of either 500 hours/8,760 hours or 144 hours/8,760 hours). All emissions were modeled at the same location.

Table 8-6 lists the flare operational characteristics assumed for the calculation of short-term modeled emission rates.

The exhaust velocity was 20 m/s, a recommended modeling value described in the Project Modeling Reports.

The exhaust temperature was 1,273°K, a recommended modeling value described in the Project Modeling Reports.

In accordance with USEPA Guidance (USEPA 1995), flares also required an additional consideration for the calculation of their modeled heights and diameters. It is understood that flares are different from most other emissions sources in that the gas combustion occurs at the exit point into the atmosphere, rather than upstream of the stack inlet. Because of the location of the emissions release above the flame, the height of plume release will actually be much higher than the physical stack height. For this reason, an effective height was calculated to simulate a taller stack to better represent the true plume elevation. An effective diameter was also calculated for the flares to account for the correct initial size of the plume after the combustion has occurred beyond the flare exit. Both the effective height and effective diameter were estimated based on the heat release rate of the gas flow to the flare prior to combustion. Detailed development of the effective stack heights and diameters are shown in **Section EC-6**.

Table 8-7 summarizes the operational loads that were assumed to develop the thermal oxidizer emission rates and stack parameters for the short-term dispersion modeling (averaging times of 1 to 24 hours).

The exhaust velocity was based on the maximum load operation of the thermal oxidizer. This value is not dependent on ambient temperature.

The exhaust temperature was based on the maximum load operation of the thermal oxidizer. This value is not dependent on ambient temperatures.

Table 8-8 and **Table 8-9** summarize the information for development of annual flaring and thermal oxidizer emission estimates. All annual emission rates for the maximum/emergency operating scenarios were based on the maximum hourly emission rate derated by a factor of 500 hours/8,760 hours. The routine flaring operation emission rates for the LP Flare were derated using a factor of144 hours/8,760 hours.

Table 8-6 Short-Term Modeling Parameters for the Liquefaction Facility Flares

Pollutant	Emission Type	Purge/Pilot Emissions	Maximum/ Routine Operation Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load		
NO_x	1-Hour	Purge/Pilot Operating Load (100%)	Maximum Operating Load (100%)	USEPA and ADEC Standard (20 m/s)	USEPA and ADEC Standard (1,273°K)
CO	1-Hour				
	8-Hour				
PM_{10}	24-Hour				
$PM_{2.5}$	24-Hour				
SO_2	1-Hour				
	3-Hour				
	24-Hour				

Table 8-7 Short-Term Modeling Parameters for the Liquefaction Facility Thermal Oxidizer

Pollutant	Emission Type	Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load	Selected Load
NO_x	1-Hour	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO	1-Hour			
	8-Hour			
PM_{10}	24-Hour			
$PM_{2.5}$	24-Hour			
SO_2	1-Hour			
	3-Hour			
	24-Hour			

Table 8-8 Long-Term Modeling Parameters for the Liquefaction Facility Flares

Pollutant	Purge/Pilot Emissions	Maximum/ Routine Operation Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load		
NO_x	Purge/Pilot Operating Load (100%)	Maximum Operating Load (100%)	USEPA and ADEC Standard (20 m/s)	USEPA and ADEC Standard (1,273°K)
CO				
PM_{10}				
$PM_{2.5}$				
SO_2				

Table 8-9 Long-Term Modeling Parameters for the Liquefaction Facility Thermal Oxidizer

Pollutant	Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load	Selected Load
NO_x	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO			
PM_{10}			
$PM_{2.5}$			
SO_2			

Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the flares to be included in the facility's modeling compliance demonstration are shown in **Table 8-10, Table 8-11**, and **Table 8-12**.

Table 8-10 Modeling Emissions Summary for Liquefaction Facility Flares

Pollutant		Dry Flare Flare (Per Flare)				Reference to Calculation
		Purge/Pilot Emission (g/s)	Maximum Emissions (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	0.06	29.3 (Annualized)	1,273	20	Sections EC-2 and EC-6
	Long-Term	0.06	29.3			
CO	1-hour	0.28	1,170			
	8-hour	0.28	146			
PM_{10}	Short-Term	0.03	4.44			
	Long-Term	0.03	12.2			
$PM_{2.5}$	Short-Term	0.03	4.44			
	Long-Term	0.03	12.2			
SO_2	Short-Term (Hourly)	2.17E-03	1.08 (Annualized)			
	Short-Term (Daily)	2.17E-03	3.14			
	Long-Term	2.17E-03	1.08			

Table 8-11 Modeling Emissions Summary for Liquefaction Facility Flares

Pollutant		Wet Flare (Per Flare)				LP Flare (Per Flare)				Reference to Calculation
		Purge/Pilot Emission (g/s)	Maximum Emissions (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Purge/Pilot Emission (g/s)	Maximum Emissions (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	0.02	6.86 (Annualized)	1,273	20	0.09	0.15 (Annualized)	1,273	20	Sections EC-2 and EC-6
	Long-Term	0.02	6.86			0.09	0.15			
CO	1-hour	0.09	274			0.41	39.2			
	8-hour	0.09	34.2			0.41	39.2			
PM_{10}	Short-Term	8.00E-03	1.04			0.04	3.55			
	Long-Term	8.00E-03	2.85			0.04	0.06			
$PM_{2.5}$	Short-Term	8.00E-03	1.04			0.04	3.55			
	Long-Term	8.00E-03	2.85			0.04	0.06			
SO_2	Short-Term (Hourly)	7.09E-04	0.25 (Annualized)			6.36E-03	5.67E-03 (Annualized)			
	Short-Term (Daily)	7.09E-04	0.73			6.36E-03	0.35			
	Long-Term	7.09E-04	0.25			6.36E-03	5.67E-03			

Table 8-12 Modeling Emissions Summary for Liquefaction Facility Thermal Oxidizer

Pollutant		Thermal Oxidizer Emission (g/s)	Thermal Oxidizer Exhaust Temp (°K)	Thermal Oxidizer Exhaust Velocity (m/s)	Reference to Calculation
NO_x	Short-Term	0.08	1,255	8.90	Sections EC-2 and EC-7
	Long-Term	0.08			
CO	Short-Term	0.06			
PM_{10}	Short-Term	5.64E-03			
	Long-Term	5.64E-03			
$PM_{2.5}$	Short-Term	5.64E-03			
	Long-Term	5.64E-03			
SO_2	Short-Term (Hourly)	2.07E-03			
	Short-Term (Daily)	2.07E-03			
	Long-Term	2.07E-03			

8.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling in that it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the other short-term impact modeling described in **Section 8.3.2**. The short-term particulate matter emissions were speciated in the AQRV analysis as described in the following subsection.

PM Speciation Breakdown

Table 8-13 and **Table 8-14** show the assumed breakdown and basis for the short-term Liquefaction Facility flare and thermal oxidizer emissions of the PM_{10} and $PM_{2.5}$ into filterable and condensable fractions, as required for AQRV modeling.

Table 8-13 AQRV PM Speciation for Liquefaction Facility Flares

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}	
Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (pilot/purge fuel gas, assumed as external combustion source) (USEPA 2009)

Table 8-14 AQRV PM Speciation for Liquefaction Facility Thermal Oxidizer

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}	
Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (USEPA 2009)

9.0 LIQUEFACTION FACILITY MOBILE SOURCES

Mobile sources typically are not included in a PSD Applicability assessment or in PSD modeling, However, mobile source emissions associated with the operational Liquefaction Facility were provided for full assessment of potential Project impacts to air quality in FERC Resource Report 9 submittal. The following sections describe the intended methodology for developing this information.

9.1.1 On Land

There is currently no inventory proposed for the Liquefaction Facility that addresses the required mobile and/or non-road equipment associated with its operation. The current GTP inventory of mobile sources was assumed to be conservatively representative for the Liquefaction Facility, which would be a fairly comparably sized facility. The mobile source emissions were conservative due to the harsher climate and more remote location of the GTP facility. These factors required additional snow removal equipment and man camp/personnel vehicles.

Emissions of NO_x, CO, VOC, SO_2, PM_{10}, $PM_{2.5}$, CO_2, CH_4, N_2O, and HAPs from on-road equipment associated with routine operations were estimated based on USEPA's MOVES2014 motor vehicle emissions estimation program. The latest county-specific MOVES2014 input data available from ADEC was used and adjusted to approximate on-road emission factors for 2027. The assumed first full year of normal operation that does not include additional overlapping construction activities. As previously stated, construction-related emissions are not included in this Report.

The MOVES-generated emission factors (g/mi) for individual vehicle categories were multiplied by the average speeds of the equipment and the corresponding yearly operating hours to estimate annual emissions. The annual operating hours per unit for the vehicles were estimated based on assumed operations of 5 hours per day for garbage and food delivery trucks, 10 hours per month for various delivery and hazardous waste trucks, 20 hours per month for maintenance personnel and vacuum trucks, and 120 hours per month for the intercity bus operation. It was assumed that idling time has been included in the operating hours provided by the facility design team. All emissions were calculated in lb/hr and tons per year. All on-road vehicle types considered for mobile emissions are shown in **Table 9-1**.

The non-road emissions include mobile vehicles that would only be operated on-site, such as cranes and backhoes. Additionally, portable emissions sources were included in this category such as mobile generator sets or air compressors. These portable emission sources would not produce emissions while moving, but would not be bound to one location. The non-road emissions were calculated using Tier 4 standards from the NON-ROAD program for NO_x, CO, PM, and Total Hydrocarbon (THC). The equipment type was assigned a Standard Classification Code (SCC) which connects the equipment type to the emissions. In addition to the emission factors for each pollutant, a load factor from the NMIM/NONROAD08 model factors (USEPA 2010) was applied to the diesel engine capacity to account for efficiency of the engine and to more accurately calculate emissions per normal operating horsepower output. All non-road vehicle types considered for mobile emissions are shown in **Table 9-1**.

Table 9-1 Liquefaction Facility Emitting Mobile and Non-Road Equipment Types

Source Type	Source Description
Mobile	Single Unit Short-Haul Truck
	Light Commercial Truck
	Intercity Bus
	Passenger Truck
Non-Road	Light Commercial Air Compressor
	Graders
	Tractors/Loaders/Backhoes
	Crane
	Rubber Tire Dozer
	Rubber Tire Loader
	Light Commercial Generator Set
	Forklifts
	Aerial Lift
	Skid Steer Loader
	Light Commercial Welders

9.1.2 Marine

9.1.2.1 Facility Supply Vessels

Cargo shipments to the Liquefaction Facility would be coming from surrounding Alaskan cities (mainly Anchorage) via barge and assisting tow tug. The emissions from the trips to the Liquefaction Facility were based on the assumed size of the tow tug and emissions factors from the USEPA's *Current Methodologies in Preparing Mobile Source Port-Related Emissions Inventories* (USEPA 2009), Harbor Craft Emissions Table 3-8. A fleet mixture of Tier 1 and Tier 2 harbor craft emissions, which are applicable to older vessels, were assumed, since these vessels would be operated by a third party and are likely to represent a range of ages. No emissions were assumed for the barges. A barge with propulsion capabilities was assumed to have the same engine size as an appropriate tow tug. Therefore, only one common emissions rate per distance was assumed for all barge/tow activity. All emissions were calculated in units of lb/hr and tons per year.

9.1.2.2 LNG Marine Equipment

Two different sets of emissions were used to represent the Liquefaction Facility marine terminal operations and emissions. For FERC Impact Assessment, all emissions within state waters were calculated for both the LNG carriers and support tugs. For modeling, only emissions produced by the LNG carriers and support tugs within 500 meters of the terminal were considered to be associated with the facility.

The sources of the emission factors that were used to quantify emissions for each marine vessel type associated with the Liquefaction Facility marine are described In **Table 9-2**.

Table 9-2 Data Sources for Marine Equipment Emissions Estimation

Pollutant	Engine Tier Assumption	Category 1 Auxilary Engine	Category 2 Auxilary Engine	Category 3 Auxilary Engine	Internal Combustion Main Propulsion	Steam Main Propulsion
NO_x	Tier 1 & 2	40 CFR 1042 Subpart J		40 CFR 1042 Subpart B		Port-Related Emissions Inventories
	Tier 3 & 4	40 CFR 1042 Subpart B				
CO	Tier 1 & 2	40 CFR 1042 Subpart J				
	Tier 3 & 4	40 CFR 1042 Subpart B				
VOC	Tier 1 & 2	40 CFR 1042 Subpart J				
	Tier 3 & 4	40 CFR 1042 Subpart B				
PM_{10}	Tier 1 & 2	40 CFR 1042 Subpart J		Port-Related Emissions Inventories		
	Tier 3 & 4	40 CFR 1042 Subpart B				
$PM_{2.5}$	Tier 1 & 2	40 CFR 1042 Subpart J				
	Tier 3 & 4	40 CFR 1042 Subpart B				
SO_2	Tier 1 & 2	Mass Balance assuming ULSD with 15 ppm sulfur				
	Tier 3 & 4					
Lead[1]	Tier 1 & 2	Negligible				
	Tier 3 & 4					
Total GHG	Tier 1 & 2	Port-Related Emissions Inventories				
	Tier 3 & 4					
Total HAPs	Tier 1 & 2	AP-42 equipment emission factors, Section 3.3				
	Tier 3 & 4					

Note 1: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

It is currently estimated that 204 LNG carrier vessels per year would call at the Nikiski facility to receive LNG loads for shipment. While it would be possible for two LNG carriers to be docked at the terminal at the same time, it would not be possible for both to be loading LNG simultaneously. Each LNG carrier call is anticipated to last roughly 34.5 hours, with the majority of time, 18 hours, spent hoteling/loading. Additional LNG Carrier operation modes considered within each call are:

- Cruising – vessel at full speed near state-water boundary
- Approach – vessel has slowed to near-terminal speeds, but still outside of terminal boundaries
- Maneuvering – vessel moving into or out of port
- Cool down – stationary phase subsequent to docking
- Hoteling – vessel is stationary at dock but not loading
- Loading – loading LNG
- Purge lines – stationary phase after loading finishes, just prior to undocking

LNG Carriers emissions come from both the main propulsion systems (steam boiler, steam turbine powered or diesel-electric) and the auxiliary diesel engines that would be used to provide power for onboard electrical needs. **Table 9-3** shows the assumptions for each operational mode per marine terminal call, assuming the normal cold arrival of a LNG Carrier. **Table 9-4** describes the assumptions for each operation mode per call for a warm LNG Carrier arrival, which would entail additional time to purge the vessel of inert gas and cool it prior to LNG loading.

Table 9-3 LNG Carrier Operational Modes Per Call – Normal Cold Arrival

Operation Mode	Main Propulsion Engine		Auxiliary Diesel Enigne	
	Time in Mode (hr)	Selected Load	Time in Mode (hr)	Selected Load
Cruising IN	0.8	80%	0.8	80%
Approach IN	2.0	25%	2.0	80%
Far-Terminal Operation Maneuvering IN[1]	1.0	15%	1.0	80%
Near-Terminal Operation Maneuvering IN[1]	1.0	15%	1.0	80%
Cool Down/Vessel Purge	3.5	0% (Shut Down)	3.5	80%
LNG Loading/Hoteling	18	0% (Shut Down)	18	53% (If Loading) 20% (If Hoteling)
Line Purge/Prep	3.5	0% (Shut Down)	3.5	80%
Near-Terminal Operation Maneuvering OUT[1]	1.0	15%	1.0	80%
Far-Terminal Operation Maneuvering OUT[1]	1.0	15%	1.0	80%
Approach OUT	2.0	25%	2.0	80%
Cruising OUT	0.8	80%	0.8	80%

Note 1: Far-Terminal and Near-Terminal operations were differentiated by the distance from the terminal where they occur. Far-Terminal applied to anything outside of a 500 meter radius from the terminal, while Near-Terminal was all activity occurring within 500 meters.

Table 9-4 LNG Carrier Operational Modes Per Call – Warm Arrival

Operation Mode	Main Propulsion Engine		Auxiliary Diesel Enigne	
	Time in Mode (hr)	Selected Load	Time in Mode (hr)	Selected Load
Cruising IN	0.8	80%	0.8	80%
Approach IN	2.0	25%	2.0	80%
Far-Terminal Operation Maneuvering IN[1]	1.0	15%	1.0	80%
Near-Terminal Operation Maneuvering IN[1]	1.0	15%	1.0	80%
Cool Down/Vessel Purge	48	0% (Shut Down)	48	80%
LNG Loading/Hoteling	18	0% (Shut Down)	18	53% (If Loading) 20% (If Hoteling)
Line Purge/Prep	3.5	0% (Shut Down)	3.5	80%
Near-Terminal Operation Maneuvering OUT[1]	1.0	15%	1.0	80%
Far-Terminal Operation Maneuvering OUT[1]	1.0	15%	1.0	80%
Approach OUT	2.0	25%	2.0	80%
Cruising OUT	0.8	80%	0.8	80%

Note 1: Far-Terminal and Near-Terminal operations were differentiated by the distance from the terminal where they occur. Far-Terminal applied to anything outside of a 500 meter radius from the terminal, while Near-Terminal was all activity occurring within 500 meters.

Since most of the fleet would be purpose built, it is expected that the propulsion systems for the LNG carriers loading at the terminal would be dominated by internal combustion (IC) engines, rather than steam turbine engines. Therefore, when calculating emissions, 98% of the carriers loading at the facility were assumed to be powered by IC engines with the remaining 2% powered by steam driven units. Additionally, it was assumed that the vessels powered by IC engines would comprise a fleet of roughly 80% purpose-built vessels and 20% vessels of opportunity. The latter vessels could only arrive at the terminal during the summer periods. The fleet mix that was used for emissions estimation purposes assumed compliance with the International Maritime Organization (IMO) vessel emissions requirements for year 2025 for all purpose-built ships. The IMO standards require Tier 3 from the Port Related Emissions Inventory document and from 40 CFR 1042: Control of Emissions from New and In-Use Marine Compression-Ignition Engines (USEPA 2013) and Vessels and higher emission controls for all engine categories by 2025.

A fleet-weighted average emission factor was used to account for the vessels of opportunity, which could potentially have engines rated at the lower IMO tiers since they could have been built during a previous year. The same type of fleet mix evaluation and weighted emission factors was used for the LNG carrier auxiliary engines.

There would be five facility-dedicated tugs located at the berth at all times, however only four would ever be operating concurrently. The four tugs would be used to assist the LNG Carriers embarking and disembarking within 500 meters of the facility. There would be one additional tug available as a redundant (spare) tug, in the event any other tug requires maintenance such as propeller replacement or cooling system maintenance.

The tug operations were determined based on how they would assist during the LNG Carrier call operational modes. There is a total of 39 hours of tug operation associated with each normal/cool LNG Carrier call, and it is assumed that no additional ice clearing was required in the summer months. The warm LNG Carrier Calls include 69 hours of associated tug operation to account for additional tug needs during the purging and cooling of the LNG Carrier at the berth, again, the tug operation assumes no additional ice clearing during the summer months. Tug operations would only consist of maneuvering and idling. **Table 9-5** describes engine assumptions for each operational mode of the tugs per normal/cool LNG Carrier vessel call without additional ice management requirements (summer). **Table 9-6** describes engine assumptions for each operational mode of the tugs per warm LNG Carrier vessel call without additional ice management requirements (summer). **Table 9-7** describes engine assumptions for each operational mode of the tugs per normal/cool LNG Carrier vessel call with additional ice management requirements (winter). **Table 9-8** describes engine assumptions for each operational mode of the tugs per warm LNG Carrier vessel call with additional ice management requirements (winter).

Table 9-5 Tug Operational Modes Per LNG Carrier Call – Normal No Ice

Operation Mode	Tug Manuevering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	--	--	--	1	4.0	10%
Approach Cruising IN	1	1.0	75%	3	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	1	25.0	75%	3	25.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					39	hours

Table 9-6 Tug Operational Modes Per LNG Carrier Call – Warm No Ice

Operation Mode	Tug Manuevering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	--	--	--	1	4.0	10%
Approach Cruising IN	1	1.0	75%	3	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	1	55.0	75%	3	55.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					69	hours

Table 9-7 Tug Operational Modes Per LNG Carrier Call – Normal with Ice Management

Operation Mode	Tug Manuevering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	1	4.0	75%	1	4.0	10%
Approach Cruising IN	2	1.0	75%	2	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	2	25.0	75%	2	25.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					39	hours

Table 9-8 Tug Operational Modes Per LNG Carrier Call – Warm with Ice Management

Operation Mode	Tug Manuevering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	1	4.0	75%	1	4.0	10%
Approach Cruising IN	2	1.0	75%	2	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	2	55.0	75%	2	55.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					69	hours

The annual PTE emissions for marine sources associated with the Liquefaction Facility were calculated based on a total of 204 calls per year for all types of Carrier arrivals (normal/cool and warm) and also additional ice management requirements during the months of December through May. The total emissions for each call were calculated based on the load and time assumptions given in **Tables 9-3** through **Table 9-8**.

Maximum modeled 1-hour emissions for the marine terminal were based on a conservative assumption of two LNG Carriers calling at nearly the same time. The scenario entailed the first LNG carrier purging its lines in preparation for departing the southern berth after completing LNG loading, while the second carrier begins loading at the northern berth. While both carriers are docked, two tugs are present at all times around the terminal. Both tugs are operating at a high engine load, as one guards the carriers within 800 feet and the other assists with ice maintenance, ensuring that the ice in the area does not prevent carrier arrivals and departures.

Maximum modeled 24-hour marine vessel emissions were also based on a conservative assumption involving two LNG Carriers calling at nearly the same time. This scenario entailed one carrier beginning to load LNG at the southern berth, while a second incoming carrier begins maneuvering within 500 meters of the northern berth with the assistance of all four tugs at a high engine load. Once the second carrier has been docked, it would begin cooling down and purging the vessel cargo compartments in preparation for LNG loading, while two of the tugs return to a standby mode outside of the 500 meter zone. The other two tugs would remain near the carriers at a high engine load to guard the carriers within 800 feet and to assist with ice maintenance operations. After the first carrier has completed the 18 hours of LNG loading, it would begin to purge its lines and prepare for departure from the terminal, while the second carrier commences LNG loading. When the first carrier is ready to depart, all four tugs would be used to maneuver it out of the 500 meter near-terminal operation area, after which two tugs would return to the berth to resume carrier guarding and ice clearing.

The engine load percentages shown in **Tables 9-3** through **Table 9-8** were used to calculate an engine output for each vessel operational mode described in the worst-case short-term scenarios described above. The fleet-weighted emission factors for the LNG Carriers and the tug emission factors were then applied to the operating loads to produce emission rates for each mode that would occur within the specified averaging period.

The LNG Carrier and tug exhaust velocities were calculated because of the current lack of available engine-specific information. Stack diameters for the vessels were assumed based on permitted vessel stack parameters from the Corpus Christi Liquefaction LLC project (Chenier 2013). 40 CFR 60 Method 19: Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates (USEPA 1991) was used to estimate the exhaust flow rates based on an assumed dry oxygen concentration in the exhaust. Equation 19-1 of Method 19 was employed to determine the exhaust flow using an Fd factor, engine output power, and the O_2 concentration. An Fd factor of 9,190 dscf/MMBtu was used since only diesel oil would be used as the fuel for the vessels. The oxygen and water concentrations were assumed to be 8% and a 6.5%, respectively, based on available data for other internal combustion devices (generators/turbines).

9.1.3 Final Mobile and Marine Emissions

The emissions from the mobile and non-road/portable sources used for calculating the potential emissions from mobile equipment are shown in **Sections EC-12** and **EC-13**.

The emissions from the offsite sources used for the near field and far-field modeling are shown in **Sections MEC-1** through **MEC-19**.

10.0 OFF-SITE EMISSIONS SOURCES

The previous sections of this Report have described the development of air pollutant emissions information for the specific sources within the Project facility. This section provides comparable information on the methods that were used to characterize the emissions of off-site facilities that were included explicitly in predicting near-field and far-field cumulative impacts. For purposes of this discussion, "near-field" impacts were those predicted to occur at receptors within a 50-kilometer radius from the Liquefaction Facility, whereas "far-field" impacts were those at distances greater than 50 kilometers. The PSD modeling that was conducted to evaluate near-field cumulative impacts of the Liquefaction Facility for comparison with ambient air quality standards and increment limits explicitly included emissions from existing facilities at Nikiski. Data for the existing facilities were determined from facility permit documents and model input and output files from previous modeling analyses. Assessment of far-field impacts to air quality and AQRVs in Class I and sensitive Class II areas in Alaska required development of much larger modeling emissions inventories of existing sources that were compiled using national and state electronic databases. These emissions data on existing facilities were augmented with estimates for reasonably foreseeable future sources in the project areas that are currently undergoing permitting or construction. The following sections describe the methods and resources that were used to construct the emissions data needed to support both types of modeling analyses.

10.1 EMISSIONS DATA FOR NEAR-FIELD IMPACT ANALYSES

10.1.1 Cumulative Liquefaction Facility Modeling

Existing emissions sources in the vicinity of the proposed Project's Liquefaction Facility site include:

- Tesoro Refinery
- Existing ConocoPhillips Company (COP) Kenai LNG Facility (including ships)
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships)
- Homer Electric Association (HEA) Bernice Lake Power Plant
- Tesoro Kenai Pipe Line (KPL) Marine Loading Terminal (including ships)
- HEA Nikiski Generation Plant

These facilities and associated marine vessels were included explicitly in the NAAQS and PSD increment compliance modeling for the Liquefaction Facility. Other relatively nearby sources were either considered incapable of producing a significant concentration gradient at the Liquefaction Facility site or had impacts that were captured as part of monitored background concentrations included as part of the cumulative impact analysis. As many of the individual emission units at these facilities operate intermittently, it was considered overly conservative to model them at their full PTE levels simultaneously. Furthermore, USEPA has recently proposed modifications to the Guideline on Air Quality Models (USEPA 2011) that explicitly allows for representing nearby sources in cumulative impact analyses at their actual operating conditions. Accordingly, modeling to evaluate cumulative impacts of the Liquefaction Facility used actual operating emissions for the off-site sources listed above in both the NAAQS and PSD increment compliance assessments.

The marine emissions for both the short-term and long-term modeling impacts were calculated based on a known 2010 inventory within the Cook Inlet, then scaled by an annual growth rate for increased activity to account for development of the Liquefaction Facility not occurring until much later. There is only one berth present, therefore only one vessel can call at a time. The maximum emissions from all vessel types was assumed for the short-term emissions and the increased total calls per year was assumed at the maximum emissions rate for the total annual.

Modeling representations of the listed off-site sources were determined from a cumulative analysis conducted for a recent construction permitting project at Nikiski (Agrium), and actual emissions for these facilities were taken from the ADEC point source emissions inventory for 2011 to match the NEI Database (NEI 2011) that was used to support the far-field air quality and AQRV modeling analyses. No stack parameter information was available for modeling the vessels, the offsite source vessels were assumed to have the same stack parameters as the Liquefaction Facility marine terminal.

The ARM2 NO and NO_2 chemical transformation algorithm was used for predicting cumulative NO_2 impacts. This method does not rely on source-specific in-stack ratios, but rather applies an ambient ratio to the 1-hour modeled NO_x concentrations based on a formula derived empirically from ambient monitored ratios of NO_2/NO_x. It includes default upper and lower limits on the ambient ratio applied to the modeled concentration of 0.9 and 0.2, respectively.

Speciation of particulate matter emissions from the off-site emission units was estimated using $PM_{10}/PM_{2.5}$ splits for the appropriate facility equipment categories, as provided in the USEPA AP-42 compilation (USEPA 2009). The relevant splits and corresponding AP-42 citations are presented in **Table 10-1**.

Table 10-1 PM Speciation Assumed for Equipment at Nikiski Off-Site Sources

Equipment	Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
			$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}	
Turbines	Gas	0	29%	29%	71%	71%	AP-42 Table 3.1-2a (USEPA 2009)
Heaters/ Boilers	Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (USEPA 2009)
Generator	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 (USEPA 2009)
Generator	Gas	0	49%	49%	51%	51%	AP-42 Table 3.2-3 (USEPA 2009)
Pump	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 (USEPA 2009)
Pump	Gas	0	49%	49%	51%	51%	AP-42 Table 3.2-3 (USEPA 2009)
Flares	Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (pilot/purge fuel gas, assumed as external combustion source) (USEPA 2009)
Cooling Tower	N/A	0	0%	0%	100%	100%	The particulates from cooling towers are hygroscopic particles which are likely organic - therefore assumed 100% SOA.

10.2 EMISSIONS DATA FOR FAR-FIELD IMPACT ANALYSES

PSD Applicability determinations required dispersion modeling to evaluate Liquefaction Facility impacts at Class I areas located within 300 kilometers of the facility, including air quality and AQRVs (visibility, acid deposition, impacts to soils and vegetation). It is also anticipated that Federal Land Managers (FLMs) will request additional modeling to evaluate the impacts of these facilities, as well as those of other existing sources and reasonably foreseeable future developments, at several Class II areas that are considered by these agencies to be potentially sensitive to air quality and related impacts from the Project facility.

The Class I and Class II areas for which Liquefaction Facility impacts were modeled:

- Denali National Park and Preserve (Class I)
- Tuxedni National Wildlife Refuge (Class I)
- Kenai National Wildlife Refuge (Class II)
- Lake Clark National Park and Preserve (Class II)
- Kenai Fjords National Park (Class II)
- Chugach State Park (Class II)
- Kodiak National Wildlife Refuge (Class II)

10.2.1 Emissions Databases to Support Far-Field Modeling

Far-field modeling to evaluate cumulative impacts at the Class I and Class II areas identified in the previous section involved searches of emissions databases compiled by National Emissions Inventory (NEI) and ADEC, as described in the following subsections. The NEI database (NEI 2011) was used to compile all active facilities near the proposed project locations, while the ADEC Point Source (ADEC 2011) reports provided detailed actual emissions data specific to those facilities that have been identified as potential contributors to the cumulative impacts of the proposed facility.

10.2.1.1 NEI Database

The NEI is a comprehensive and detailed inventory of air emissions for criteria pollutants and precursors, as well as hazardous air pollutants, from stationary air emissions sources. Sources in the NEI include large industrial facilities and electric power plants, airports, and smaller industrial, non-industrial and commercial facilities. A small number of portable sources such as some asphalt and rock crushing operations are also included. The NEI database for a given year includes actual emissions for all criteria pollutants in tons per year, modeled stack parameters and coordinates for all point sources. The most recent available inventory for Alaska was compiled for calendar year 2011. This database was the primary resource available for identifying off-site emission sources to be included in the far-field modeling analyses for the Liquefaction Facility.

10.2.1.2 ADEC Point Source Database

The ADEC is required by Federal Regulation 40 CFR 51.30 to submit an annual statewide point-source emission inventory report to USEPA. This report is required to include all sources with potential emissions at or above one of the following thresholds: 2,500 tons per year of SO_x, NO_x, or CO or 250 tons per year of VOC, PM_{10}, or $PM_{2.5}$. This database (ADEC 2011) was used in combination with the NEI database to ensure that all potentially significant sources are included.

10.2.2 Identifying Off-Site Sources

A computer program was used to search the 2011 NEI database (NEI 2011) for Alaska. Any source located within 300 km of a Class I or Class II area receptor and inside the modeling domain was included. The boundary of the modeling domain was defined by pre-developed meteorological datasets that have been accepted for modeling for the area within Alaska that contain the proposed Liquefaction Facility sites.

In order to screen this inventory to remove sources too small to impact the cumulative analysis, a Q/d analysis was conducted following the FLAG 2010 guidance (NPS 2010) on all of the sources previously identified. The total facility emissions (Q) in tons were obtained by adding together the annual emissions for the three main criteria pollutants specified by FLAG 2010: NO_x, SO_2, and PM_{10}. The Q/d guideline specifies the use of maximum short-term PTE level emissions for this purpose. Since the NEI database only contains actual emissions, these facility totals were doubled to approximate PTE levels. Note that FLAG 2010 also specifies that H_2SO_4 emissions should be added to the total facility emissions for the Q/d calculation. The NEI Database PM emissions data are presented as primary PM_{10} (PM10-PRI), which was assumed to include both the filterable and condensable particulate matter fractions, which would include the conversion of the SO_2 to H_2SO_4.

The distances (d) between point sources and the Class I and II locations in kilometers were provided by a computer program and were supplemented by using the Google Earth measurement tool, as needed. The distances for each facility were determined by taking the closest distance from the individual facility's point sources to the Class I/II location.

Finally, the total annual emissions for each source facility in tons were divided by the corresponding average distance in kilometers to obtain a Q/d value. Using thresholds identified in the FLAG 2010 guidance (NPS 2010), only facilities with a Q/d value or equal to or greater than 10 were included in the final offsite source inventory for far-field modeling.

10.2.3 Modeling Representation of Off-Site Sources

Facilities close to the Liquefaction facilities were modeled as point sources for the near-field modeling (see **Sections 10.1**), and were also included as point sources in the far-field modeling. The additional sources that were added by means of the Q/d analysis described in the previous section, were modeled as volume sources for simplicity and consistency. This representation, which used emission totals over all emission units within a given facility, was necessary to prevent an excessive number of individual stack sources in the far-field simulations.

10.2.3.1 Point Source Modeling Parameters

As described previously, offsite sources within 50 km of the Project facility were included in the near-field (AERMOD) impact assessment and were modeled as point sources at either their PTE emissions or actual emission rates. These sources also carried the same point source representations into the far-field (CALMET/CALPUFF) modeling analysis with the more distant sources from the Q/d screening.

All off-site sources in the far-field modeling were represented by actual emissions, rather than PTE, as is now allowed by USEPA according to recently proposed revisions to the Appendix W modeling guidelines (USEPA 2011).

Particulate matter speciation for these point sources in the AQRV modeling was based on individual equipment type/size and corresponding filterable/condensable $PM_{10/2.5}$ splits consistent with those previously described for the near-field off-site inventory (**Table 10-1**).

10.2.3.2 Volume Source Modeling Parameters

Far-field off-site sources were modeled as volume sources as previously described. The actual criteria pollutant emissions for a particular facility were represented as the summation over all contributing point sources, as obtained from the NEI Database (NEI 2011) (not doubled as in the Q/d analysis).

For conservatism with respect to the predicted visibility impacts, all filterable particulate matter, including that from non-combustion sources, was treated as elemental carbon, and all condensable particulate matter was treated as secondary organic aerosols. The NEI Database (NEI 2011) includes information on filterable PM_{10}, filterable $PM_{2.5}$ and condensable PM for all listed Alaska sources, except the Ted Stevens Airport in Anchorage. This facility was included in the far-field impacts analysis for the Liquefaction Facility. For this airport, the Total PM (PM10-PRI and PM2.5-PRI) was assumed to result from equal parts of mobile diesel sources, diesel generators, gas-fired heaters, and diesel-fired heaters. AP-42 PM speciation data was used for the stationary sources, and emission factors were derived from the MOVES emissions model for the airport's mobile diesel sources.

In far-field modeling for the Liquefaction Facility, the ARM2 method, which does not rely on stack-specific ratios, was used to estimate NO_2 impacts.

For consistency, all volume sources were given the same source dimensions of 10 meters wide, by 10 meters long, and 10 meters in height, as shown in **Table 10-2**. The Sigma-Y and Sigma-Z dimensions are based on a modeling approach that assigns the initial lateral dimension (Sigma-Y) to the length of the side divided by 4.3 and the initial vertical dimension (Sigma-Z) as the height divided by 4.3 also, if the elevated source is not adjacent to a building.

Table 10-2 Far-Field Modeling Volume Source Dimensions

RELEASE HEIGHT (M)	SIGMA-Y (M)	SIGMA-Z (M)
10	2.33	2.33

Sigma-y and sigma-z are measures of the volume source's horizontal and vertical dimensions.

10.2.3.3 Model Parameters for Reasonably Foreseeable Development (RFD)

In order to ensure that potential impacts in the Class I and Class II areas were fully addressed, ADEC was contacted regarding other new projects throughout the state that are currently engaged in the permitting process or in construction, and may become operational over the next several years. Lists of such projects were provided by ADEC for the modeling domain containing the Project's Liquefaction Facility. Information on the corresponding emissions was obtained from permit documents available on the ADEC website (ADEC 2015). Specifically, maximum allowable (PTE) emissions totaled over all emitting equipment at a new facility were used. The same Q/d analysis described above for existing sources was also used for the RFD sources to screen out those for which projected emissions are below a level of concern. Projects exceeding the Q/d criteria were represented as volume sources with the dimensions described in the previous section. The conservative USEPA (USEPA 2011) default NO_2/NO_x ratio of 0.5 was used for all these future sources in the modeling to estimate NO_2.

In Appendix L – Cumulative Impacts of Resource Report #1, Table 1 provides a list of RFDs to be considered in assessing cumulative environmental impacts of the AKLNG facilities. For each identified project, publicly available information was used to provide a brief description of the activity, as well as a "timeframe for construction and operation, location, footprint, and potential resource impacts that would need to be considered in conjunction with Project resource impacts." Air quality is listed as a potentially affected resource for nearly all of the listed projects since at least some emissions of air pollutants would occur during construction, operations or both.

However, not all of the projects listed in Table 1 of Appendix L were included in the long-range cumulative modeling. Reasons for excluding specific projects from the far-field modeling analysis are described below:

- Many of the projects are scheduled for completion by 2014 or 2015. By using the available historical air quality monitoring data to establish background concentrations for the area, the cumulative analysis included the contributions of these sources without explicitly modeling them.
- Some of the projects will be at a considerable distance from the proposed Liquefaction Facility location, or constitute a minor modification of an existing facility that would introduce minimal incremental emissions. These two factors would result in very small Q/d values that would screen out such projects from the modeling. (See **Section 10.2.2**)
- Many of the projects are currently only at the conceptual and/or study phase, such that the parameters needed for a meaningful estimation of emissions are insufficiently defined.

Additionally, the long-range modeling included a few RFDs that were not identified in the Appendix L list. As noted above, the final list of RFDs for the modeling analysis was developed in direct discussions with ADEC.

10.2.4 Final Offsite Sources with Emissions

The emissions from the offsite sources used for the near field and far-field modeling are shown in Sections EC-12.

11.0 ACRONYMS AND TERMS

AAAQS	Alaska Ambient Air Quality Standards
ADEC	Alaska Department of Environmental Conservation
ARM2	Ambient Ratio Method 2
BTU	British Thermal Unit
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
FERC	Federal Energy Regulatory Commission
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
GHG	Greenhouse Gas
GTP	Gas Treatment Plant
HAP	Hazardous Air Pollutant
HP	High Pressure
HRSG	Heat Recovery Stream Generator
IC	Internal Combustion
IMO	International Maritime Organization
LNG	Liquefied Natural Gas
lb/hr	Pounds per hour
LP	Low pressure
MM	Million
MMSCFD	Million Standard Cubic Feet per Day
NAAQS	National Ambient Air Quality Standards
N_2O	Nitrous Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
Pb	Lead
PBU	Prudhoe Bay Unit
$PM_{2.5}$	Particulate matter having an aerodynamic diameter of 2.5 microns or less
PM_{10}	Particulate matter having an aerodynamic diameter of 10 microns or less
PMF	Particulate Matter Fine – from non-combustion sources
ppmv	Parts per million by volume
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTU	Point Thomson Unit
RICE	Reciprocating Internal Combustion Engine
SF	Supplemental Firing
SO_2	Sulfur Dioxide
tpy	Tons per Year
USEPA	U.S. Environmental Protection Agency
VOC	Volatile Organic Compounds
WHRU	Waste Heat Recovery Unit

12.0 REFERENCES

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EC-1 LIQUEFACTION FACILITY POTENTIAL TO EMIT SUMMARY

Model ID	Source Description	Annual Operating Hours	Potential to Emit (PTE) Emission Rates																							
			NO_x		CO			VOC		PM_{10}			$PM_{2.5}$			SO_2 @ 16 ppmvd			CO_2	CH_4	N_2O	CO_2e	HAPs (Formaldehyde)		HAPs (Total)	
			lb/hr	tpy	lb/hr	lb/8-hr	tpy	lb/hr	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	tonnesyr	tonnes/yr	tonnes/yr	tonnes/yr	lb/hr	tpy	lb/hr	tpy
TURB1	Train 1a Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB2	Train 1b Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB3	Train 2a Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB4	Train 2b Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB5	Train 3a Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB6	Train 3b Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TRB_GEN1	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
TRB_GEN2	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
TRB_GEN3	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
TRB_GEN4	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
Aux_COMP	Auxiliary Air Compressor (224 kW)	500	0.25	0.06	2.16	17.26	0.54	0.12	0.03	0.01	0.30	3.08E-03	0.01	0.30	0.00	0.00	0.07	7.33E-04	77.66	0.00	0.00	77.92	0.00	0.00	0.01	2.12E-03
FPUMP	Firewater Pump (429 kW)	500	4.52	1.13	4.12	32.96	1.03	0.24	0.06	0.24	5.70	0.06	0.24	5.70	0.06	0.01	0.13	1.40E-03	148.84	0.01	0.00	149.36	0.00	0.00	0.02	4.07E-03
FLARE_1D	Dry Flare Pilot/Purge	8760	0.49	2.13	2.22	17.73	9.71	4.08	17.85	0.20	4.84	0.88	0.20	4.84	0.88	0.02	0.41	0.08	3323.36	0.06	0.01	3326.79	0.01	0.04	0.02	0.09
FLARE_2D	Dry Flare Pilot/Purge	8760	0.49	2.13	2.22	17.73	9.71	4.08	17.85	0.20	4.84	0.88	0.20	4.84	0.88	0.02	0.41	0.08	3323.36	0.06	0.01	3326.79	0.01	0.04	0.02	0.09
	Dry Flare Pilot/Purge (Not Modeled)	8760																								
FLARE_1W	Wet Flare Pilot/Purge	8760	0.15	0.67	0.70	5.58	3.06	1.28	5.62	0.06	1.52	0.28	0.06	1.52	0.28	0.01	0.14	0.02	1045.81	0.02	0.00	1046.89	0.00	0.01	0.01	0.03
FLARE_2W	Wet Flare Pilot/Purge	8760	0.15	0.67	0.70	5.58	3.06	1.28	5.62	0.06	1.52	0.28	0.06	1.52	0.28	0.01	0.14	0.02	1045.81	0.02	0.00	1046.89	0.00	0.01	0.01	0.03
	Wet Flare Pilot/Purge (Not Modeled)	8760																								
DRY_MAX1	Dry Flare Maximum Case	500	2039.73	1019.86	9298.76	9298.76	4649.38	17097.72	8548.86	846.49	846.49	423.25	846.49	846.49	423.25	74.75	74.75	37.38	1591587.76	30.00	3.00	1593231.54	34.38	17.19	86.90	43.45
DRY_MAX2	Dry Flare Maximum Case	500	2039.73	1019.86	9298.76	9298.76	4649.38	17097.72	8548.86	846.49	846.49	423.25	846.49	846.49	423.25	74.75	74.75	37.38	1591587.76	30.00	3.00	1593231.54	34.38	17.19	86.90	43.45
	Dry Flare Maximum Case (Not Modeled)	500																								
WET_MAX1	Wet Flare Maximum Case	500	476.68	238.34	2173.10	2173.10	1086.55	3995.70	1997.85	197.82	197.82	98.91	197.82	197.82	98.91	17.48	17.48	8.74	371950.60	7.01	0.70	372334.75	8.03	4.02	20.31	10.15
WET_MAX2	Wet Flare Maximum Case	500	476.68	238.34	2173.10	2173.10	1086.55	3995.70	1997.85	197.82	197.82	98.91	197.82	197.82	98.91	17.48	17.48	8.74	371950.60	7.01	0.70	372334.75	8.03	4.02	20.31	10.15
	Wet Flare Maximum Case (Not Modeled)	500																								
LP_FLARE	LP Flare Pilot/Purge	8760	0.71	3.13	3.26	26.04	14.26	5.99	26.21	0.30	7.11	1.30	0.30	7.11	1.30	0.05	1.21	0.22	4880.46	0.09	0.01	4885.50	0.01	0.05	0.03	0.13
LP_MAX	LP Flare Maximum Flow (Maintenance)	144	71.37	5.14	311.38	2491.02	22.42	568.58	40.94	28.15	675.59	2.03	28.15	675.59	2.03	2.74	65.72	0.20	7621.54	0.14	0.01	7629.41	1.14	0.08	2.89	0.21
TH_OX	Thermal Oxidizer	8760	0.60	2.63	0.49	3.96	2.17	0.03	0.14	0.04	1.07	0.20	0.04	1.07	0.20	0.02	0.39	0.07	2793.48	0.05	0.01	2796.37	0.00	0.00	0.01	0.05
	Tank Emissions	8760																								
	Fugitive Emissions	8760						4.10	17.96											96.95		2,424				
	Mobile Equipment Emissions (Normal Operation)	8760		3.26			3.26		0.33			0.19			0.17			0.02	2,160	0.13	0	2,165				0
	Non-Road/Portable Equipment Emissions (Normal Operation)	8760		7.59			3.22		2.43			0.69			0.69											
	Marine Terminal Emissions (Normal Operation)	8760	279.31	379.59	457.69	3661.53	630.38	59.17	116.58	13.33	319.84	14.01	12.26	294.18	12.98	18.28	438.81	1.17				81247.80			0.31	0.33
Total Emissions (Without Maximum Flare)			**642.3**	**1,560.1**	**1,198.5**	**9,587.7**	**2,364.6**	**668.5**	**332.1**	**104.2**	**2,499.7**	**273.9**	**103.1**	**2,474.1**	**272.8**	**43.0**	**1,030.9**	**91.5**	**3,844,333.2**	**169.5**	**7.3**	**3,931,979.3**	**7.0**	**25.8**	**11.8**	**38.0**
Total Emissions (With Maximum Flare)			**5,675.1**	**4,076.5**	**24,142.2**	**32,531.4**	**13,836.5**	**42,855.4**	**21,425.6**	**2,192.8**	**4,588.4**	**1,318.2**	**2,191.7**	**4,562.7**	**1,317.1**	**227.4**	**1,215.4**	**183.8**	**7,771,409.9**	**243.5**	**14.7**	**7,863,111.9**	**91.8**	**68.2**	**226.2**	**145.2**

8 CO Standard Requirement
24 Intermittent unit hours/day operation
24 Non-intermittent unit hours/day operation
0.5 Flare hours/day operation

EC-2 LIQUEFACTION FACILITY MODELED EMISSIONS SUMMARY

Modeled ID	Emission Unit	Configuration	Coordinates (UTM)		Base Elevation	Modeled Height		Temperature		Velocity		Diameter		In-Stack Ratio	NOx			CO		PM_{10}		$PM_{2.5}$		SO_2 @16 ppmvd		
			x	y	(m)	(ft)	(m)	(°F)	(°K)	(ft/s)	(m/s)	(ft)	(m)	(-)	1-hour	24-hour	Annual	1-hour	8-hour	24-hour	Annual	24-hour	Annual	1-hour	3&24-hour	Annual
Turbines																										
TURB1	Train 1a Compression Turbine Stack	Vert./no Cap	589612.04	6726290.1	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01
TURB2	Train 1b Compression Turbine Stack	Vert./no Cap	589704.73	6726354	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01
TURB3	Train 2a Compression Turbine Stack	Vert./no Cap	589477.15	6726485.3	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01
TURB4	Train 2b Compression Turbine Stack	Vert./no Cap	589570.16	6726549.4	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01
TURB5	Train 3a Compression Turbine Stack	Vert./no Cap	589343.13	6726679.9	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01
TURB6	Train 3b Compression Turbine Stack	Vert./no Cap	589435.88	6726744.2	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01
TRB_GEN1	Power Generator Turbines	Vert./no Cap	589851.09	6726009.6	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01
TRB_GEN2	Power Generator Turbines	Vert./no Cap	589931.34	6726064.9	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01
TRB_GEN3	Power Generator Turbines	Vert./no Cap	590011.59	6726120.3	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01
TRB_GEN4	Power Generator Turbines	Vert./no Cap	590091.83	6726175.8	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01
Diesel Equipment																										
Aux_COMP	Auxiliary Air Compressor (224 kW)[1]	Vert./no Cap	589576.44	6726013.5	38.0	10.00	3.05	883.00	745.93	115.00	35.05	0.67	0.20	0.50	1.77E-03	3.11E-02	1.77E-03	2.72E-01	2.72E-01	1.55E-03	8.87E-05	1.55E-03	8.87E-05	2.11E-05	3.69E-04	2.11E-05
FPUMP	Firewater Pump (429 kW)[1]	Vert./no Cap	590146.73	6726056.2	38.0	10.00	3.05	908.00	759.82	157.00	47.85	0.67	0.20	0.50	3.25E-02	5.69E-01	3.25E-02	5.19E-01	5.19E-01	2.99E-02	1.71E-03	2.99E-02	1.71E-03	4.04E-05	7.08E-04	4.04E-05
Flares																										
FLARE_1D	Dry Flare Pilot/Purge	Vert./no Cap	589999.69	6725837.1	38.0	7.56	2.30	1831.73	1273.00	65.62	20.00	1.46	0.45	0.50	6.13E-02	6.13E-02	6.13E-02	2.79E-01	2.79E-01	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.17E-03	2.17E-03	2.17E-03
FLARE_2D	Dry Flare Pilot/Purge	Vert./no Cap	590097.74	6725906.3	38.0	7.56	2.30	1831.73	1273.00	65.62	20.00	1.46	0.45	0.50	6.13E-02	6.13E-02	6.13E-02	2.79E-01	2.79E-01	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.17E-03	2.17E-03	2.17E-03
FLARE_1W	Wet Flare Pilot/Purge	Vert./no Cap	589999.69	6725837.1	38.0	4.35	1.32	1831.73	1273.00	65.62	20.00	0.82	0.25	0.50	1.93E-02	1.93E-02	1.93E-02	8.79E-02	8.79E-02	8.00E-03	8.00E-03	8.00E-03	8.00E-03	7.09E-04	7.09E-04	7.09E-04
FLARE_2W	Wet Flare Pilot/Purge	Vert./no Cap	590097.74	6725906.3	38.0	4.35	1.32	1831.73	1273.00	65.62	20.00	0.82	0.25	0.50	1.93E-02	1.93E-02	1.93E-02	8.79E-02	8.79E-02	8.00E-03	8.00E-03	8.00E-03	8.00E-03	7.09E-04	7.09E-04	7.09E-04
DRY_MAX1	Dry Flare Maximum Case[1]	Vert./no Cap	589999.69	6725837.1	38.0	567.00	172.82	1831.73	1273.00	65.62	20.00	133.98	40.84	0.50	2.93E+01	1.07E+01	2.93E+01	1.17E+03	1.46E+02	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.08E+00	3.14E+00	1.08E+00
DRY_MAX2	Dry Flare Maximum Case[1]	Vert./no Cap	590097.74	6725906.3	38.0	567.00	172.82	1831.73	1273.00	65.62	20.00	133.98	40.84	0.50	2.93E+01	1.07E+01	2.93E+01	1.17E+03	1.46E+02	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.08E+00	3.14E+00	1.08E+00
WET_MAX1	Wet Flare Maximum Case[1]	Vert./no Cap	589999.69	6725837.1	38.0	283.14	86.30	1831.73	1273.00	65.62	20.00	64.80	19.75	0.50	6.86E+00	2.50E+00	6.86E+00	2.74E+02	3.42E+01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.51E-01	7.34E-01	2.51E-01
WET_MAX2	Wet Flare Maximum Case[1]	Vert./no Cap	590097.74	6725906.3	38.0	283.14	86.30	1831.73	1273.00	65.62	20.00	64.80	19.75	0.50	6.86E+00	2.50E+00	6.86E+00	2.74E+02	3.42E+01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.51E-01	7.34E-01	2.51E-01
LP_FLARE	LP Flare Pilot/Purge	Vert./no Cap	589339.8	6726051.8	38.0	208.08	63.42	1831.73	1273.00	65.62	20.00	1.77	0.54	0.50	9.00E-02	9.00E-02	9.00E-02	4.10E-01	4.10E-01	3.73E-02	3.73E-02	3.73E-02	3.73E-02	6.36E-03	6.36E-03	6.36E-03
LP_MAX	LP Flare Maximum Flow[1] (Maintenance)	Vert./no Cap	589339.8	6726051.8	38.0	278.94	85.02	1831.73	1273.00	65.62	20.00	17.26	5.26	0.50	1.48E-01	8.99E+00	1.48E-01	3.92E+01	3.92E+01	3.55E+00	5.83E-02	3.55E+00	5.83E-02	5.67E-03	3.45E-01	5.67E-03
TH_OX	Thermal Oxidizer	Vert./no Cap	589545.89	6725947.9	38.0	47.00	14.33	1800.00	1255.37	8.90	2.71	5.00	1.52	0.50	7.57E-02	7.57E-02	7.57E-02	6.24E-02	6.24E-02	5.64E-03	5.64E-03	5.64E-03	5.64E-03	2.07E-03	2.07E-03	2.07E-03
Total Emissions (Without Maximum Flare)															**36.33**	**45.74**	**33.65**	**93.33**	**93.33**	**11.44**	**7.45**	**11.44**	**7.45**	**2.77**	**3.11**	**2.60**
Total Emissions (With Maximum Flare)															**108.72**	**72.16**	**106.04**	**2984.18**	**454.69**	**22.41**	**37.49**	**22.41**	**37.49**	**5.42**	**10.86**	**5.25**

NOTES

500 hours	Intermittent Diesel Equipment has been modeled with an annual value based on operating only 500 hours/year.
500 hours	Maximum Flaring Events have been modeled with an annual value based on operating only 500 hours/year.
144 hours	Maximum LP Flaring Events have been modeled with an annual value based on operating only 144 hours/year.
8,760 hours	Annual hours
0.5 hours	Per day maximum flare operation

1 Intermittent equipment 1-hr NOx and SO2 emissions can be annualized

Modeled ID	Emission Unit	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
				g/s	g/s	g/s	g/s	g/s
Turbines								
TURB1	Train 1a Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB2	Train 1b Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB3	Train 2a Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB4	Train 2b Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB5	Train 3a Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB6	Train 3b Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TRB_GEN1	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
TRB_GEN2	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
TRB_GEN3	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
TRB_GEN4	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
Diesel Equipment								
Aux_COMP	Auxiliary Air Compressor (224 kW)[1]	Compressor	Diesel	0.000E+00	1.338E-03	1.345E-03	2.151E-04	2.088E-04
FPUMP	Firewater Pump (429 kW)[1]	Pump	Diesel	0.000E+00	2.580E-02	2.592E-02	4.147E-03	4.024E-03
Flares								
FLARE_1D	Dry Flare Pilot/Purge	Flare	Gas	0.000E+00	6.356E-03	6.356E-03	1.907E-02	1.907E-02
FLARE_2D	Dry Flare Pilot/Purge	Flare	Gas	0.000E+00	6.356E-03	6.356E-03	1.907E-02	1.907E-02
FLARE_1W	Wet Flare Pilot/Purge	Flare	Gas	0.000E+00	2.000E-03	2.000E-03	6.000E-03	6.000E-03
FLARE_2W	Wet Flare Pilot/Purge	Flare	Gas	0.000E+00	2.000E-03	2.000E-03	6.000E-03	6.000E-03
DRY_MAX1	Dry Flare Maximum Case[1]	Flare	Gas	0.000E+00	1.111E+00	1.111E+00	3.333E+00	3.333E+00
DRY_MAX2	Dry Flare Maximum Case[1]	Flare	Gas	0.000E+00	1.111E+00	1.111E+00	3.333E+00	3.333E+00
WET_MAX1	Wet Flare Maximum Case[1]	Flare	Gas	0.000E+00	2.596E-01	2.596E-01	7.789E-01	7.789E-01
WET_MAX2	Wet Flare Maximum Case[1]	Flare	Gas	0.000E+00	2.596E-01	2.596E-01	7.789E-01	7.789E-01
LP_FLARE	LP Flare Pilot/Purge	Flare	Gas	0.000E+00	9.334E-03	9.334E-03	2.800E-02	2.800E-02
LP_MAX	LP Flare Maximum Flow[1] (Maintenance)	Flare	Gas	0.000E+00	8.867E-01	8.867E-01	2.660E+00	2.660E+00
TH_OX	Thermal Oxidizer	Heater	Gas	0.000E+00	1.411E-03	1.411E-03	4.232E-03	4.232E-03
Total Emissions (Without Maximum Flare)								
Total Emissions (With Maximum Flare)								

NOTES

500 hours	Intermittent Diesel Equipment has been modeled with an annual value based on operating only 500 hours/year.
500 hours	Maximum Flaring Events have been modeled with an annual value based on operating only 500 hours/year.
144 hours	Maximum LP Flaring Events have been modeled with an annual value based on operating only 144 hours/year.
8,760 hours	Annual hours
0.5 hours	Per day maximum flare operation

1 Intermittent equipment 1-hr NOx and SO2 emissions can be annualized

EC-3 LIQUEFACTION FACILITY FUEL SPECIFICATIONS

LNG Fuel Gas Specification

Component	% By Volume	MW
N_2 - Nitrogen	0.6872	
CO_2 - Carbon Dioxide	0.005	
H_2O - Water		
O_2 - Oxygen	0.001	
Ar - Argon		
H_2 - Hydrogen		
CH_4 - Methane	91.1475	
C_2H_6 - Ethane	5.8251	
C_3H_8 - Propane	1.8872	
C_4H_{10} - IsoButane	0.1374	
C_4H_{10} - Normal Butane	0.2056	
C_5H_{12} - IsoPentane	0.0463	
C_5H_{12} - N-Pentane	0.0443	
C_6H_{14} - 2-Methylpentane	0.0017	
C_6H_{14} - Hexane	0.0023	
C_6H_{12} -Methylcyclopentane	0.0013	
C_6H_{12} - Cyclohexane	0.0012	
C_7H_{16} - Heptane	0.0041	
C_7H_{14} - Methylcyclohexane	0.0011	
C_8H_{18} - Octane	0.001	
C_9H_{20} - Nonane	0.0003	
$C_{10}H_{22}$ - Decane	0.0001	
$C_{10}H_{18}$ - Heavy Oil		
$C_{12}H_{26}$ - Distillate		
C_6H_6 - Benzene		
C_7H_8 - Toluene		
C_8H_{10} - Xylene		
C_8H_8 - Styrene		
Hg - Mercury		
C_2H_4 - Ethylene		
C_2H_2 - Acetylene		
C_3H_6 - Propylene		
C_4H_8 - Butylene		
C_4H_6 - Butadienes		
C_6H_{12} - Hexene		
CH_3OH - Methanol		
C_2H_5OH - Ethyl Alcohol		
CO - Carbon Monoxide		
NO - Nitric Oxide		
NO_2 - Nitrogen Dioxide		
NH_3 - Ammonia		
H_2S - Hydrogen Sulfide COS - Carbonyl Sulfide $C_2H_6S_2$ - DiMethyl DiSulfide SO_2	0.0016	64.066
Properties		
Temp		
MW	17.6800	
Fuel Heating Value at 82ºF:		
Net (Btu/lbm)		
Net (Btu/scf)	981.0000	
Gross (Btu/lbm)		
Gross (Btu/scf)	1087.0000	
scf defined at 14.676 psia, 60F		

Notes:

1 Normal maximum sulfur based on 16 ppmv for total sulfur being equal to the pipeline specification of 1 grain/100 scf. This assumes all H2S and other mercaptans are included in Sulfur value

LNG Diesel Fuel Specification

Sulfur Content (H2S)	15	ppm	Assume ULSD required	
Specific Gravity	0.855		average value at 60oF	
Density	7.1307	lb/gal		
LHV	0.131133573	MMBtu/gal		
LHV	18,390	Btu/lb		
HHV	0.14424693	MMBtu/gal	Assumed 10% higher than LHV	
HHV	20,229	Btu/lb		
lb SO2/gal Fuel	0.000201337			

EC-4 LIQUEFACTION FACILITY FUEL GAS-DRIVEN TURBINES

EMISSION FACTORS	Standard Factors		Special/Vendor						
	AP42 Table 3.1-1 and 3.1-2a	40 CFR Part 98 (Natural Gas)		Ambient Temp Basis (F)	Load % Basis	Compression Turbine Vendor	Ambient Temp Basis (F)	Load % Basis	Power Generation Turbine Vendor
NOx (lb/MMBtu)	0.341		Short-Term ppmvd @ 15% NOx	-30.00	100%	9.00	-30.00	100%	9.00
CO (lb/MMBtu)	0.087		Short-Term ppmvd @ 15% CO	-30.00	100%	25.00	-30.00	100%	8.00
VOC (lb/MMBtu)	0.002		Annual ppmvd @ 15% NOx	40.00	100%	9.00	40.00	100%	9.00
PM10 (lb/MMBtu)	0.007		Annual ppmvd @ 15% CO	40.00	100%	25.00	40.00	100%	5.00
PM2.5 (lb/MMBtu)	0.007								
CO2 (kg CO2/MMBtu)		53.060							
CH4 (kg CH4/MMBtu)		0.001							
N2O (kg N2O/MMBtu)		0.0001							

Notes:

1.) Emission Factors have been convert to AlaskaLNG fuel gas HHV by ratio of project fuel gas/1020 (btu/scf)

EMISSIONS CALCULATIONS	Compressor Turbines		Power Generation Turbines with CO Catalyst and HRSG		References/Comments
Turbine Parameters	Short-Term	Annual	Short-Term	Annual	
Total Installed	6	6	4	4	From CB&I/Chiyoda Calculation
Ambient Temperature Basis (F)	-30	40	-30	40	
Load % Basis	100%	100%	100%	100%	
Operation (hr/yr)	8,760	8,760	8,760	8,760	
Device Power (hp)	155,760	152,876	60,603	53,756	
Device Power (kW)	116,150	114,000	45,192	40,086	From CB&I/Chiyoda Calculation - Output
Turbine Heat Input HHV (MMBtu/hr)	1,170	1,113	433	384	From CB&I/Chiyoda Calculation
Fuel Flow Rate (lbmol/hr)	2,845	2,706	1,052	933	From CB&I/Chiyoda Calculation
Exhaust Flow MW (lb/lbmol)	28.6	28.5	28.51	28.54	From CB&I/Chiyoda Calculation
Exhaust Flow Rate WET (lb/hr)	2,524,290	2,477,111	1,027,143	924,064	From CB&I/Chiyoda Calculation
Exhaust Flow Rate (lbmol/hr)	88,416	86,916	36,027	32,378	
Exhaust H2O Concentration	6.72%	7.10%	6.94%	6.44%	From CB&I/Chiyoda Calculation
Exhaust Flow Rate DRY (lbmol/hr)	82,475	80,745	33,527	30,293	
Exhaust O2 Concentration DRY	14.40%	14.59%	14.7%	15.2%	From CB&I/Chiyoda Calculation
Exhaust Flow Rate (acfh)	92,314,464	90,748,034	21,070,109	18,935,692	

EMISSIONS CALCULATIONS	Compressor Turbines		Power Generation Turbines with CO Catalyst and HRSG		References/Comments
Turbine Emission Factors	Short-Term	Annual	Short-Term	Annual	
NOx (ppmvd @15% O2)	9.00	9.00	9.00	9.00	Adjusted to Actual O2 Amount
CO (ppmvd @15% O2)	25.00	25.00	8.00	5.00	Adjusted to Actual O2 Amount
VOC (lb/MMBtu)	0.002	0.002	0.002	0.002	
PM10 (lb/MMBtu)	0.007	0.007	0.007	0.007	
PM2.5 (lb/MMBtu)	0.007	0.007	0.007	0.007	
SO2	No Emission Facto	No Emission Facto	No Emission Facto	o Emission Fact	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	53.060	53.060	53.060	
CH4 (kg CH4/MMBtu)	0.001	0.001	0.001	0.001	
N2O (kg N2O/MMBtu)	0.0001	0.0001	0.0001	0.0001	
Turbine Emission Calculations (Maximum 1-hour)					
NOx (lb/hr)	37.640	35.784	14.614	12.076	
CO (lb/hr)	63.651	60.513	7.908	4.084	
VOC (lb/hr)	2.618	2.491	0.969	0.859	
PM10 (lb/hr)	8.229	7.828	3.046	2.701	
PM2.5 (lb/hr)	8.229	7.828	3.046	2.701	
SO2 @ 16 ppm (lb/hr)	2.917	2.774	1.078	0.956	
CO2 (lb/hr)	136,862.009	130,194.373	50,650.641	44,918.813	
CH4 (lb/hr)	2.579	2.454	0.955	0.847	
N2O (lb/hr)	0.258	0.245	0.095	0.085	
CO2e (lb/hr)	137,003.359	130,328.836	50,702.953	44,965.205	
Total Emission Calculations (Annual)					
NOx (tpy)	164.861	156.735	64.009	52.892	
CO (tpy)	278.789	265.048	34.638	17.889	
VOC (tpy)	11.469	10.910	4.244	3.764	
PM10 (tpy)	36.044	34.288	13.339	11.830	
PM2.5 (tpy)	36.044	34.288	13.339	11.830	
SO2 @ 16 ppm (tpy)	12.775	12.151	4.723	4.189	
CO2 (tonnes/yr)	543,822.552	517,328.633	201,260.825	178,485.350	
CH4 (tonnes/yr)	10.249	9.750	3.793	3.364	
N2O (tonnes/yr)	1.025	0.975	0.379	0.336	
CO2e (tonnes/yr)	544,384.208	517,862.926	201,468.686	178,669.689	
Stack Parameters					
Stack Height (ft)	210	210	150	150	From CB&I/Chiyoda Calculation
Exhaust Temp Ambient Temp Basis (F)	-30	-30	--	--	
Exhaust Temp Load % Basis	100%	100%	--	--	
Exhaust Temperature (F)	970	970	341	341	From CB&I/Chiyoda Calculation with HRSG
Exhaust Velocity Ambient Temp Basis (F)	71	71	70	70	
Exhaust Velocity Load % Basis	100%	100%	60%	60%	
Exhaust Velocity (ft/s)	86	86	48.00	48.00	From CB&I/Chiyoda Calculation with HRSG adjustment
Stack Diameter (ft)	19	19	10	10	From CB&I/Chiyoda Calculation
NO2/NOx Ratio	0.5	0.5	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-5 LIQUEFACTION FACILITY DIESEL EQUIPMENT

	Emergency				Non-Emergency		
	Standard Factors						
EMISSION FACTORS	40 CFR Part 89.112 Tier 3 130<kW<225	40 CFR Part 89.112 Tier 3 225<kW<450	40 CFR Part 60 Subpart IIII 175<hp<300	40 CFR Part 60 Subpart IIII 300<hp<600	40 CFR 1039 Subpart B Tier 4 130<kW<560	40 CFR 1039 Subpart B Tier 4 kW > 560	40 CFR Part 98 (Petroleum)
NOx (g/hp-hr) (95% of NOx+NMHC)	2.834	2.834	2.850	2.850	0.298	2.610	
CO (g/hp-hr)	2.610	2.610	2.600	2.600	2.610	2.610	
VOC (g/hp-hr) (5% of NOx+NMHC)	0.149	0.149	0.150	0.150	0.142	0.142	
PM10 (g/hp-hr)	0.149	0.149	0.150	0.150	0.015	0.030	
PM2.5 (g/hp-hr)	0.149	0.149	0.150	0.150	0.015	0.030	
CO2 (kg CO2/MMBtu)							73.960
CH4 (kg CH4/MMBtu)							0.003
N2O (kg N2O/MMBtu)							0.001

EMISSIONS CALCULATIONS	Auxiliary Air Compressor	Firewater Pump	References/ Comments
Total Installed	1	1	From CB&I/Chiyoda Calculation
Load	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	500	500	Intermittent Assumption
Rated Power (hp)	300	575	From Chiyoda Calculation
Rated Power (kW)	224	429	From Chiyoda Calculation
BSFC (Btu/hp-hr)	7,000	7,000	AP42 Table 3.3-1
Rated Duty (MMBtu/hr)	2.10	4.03	For HAPs calculation and CO2e
Fuel Flow Rate (gal/hr)	14.56	27.90	Used ULSD HHV
Emission Factors			
Not-to-Exceed Factor	25%	25%	
NOx (g/hp-hr)	0.298	2.850	
CO (g/hp-hr)	2.610	2.600	
VOC (g/hp-hr)	0.142	0.150	
PM10 (g/hp-hr)	0.015	0.150	
PM2.5 (g/hp-hr)	0.015	0.150	
SO2	No Emission Factor	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	73.960	73.960	
CH4 (kg CH4/MMBtu)	0.003	0.003	
N2O (kg N2O/MMBtu)	0.001	0.001	
Emission Calculations (Maximum 1-hour)			
NOx (lb/hr)	0.247	4.516	
CO (lb/hr)	2.158	4.120	
VOC (lb/hr)	0.117	0.238	
PM10 (lb/hr)	0.012	0.238	
PM2.5 (lb/hr)	0.012	0.238	
SO2 (lb/hr)	0.003	0.006	
CO2 (lb/hr)	342.410	656.285	
CH4 (lb/hr)	0.014	0.027	
N2O (lb/hr)	0.003	0.005	
CO2e (lb/hr)	343.585	658.537	
Emission Calculations (Annual)			
NOx (tpy)	0.062	1.129	
CO (tpy)	0.539	1.030	
VOC (tpy)	0.029	0.059	
PM10 (tpy)	0.003	0.059	
PM2.5 (tpy)	0.003	0.059	
SO2 (tpy)	0.001	0.001	
CO2 (tonnes/yr)	77.658	148.845	
CH4 (tonnes/yr)	0.003	0.006	
N2O (tonnes/yr)	0.001	0.001	
CO2e (tonnes/yr)	77.924	149.355	
Stack Parameters			
Stack Height (ft)	10	10	From CB&I/Chiyoda Calculation
Exhaust Temperature (F)	883	908	From CB&I/Chiyoda Calculation
Exhaust Velocity (ft/s)	115	157	From CB&I/Chiyoda Calculation
Stack Diameter (ft)	0.665	0.665	From CB&I/Chiyoda Calculation
NO2/NOx Ratio	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-6 LIQUEFACTION FACILITY FLARES

EMISSION FACTORS	Standard Factors	
	AP42 Tables 13.5-1 and 13.5-2	40 CFR Part 98 (Natural Gas)
NOx (lb/MMBtu)	0.068	
CO (lb/MMBtu)	0.310	
VOC (lb/MMBtu)	0.570	
PM10 (μg/L Exhaust)	40.000	
PM2.5 (μg/L Exhaust)	40.000	
CO2 (kg CO2/MMBtu)		53.060
CH4 (kg CH4/MMBtu)		0.001
N2O (kg N2O/MMBtu)		0.0001

MODELING PARAMETERS CALCULATION	Dry Flare Purge/Pilot/Valve Passing	Wet Flare Purge/Pilot	LP Flare Purge/Pilot/Comp Seal Gas	Dry Flare Maximum	Wet Flare Maximum	LP Flare Maximum	References/ Comments
Exhaust Flow Calculation							
Fuel Flow Rate (scfh)	6,373	2,077	18,634	55,201,793	12,905,048	992,916	From CB&I/Chiyoda Calculation (Wet/dry Purge/Pilot divided by 2)
Fuel Flow Rate (lbmol/hr)	16.84	5.49	49.23	145,847.43	34,096.14	2,623.36	
Fuel MW(lb/lbmol)	18.50	17.68	23.10	17.68	17.68	25.70	All cases not based on fuel gas from CB&I/Chiyoda Calculation
Fuel Flow Rate (lb/hr)	311.50	97.02	1,137.27	2,578,582.53	602,819.75	67,420.35	
Fuel Flow HHV (MMBtu/hr)	7.15	2.25	10.50	59,992.00	14,020.00	997.50	From CB&I/Chiyoda Calculation (Wet/dry Purge/Pilot divided by 2)
Fd Factor (dscf/MMBtu)	8,710.00	8,710.00	8,710.00	8,710.00	8,710.00	8,710.00	Method 19 for gas fuel
Exhaust O2 Concentration	3%	3%	3%	3%	3%	3%	Assumed Dry Oxygen Concentration
Exhaust Flow (dscfh) (@HHV)	72,713.90	22,882.00	106,782.65	610,105,233.97	142,580,267.04	10,144,352.09	
Exhaust Water Concentration	10%	10%	10%	10%	10%	10%	Assumed Water Content
Exhaust Flow (scfh) (@HHV)	80,793.22	25,424.44	118,647.39	677,894,704.41	158,422,518.93	11,271,502.33	
Ratio of Exhaust to Fuel	12.68	12.24	6.37	12.28	12.28	11.35	
Exhaust Flow (L/h) (@HHV)	2,288,064.12	720,020.18	3,360,094.17	19,197,978,028.81	4,486,525,736.16	319,208,945.92	
Effective Height and Diameter Calculation							
Heat Release Rate (MMBtu/hr)	6.46	2.03	9.49	54,141.81	12,664.48	898.65	Based on LHV From CB&I/Chiyoda Calculation
Buoyancy flux	7.51	2.36	11.03	62,912.79	14,716.12	1,044.23	SCREEN3 Model User's Guide
Actual Stack Height (m)	0	0	60.6552	0	0	60.6552	From CB&I/Chiyoda Calculation converted to meters
GEP stack height (m)	65.00	65.00	65.00	65.00	65.00	65.00	EPA GEP Stack Height Guideline
Effective Stack Height (m)	2.30	1.32	63.42	172.82	86.30	85.02	SCREEN3 Model User's Guide
Effective Stack Diameter (m)	0.45	0.25	0.54	40.84	19.75	5.26	SCREEN3 Model User's Guide

Note:

1.) Method 19 used to develop Exhaust Flow Rate for PM calculation. Assumed typical Boiler Exhaust parameters of 3% O2 and 10% H2O

EMISSIONS CALCULATIONS	Dry Flare Purge/Pilot/Valve Passing	Wet Flare Purge/Pilot	LP Flare Purge/Pilot/Comp Seal Gas	Dry Flare Maximum	Wet Flare Maximum	LP Flare Maximum	References/ Comments
Total Installed	3	3	1	3	3	1	From CB&I/Chiyoda Calculation (2 op, 1 spare)
Load	100%	100%	100%	100%	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	8,760	8,760	8,760	500	500	144	Maximum Case Intermittent
Rated Duty HHV (MMBtu/hr)	7.15	2.25	10.50	59,992.00	14,020.00	997.50	From CB&I/Chiyoda Calculation for HAPs Calculation
Emission Factors							
NOx (lb/MMBtu)	0.068	0.068	0.068	0.068	0.068	0.068	Based on HHV
CO (lb/MMBtu)	0.310	0.310	0.310	0.310	0.310	0.310	Based on HHV
VOC (lb/MMBtu)	0.570	0.570	0.570	0.570	0.570	0.570	Based on HHV
PM10 (µg/L Exhaust)	40.000	40.000	40.000	40.000	40.000	40.000	
PM2.5 (µg/L Exhaust)	40.000	40.000	40.000	40.000	40.000	40.000	
SO2	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	53.060	53.060	53.060	53.060	53.060	Based on HHV
CH4 (kg CH4/MMBtu)	0.001	0.001	0.001	0.001	0.001	0.001	Based on HHV
N2O (kg N2O/MMBtu)	0.000	0.000	0.000	0.000	0.000	0.000	Based on HHV
Additional Warm Vessel Arrival Inert Gas Emissions (Annual)							
NOx (tpy)						0.255	From CB&I/Chiyoda Calculation
CO (tpy)						0.155	From CB&I/Chiyoda Calculation
SO2 (tpy)						0.00356	From CB&I/Chiyoda Calculation
CO2 (tpy)						366.39	From CB&I/Chiyoda Calculation
Emission Calculations (Maximum 1-hour)							
NOx (lb/hr)	0.486	0.153	0.714	4,079.456	953.360	71.372	
CO (lb/hr)	2.217	0.698	3.255	18,597.520	4,346.200	311.378	
VOC (lb/hr)	4.076	1.283	5.985	34,195.440	7,991.400	568.575	
PM10 (lb/hr)	0.202	0.063	0.296	1,692.981	395.646	28.150	
PM2.5 (lb/hr)	0.202	0.063	0.296	1,692.981	395.646	28.150	
SO2 @ 16 ppm (lb/hr)	0.0173	0.0056	0.0505	149.5018	34.9505	2.7385	
CO2 (lb/hr)	836.379	263.196	1,228.249	7,017,628.751	1,640,004.586	121,772.395	
CH4 (lb/hr)	0.016	0.005	0.023	132.258	30.908	2.199	
N2O (lb/hr)	0.002	0.000	0.002	13.226	3.091	0.220	
CO2e (lb/hr)	837.243	263.468	1,229.517	7,024,876.510	1,641,698.371	121,892.905	
Emission Calculations (Annual)							
NOx (tpy)	2.130	0.670	3.127	1,019.864	238.340	5.139	
CO (tpy)	9.708	3.055	14.257	4,649.380	1,086.550	22.419	
VOC (tpy)	17.851	5.617	26.214	8,548.860	1,997.850	40.937	
PM10 (tpy)	0.884	0.278	1.298	423.245	98.911	2.027	
PM2.5 (tpy)	0.884	0.278	1.298	423.245	98.911	2.027	
SO2 @ 16 ppm (tpy)	0.076	0.025	0.221	37.375	8.738	0.197	
CO2 (tonnes/yr)	3,323.360	1,045.813	4,880.459	1,591,587.760	371,950.600	7,621.538	
CH4 (tonnes/yr)	0.063	0.020	0.092	29.996	7.010	0.144	
N2O (tonnes/yr)	0.006	0.002	0.009	3.000	0.701	0.014	
CO2e (tonnes/yr)	3,326.792	1,046.893	4,885.499	1,593,231.541	372,334.748	7,629.410	
Stack Parameters							
Stack Height (m)	2.30	1.32	63.42	172.82	86.30	85.02	
Exhaust Temperature (K)	1,273	1,273	1,273	1,273	1,273	1,273	
Exhaust Velocity (m/s)	20	20	20	20	20	20	
Stack Diameter (m)	0.45	0.25	0.54	40.84	19.75	5.26	
NO2/NOx Ratio	0.5	0.5	0.5	0.5	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-7 LIQUEFACTION FACILITY THERMAL OXIDIZER

EMISSION FACTORS	Standard Factors	
	TCEQ Vapor Oxidizers Emission Factors	40 CFR Part 98 (Natural Gas)
NOx (lb/MMBtu)	0.1	
CO (lb/MMBtu)	0.082	
VOC (lb/MMBtu)	0.005	
PM10 (lb/MMBtu)	0.007	
PM2.5 (lb/MMBtu)	0.007	
CO2 (kg CO2/MMBtu)		53.060
CH4 (kg CH4/MMBtu)		0.001
N2O (kg N2O/MMBtu)		0.0001

Notes:
1.) Emission Factor for CO has been based on AP42 Section 1.4, to ensure CO emissions are not underestimated (TCEQ references AP42 Section 1.4 for VOC and PM emissions)

EMISSIONS CALCULATIONS	Thermal Oxidizer	References/ Comments
Total Installed	1	From CB&I/Chiyoda Calculation
Load	100%	From CB&I/Chiyoda Calculation
Operation (hr/yr)	8,760	
Rated Duty LHV (MMBtu/hr)	5.55	From CB&I/Chiyoda Calculation
Rated Duty HHV (MMBtu/hr)	6.01	From CB&I/Chiyoda Calculation
Fuel Flow Rate (lbmol/hr)	16.00	From CB&I/Chiyoda Calculation
Emission Factors		
NOx (lb/MMBtu)	0.100	Based on HHV
CO (lb/MMBtu)	0.082	Based on HHV
VOC (lb/MMBtu)	0.005	Based on HHV
PM10 (lb/MMBtu)	0.007	Based on HHV
PM2.5 (lb/MMBtu)	0.007	Based on HHV
SO2	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	Based on HHV
CH4 (kg CH4/MMBtu)	0.001	Based on HHV
N2O (kg N2O/MMBtu)	0.000	Based on HHV
Emission Calculations (Maximum 1-hour)		
NOx (lb/hr)	0.601	
CO (lb/hr)	0.495	
VOC (lb/hr)	0.032	
PM10 (lb/hr)	0.045	
PM2.5 (lb/hr)	0.045	
SO2 @ 16 ppm (lb/hr)	0.016	
CO2 (lb/hr)	703.026	
CH4 (lb/hr)	0.013	
N2O (lb/hr)	0.001	
CO2e (lb/hr)	703.752	
Emission Calculations (Annual)		
NOx (tpy)	2.632	
CO (tpy)	2.168	
VOC (tpy)	0.142	
PM10 (tpy)	0.196	
PM2.5 (tpy)	0.196	
SO2 @ 16 ppm (tpy)	0.072	
CO2 (tonnes/yr)	2793.482	
CH4 (tonnes/yr)	0.053	
N2O (tonnes/yr)	0.005	
CO2e (tonnes/yr)	2796.367	
Stack Parameters		
Stack Height (ft)	47	From CB&I/Chiyoda Calculation
Exhaust Temperature (F)	1800	From CB&I/Chiyoda Calculation
Exhaust Velocity (ft/s)	8.9	From CB&I/Chiyoda Calculation
Stack Diameter (ft)	5	From CB&I/Chiyoda Calculation
NO2/NOx Ratio	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-8 LIQUEFACTION FACILITY MISCELLANEOUS SOURCES

EMISSIONS CALCULATIONS	Tank	Fugitive	References/ Comments
Methane (lb/hr)		24.400	From CB&I/Chiyoda Calculation
NMHC (lb/hr)		4.100	From CB&I/Chiyoda Calculation
CO2e (lb/hr)		610.000	
Emissions Calculation (Annual)			
Operation (hr/yr)	8,760	8,760	From CB&I/Chiyoda Calculation
Methane (tonnes/yr)		96.954	
CO2e (tonnes/yr)		2423.841	
NMHC (tpy)	0.00	17.96	

EC-9 LIQUEFACTION FACILITY HAZARDOUS AIR POLLUTANTS (HAPS) EMISSIONS SUMMARY

Emission Unit ID	TURB1	TURB2	TURB3	TURB4	TURB5	TURB6	TRB_GEN1	TRB_GEN2	TRB_GEN3	TRB_GEN4	Aux_COMP	FPUMP	FLARE_1D	FLARE_2D	0
CT Mfg / Model	Train 1a Compression Turbine Stack	Train 1b Compression Turbine Stack	Train 2a Compression Turbine Stack	Train 2b Compression Turbine Stack	Train 3a Compression Turbine Stack	Train 3b Compression Turbine Stack	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Auxiliary Air Compressor (224 kW)	Firewater Pump (429 kW)	Dry Flare Pilot/Purge	Dry Flare Pilot/Purge	Dry Flare Pilot/Purge (Not Modeled)
Source Category	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	ICE	ICE	Flare	Flare	Flare
ISO Power (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISO Heat Rate (MMBtu/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10°F Heat Consumption (MMBtu/hr)	1113	1113	1113	1113	1113	1113	384	384	384	384	2.1	4.025	7.15	7.15	0
Load Basis for CT EF	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	<600hp	<600hp	0	0	0
Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	D	D	NG	NG	NG
hrs/yr	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	500	500	8760	8760	0
1,1,2,2-Tetrachloroethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,1,2-Trichloroethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,3-Butadiene	0.002096224	0.002096224	0.002096224	0.002096224	0.002096224	0.002096224	0.000723226	0.000723226	0.000723226	0.000723226	2.05275E-05	3.93444E-05	0	0	0
1,3-Dichloropropene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,4-Dichlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,2,4-Trimethylpentane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Acetaldehyde	0.1949976	0.1949976	0.1949976	0.1949976	0.1949976	0.1949976	0.0672768	0.0672768	0.0672768	0.0672768	0.000402675	0.000771794	0.001320226	0.001320226	0
Acrolein	0.031199616	0.031199616	0.031199616	0.031199616	0.031199616	0.031199616	0.010764288	0.010764288	0.010764288	0.010764288	4.85625E-05	9.30781E-05	0.000307029	0.000307029	0
Antimony	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Arsenic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benzene	0.05849928	0.05849928	0.05849928	0.05849928	0.05849928	0.05849928	0.02018304	0.02018304	0.02018304	0.02018304	0.000489825	0.000938831	0.004881768	0.004881768	0
Beryllium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biphenyl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cadmium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Tetrachloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chloroform	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chromium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cobalt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dibutylphthalate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethylbenzene	0.15599808	0.15599808	0.15599808	0.15599808	0.15599808	0.15599808	0.05382144	0.05382144	0.05382144	0.05382144	0	0	0.044335047	0.044335047	0
Ethylene Dibromide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethylene Dichloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Formaldehyde	3.4612074	3.4612074	3.4612074	3.4612074	3.4612074	3.4612074	1.1941632	1.1941632	1.1941632	1.1941632	0.0006195	0.001187375	0.035891738	0.035891738	0
HCl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lead	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Manganese	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methylene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
n-Hexane	0	0	0	0	0	0	0	0	0	0	0	0	0.000890385	0.000890385	0
Nickel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PAHs	0.010724868	0.010724868	0.010724868	0.010724868	0.010724868	0.010724868	0.003700224	0.003700224	0.003700224	0.003700224	0.0000882	0.00016905	0.000429841	0.000429841	0
Phenol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Phosphorus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM (Total)	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.002186496	0.002186496	0.002186496	0.002186496	8.83376E-05	0.000169314	3.3111E-07	3.3111E-07	0
POM 2-Methylnaphthalene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM 3-Methylcholanthrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM 7,12-Dimethylbenz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM Acenaphthene	0	0	0	0	0	0	0	0	0	0	7.455E-07	1.42888E-06	0	0	0
POM Acenaphthylene	0	0	0	0	0	0	0	0	0	0	2.6565E-06	5.09163E-06	0	0	0
POM Anthracene	0	0	0	0	0	0	0	0	0	0	9.8175E-07	1.88169E-06	0	0	0
POM Benz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0.000000882	1.6905E-06	0	0	0
POM Benzo(a)pyrene	0	0	0	0	0	0	0	0	0	0	9.87E-08	1.89175E-07	0	0	0
POM Benzo(b)fluoranthene	0	0	0	0	0	0	0	0	0	0	5.20275E-08	9.97194E-08	0	0	0
POM Benzo(g,h,i)perylene	0	0	0	0	0	0	0	0	0	0	2.56725E-07	4.92056E-07	0	0	0
POM Benzo(k)fluoranthene	0	0	0	0	0	0	0	0	0	0	8.1375E-08	1.55969E-07	0	0	0
POM Chrysene	0	0	0	0	0	0	0	0	0	0	1.85325E-07	3.55206E-07	0	0	0
POM Dibenz(a,h)anthracene	0	0	0	0	0	0	0	0	0	0	3.06075E-07	5.86644E-07	0	0	0
POM Fluoranthene	0	0	0	0	0	0	0	0	0	0	3.99525E-06	7.65756E-06	0	0	0
POM Fluorene	0	0	0	0	0	0	0	0	0	0	0.000015435	2.95838E-05	0	0	0
POM Indeno(1,2,3-c,d)pyrene	0	0	0	0	0	0	0	0	0	0	1.96875E-07	3.77344E-07	0	0	0
POM Naphthalene	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.002186496	0.002186496	0.002186496	0.002186496	0.00004452	0.00008533	0.000337732	0.000337732	0
POM Phenanthrene	0	0	0	0	0	0	0	0	0	0	0.000015435	2.95838E-05	0	0	0
POM Pyrene	0	0	0	0	0	0	0	0	0	0	2.5095E-06	4.80988E-06	0	0	0
Propional[dehyde]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propylene Oxide	0.14137326	0.14137326	0.14137326	0.14137326	0.14137326	0.14137326	0.04877568	0.04877568	0.04877568	0.04877568	0	0	0	0	0
Selenium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Styrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tetrachloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Toluene	0.6337422	0.6337422	0.6337422	0.6337422	0.6337422	0.6337422	0.2186496	0.2186496	0.2186496	0.2186496	0.000214725	0.000411556	0.001780771	0.001780771	0
Trichloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vinyl Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vinylidene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Xylenes(m,p,o)	0.31199616	0.31199616	0.31199616	0.31199616	0.31199616	0.31199616	0.10764288	0.10764288	0.10764288	0.10764288	0.000149625	0.000286781	0.000890385	0.000890385	0
CDD/CDF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOURCE TOTAL (tpy)	**5.008**	**5.008**	**5.008**	**5.008**	**5.008**	**5.008**	**1.728**	**1.728**	**1.728**	**1.728**	**0.002**	**0.004**	**0.091**	**0.091**	**0.000**

Emission Unit ID	FLARE_1W	FLARE_2W	0	DRY_MAX1	DRY_MAX2	0	WET_MAX1	WET_MAX2	0	LP_FLARE	LP_MAX	TH_OX	
CT Mfg / Model	Wet Flare Pilot/Purge	Wet Flare Pilot/Purge	Wet Flare Pilot/Purge (Not Modeled)	Dry Flare Maximum Case	Dry Flare Maximum Case	Dry Flare Maximum Case (Not Modeled)	Wet Flare Maximum Case	Wet Flare Maximum Case	Wet Flare Maximum Case (Not Modeled)	LP Flare Pilot/Purge	LP Flare Maximum Flow	Thermal Oxidizer	
Source Category	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Heater	
ISO Power (kW)	0	0	0	0	0	0	0	0	0	0	0	0	
ISO Heat Rate (MMBtu/hr)	0	0	0	0	0	0	0	0	0	0	0	0	
10°F Heat Consumption (MMBtu/hr)	2.25	2.25	0	59992	59992	0	14020	14020.00	0.00	10.50	997.50	6.01	
Load Basis for CT EF	0	0	0	0	0	0	0	0	0	0	0.00	0.00	
Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	
hrs/yr	8760	8760	0	500	500	0	500	500	0	8760	144.00	8760.00	**Total**
1,1,2,2-Tetrachloroethane	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
1,1,2-Trichloroethane	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
1,3-Butadiene	0	0	0	0	0	0	0	0	0	0	0	0	**0.02**
1,3-Dichloropropene	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
1,4-Dichlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
2,2,4-Trimethylpentane	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Acetaldehyde	0.000415456	0.000415456	0	0.632268627	0.632268627	0	0.147759804	0.147759804	0	0.001938794	0.003027706	0	**3.01**
Acrolein	9.66176E-05	9.66176E-05	0	0.147039216	0.147039216	0	0.034362745	0.034362745	0	0.000450882	0.000704118	0	**0.60**
Antimony	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Arsenic	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Benzene	0.001536221	0.001536221	0	2.337923529	2.337923529	0	0.546367647	0.546367647	0	0.007169029	0.011195471	5.41954E-05	**6.23**
Beryllium	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Biphenyl	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Cadmium	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Carbon Tetrachloride	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Chlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Chloroform	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Chromium	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Cobalt	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Dibutylphthalate	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Ethylbenzene	0.013951588	0.013951588	0	21.23246275	21.23246275	0	4.961980392	4.961980392	0	0.065107412	0.101674588	0	**53.82**
Ethylene Dibromide	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Ethylene Dichloride	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Formaldehyde	0.011294603	0.011294603	0	17.18888431	17.18888431	0	4.017004902	4.017004902	0	0.052708147	0.082311353	0.001935573	**68.19**
HCl	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Lead	0	0	0	0	0	0	0	0	0	0	0	1.29039E-05	**0.00**
Manganese	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Mercury	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Methylene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
n-Hexane	0.000280191	0.000280191	0	0.426413725	0.426413725	0	0.099651961	0.099651961	0	0.001307559	0.002041941	0.046453765	**1.10**
Nickel	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
PAHs	0.000135265	0.000135265	0	0.205854902	0.205854902	0	0.048107843	0.048107843	0	0.000631235	0.000985765	0	**0.59**
Phenol	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Phosphorus	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
POM (Total)	1.04196E-07	1.04196E-07	0	0.000158572	0.000158572	0	3.70579E-05	3.70579E-05	0	4.86246E-07	7.59343E-07	1.80265E-05	**0.05**
POM 2-Methylnaphthalene	0	0	0	0	0	0	0	0	0	0	0	6.18609E-07	**0.00**
POM 3-Methylcholanthrene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM 7,12-Dimethylbenz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	4.13284E-07	**0.00**
POM Acenaphthene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Acenaphthylene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Anthracene	0	0	0	0	0	0	0	0	0	0	0	6.31771E-08	**0.00**
POM Benz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Benzo(a)pyrene	0	0	0	0	0	0	0	0	0	0	0	3.15886E-08	**0.00**
POM Benzo(b)fluoranthene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Benzo(g,h,i)perylene	0	0	0	0	0	0	0	0	0	0	0	3.15886E-08	**0.00**
POM Benzo(k)fluoranthene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Chrysene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Dibenz(a,h)anthracene	0	0	0	0	0	0	0	0	0	0	0	3.15886E-08	**0.00**
POM Fluoranthene	0	0	0	0	0	0	0	0	0	0	0	7.6339E-08	**0.00**
POM Fluorene	0	0	0	0	0	0	0	0	0	0	0	7.10743E-08	**0.00**
POM Indeno(1,2,3-c,d)pyrene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	**0.00**
POM Naphthalene	0.000106279	0.000106279	0	0.161743137	0.161743137	0	0.03779902	0.03779902	0	0.000495971	0.000774529	1.57416E-05	**0.45**
POM Phenanthrene	0	0	0	0	0	0	0	0	0	0	0	4.39607E-07	**0.00**
POM Pyrene	0	0	0	0	0	0	0	0	0	0	0	1.28987E-07	**0.00**
Propional[dehyde]	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Propylene Oxide	0	0	0	0	0	0	0	0	0	0	0	0	**1.04**
Selenium	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Styrene	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Tetrachloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Toluene	0.000560382	0.000560382	0	0.852827451	0.852827451	0	0.199303922	0.199303922	0	0.002615118	0.004083882	8.77451E-05	**6.79**
Trichloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Vinyl Chloride	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Vinylidene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
Xylenes(m,p,o)	0.000280191	0.000280191	0	0.426413725	0.426413725	0	0.099651961	0.099651961	0	0.001307559	0.002041941	0	**3.36**
CDD/CDF	0	0	0	0	0	0	0	0	0	0	0	0	**0.00**
SOURCE TOTAL (tpy)	**0.029**	**0.029**	**0.000**	**43.450**	**43.450**	**0.000**	**10.154**	**10.154**	**0.000**	**0.133**	**0.208**	**0.049**	**144.80**

EC-10 LIQUEFACTION FACILITY EMISSION FACTOR SUMMARY

	Short-Term Maximum		Short-Term Maximum		Annual									
	Compressor Turbine		Power Generator Turbine		Power Generator Turbine		Auxiliary Air Compressor		Diesel Firewater Pump		Flares		Thermal Oxidizer	
Pollutant	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units
NOx	9.00	ppmvd @15% O2	9.00	ppmvd @15% O2	9.00	ppmvd @15% O2	0.373	g/hp-hr	3.56	g/hp-hr	0.068	lb/MMBtu	0.100	lb/MMBtu
CO	25.00	ppmvd @15% O2	8.00	ppmvd @15% O2	5.00	ppmvd @15% O2	3.262	g/hp-hr	3.25	g/hp-hr	0.310	lb/MMBtu	0.082	lb/MMBtu
VOC	0.002	lb/MMBtu	0.002	lb/MMBtu	0.002	lb/MMBtu	0.177	g/hp-hr	0.188	g/hp-hr	0.570	lb/MMBtu	0.005	lb/MMBtu
PM10	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu	0.019	g/hp-hr	0.188	g/hp-hr	40.00	μg/L	0.007	lb/MMBtu
PM2.5	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu	0.019	g/hp-hr	0.188	g/hp-hr	40.00	μg/L	0.007	lb/MMBtu
Fuel Sulfur Normal Operation	16.00	ppmv	16.00	ppmv	16.00	ppmv	16.000	ppmv	15.00	ppmv	16.00	ppmv	16.000	ppmv
CO2	53.06	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu	73.960	kg/MMBtu	73.96	kg/MMBtu	53.06	kg/MMBtu	53.060	kg/MMBtu
CH4	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.003	kg/MMBtu	0.003	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu
N2O	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.001	kg/MMBtu	0.0006	kg/MMBtu	0.0001	kg/MMBtu	0.000	kg/MMBtu
1,1,2,2-Tetrachloroethane														
1,1,2-Trichloroethane														
1,3-Butadiene	4.30E-07	lb/MMBtu	4.30E-07	lb/MMBtu	4.30E-07	lb/MMBtu	3.91E-05	lb/MMBtu	3.91E-05	lb/MMBtu				
1,3-Dichloropropene														
1,4-Dichlorobenzene														
2,2,4-Trimethylpentane														
Acetaldehyde	4.00E-05	lb/MMBtu	4.00E-05	lb/MMBtu	4.00E-05	lb/MMBtu	7.67E-04	lb/MMBtu	7.67E-04	lb/MMBtu	4.22E-05	lb/MMBtu		
Acrolein	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	9.25E-05	lb/MMBtu	9.25E-05	lb/MMBtu	9.80E-06	lb/MMBtu		
Antimony														
Arsenic														
Benzene	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	9.33E-04	lb/MMBtu	9.33E-04	lb/MMBtu	1.56E-04	lb/MMBtu	2.06E-06	lb/MMBtu
Beryllium														
Biphenyl														
Cadmium														
Carbon Tetrachloride														
Chlorobenzene														
Chloroform														
Chromium														
Cobalt														
Dibutylphthalate														
Ethylbenzene	3.20E-05	lb/MMBtu	3.20E-05	lb/MMBtu	3.20E-05	lb/MMBtu					1.42E-03	lb/MMBtu		
Ethylene Dibromide														
Ethylene Dichloride														
Formaldehyde	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	1.18E-03	lb/MMBtu	1.18E-03	lb/MMBtu	1.15E-03	lb/MMBtu	7.35E-05	lb/MMBtu
HCl														
Lead													4.90E-07	lb/MMBtu
Manganese														
Mercury														
Methanol														
Methylene Chloride														
n-Hexane											2.84E-05	lb/MMBtu	1.76E-03	lb/MMBtu
Nickel														
PAHs	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	1.68E-04	lb/MMBtu	1.68E-04	lb/MMBtu	1.37E-05	lb/MMBtu		
Phenol														
Phosphorus														
POM 2-Methylnaphthalene													2.35E-08	lb/MMBtu
POM 3-Methylcholanthrene													1.80E-09	lb/MMBtu
POM 7,12-Dimethylbenz(a)anthracene													1.57E-08	lb/MMBtu
POM Acenaphthene							1.42E-06	lb/MMBtu	1.42E-06	lb/MMBtu			1.80E-09	lb/MMBtu
POM Acenaphthylene							5.06E-06	lb/MMBtu	5.06E-06	lb/MMBtu			1.80E-09	lb/MMBtu
POM Anthracene							1.87E-06	lb/MMBtu	1.87E-06	lb/MMBtu			2.40E-09	lb/MMBtu
POM Benz(a)anthracene							1.68E-06	lb/MMBtu	1.68E-06	lb/MMBtu			1.80E-09	lb/MMBtu
POM Benzo(a)pyrene							1.88E-07	lb/MMBtu	1.88E-07	lb/MMBtu			1.20E-09	lb/MMBtu
POM Benzo(b)fluoranthene							9.91E-08	lb/MMBtu	9.91E-08	lb/MMBtu			1.80E-09	lb/MMBtu
POM Benzo(g,h,i)perylene							4.89E-07	lb/MMBtu	4.89E-07	lb/MMBtu			1.20E-09	lb/MMBtu
POM Benzo(k)fluoranthene							1.55E-07	lb/MMBtu	1.55E-07	lb/MMBtu			1.80E-09	lb/MMBtu
POM Chrysene							3.53E-07	lb/MMBtu	3.53E-07	lb/MMBtu			1.80E-09	lb/MMBtu
POM Dibenz(a,h)anthracene							5.83E-07	lb/MMBtu	5.83E-07	lb/MMBtu			1.20E-09	lb/MMBtu
POM Fluoranthene							7.61E-06	lb/MMBtu	7.61E-06	lb/MMBtu			2.90E-09	lb/MMBtu
POM Fluorene							2.94E-05	lb/MMBtu	2.94E-05	lb/MMBtu			2.70E-09	lb/MMBtu
POM Indeno(1,2,3-c,d)pyrene							3.75E-07	lb/MMBtu	3.75E-07	lb/MMBtu			1.80E-09	lb/MMBtu
POM Naphthalene	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	8.48E-05	lb/MMBtu	8.48E-05	lb/MMBtu	1.08E-05	lb/MMBtu	5.98E-07	lb/MMBtu
POM Phenanthrene							2.94E-05	lb/MMBtu	2.94E-05	lb/MMBtu			1.67E-08	lb/MMBtu
POM Pyrene							4.78E-06	lb/MMBtu	4.78E-06	lb/MMBtu			4.90E-09	lb/MMBtu
Propional*[dehyde]*														
Propylene Oxide	2.90E-05	lb/MMBtu	2.90E-05	lb/MMBtu	2.90E-05	lb/MMBtu								
Selenium														
Styrene														
Tetrachloroethylene														
Toluene	1.30E-04	lb/MMBtu	1.30E-04	lb/MMBtu	1.30E-04	lb/MMBtu	4.09E-04	lb/MMBtu	4.09E-04	lb/MMBtu	5.69E-05	lb/MMBtu	3.33E-06	lb/MMBtu
Trichloroethylene														
Vinyl Chloride														
Vinylidene Chloride														
Xylenes(m,p,o)	6.40E-05	lb/MMBtu	6.40E-05	lb/MMBtu	6.40E-05	lb/MMBtu	2.85E-04	lb/MMBtu	2.85E-04	lb/MMBtu	2.84E-05	lb/MMBtu		
CDD/CDF														

EC-11 LIQUEFACTION FACILITY ANNUAL FUEL CONSUMPTION

Gas-Fired Equipment (Fuel Gas Users)	Rated Duty (HHV)	Daily Average Fuel Flow
	MMBtu/hr	MMSCFD
Train 1a Compression Turbine	1113.00	24.57
Train 1b Compression Turbine	1113.00	24.57
Train 2a Compression Turbine	1113.00	24.57
Train 2b Compression Turbine	1113.00	24.57
Train 3a Compression Turbine	1113.00	24.57
Train 3b Compression Turbine	1113.00	24.57
Power Generator Turbines	384.00	8.48
Power Generator Turbines	384.00	8.48
Power Generator Turbines	384.00	8.48
Power Generator Turbines	384.00	8.48
Dry Flare Pilot/Purge	7.15	0.16
Dry Flare Pilot/Purge	7.15	0.16
Dry Flare Pilot/Purge (Not Modeled)	0.00	0.00
Wet Flare Pilot/Purge	2.25	0.05
Wet Flare Pilot/Purge	2.25	0.05
Wet Flare Pilot/Purge (Not Modeled)	0.00	0.00
LP Flare Pilot/Purge	10.50	0.23
Thermal Oxidizer	6.01	0.13
Total Fuel Gas Consumption	**8,249**	**182**
Liquid-Driven Equipment (Diesel Users)	**Rated Duty (HHV)**	**Daily Average Diesel Flow**
	MMBtu/hr	**gal/day**
Auxiliary Air Compressor (224 kW)	2.10	349.40
Firewater Pump (429 kW)	4.03	669.68
Mobile Equipment Emissions (Normal Operation)	6.53	1086.64
Non-Road/Portable Equipment Emissions (Normal Operation)	27.32	4546.20
Marine Terminal Emissions (Normal Operation)	6,120	1018295.68
Total Diesel Consumption	**6,160.2**	**1,024,947.6**
Additional GHG Emission Sources not from Fuel Gas or Diesel Consumption		
Dry Flare Maximum Case		
Wet Flare Maximum Case		
LP Flare Maximum Flow (Maintenance)		
Tank Emissions		
Fugitive Emissions		

EC-12 LIQUEFACTION FACILITY MOBILE SOURCE EMISSIONS SUMMARY

Moves Vehicle Class	Total Miles Per Year	MOVES EFs (g/mi) [1]											Ton/year										
		VOC	NOx	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e[4]	HAPs[2]	VOC	NOx	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e[4]	HAPs[2]
Single Unit Short-Haul Truck	306,480	0.384	3.257	1.296	0.014	0.217	0.188	1624.180	0.102	0.004	1627.959	0.070	0.1298	1.1004	0.4379	0.0046	0.0733	0.0637	548.7099	0.0344	0.0014	549.9866	0.0238
Light Commercial Truck	191,040	0.079	0.796	1.642	0.006	0.041	0.041	729.512	0.042	0.003	731.571	0.020	0.0166	0.1676	0.3458	0.0013	0.0085	0.0087	153.6255	0.0088	0.0007	154.0591	0.0042
Intercity Bus	100,800	0.594	5.731	1.842	0.020	0.440	0.269	2310.040	0.098	0.003	2313.465	0.076	0.0661	0.6368	0.2046	0.0022	0.0489	0.0299	256.6768	0.0108	0.0004	257.0573	0.0085
Passenger Truck	1,384,800	0.079	0.887	1.487	0.007	0.041	0.044	786.544	0.048	0.004	788.971	0.022	0.1206	1.3542	2.2700	0.0101	0.0625	0.0667	1200.6505	0.0733	0.0063	1204.3560	0.0333
												TOTAL PER POLLUTANT (tpy)	**0.33**	**3.26**	**3.26**	**0.02**	**0.19**	**0.17**	**2159.66**	**0.13**	**0.01**	**2165.46**	**0.07**

Note 1: Emissions estimates are based on EPA's MOVES2014 motor vehicle emissions estimation program. Year 2027 is used as the base year for North Slope Borough, based on latest county-specific MOVES2014 input data available from Alaska DEC.

Note 2: HAPs are aggregated for benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, toluene, and xylene

Note 3: tons/year emissions = (Average distance traveled (mi/year)) * Emission factor (g/mi) / (453.59 g/lb) * (1 / 2000)

Note 4: Greenhouse gasses (GHG) are converted to carbon dioxide equivalents (CO_2e) using 100-year Global Warming Potentials values from IPCC's Fourth Assessment Report (AR4) Chapter 2, Table 2.14 of Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the IPCC
CO_2 = 1, CH_4 = 25, N_2O = 298

EC-13 LIQUEFACTION FACILITY NON-ROAD/PORTABLE EMISSIONS SUMMARY

							Emission Factors (g/hp-hr) [2]									Deterioration Factors [2]				Adjusted Emission Factors (g/hp-hr) [2]					Emissions (ton/year)			
Engine Description	Equipment category based on NONROAD classification	SCC [1]	Fuel Type	Equipment Horsepower	Operating hrs/year	BSFC [2]	NOx	CO	PM	THC	Age Factor [3]	NOx "A" [3]	CO "A" [3]	PM "A" [3]	THC "A" [3]	NOx	CO	PM	THC	NOx	CO	PM[5]	THC	Load Factor [2]	NOx	CO	PM	VOC[6]
Air Compressor -900CFM (Sullair; caterpillar C-9 ATAAC engine)	Light Commercial Air Compressor	2270006015	Diesel	300	2880	0.367	0.276	0.084	0.0092	0.1314	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.278	0.097	0.014	0.135	0.43	0.35	0.12	0.02	0.18
Motor Grader - Cat 16G (6 tires, 7gph, 6-cylinder engine)	Graders	2270002048	Diesel	250	3600	0.371	0.28	0.11	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.127	0.014	0.134	0.59	0.40	0.18	0.02	0.20
Backhoe (CAT 966F)	Tractors/Loaders/Backhoes	2270002066	Diesel	220	720	0.433	0.28	0.19	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.219	0.014	0.134	0.21	0.13	0.10	0.01	0.06
Crane (small) - 50/60 ton , Grove, RT700E (Cummins QSB engine)	Crane	2270002045	Diesel	240	2880	0.367	0.28	0.07	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.081	0.014	0.134	0.43	0.28	0.08	0.01	0.14
Crane (large) - 200 ton, Manitowoc 888 (Cummins M11 engine)	Crane	2270002045	Diesel	330	720	0.367	0.28	0.08	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.092	0.014	0.134	0.43	0.39	0.13	0.02	0.19
Crane (large) - 90 ton, Grove 890E (Cummins QSB engine)	Crane	2270002045	Diesel	275	720	0.367	0.28	0.07	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.081	0.014	0.134	0.43	0.32	0.09	0.02	0.16
Dozer - Cat D9, 475 HP	Rubber Tire Dozer	2270002063	Diesel	475	1500	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.76	0.40	0.04	0.38
Boom Truck (National Crane 800D)	Crane	2270002045	Diesel	350	720	0.367	0.28	0.08	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.092	0.014	0.134	0.43	0.41	0.13	0.02	0.20
Loader - Cat 988H, 501HP	Rubber Tire Loader	2270002060	Diesel	501	7200	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.81	0.43	0.04	0.40
Light Plants (Genie TML-4000)	Light Commercial Generator Set	2270006005	Diesel	15	36000	0.408	0.28	0.22	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.253	0.014	0.134	0.43	0.02	0.02	0.00	0.01
Forklift - 15 Ton (Cat P30000)	Forklifts	2270003020	Diesel	148	1440	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.24	0.13	0.01	0.12
Forklift - Cat (2P5000)	Forklifts	2270003020	Diesel	61	4320	0.412	0.28	0.36	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.414	0.014	0.134	0.59	0.10	0.14	0.00	0.05
Generator - 100 kW	Light Commercial Generator Set	2270006005	Diesel	135	2880	0.367	0.28	0.09	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.104	0.014	0.134	0.43	0.16	0.06	0.01	0.08
Generator - 50 kW	Light Commercial Generator Set	2270006005	Diesel	67	14400	0.408	0.28	0.24	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.276	0.014	0.134	0.43	0.08	0.08	0.00	0.04
Man lifts - 80' Gemie (Z80/60)	Aerial Lift	2270003010	Diesel	78	1440	0.481	0.28	0.61	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.702	0.014	0.134	0.21	0.04	0.11	0.00	0.02
Man lift - 45' Genie (Z45, Perkins 404D-22 4 cylinder engine)	Aerial Lift	2270003010	Diesel	51	2880	0.481	0.28	0.61	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.702	0.014	0.134	0.21	0.03	0.07	0.00	0.01
Zoom Boom - Telehandler (used on warehouse), GTH-1056	Forklifts	2270003020	Diesel	125	7200	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.20	0.11	0.01	0.10
Bobcat (2500 lb capacity, 75 hp, Kubota S250)	Skid Steer Loader	2270002072	Diesel	75	8640	0.481	0.28	0.61	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.702	0.014	0.134	0.21	0.04	0.11	0.00	0.02
Welding Machines (in shop) (Lincoln Electric)	Light Commercial Welders	2270006025	Diesel	36	8640	0.481	0.28	0.39	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.449	0.014	0.134	0.21	0.02	0.03	0.00	0.01

Heater Description	Fuel Type	Equipment MMBtu/hr	Operating hrs/year	Emission Factors (lb/MMBtu)				Emissions (ton/year)			
				NOx	CO	PM	THC	NOx	CO	PM	THC
Ground thaw Heater (E3000)	Diesel	0.60	8640	0.14	0.04	0.02	0.00	0.38	0.09	0.06	0.01
Tioga Heaters (600,000 Btu/hr heater)	Diesel	0.60	56160	0.14	0.04	0.02	0.00	2.44	0.61	0.40	0.04

Total Non-Road/Portable Emissions	Emissions (ton/year)			
	NOx	CO	PM	THC
	7.59	3.22	0.69	2.43

NOTES:

Note 1: SCC code based on Appendix A of "Median Life, Annual Activity, and Load Factor Values for Nonroad Engine Emissions Modeling", July 2010, EPA-420-R-10-018.

Note 2: Brake-specific fuel consumption, zero hour steady state emission factor (EFss; g/hp-hr), and load factor are from NMIM/NONROAD08 model factors dated April 5, 2009.
EFss from NMIM/NONROAD08 have transient adjustment factors (TAFs) built in. The EFss are weighted averages based on Tier 4 engines.

Note 3: Age factor and Deterioration factors calculated using Equation 4 from "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition", July 2010, EPA-420-R-10-018.
Age Factor = LF * cumulative hours / median life {where Age factor is capped at 1. For this calculation, age factor is assumed to be 1 for simplification purposes}.
Deterioration Factor = 1 + (A * Age Factor^b), where b = 1 for diesel engines and A is taken from Table A6 from above mentioned source

Note 4: Adjusted Emission Factors are calculated using Equation 1 from, "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition", July 2010, EPA-420-R-10-018.
Adjusted EF = Efss * TAF * DF (as stated in Note 2, EFss have TAFs built in)

Note 5: Adjusted Emission Factors for PM_{10} are calculated using Equation 2 from, "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition", July 2010, EPA-420-R-10-018.
The correction factor S_{PMadj} is made to account for fuel sulfur variations; inputs specific to this calculation are noted below

0.02247 soxcnv (fraction of fuel sulfur converted to direct PM) for Base, T0, T1, T2, T3, T3B, T4A, T4B
0.30 soxcnv (fraction of fuel sulfur converted to direct PM) for Base, T4 and T4N
0.03 soxcnv (fraction of fuel sulfur converted to direct PM) for gasoline engines
0.0015 soxdsl (weight percent of sulfur in diesel fuel)
0.0015 soxbas (default certification fuel sulfur weight percent, 0.0015 is default for Tier 4 engines)

Note 6: Adjusted emissions from THC to VOC by 1.053 is the ratio of VOC to THC (for diesel equipment) from "Conversion Factors for Hydrocarbon Components", July 2010, EPA-420-R-10-015.

EC-14 LIQUEFACTION FACILITY OFFSITE SOURCE EMISSIONS SUMMARY

Tesoro Refinery Emissions – Actual Emissions

		Location			Emissions (g/sec)														
Model ID	Point Sources Description	UTM X	UTM Y	Base Elev. (m)	NOx (1-hr)	NOx (ann)	$PM_{2.5}/PM_{10}$ (24-hr)	$PM_{2.5}/PM_{10}$ (annual)	SO2 (1-hr)	SO2 (3-hr & 24-hr)	SO2 annual	CO	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
TR1	Crude Heater H-101A, Unit 0001	589027.60	6728817.60	40	2.684E+00	2.684E+00	7.278E-02	7.278E-02	2.647E-02	2.647E-02	2.647E-02	8.052E-01	Heater	Gas	0.000E+00	1.819E-02	1.819E-02	5.458E-02	5.458E-02
TR2	Crude Heater H-101B, Unit 0002	589028.02	6728824.94	40	7.646E-01	7.646E-01	9.493E-02	9.493E-02	3.423E-02	3.423E-02	3.423E-02	1.049E+00	Heater	Gas	0.000E+00	2.373E-02	2.373E-02	7.120E-02	7.120E-02
TR3_5	Pow erformer Preheater H-201, Unit 0003 - 0005	589117.10	6728825.10	40	8.440E-01	8.440E-01	6.415E-02	6.415E-02	2.330E-02	2.330E-02	2.330E-02	7.088E-01	Heater	Gas	0.000E+00	0.000E+00	1.604E-02	0.000E+00	4.811E-02
TR6	Pow erformer Reheater H-204, Unit 0006	589116.70	6728835.80	40	2.836E-01	2.836E-01	2.647E-02	2.647E-02	9.493E-03	9.493E-03	9.493E-03	2.923E-01	Heater	Gas	0.000E+00	6.616E-03	6.616E-03	1.985E-02	1.985E-02
TR7	Pow erformer Reheater H-205, Unit 0007	589112.70	6728843.50	40	1.815E-01	1.815E-01	1.697E-02	1.697E-02	6.041E-03	6.041E-03	6.041E-03	1.870E-01	Heater	Gas	0.000E+00	4.243E-03	4.243E-03	1.273E-02	1.273E-02
TR8	Hydrocracker Recycle Gas Heater, H-401, Unit 0008	589188.20	6728839.60	40	1.588E-01	1.588E-01	1.467E-02	1.467E-02	5.466E-03	5.466E-03	5.466E-03	1.634E-01	Heater	Gas	0.000E+00	3.668E-03	3.668E-03	1.100E-02	1.100E-02
TR9	Hydrocracker Recycle Gas Heater, H-402, Unit 0009	589170.80	6728839.20	40	9.464E-02	9.464E-02	8.918E-03	8.918E-03	3.164E-03	3.164E-03	3.164E-03	9.723E-02	Heater	Gas	0.000E+00	2.229E-03	2.229E-03	6.688E-03	6.688E-03
TR10	Hydrocracker Fractionater Reboiler, H-403, Unit 0010	589165.50	6728839.00	40	2.592E-01	2.592E-01	3.222E-02	3.222E-02	1.151E-02	1.151E-02	1.151E-02	3.558E-01	Heater	Gas	0.000E+00	8.055E-03	8.055E-03	2.416E-02	2.416E-02
TR11	Hydrocracker Fractionater Reboiler, H-404, Unit 0011	589160.20	6728838.90	40	3.484E-01	3.484E-01	3.251E-02	3.251E-02	1.179E-02	1.179E-02	1.179E-02	3.587E-01	Heater	Gas	0.000E+00	8.127E-03	8.127E-03	2.438E-02	2.438E-02
TR12	Hot Oil Heater, H-609, Unit 0012	588857.42	6728656.97	40	2.160E-01	2.160E-01	1.640E-02	1.640E-02	6.041E-03	6.041E-03	6.041E-03	1.815E-01	Heater	Gas	0.000E+00	4.099E-03	4.099E-03	1.230E-02	1.230E-02
TR15	Fired Steam Generator, H-701, Unit 0015	589041.80	6728857.40	40	1.726E-03	1.726E-03	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.438E-03	Generator	Gas	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR16	Fired Steam Generator, H-702, Unit 0016	589035.80	6728856.10	40	6.214E-02	6.214E-02	4.603E-03	4.603E-03	1.726E-03	1.726E-03	1.726E-03	5.236E-02	Generator	Gas	0.000E+00	2.253E-03	2.253E-03	2.350E-03	2.350E-03
TR17	Natural Gas Supply Heater, H-704, Unit 0017	589149.60	6728575.30	40	3.452E-02	3.452E-02	2.589E-03	2.589E-03	8.630E-04	8.630E-04	8.630E-04	2.905E-02	Heater	Gas	0.000E+00	6.472E-04	6.472E-04	1.942E-03	1.942E-03
TR18	Fired Steam Generator, H-801, Unit 0018	589029.70	6728856.00	40	5.840E-02	5.840E-02	4.315E-03	4.315E-03	2.877E-04	2.877E-04	2.877E-04	4.890E-02	Generator	Gas	0.000E+00	2.112E-03	2.112E-03	2.203E-03	2.203E-03
TR19	Hot Glycol Heater, H-802, Unit 0019	589148.10	6728833.30	40	6.674E-02	6.674E-02	5.178E-03	5.178E-03	2.877E-04	2.877E-04	2.877E-04	5.609E-02	Heater	Gas	0.000E+00	1.294E-03	1.294E-03	3.883E-03	3.883E-03
TR20	Hydrogen Reformer Furnace, H-1001, Unit 0020	589233.00	6728817.70	40	4.421E-01	4.421E-01	4.114E-02	4.114E-02	2.963E-02	2.963E-02	2.963E-02	4.554E-01	Heater	Gas	0.000E+00	1.028E-02	1.028E-02	3.085E-02	3.085E-02
TR21_26	Heaters, H-1101-1106, Units 0021-0026 (common stack)	589216.51	6728869.90	40	4.056E-02	4.056E-02	3.164E-03	3.164E-03	0.000E+00	0.000E+00	0.000E+00	3.452E-02	Heater	Gas	0.000E+00	0.000E+00	7.911E-04	2.373E-03	2.373E-03
TR27	Prip Absorber Feed Furnace, H-1201/1203, Unit 0027	589123.70	6728843.50	40	7.019E-02	7.019E-02	5.178E-03	5.178E-03	2.877E-04	2.877E-04	2.877E-04	5.782E-02	Heater	Gas	0.000E+00	1.294E-03	1.294E-03	3.883E-03	3.883E-03
TR28	Prip Recycle H2 Furnace, H-1202, Unit 0028	589128.50	6728843.80	40	1.271E-01	1.271E-01	9.493E-03	9.493E-03	2.877E-04	2.877E-04	2.877E-04	1.047E-01	Heater	Gas	0.000E+00	2.373E-03	2.373E-03	7.120E-03	7.120E-03
TR29	Vacuum Tow er Heater, H-1701, Unit 0029	588965.36	6728845.83	40	4.157E-01	4.157E-01	5.149E-02	5.149E-02	1.870E-02	1.870E-02	1.870E-02	5.704E-01	Heater	Gas	0.000E+00	1.287E-02	1.287E-02	3.862E-02	3.862E-02
TR32	Solar Centaur Turbine, GT-1400	589304.50	6728918.50	40	1.179E-01	1.179E-01	6.904E-03	6.904E-03	2.877E-04	2.877E-04	2.877E-04	7.508E-02	Turbine	Gas	0.000E+00	1.988E-03	1.988E-03	4.916E-03	4.916E-03
TR33	Solar Centaur Turbine, GT-1410	589304.50	6728918.50	40	6.588E-02	6.588E-02	3.740E-03	3.740E-03	0.000E+00	0.000E+00	0.000E+00	4.200E-02	Turbine	Gas	0.000E+00	1.077E-03	1.077E-03	2.663E-03	2.663E-03
TR34	Electrical Generator CAT 3412, EG-704 Unit 0034	589054.42	6728869.43	40	2.877E-03	2.877E-03	2.877E-04	2.877E-04	0.000E+00	0.000E+00	0.000E+00	5.753E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
TR35	Stew art-Stevens Generator, EG-801, Unit 0035	589181.30	6728736.30	40	1.151E-03	1.151E-03	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	2.877E-04	Generator	Diesel	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR36	North Caterpillar CAT G399, P-605A, Unit 0036	588891.80	6728653.60	37	4.108E-01	4.108E-01	7.040E-03	1.005E-03	1.171E-02	1.171E-02	1.671E-03	2.237E-01	Generator	Diesel	0.000E+00	6.065E-03	6.094E-03	9.749E-04	9.460E-04
TR37	South Caterpillar CAT G399, P-605B, Unit 0037	588891.90	6728643.70	37	2.100E-02	2.100E-02	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.726E-03	Generator	Diesel	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR38	North Cummins NHS6-1F, P-708A, Unit 0038	588655.80	6728681.90	30	1.102E-01	1.102E-01	7.767E-03	7.767E-03	0.000E+00	0.000E+00	0.000E+00	2.359E-02	Generator	Diesel	0.000E+00	6.691E-03	6.723E-03	1.076E-03	1.044E-03
TR40	Upper Tank Farm CAT 3412DT, P-708C, Unit 0040	589336.30	6728894.30	40	1.187E-01	1.187E-01	3.104E-02	2.126E-03	1.346E-02	1.965E-01	1.346E-02	4.605E-01	Tank	N/A	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR41	Cooling Tow er CAT G333. P-719C, Unit 0041	589058.60	6728708.60	40	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	Cooling Tow er	N/A	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR42	Refinery Flare, J-801, Unit 0042	589399.00	6728816.00	40	3.706E-02	3.706E-02	2.816E-03	2.816E-03	1.016E-02	1.016E-02	1.016E-02	3.113E-02	Flare	Gas	0.000E+00	7.041E-04	7.041E-04	2.112E-03	2.112E-03
TR43	SRU Flare, Unit 0043	589238.60	6728872.13	40	1.726E-03	1.726E-03	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.438E-03	Flare	Gas	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR44	Soil Vapor Extraction Unit, E77 SVE/TO, Unit 0044	589292.80	6728693.30	40	6.176E-03	6.176E-03	4.694E-04	4.694E-04	1.046E-03	1.046E-03	1.046E-03	5.188E-03	Heater	Gas	0.000E+00	1.174E-04	1.174E-04	3.521E-04	3.521E-04
TR45	Soil Vapor Extraction Unit, LTF SVE, Unit 0045	588747.60	6728858.63	40	2.471E-02	2.471E-02	1.878E-03	1.878E-03	4.183E-03	4.183E-03	4.183E-03	2.075E-02	Heater	Gas	0.000E+00	4.694E-04	4.694E-04	1.408E-03	1.408E-03
TR118	DDU Fractionator Reboiler, H1602 Unit 118	589282.00	6728838.00	40	6.329E-02	6.329E-02	1.726E-03	1.726E-03	4.315E-03	4.315E-03	4.315E-03	9.493E-03	Heater	Gas	0.000E+00	4.315E-04	4.315E-04	1.294E-03	1.294E-03
TR119	H-1801-Naptha Splitter Reboiler Heater	589019.00	6728839.70	40	5.233E-01	5.233E-01	6.501E-02	6.501E-02	2.359E-02	2.359E-02	2.359E-02	7.180E-01	Heater	Gas	0.000E+00	1.625E-02	1.625E-02	4.876E-02	4.876E-02
TR121	Cooling Tow er	589065.78	6728699.12	40	0.000E+00	0.000E+00	2.877E-02	2.877E-02	0.000E+00	0.000E+00	0.000E+00	0.000E+00	Cooling Tow er	N/A	0.000E+00	0.000E+00	0.000E+00	2.877E-02	2.877E-02
TES_SHP	Tesoro Tanker	587369.12	6728656.39	0	6.405E+00	2.800E-03	3.085E-01	1.349E-04	4.272E-01	4.272E-01	1.868E-04	5.488E-01	Generator	Diesel	0.000E+00	2.658E-01	2.670E-01	4.272E-02	4.146E-02

Left at permit emissions since Actuals w ere not available from ADEC point source reporting

Model ID	Point Sources Description	Stack Parameters: Stack Ht. (m)	Exit Temp. (K)	Exit Vel. (m/sec)	Stack Diam. (m)	1988 Consumes NO_2 Increment	1979 Consumes SO_2 Increment	1982 Consumes PM_{10} Increment	2013 Consumes $PM_{2.5}$ Increment	install/ mod date from permit
TR1	Crude Heater H-101A, Unit 0001	15.85	602	6.71	1.52	No	No	No	No	1969
TR2	Crude Heater H-101B, Unit 0002	26.52	531	6.10	1.22	Yes	Yes	Yes	No	1977/1997
TR3_5	Pow erformer Preheater H-201, Unit 0003 - 0005	32.31	730	4.27	2.13	No	No	No	No	1975
TR6	Pow erformer Reheater H-204, Unit 0006	46.33	533	6.10	1.52	No	Yes	No	No	1980
TR7	Pow erformer Reheater H-205, Unit 0007	46.33	533	6.10	1.52	No	Yes	No	No	1980
TR8	Hydrocracker Recycle Gas Heater, H-401, Unit 0008	25.91	532	5.18	1.22	Yes	Yes	Yes	No	1981/1989
TR9	Hydrocracker Recycle Gas Heater, H-402, Unit 0009	23.47	509	3.05	1.22	Yes	Yes	Yes	No	1981/1989
TR10	Hydrocracker Fractionater Reboiler, H-403, Unit 0010	22.86	564	7.62	1.22	Yes	Yes	Yes	No	1997
TR11	Hydrocracker Fractionater Reboiler, H-404, Unit 0011	23.47	561	5.49	1.52	Yes	Yes	Yes	No	1981/1989
TR12	Hot Oil Heater, H-609, Unit 0012	16.76	553	10.67	0.91	No	No	No	No	1969
TR15	Fired Steam Generator, H-701, Unit 0015	12.19	556	9.14	0.61	No	No	No	No	1969
TR16	Fired Steam Generator, H-702, Unit 0016	12.19	556	9.14	0.61	No	No	No	No	1969
TR17	Natural Gas Supply Heater, H-704, Unit 0017	4.88	600	65.84	0.12	No	Yes	Yes	No	1985
TR18	Fired Steam Generator, H-801, Unit 0018	12.19	450	8.53	0.61	No	Yes	No	No	1980
TR19	Hot Glycol Heater, H-802, Unit 0019	4.57	450	2.44	0.91	No	Yes	No	No	1980
TR20	Hydrogen Reformer Furnace, H-1001, Unit 0020	21.34	446	21.03	1.22	No	Yes	No	No	1981
TR21_26	Heaters, H-1101-1106, Units 0021-0026 (common stack)	30.48	450	0.91	0.91	No	Yes	Yes	No	1985
TR27	Prip Absorber Feed Furnace, H-1201/1203, Unit 0027	14.02	589	0.61	0.91	No	Yes	Yes	No	1986
TR28	Prip Recycle H2 Furnace, H-1202, Unit 0028	15.85	490	2.74	0.91	No	Yes	Yes	No	1986
TR29	Vacuum Tow er Heater, H-1701, Unit 0029	23.16	477	10.67	1.22	Yes	Yes	Yes	No	1994/2006
TR32	Solar Centaur Turbine, GT-1400	8.53	433	22.56	1.22	Yes	Yes	Yes	Yes	1988/2013?
TR33	Solar Centaur Turbine, GT-1410	8.53	433	22.56	1.22	Yes	Yes	Yes	Yes	1988/2013?
TR34	Electrical Generator CAT 3412, EG-704 Unit 0034	7.00	600	48.77	0.30	Yes	Yes	Yes	No	1989
TR35	Stew art-Stevens Generator, EG-801, Unit 0035	3.05	600	10.67	0.30	No	No	No	No	1969
TR36	North Caterpillar CAT G399, P-605A, Unit 0036	4.57	600	32.00	0.30	No	No	No	No	1969
TR37	South Caterpillar CAT G399, P-605B, Unit 0037	6.10	600	32.00	0.30	No	No	No	No	1969
TR38	North Cummins NHS6-1F, P-708A, Unit 0038	3.66	600	18.29	0.03	No	No	No	No	1969
TR40	Upper Tank Farm CAT 3412DT, P-708C, Unit 0040	3.66	600	39.29	0.240	Yes	Yes	Yes	No	1990
TR41	Cooling Tow er CAT G333. P-719C, Unit 0041	2.44	600	10.36	0.30	No	No	No	No	1969
TR42	Refinery Flare, J-801, Unit 0042	30.48	1273	20.00	0.305	No	Yes	No	No	1981
TR43	SRU Flare, Unit 0043	31.39	1273	20.00	1.52	No	Yes	Yes	No	1983
TR44	Soil Vapor Extraction Unit, E77 SVE/TO, Unit 0044	3.05	1061	1.83	0.30	Yes	Yes	Yes	No	2001/2002
TR45	Soil Vapor Extraction Unit, LTF SVE, Unit 0045	2.44	1061	1.22	0.91	Yes	Yes	Yes	No	2002
TR118	DDU Fractionator Reboiler, H1602 Unit 118	26.82	580	5.79	1.22	Yes	Yes	Yes	No	2007
TR119	H-1801-Naptha Splitter Reboiler Heater	26.82	580	5.79	1.22	Yes	Yes	Yes	No	2010
TR121	Cooling Tow er	9.14	272	0.30	6.10	Yes	Yes	Yes	No	2012
TES_SHP	Tesoro Tanker	45	589	4.2	1.68	No	No	No	No	1969

Agrium – Kenai Nitrogen Operations Plant – Actual Emissions

Model ID	SOURCE DESCRIPTION	Location: Base Elev (m)	Emissions (g/sec): NO_x (1-hr) (g/sec)	NO2 Annual (g/sec)	$PM_{2.5}$ (24-hr) (g/sec)	PM2.5 Annual (g/sec)	SO2 1HR (lb/hr, from report)	SO_2 (1-hr) (g/sec)	SO_2 (3-hr, 24hr)	SO2 Ann (tpy, from report)	SO2 Annual (g/sec)	CO (lb/hr, from report)	CO (g/sec)	Equip Type	Fuel Type	PMF/SOIL (g/sec)	EC - PM2.5 (g/sec)	EC - PM10 (g/sec)	SOA - PM2.5 (g/sec)	SOA - PM10 (g/sec)
AG_11	Ammonia Tank Storage System Flare	39.6	1.260E-02	1.064E-02	1.134E-03	1.151E-03	0.0	9.264E-05	9.264E-05	3.220E-03	9.264E-05	5.000E-02	6.300E-03	Flare	Gas	0.000E+00	2.835E-04	2.835E-04	8.505E-04	8.505E-04
AG_12	Primary Reformer	39.6	3.402E+00	3.403E+00	1.273E+00	1.269E+00	0.8	1.008E-01	1.008E-01	3.500E+00	1.007E-01	5.750E+01	7.245E+00	Boiler	Gas	0.000E+00	3.182E-01	3.182E-01	9.545E-01	9.545E-01
AG_13	Startup Heater	39.6	0.000E+00	2.848E-02	1.008E-01	2.158E-03	0.0	0.000E+00	1.726E-04	6.000E-03	1.726E-04	8.000E-01	1.008E-01	Heater	Gas	0.000E+00	2.520E-02	2.520E-02	7.560E-02	7.560E-02
AG_14	CO2 Vent	39.6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	--	0.000E+00	0.000E+00	--	0.000E+00	1.270E+01	1.600E+00							
AG_16	Amine Fat Flasher Vent	39.6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	--	0.000E+00	0.000E+00	--	0.000E+00	4.600E+00	5.796E-01							
AG_19	H2 Vent Stack (dry gas vent)	39.6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	--	0.000E+00	0.000E+00	--	0.000E+00	1.269E+02	1.599E+01							
AG_22	Plants 4 and 5 Small Flare	39.6	1.071E-02	1.070E-02	1.172E-03	1.179E-03	0.0	9.264E-05	9.264E-05	3.220E-03	9.264E-05	2.000E+00	2.520E-01	Flare	Gas	0.000E+00	2.930E-04	2.930E-04	8.789E-04	8.789E-04
AG_23	Plants 4 and 5 Emergency Flare	39.6	3.402E-03	5.753E-03	3.780E-04	3.768E-04	0.0	2.963E-05	2.963E-05	1.030E-03	2.963E-05	6.000E-01	7.560E-02	Flare	Gas	0.000E+00	9.450E-05	9.450E-05	2.835E-04	2.835E-04
AG_35	Granulator A/B Scrubber Exhaust Vent Stack	39.6	0.000E+00	0.000E+00	1.260E+00	1.260E+00	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tower	N/A	0.0	0.0	0.0	1.3	1.3
AG_36	Granulator C/D Scrubber Exhaust Vent Stack	39.6	0.000E+00	0.000E+00	1.260E+00	1.260E+00	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tower	N/A	0.0	0.0	0.0	1.3	1.3
AG_40W	Cooling Tower W	39.6	0.000E+00	0.000E+00	8.820E-05	8.342E-05	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tower	N/A	0.0	0.0	0.0	0.0	0.0
AG_40E	Cooling Tower E	39.6	0.000E+00	0.000E+00	8.820E-05	8.342E-05	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tower	N/A	0.0	0.0	0.0	0.0	0.0
AG_44	Package Boiler	39.6	3.024E-01	3.049E-01	2.268E-01	2.273E-01	0.1	1.726E-02	1.726E-02	6.000E-01	1.726E-02	9.000E+00	1.134E+00	Boiler	Gas	0.000E+00	5.670E-02	5.670E-02	1.701E-01	1.701E-01
AG_47C	Urea Warehouse/Transfer (stack) [c]	39.6	0.000E+00	0.000E+00	3.654E-03	3.452E-04	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tower	N/A	0.0	0.0	0.0	0.0	0.0
AG_47D	Urea Transfer [c]	0.0	0.000E+00	0.000E+00	3.780E-03	3.740E-04	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tower	N/A	0.0	0.0	0.0	0.0	0.0
AG_48	Package Boiler	39.6	3.024E-01	3.049E-01	2.268E-01	2.273E-01	0.1	1.726E-02	1.726E-02	6.000E-01	1.726E-02	9.000E+00	1.134E+00	Boiler	Gas	0.000E+00	5.670E-02	5.670E-02	1.701E-01	1.701E-01
AG_49	Package Boiler	39.6	3.024E-01	3.049E-01	2.268E-01	2.273E-01	0.1	1.726E-02	1.726E-02	6.000E-01	1.726E-02	9.000E+00	1.134E+00	Boiler	Gas	0.000E+00	5.670E-02	5.670E-02	1.701E-01	1.701E-01
AG_50	Waste Heat Boiler	39.6	0.000E+00	2.733E-01	7.812E-02	7.623E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_51	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_52	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_53	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_54	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_55	Solar Turbine/Generator Set	39.6	2.482E+00	5.782E-02	0.000E+00	7.336E-04	0.65	8.631E-02	8.631E-02	3.000E+00	8.631E-02	2.050E+01	2.583E+00	Turbine	Gas	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
AG_65	Diesel Fired Well Pump	39.6	2.873E-02	2.873E-02	1.008E-01	2.023E-03	0.8	2.014E-03	2.014E-03	7.000E-02	2.014E-03	2.600E+00	3.276E-01	Pump	Diesel	0.000E+00	8.684E-02	8.725E-02	1.396E-02	1.355E-02
AG_66A	Gasoline Fired Firewater Pump [c]	34.1	4.133E-03	4.133E-03	2.205E-03	2.537E-04	0.09	2.135E-04	1.134E-02	7.420E-03	2.135E-04	2.100E+00	2.646E-01	Pump	Gas	0.000E+00	1.079E-03	1.079E-03	1.126E-03	1.126E-03
AG_66B	Gasoline Fired Firewater Pump [c]	34.1	4.133E-03	4.133E-03	2.205E-03	2.537E-04	0.09	2.135E-04	1.134E-02	7.420E-03	2.135E-04	2.210E+00	2.785E-01	Pump	Gas	0.000E+00	1.079E-03	1.079E-03	1.126E-03	1.126E-03
ASHIPSTK	Ammonia Vessel (900 kW) [b]	0.0	7.299E+00	5.198E-01	1.273E-01	8.918E-03	0.98	1.230E-01	1.230E-01	3.046E-01	8.764E-03	6.640E+00	8.366E-01	Generator	Diesel	0.000E+00	1.096E-01	1.102E-01	1.762E-02	1.710E-02
USHIPSTK	Urea Vessel (240 kW) [b]	0.0	9.727E-01	2.822E-01	1.638E-02	4.890E-03	0.26	3.281E-02	3.281E-02	4.077E-01	1.173E-02	1.770E+00	2.230E-01	Generator	Diesel	0.000E+00	1.411E-02	1.418E-02	2.268E-03	2.201E-03
	HOMER ELECTRIC IS NOT PSD INCRMENT SOURCE																			
HOM_EL	Frame 6 Gas Turbine	39.6	1.309E+01	1.309E+01	3.452E-01	3.45E-01		1.726E-01	1.726E-01	6.00E+00	1.726E-01		5.75E-02	Turbine	Gas	0.000E+00	9.938E-02	9.938E-02	2.458E-01	2.458E-01

Notes:

a Location, emissions, and stack parameters obtained from dispersion modeling information submitted to ADEC supporting Agrium permit application (Agrium 2014).

b SO_2 emissions for vessels based on AP-42 Chapter 3.4 (per Agrium Modeling Report, 2014), assuming 0.1% S and 624 hrs/yr for the ammonia vessel and 3132 hrs/yr for the Urea vessel.

c Horizontal stack.

horizontal sources

Actual emissions from NEI Database

*some annual emission rates are higher than 1 hr rates due to scenarios Agrium modeled

Model ID	SOURCE DESCRIPTION	Stack Parameters Stack Ht. (m)	Exit Temp (K)	Exit Vel (m/sec)	Stack Diam (m)	PM_{10} (24-hr) (g/sec)	PM_{10} (annual) (g/sec)	NO2 Ratio	Horiz
AG_11	Ammonia Tank Storage System Flare	9.14	394.26	45.72	0.40	1.134E-03	1.151E-03	0.50	NO
AG_12	Primary Reformer	30.48	526.48	24.40	3.66	6.363E-01	1.269E+00	0.50	NO
AG_13	Startup Heater	27.43	1033.15	13.53	1.83	1.008E-01	2.158E-03		CAP
AG_14	CO2 Vent	46.94	348	26.91	0.53	0.000E+00	0.000E+00		
AG_16	Amine Fat Flasher Vent	70.0	366.5	12.3	22.5	0.000E+00	0.000E+00		
AG_19	H2 Vent Stack (dry gas vent)	46.0	373.2	20.0	8.0	0.000E+00	0.000E+00		
AG_22	Plants 4 and 5 Small Flare	74.98	922.04	1.09	0.61	1.172E-03	1.179E-03	0.50	NO
AG_23	Plants 4 and 5 Emergency Flare	74.98	922.04	121.92	1.68	3.780E-04	3.768E-04	0.50	NO
AG_35	Granulator A/B Scrubber Exhaust Vent Stack	42.67	449.82	11.50	2.29	1.260E+00	1.260E+00		NO
AG_36	Granulator C/D Scrubber Exhaust Vent Stack	42.67	449.82	11.50	2.29	1.260E+00	1.260E+00		NO
AG_40W	Cooling Tower W	20.57	288.71	2.80	10.36	1.449E-02	1.424E-02		NO
AG_40E	Cooling Tower E	20.57	288.71	2.80	10.36	1.449E-02	1.424E-02		NO
AG_44	Package Boiler	30.48	422.04	12.61	1.83	2.268E-01	2.273E-01	0.10	NO
AG_47C	Urea Warehouse/Transfer (stack) [c]	9.91	-0.10	11.48	0.61	1.008E-02	1.007E-03		HOR
AG_47D	Urea Transfer [c]	24.38	-0.10	4.85	0.61	1.071E-02	1.064E-03		HOR
AG_48	Package Boiler	30.48	422.04	10.75	1.98	2.268E-01	2.273E-01	0.10	NO
AG_49	Package Boiler	30.48	422.04	10.75	1.98	2.268E-01	2.273E-01	0.10	NO
AG_50	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.623E-02		NO
AG_51	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_52	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_53	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_54	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_55	Solar Turbine/Generator Set	18.29	608.15	40.21	1.01	0.000E+00	7.336E-04	0.30	NO
AG_65	Diesel Fired Well Pump	9.14	533.15	16.17	0.30	1.008E-01	2.023E-03	0.22	HOR
AG_66A	Gasoline Fired Firewater Pump [c]	2.08	699.82	29.11	0.10	2.205E-03	2.537E-04	0.22	HOR
AG_66B	Gasoline Fired Firewater Pump [c]	2.08	699.82	29.11	0.10	2.205E-03	2.537E-04	0.22	HOR
ASHIPSTK	Ammonia Vessel (900 kW) [b]	39.00	613.15	69.72	0.25	1.307E+00	9.320E-02	0.22	NO
USHIPSTK	Urea Vessel (240 kW) [b]	29.00	358.15	6.14	0.30	1.739E-01	5.063E-02	0.22	NO
	HOMER ELECTRIC IS NOT PSD INCRMENT SOURCE								
HOM_EL	Frame 6 Gas Turbine	30.78	403.15	19.81	3.35	3.452E-01	3.45E-01	0.30	NO

Notes:

a Location, emissions, and stack parameters obtained from dispersion modeling information submitted to ADEC supporting Agrium permit application (Agrium 2014).

b SO_2 emissions for vessels based on AP-42 Chapter 3.4 (per Agrium Modeling Report, 2014), assuming 0.1% S and 624 hrs/yr for the ammonia vessel and 3132 hrs/yr for the Urea vessel.

c Horizontal stack.

horizontal sources

Actual emissions from NEI Database

*some annual emission rates are higher than 1 hr rates due to scenarios Agrium modeled

Volume Sources

Model ID	SOURCE DESCRIPTION	Location[a] Base Elev (m)	Emissions[a] (g/sec) NOx (1-hr) (g/sec)	Annual* (g/sec)	$PM_{2.5}$ (24-hr) (g/sec)	Annual (g/sec)	1HR (lb/hr)	SO_2 (1-hr) (g/sec)		SO2 Annual		CO	Equip Type	Fuel Type	PMF/SOIL (g/sec)	EC - PM2.5 (g/sec)	EC - PM10 (g/sec)	SOA - PM2.5 (g/sec)	SOA - PM10 (g/sec)
47B	FUGITIVE DUST	39.60	--	--	1.890E-02	2.01E-03		--		--		--			1.890E-02		0.000E+00		0.000E+00
47	FUGITIVE DUST	0.00	--	--	4.725E-02	4.72E-03		--		--		--			4.725E-02		0.000E+00		0.000E+00

Model ID	SOURCE DESCRIPTION	Stack Parameters[a] Rel.Ht. (m)	Syinit (m)	Szinit (m)	PM_{10} (24-hr) (g/sec)	PM_{10} (annual) (g/sec)
47B	FUGITIVE DUST	14.02	11.63	9.91	5.42E-02	5.47E-04
47	FUGITIVE DUST	18.29	3.54	2.83	1.34E-01	1.34E-02

Kenai Liquefied Natural Gas (LNG) Plant

Model ID	Source Description	Location UTM X	UTM Y	lc-x	lc-y	Emissions (g/sec) Base Elev. (m)	NOx (1-hr)	NOx (ann)	$PM_{2.5}$ /PM_{10} (24-hr)	$PM_{2.5}$ / PM_{10} (ann)	SO_2 (1-hr, 3hr, 24hr)	SO_2 (ann)	CO (1hr, 8hr)	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
COMP_151	GE Frame 5 - Cycle #151	588333.7	6728012.7	-21.0	186.9	34.9	3.170E-01	3.17E-01	8.342E-03	8.34E-03	5.753E-04	5.75E-04	1.03E-01	Turbine	Gas	0.000E+00	2.402E-03	2.402E-03	5.941E-03	5.941E-03
COMP_152	GE Frame 5 - Cycle #152	588326.4	6728012.5	-21.0	186.9	34.9	5.150E+00	5.15E+00	1.349E-01	1.35E-01	8.342E-03	8.34E-03	1.68E+00	Turbine	Gas	0.000E+00	3.884E-02	3.884E-02	9.608E-02	9.608E-02
COMP_251	GE Frame 5 - Cycle #251	588363.0	6728013.4	-21.0	186.9	34.9	1.786E+00	1.79E+00	3.912E-02	3.91E-02	2.301E-03	2.30E-03	4.85E-01	Turbine	Gas	0.000E+00	1.126E-02	1.126E-02	2.786E-02	2.786E-02
COMP_252	GE Frame 5 - Cycle #252	588355.7	6728013.2	-21.0	186.9	34.9	4.168E+00	4.17E+00	9.119E-02	9.12E-02	5.753E-03	5.75E-03	1.13E+00	Turbine	Gas	0.000E+00	2.625E-02	2.625E-02	6.494E-02	6.494E-02
COMP_351	GE Frame 5 - Cycle #351	588348.4	6728013.0	-21.0	186.9	34.9	7.465E-01	7.46E-01	1.899E-02	1.90E-02	1.151E-03	1.15E-03	2.36E-01	Turbine	Gas	0.000E+00	5.466E-03	5.466E-03	1.352E-02	1.352E-02
COMP_352	GE Frame 5 - Cycle #352	588341.0	6728012.9	-21.0	186.9	34.9	3.580E+00	3.58E+00	9.119E-02	9.12E-02	5.753E-03	5.75E-03	1.13E+00	Turbine	Gas	0.000E+00	2.625E-02	2.625E-02	6.494E-02	6.494E-02
COMP_701	SOLAR TAURUS 60	588319.1	6728012.3	-21.0	186.9	34.9	1.174E-01	1.17E-01	2.359E-02	2.36E-02	1.438E-03	1.44E-03	1.78E-02	Turbine	Gas	0.000E+00	6.791E-03	6.791E-03	1.680E-02	1.680E-02
BLR_501	BOILER 501	588412.2	6728019.6	-20.9	186.9	35.1	8.342E-02	8.34E-02	6.329E-03	6.33E-03	2.877E-04	2.88E-04	7.02E-02	Boiler	Gas	0.000E+00	1.582E-03	1.582E-03	4.746E-03	4.746E-03
BLR_502	BOILER 502	588417.4	6728019.7	-20.9	186.9	35.1	1.269E-01	1.27E-01	9.493E-03	9.49E-03	5.753E-04	5.75E-04	1.06E-01	Boiler	Gas	0.000E+00	2.373E-03	2.373E-03	7.120E-03	7.120E-03
BLR_511	BOILER 511	588422.6	6728019.9	-20.9	186.9	35.1	1.464E-01	1.46E-01	1.122E-02	1.12E-02	5.753E-04	5.75E-04	1.23E-01	Boiler	Gas	0.000E+00	2.805E-03	2.805E-03	8.414E-03	8.414E-03
E_GEN	Caterpillar D379 Emergency Generator	588407.5	6728012.6	-20.9	186.9	35.0	7.479E-03	7.48E-03	5.753E-04	5.75E-04	0.000E+00	0.00E+00	1.73E-03	Generator	Diesel	0.000E+00	4.957E-04	4.980E-04	7.968E-05	7.731E-05
FW_PUMP2	Caterpillar D3406 Firewater Pump #2	588246.7	6727999.8	-21.1	186.8	35.0	4.315E-03	4.31E-03	2.877E-04	2.88E-04	0.000E+00	0.00E+00	8.63E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
FW_PUMP3	Caterpillar D3406 Firewater Pump #3	588246.6	6728001.5	-21.1	186.8	35.0	4.027E-03	4.03E-03	2.877E-04	2.88E-04	0.000E+00	0.00E+00	8.63E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
FW_PUMP4	Caterpillar D3406 Firewater Pump #4	588246.5	6728007.0	-21.1	186.8	35.0	3.164E-03	3.16E-03	2.877E-04	2.88E-04	0.000E+00	0.00E+00	5.75E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
FLARE	Ground Flare	588187.6	6728327.0	-21.1	187.2	26.7	1.076E-01	1.08E-01	4.171E-02	4.17E-02	5.753E-04	5.75E-04	5.84E-01	Flare	Gas	0.000E+00	1.043E-02	1.043E-02	3.128E-02	3.128E-02
KSHP	Tanker	587510.4	6728052.6	-21.835	186.91	0.0	5.289E+00	1.040E+00	1.990E-01	4.364E-02	9.025E-01	2.698E-02	6.944E+00	Generator	Diesel	0.000E+00	1.715E-01	1.723E-01	2.756E-02	2.674E-02

Notes: horizontal/capped source

Location, emissions, and stack parameters obtained from **AERMOD_input_file_spreadsheet_04_26_2013.xls**

Emissions based on maximum short-term permitted limits, except where noted.

It was assumed that the tanker was similar to vessels that will be used at the AKLNG facility. Therefore, the emissions and stack parameters used for the AKLNG carriers were also used for the Kenai vessel.

Model ID	Source Description	Stack Parameters					1988	1982	2013?	1980	
		Stack Ht. (m)	Exit Temp. (K)	Exit Vel. (m/sec)	Stack Diam. (m)	Horiz/Cap?	no2	PM10	PM2.5	SO2	install date
COMP_151	GE Frame 5 - Cycle #151	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_152	GE Frame 5 - Cycle #152	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_251	GE Frame 5 - Cycle #251	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_252	GE Frame 5 - Cycle #252	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_351	GE Frame 5 - Cycle #351	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_352	GE Frame 5 - Cycle #352	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_701	SOLAR TAURUS 60	19.51	776	98.41	0.813		Y	Y	No	Y	2006
BLR_501	BOILER 501	19.81	589	9.10	0.975	Cap	No	No	No	No	1969
BLR_502	BOILER 502	19.81	589	9.10	0.975	Cap	No	No	No	No	1969
BLR_511	BOILER 511	19.81	589	9.10	0.975	Cap	No	No	No	No	1969
E_GEN	Caterpillar D379 Emergency Generator	6.25	600	39.29	0.244		No	No	No	No	1969
FW_PUMP2	Caterpillar D3406 Firewater Pump #2	3.96	600	39.29	0.244	Horiz	Y	Y	No	Y	1992
FW_PUMP3	Caterpillar D3406 Firewater Pump #3	3.96	600	39.29	0.244	Horiz	Y	Y	No	Y	1992
FW_PUMP4	Caterpillar D3406 Firewater Pump #4	3.96	600	39.29	0.244	Horiz	Y	Y	No	Y	1992
FLARE	Ground Flare	2.33	1273	20.00	0.451	Horiz	No	No	No	No	1992
KSHP	Tanker	45.00	589	4.2	1.68		No	No	No	No	1969

Notes: horizontal/capped source

Location, emissions, and stack parameters obtained from **AERMOD_input_file_spreadsheet_04_26_2013.xls**

Emissions based on maximum short-term permitted limits, except where noted.

It was assumed that the tanker was similar to vessels that will be used at the AKLNG facility. Therefore, the emissions and stack parameters used for the AKLNG carriers were also used for the Kenai vessel.

Additional Offsite Point Sources – Actual Emissions

SRCID	Source Description	Z(m)	NOx (1-hr & Annual)	PM (24-hr & Annual)	SO2 (All avg per)	CO	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10	Hs (m)	Ts (K)	Vs (m/sec)	Ds(m)	NO2 Ratio	UTM X	UTM Y	NO2	PM10	PM2.5	SO2
13001	Hilcorp Middle Ground Shoal Onshore Facility	50.0	4.79E-01	3.31E-02	5.20E-03	1.40E-01	Turbine	Gas	0.000E+00	9.529E-03	9.529E-03	2.357E-02	2.357E-02	5.00	500	20.00	1.00	0.50	589539.4	6734383.7	y	y	n	y
15001	Hilcorp Platform C Middle Ground Shoal	0.0	9.88E+00	1.21E-01	2.47E-01	1.01E+01	Turbine	Gas	0.000E+00	3.478E-02	3.478E-02	8.604E-02	8.604E-02	27.50	850	25.00	1.00	0.50	581223.4	6736992.7	y	y	n	y
18002	Bernice Lake Power Station - Natural Gas Turbine 2	35.0	6.99E-01	1.44E-02	2.88E-04	1.78E-01	Turbine	Gas	0.000E+00	4.141E-03	4.141E-03	1.024E-02	1.024E-02	15.20	428	18.50	2.30	0.50	587989.4	6729683.7	n	n	n	n
18003	Bernice Lake Power Station - Natural Gas Turbine 3	35.0	1.96E-01	5.47E-03	0.00E+00	2.30E-01	Turbine	Gas	0.000E+00	1.573E-03	1.573E-03	3.892E-03	3.892E-03	10.80	760	21.10	3.90	0.50	587989.4	6729683.7	n	n	n	n
18004	Bernice Lake Power Station - Natural Gas Turbine 4	35.0	1.63E+00	3.74E-02	8.63E-04	1.12E+00	Turbine	Gas	0.000E+00	1.077E-02	1.077E-02	2.663E-02	2.663E-02	10.80	760	21.10	3.90	0.50	587989.4	6729683.7	n	y	n	y
50001	KPL Marine Loading Terminal - Firewater Pump 1	30.0	4.03E-03	0.00E+00	0.00E+00	5.75E-04	Pump	Diesel	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.70	600	67.00	0.10	0.50	588092.5	6728971.4	y	y	n	y
50002	KPL Marine Loading Terminal - Firewater Pump 2	30.0	3.16E-03	2.88E-04	0.00E+00	2.88E-04	Pump	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05	3.70	600	67.00	0.10	0.50	588092.5	6728967.4	y	y	n	y

Additional Facilities – Actual Emissions (RFD sources are in PTE)

			Location[a]			2011 Emissions (g/sec)[b]														
SRCID	Model ID	Volume Sources Description	Longitude	Latitude	Base Elev. (m)	NOx (1-hr)	NOx (annual)	$PM_{2.5}$ (24-hr)	$PM_{2.5}$ (annual)	PM_{10} (24-hr)	PM_{10} (annual)	SO_2 (1-hr)	SO_2 (3-hr & 24-hr)	SO_2 (annual)	CO (1hr, 8hr)	PMF/SOIL[d]	EC - PM2.5[e,g,h]	EC - PM10	SOA - PM2.5[f,g,h]	SOA - PM10
vol_1	Bea	Beaver Creek Production Facility	-151.03	60.67	47.40	2.87	2.87	0.04	0.04	0.04	0.04	9.87	9.87	9.87	4.19	0.00	0.04	0.04	0.04	0.04
vol_1	Bel	Beluga River Pow er Plant	-151.05	61.19	27.30	99.58	99.58	2.74	2.74	2.77	2.77	0.76	0.76	0.76	25.22	0.00	3.07	3.13	2.42	2.42
vol_1	Bru	Bruce Platform	-151.33	60.83	0.00	3.09	3.09	0.05	0.05	0.05	0.05	0.00	0.00	0.00	3.60	0.00	0.06	0.06	0.04	0.04
vol_1	Cle	Clear Air Force Station	-149.13	64.31	166.80	6.46	6.46	0.04	0.04	0.03	0.03	5.88	5.88	5.88	3.66	0.00	0.06	0.16	0.01	0.01
	Dol	Dolly Varden Platform WITH KUUKPIK 5 RIG EMISSIONS	-151.63	60.81	0.00	5.76	5.76	0.21	0.21	0.21	0.21	3.92	3.92	3.92	3.53	0.00	0.24	0.24	0.16	0.16
	Dri	Drift River Terminal / Christy Lee Platform Aggregated Source	-152.15	60.57	0.30	2.22	2.22	0.03	0.03	0.03	0.03	0.12	0.12	0.12	0.27	0.00	0.06	0.06	0.00	0.00
	Geo	George Sullivan Plant Tw o	-149.72	61.23	108.40	52.28	52.28	1.08	1.08	1.08	1.08	0.01	0.01	0.01	12.12	0.00	1.19	1.19	0.97	0.97
	Gra	Grayling Platform WITH KUUKPIK 5 RIG EMISSIONS	-151.61	60.84	0.00	9.89	9.89	0.28	0.28	0.28	0.28	1.08	1.08	1.08	2.93	0.00	0.32	0.32	0.22	0.22
vol6	Sold	AE&EC - Soldonta Turbine	-151.00	60.50	74.00	7.06	7.06	1.06	1.06	1.06	1.06	0.35	0.35	0.35	6.33	0.00	0.31	0.31	0.76	0.76
vol6	Gude	Alaska Pipeline Co. - Gudenrath Compessor Station	-150.62	60.54	100.00	2.17	2.17	0.06	0.06	0.06	0.06	0.03	0.03	0.03	0.75	0.00	0.02	0.02	0.04	0.04
	Han	Hank Nikkels Plant One	-149.87	61.22	30.50	2.29	2.29	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.75	0.00	0.13	0.13	0.09	0.09
	Hea	Healy Pow er Plant	-148.95	63.85	449.20	9.08	9.08	0.80	0.80	0.80	0.80	13.24	13.24	13.24	9.53	0.00	1.48	1.48	0.11	0.11
	Ke1	Kenai Gas Field 14-6 Pad	-151.26	60.46	18.60	30.15	30.15	0.65	0.65	0.65	0.65	0.12	0.12	0.12	7.80	0.00	0.00	0.00	0.00	0.00
	Ke2	Kenai Gas Field 34-31 Pad	-151.27	60.48	16.20	2.66	2.66	0.05	0.05	0.05	0.05	0.03	0.03	0.03	0.91	1.00	0.00	0.00	0.00	0.00
	Kin	King Salmon Platform	-151.61	60.87	0.00	3.72	3.72	0.14	0.14	0.14	0.14	2.64	2.64	2.64	1.44	0.00	0.58	0.58	0.87	0.87
	LNG	LNG Plant #1	-150.08	61.43	42.00	6.18	6.18	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.88	1.00	0.58	0.58	0.87	0.87
	Pl1	Platform A	-151.50	60.80	0.00	9.15	9.15	0.14	0.14	0.14	0.14	1.00	1.00	1.00	6.34	0.00	0.01	0.01	0.01	0.01
	Pl2	Platform C, Middle Ground Shoal, Cook Inlet	-151.50	60.76	0.00	9.88	9.88	0.12	0.12	0.12	0.12	0.25	0.25	0.25	10.06	0.00	0.38	0.38	0.31	0.31
	Ste	Steelhead Platform	-151.60	60.83	0.00	5.24	5.24	0.23	0.23	0.23	0.23	0.01	0.01	0.01	1.58	0.00	0.11	0.12	0.10	0.10
	Sw a	Sw anson River Field	-150.86	60.73	44.00	30.82	30.82	0.48	0.48	0.48	0.48	0.00	0.00	0.00	5.78	0.00	0.08	0.08	0.07	0.07
	Ted	Ted Stevens Anchorage I	-150.02	61.18	26.50	65.44	65.44	1.71	1.71	1.77	1.77	6.26	6.26	6.26	113.68	0.00	0.68	0.74	1.03	1.03
	Tyo	Tyonek Platform	-150.95	61.07	0.00	4.37	4.37	0.09	0.09	0.09	0.09	0.00	0.00	0.00	3.11	0.00	0.54	0.54	0.42	0.42
	Val	Valdez Diesel Pow er Plant	-146.35	61.14	106.40	4.03	4.03	0.10	0.10	0.10	0.10	0.64	0.64	0.64	1.10	0.00	0.00	0.00	0.00	0.00

RFD Source - Emissions are PTE, not actuals

Notes:

a Locations based on 2011 NEI Database Average Point Source Longitude and Latitude

b Emissions based on Double the Actual Emissions from 2011 NEI Database.
1-hr, 3-hr, 8-hr, and 24-hr have been set equal to the annual emission rate for each pollutant. It is assumed that the same level of emissions from the facility are emitted throughout the year (8,760 hours). Specific maximum operating cases are not know n.

c All volume source plume assumed to be 10 m x 10 m x 10 m in size
Syinit assumed 4.3 from Table 3-1 in the AERMOD User's Guide for a single volume source
Syinit assumed 4.3 from Table 3-1 in the AERMOD User's Guide for an elevated source not on or adjacent to a building

d PMF/Soil Set Equal to 0 tpy w ith the assumption that the majority of the emitters w ithin the Volume Sources are combustion-driven equipment.

e The Elemental Carbon (EC) is set equal to the PM Filterable emissions provided by the 2011 NEI Database

f The Secondary Organic Aerosols (SOA) are set equal to the PM Condensable emissions provided by the 2011 NEI Database

h Ted Stevens Anchorage I EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere split into 4 equal parts to represent the possible equipment at the facility

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Mobile Source w ith Diesel Fuel	10%	90%	11%	89%
Generator w ith Diesel Fuel	86%	14%	87%	13%
Heater w ith Gas Fuel	25%	75%	25%	75%
Heater w ith Diesel Fuel	39%	61%	45%	55%

i The Solodonta Turbine and Gundenrath Compressor Station EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere assumed to be based on gas-fired turbines as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Turbine w ith Gas Fuel	29%	71%	29%	71%

j The Kuukpik 5 Rig EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere assumed to be based on diesel-fired generator as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Generator w ith Diesel Fuel	86%	14%	87%	13%

k Ted Stevens Anchorage I assumed to be all increment consuming

			Stack Parameters[c]				1988	1982	2013?	1979		
SRCID	Model ID	Volume Sources Description	Rel.Ht. (m)	Syinit (m)	Szinit (m)	NO2 Ratio	Increment Consuming NOx	Increment Consuming PM10	Increment Consuming PM2.5	Increment Consuming SO2	Oldest Install Date	Newest Install Date
vol_1	Bea	Beaver Creek Production Facility	10.0	2.33	2.33	0.5	Y	Y	N	Y	1973	2004
vol_1	Bel	Beluga River Pow er Plant	10.0	2.33	2.33	0.5	Y	Y	N	Y	1968	2011
vol_1	Bru	Bruce Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1967	2008
vol_1	Cle	Clear Air Force Station	10.0	2.33	2.33	0.5	Y	Y	N	Y	1960	2012
	Dol	Dolly Varden Platform WITH KUUKPIK 5 RIG EMISSIONS	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
	Dri	Drift River Terminal / Christy Lee Platform Aggregated Source	10.0	2.33	2.33	0.5	Y	Y	N	Y	1966	2008
	Geo	George Sullivan Plant Tw o	10.0	2.33	2.33	0.5	Y	Y	Y	Y	1975	2015
	Gra	Grayling Platform WITH KUUKPIK 5 RIG EMISSIONS	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
vol6	Sold	AE&EC - Soldonta Turbine	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
vol6	Gude	Alaska Pipeline Co. - Gudenrath Compessor Station	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
	Han	Hank Nikkels Plant One	10.0	2.33	2.33	0.5	Y	Y	N	Y	1962	2011
	Hea	Healy Pow er Plant	10.0	2.33	2.33	0.5	Y	Y	N	Y	1967	1998
	Ke1	Kenai Gas Field 14-6 Pad	10.0	2.33	2.33	0.5	Y	Y	N	Y	1980	2004
	Ke2	Kenai Gas Field 34-31 Pad	11.0	2.33	2.56	1.5	Y	Y	N	Y	1985	2001
	Kin	King Salmon Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1967	2006
	LNG	LNG Plant #1	11.0	2.33	2.56	1.5	Y	Y	N	Y	1998	2006
	Pl1	Platform A	10.0	2.33	2.33	0.5	Y	Y	Y	Y	1965	2013
	Pl2	Platform C, Middle Ground Shoal, Cook Inlet	10.0	2.33	2.33	0.5	Y	Y	Y	Y	1967	2013
	Ste	Steelhead Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1986	2009
	Sw a	Sw anson River Field	10.0	2.33	2.33	0.5	Y	Y	N	Y	1962	2007
	Ted	Ted Stevens Anchorage I	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
	Tyo	Tyonek Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1968	2002
	Val	Valdez Diesel Pow er Plant	10.0	2.33	2.33	0.5	N	N	N	N	1966	1976
		RFD Source - Emissions are PTE, not actuals										

Notes:

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b Emissions based on Double the Actual Emissions from 2011 NEI Database.
1-hr, 3-hr, 8-hr, and 24-hr have been set equal to the annual emission rate for each pollutant. It is assumed that the same level of emissions from the facility are emitted throughout the year (8,760 hours). Specific maximum operating cases are not know n.

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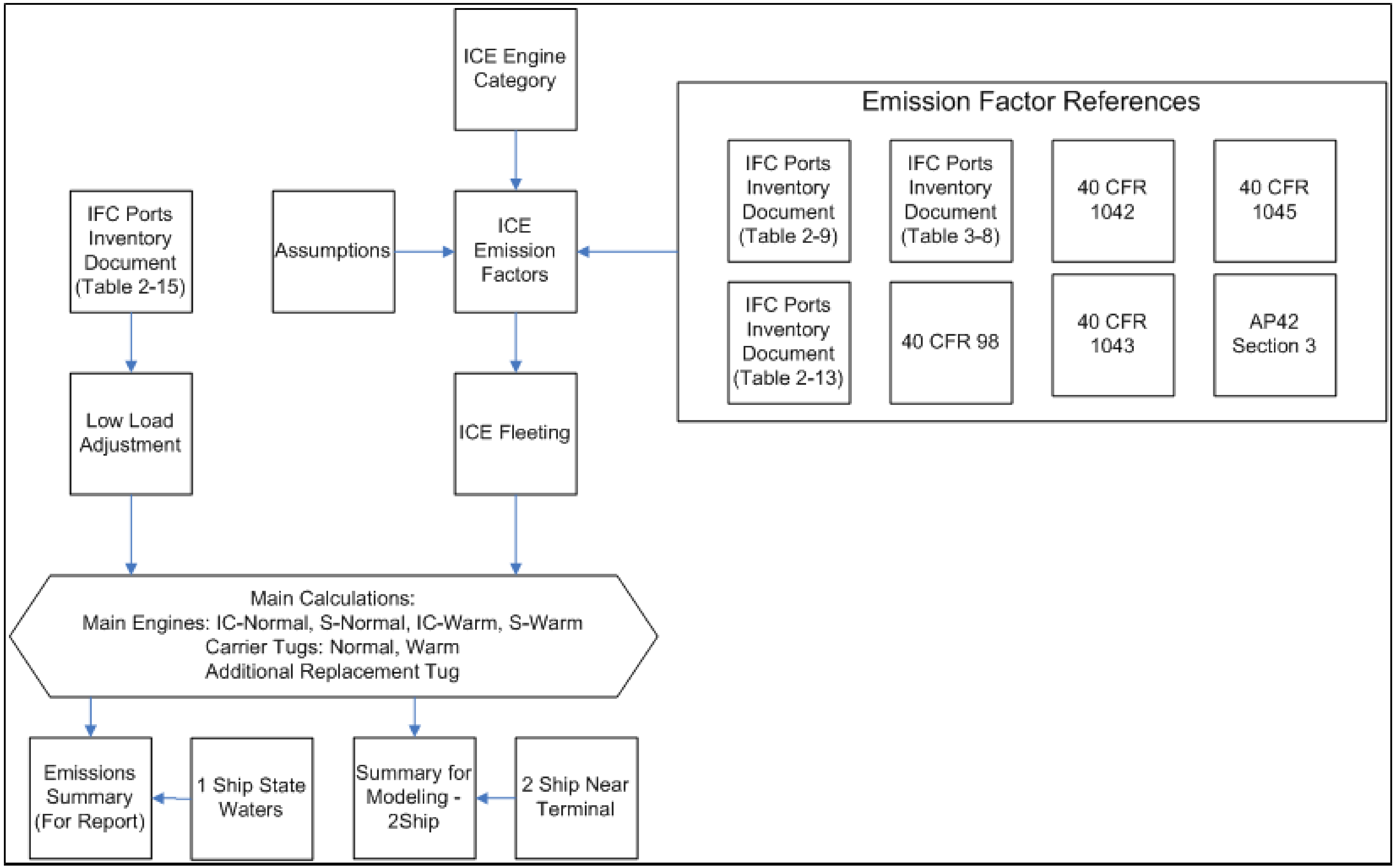
j The Kuukpik 5 Rig EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere assumed to be based on diesel-fired generator as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Generator w ith Diesel Fuel	86%	14%	87%	13%

k Ted Stevens Anchorage I assumed to be all increment consuming

MEC-1 FLOW CHART OF CALCULATION COMPONENTS



MEC-2 ANNUAL MARINE OPERATION SUMMARY

Facility Throughput (Total)			
Annual Facility LNG Production	20	MTPA	(million tonnes per annum)
	20,000,000,000	kg/yr	
Hourly Facility LNG Production	2,283,105	kg/hr	
	455	kg/m3	Average assumed density of LNG
Annual Volumetric LNG Production	43,956,044	m3/yr	
Hourly Volumetric LNG Production	5,018	m3/hr	

LNG Carrier Breakdown of Facility Production						
	Total		Normal Arrival		Warm Arrival	
	Frequency	Flow Rate	Frequency	Flow Rate	Frequency	Flow Rate
Combustion Engine Carrier	98%	43,076,923	97%	41,784,615	3%	1,292,308
Steam Carrier	2%	879,121	97%	852,747	3%	26,374

LNG Carrier Annual Calls			
	Size	No. of Normal Calls	No. of Warm Calls
Combustion Engine Carrier	216,000	193.45	5.98
Steam Carrier	216,000	3.95	0.12

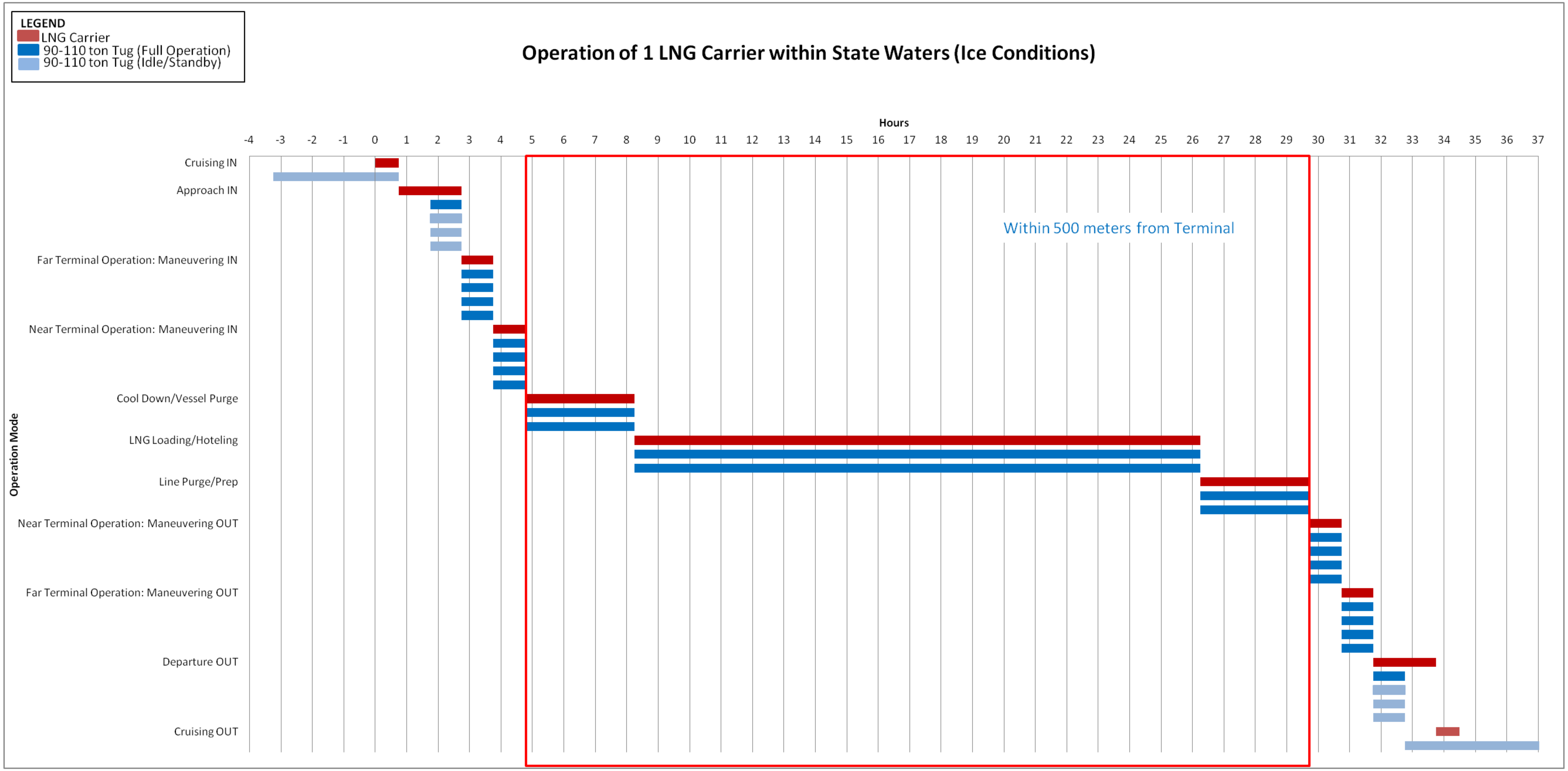
MEC-3 ANNUAL TOTAL EMISSIONS SUMMARY

Weighted Average Exhaust Gas Emissions (lb/hr)									
Pollutant	IC Engine		Steam Engine		LNG Carrier Total	Carrier Tugs		Tug Total	Marine Inventory Total
	Normal Arrival	Warm Arrival	Normal Arrival	Warm Arrival		Normal Carrier Arrival	Warm Carrier Arrival		
NO_x	69	42	34	29	174	52	53	105	279
CO	76	49	4	4	133	161	164	325	458
VOC	27	16	2	2	47	6	6	12	59
PM_{10}	3	2	3	3	10	2	2	4	13
$PM_{2.5}$	2	1	3	2	9	2	2	4	12
SO_2	0	0	10	8	18	0	0	0	18
GHG (CO2e)[1]	9,562	6,261	15,941	13,431	45,194	20,400	20,586	40,986	86,180
HAPs	0.04	0.03	0.05	0.04	0.15	0.08	0.08	0.16	0.31
Exhaust Gas Emissions (TPY) (tonnes/year for CO2e)									
Pollutant	IC Engine		Steam Engine		LNG Carrier Total	Carrier Tugs		Tug Total	Marine Inventory Total
	Normal Arrival	Warm Arrival	Normal Arrival	Warm Arrival		Normal Carrier Arrival	Warm Carrier Arrival		
NO_x	260	11	3	0	274	100	6	106	380
CO	291	13	0	0	304	309	17	326	630
VOC	100	4	0	0	104	12	1	12	117
PM_{10}	10	0	0	0	10	3	0	4	14
$PM_{2.5}$	9	0	0	0	9	3	0	4	13
SO_2	0	0	1	0	1	0	0	0	1
GHG (CO2e)[1]	36,741	1,629	1,435	76	39,881	39,202	2,165	41,367	81,248
HAPs	0.16	0.01	0.004	0.0002	0.17	0.15	0.01	0.16	0.33

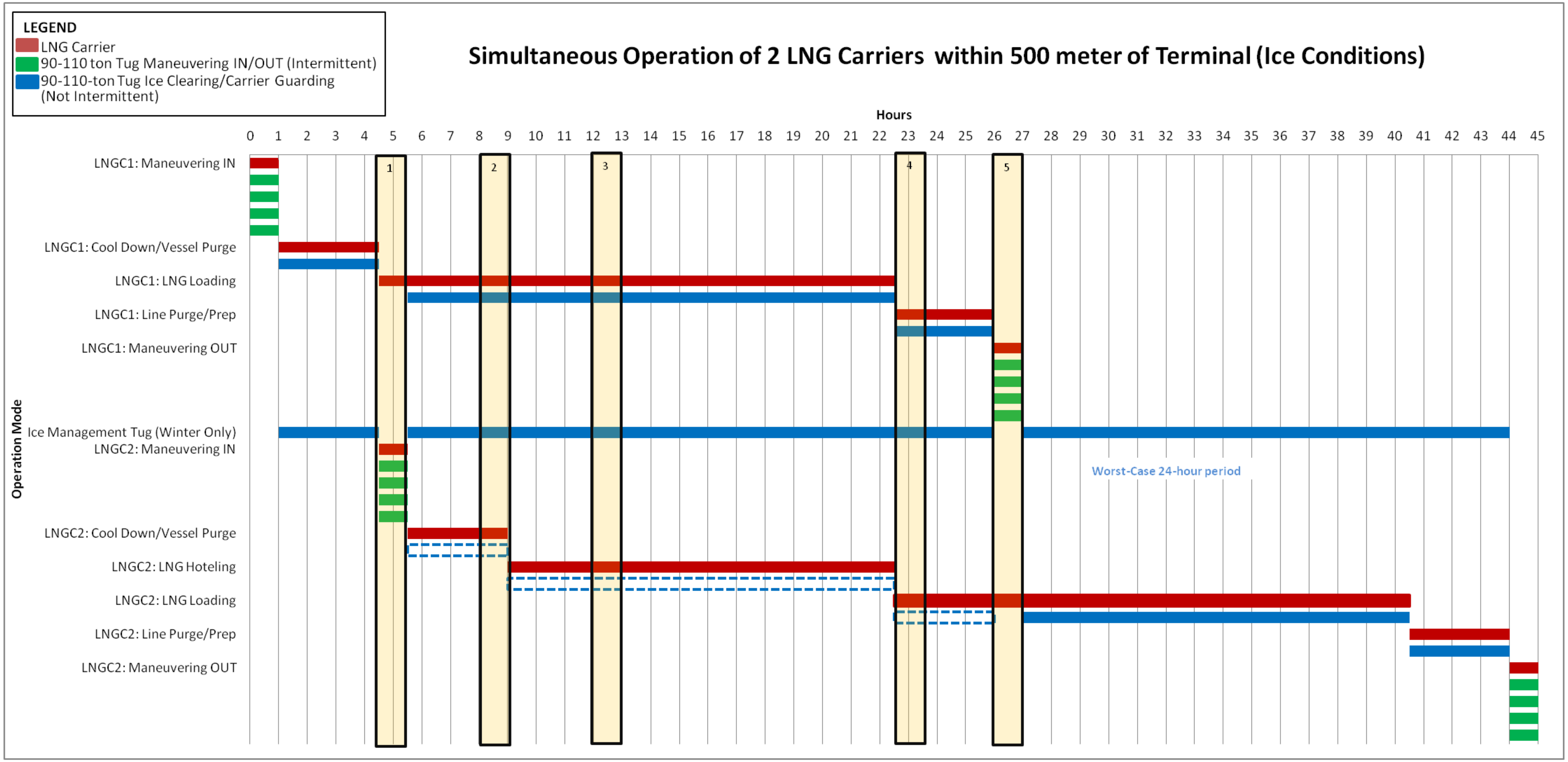
Notes:

1. Annual emissions of GHG are given in metric tons (tonnes) per year.

MEC-4 PROPOSED OPERATION OF ONE SHIP IN STATE WATERS



MEC-5 PROPOSED OPERATION OF TWO SHIPS NEAR BERTH (MODELING SCENARIOS)



MEC-6 MODELING SCENARIOS EMISSIONS SUMMARY

WORST CASE EMISSION RATES WHILE AT BERTH (2 Ship Modeling Summary)

Tug size and usaged assumed the same for LNGc with IC engine or LNGc with steam engine.
All maneuvering operations (including LNGc) considered intermittent. Emissions annualized for 1-hour NO2/SO2 modeling.

Source	Task	Emission Rates (g/s) NO2 1-hour -1-	NO2 1-hour -2-	NO2 1-hour -3-	NO2 1-hour -4-	NO2 1-hour -5-	NO2 24-hour	NO2 Annual	CO 1-hour -1-	CO 8-hour	SO2 1-hour -4-	SO2 3-hour	SO2 24-hour	SO2 Annual	PM2.5 24-hour	PM2.5 Annual	PM10 24-hour	PM10 Annual
South Carrier	LNGc 1 Maneuvering IN							1.30E-01						4.44E-04		4.21E-03		4.70E-03
	LNGc 1 Cool Down							1.50E-01						1.06E-03		5.77E-03		6.38E-03
	LNGc 1 Loading	5.29	5.29	5.29			3.9667	1.10E+00	6.94	6.94			0.68	4.14E-03	0.1859	4.16E-02	0.2107	4.60E-02
	LNGc 1 Hoteling							4.23E-01						3.91E-03		1.64E-02		1.81E-02
	LNGc 1 Purge Lines				3.08		0.450	1.09E-01			0.90	0.90	0.13	7.70E-04	0.036	4.18E-03	0.041	4.62E-03
	LNGc 1 Maneuvering OUT					0.132	0.473	1.30E-01					0.06	4.44E-04	0.016	4.21E-03	0.018	4.70E-03
North Carrier	LNGc 2 Maneuvering IN	0.132					0.473	1.30E-01	12.69	12.69			0.06	4.44E-04	0.016	4.21E-03	0.018	4.70E-03
	LNGc 2 Cool Down		3.08				0.450	1.50E-01					0.13	1.06E-03	0.036	5.77E-03	0.041	6.38E-03
	LNGc 2 Loading				5.29	5.29	1.322	1.10E+00			0.90	0.90	0.23	4.14E-03	0.062	4.16E-02	0.070	4.60E-02
	LNGc 2 Hoteling			3.08			1.734	4.23E-01					0.51	3.91E-03	0.139	1.64E-02	0.158	1.81E-02
	LNGc 2 Purge Lines							1.09E-01						7.70E-04		4.18E-03		4.62E-03
	LNGc 2 Maneuvering OUT							1.30E-01						4.44E-04		4.21E-03		4.70E-03
Support Tugs	Tug 1 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 2 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 3 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 4 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 1 Maneuver LNG Carrier Guard/Ice Clearing**		1.825	1.825	1.825		1.673	1.10E+00			0.001	0.001	0.001	7.93E-04	0.056	3.66E-02	0.056	3.66E-02
	Tug 2 Maneuver LNG Carrier Guard/Ice Clearing**		1.825	1.825	1.825		1.673	6.35E-01			0.001	0.001	0.001	4.61E-04	0.056	2.16E-02	0.056	2.16E-02
	Tug 1 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 2 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 3 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 4 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	TOTAL	5.59	12.02	12.02	12.02	5.59	12.82	6.15	39.91	39.91	1.81	1.81	1.80	0.02	0.62	0.22	0.69	0.24
Annualized Emissions		1 hr		204 calls/year														

** Emissions distributed over 5 point sources

Source	Modeled Emission Rate (g/s) NO2 1-hour	NO2 1-hour	NO2 1-hour	NO2 1-hour	NO2 1-hour	NO2 24-hour	NO2 Annual	CO 1-hour	CO 8-hour	SO2 1-hour	SO2 3-hour	SO2 24-hour	SO2 Annual	PM2.5 24-hour	PM2.5 Annual	PM10 24-hour	PM10 Annual
LNGCAR1 (South Carrier)	5.29E+00	5.29E+00	5.29E+00	3.08E+00	1.32E-01	4.89E+00	2.04E+00	6.94E+00	6.94E+00	9.03E-01	9.03E-01	8.70E-01	1.08E-02	2.38E-01	7.63E-02	2.70E-01	8.45E-02
LNGCAR2 (North Carrier)	1.32E-01	3.08E+00	3.08E+00	5.29E+00	5.29E+00	3.98E+00	2.04E+00	1.27E+01	1.27E+01	9.03E-01	9.03E-01	9.26E-01	1.08E-02	2.54E-01	7.63E-02	2.87E-01	8.45E-02
TG_MAN1S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN2S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN3S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN4S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN1N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00			5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN2N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00			5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN3N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00			5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN4N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00			5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_ICE1A Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03
TG_ICE1B Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03
TG_ICE1C Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03
TG_ICE1D Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03
TG_ICE1E Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03
TG_ICE2A Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03
TG_ICE2B Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03
TG_ICE2C Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03
TG_ICE2D Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03
TG_ICE2E Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03

WORST CASE EMISSION RATES WHILE AT BERTH (2 Ship Modeling Summary)

Tug size and usaged assumed the same for LNGc with IC
All maneuvering operations (including LNGc) considered intermittent. Emissions annualized for 1-hour NO2/SO2 modeling.

Source	Task	Equipment Type	Fuel Type	Speciated Emissions				
				PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
				short-term	short-term	short-term	short-term	short-term
South Carrier	LNGc 1 Maneuvering IN	Generator	Diesel					
	LNGc 1 Cool Down	Generator	Diesel					
	LNGc 1 Loading	Generator	Diesel	0.0000	0.1602	0.1824	0.0258	0.0283
	LNGc 1 Hoteling	Generator	Diesel					
	LNGc 1 Purge Lines	Generator	Diesel	0.0000	0.0311	0.0355	0.0050	0.0055
	LNGc 1 Maneuvering OUT	Generator	Diesel	0.0000	0.0138	0.0158	0.0022	0.0024
North Carrier	LNGc 2 Maneuvering IN	Generator	Diesel	0.0000	0.0138	0.0158	0.0022	0.0024
	LNGc 2 Cool Down	Generator	Diesel	0.0000	0.0311	0.0355	0.0050	0.0055
	LNGc 2 Loading	Generator	Diesel	0.0000	0.0534	0.0608	0.0086	0.0094
	LNGc 2 Hoteling	Generator	Diesel	0.0000	0.1201	0.1368	0.0193	0.0212
	LNGc 2 Purge Lines	Generator	Diesel					
	LNGc 2 Maneuvering OUT	Generator	Diesel					
Support Tugs	Tug 1 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 2 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 3 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 4 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 1 Maneuver LNG Carrier Guard/Ice Clearing**	Generator	Diesel	0.0000	0.0481	0.0483	0.0077	0.0075
	Tug 2 Maneuver LNG Carrier Guard/Ice Clearing**	Generator	Diesel	0.0000	0.0481	0.0483	0.0077	0.0075
	Tug 1 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 2 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 3 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 4 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
TOTAL				**0.00**	**0.54**	**0.60**	**0.09**	**0.09**

Annualized Emissions
** Emissions distributed over 5 point sources

Source	UTM X	UTM Y	lc-x	lc-y	Stack Ht	Exit Temp	Exit Vel	Diam	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
	(m)	(m)	km	km	(m)	(K)	(msec)	(m)					
LNGCAR1 (South Carrier)	588362.600	6725207.770	-21.0638	184.0375	45	589	4.2	1.68	0.00E+00	2.05E-01	2.34E-01	3.30E-02	3.63E-02
LNGCAR2 (North Carrier)	588176.020	6725657.540	-21.2378	184.4943	45	589	4.2	1.68	0.00E+00	2.19E-01	2.49E-01	3.51E-02	3.86E-02
TG_MAN1S Maneuvering (with S Carrier)	588332.800	6725273.480	-21.0918	184.1043	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN2S Maneuvering (with S Carrier)	588308.660	6725140.990	-21.1199	183.9721	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN3S Maneuvering (with S Carrier)	588375.430	6724981.830	-21.0576	183.8104	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN4S Maneuvering (with S Carrier)	588499.330	6724892.380	-20.9359	183.7170	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN1N Maneuvering (with N Carrier)	588149.500	6725723.230	-21.2624	184.5610	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN2N Maneuvering (with N Carrier)	588135.070	6725558.940	-21.2818	184.3966	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN3N Maneuvering (with N Carrier)	588189.670	6725428.530	-21.2308	184.2641	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN4N Maneuvering (with N Carrier)	588312.470	6725342.390	-21.1101	184.1741	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_ICE1A Guard/Ice Clearing S of berth	588643.590	6724743.530	-20.7956	183.5634	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1B Guard/Ice Clearing S of berth	588568.690	6724698.670	-20.8720	183.5206	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1C Guard/Ice Clearing S of berth	588468.250	6724675.720	-20.9735	183.5006	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1D Guard/Ice Clearing S of berth	588342.990	6724702.320	-21.0984	183.5309	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1E Guard/Ice Clearing S of berth	588264.510	6724768.630	-21.1752	183.5998	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2A Guard/Ice Clearing N of berth	588166.430	6725931.300	-21.2393	184.7693	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2B Guard/Ice Clearing N of berth	588038.920	6725895.240	-21.3683	184.7369	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2C Guard/Ice Clearing N of berth	587964.450	6725845.460	-21.4445	184.6891	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2D Guard/Ice Clearing N of berth	587909.780	6725743.460	-21.5024	184.5884	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2E Guard/Ice Clearing N of berth	587890.310	6725642.710	-21.5249	184.4879	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03

MEC-7 MARINE EMISSIONS ASSUMPTIONS

Vessel Fleeting Assumptions

1 The vessels coming into port at the LNG facility are assumed to be a mixture of purpose built vessels and vessels of opportunity
It is assumed that all vessels are newer than 2013
All purpose built vessels are assumed to be Category 3 Tier 3 for the Main Propulsion Engines and Tier 4 or Tier 3 for the Auxiliary Engines (either Cat 2 or 3)
Tier 4 was not assumed for the Category 2 engines to be conservative with the emissions factor estimates (All Tier 4 Category 2 Engines to have NOx emission factor of 1.8 g/kW-hr)
It is assumed that the purpose built main propulsion engines will have the capacity to be dual fuel engines and utilize the boiled off LNG gas during manuevering in and out of the terminal.

Vessels	%
Purpose Built	80
Vessels of Opp	20

2 Fleeting assumptions based on the projected 2025 fleet mix
3 SO2 liquid fuel emissions from IFC Ports Inventory Document from Table 2-9 for SSD/MDO for the Category 3 Main engines divided by 667 for 15 ppm sulfur content based on Ultra Low Sulfur Diesel (ULSD) sulfur r
4 SO2 for liquid fuel emissions from IFC Ports Inventory Table 3-8 for Tier 2 Harbor Craft, divided by 1000 based on a 15 ppm sulfur content for Ultra Low Sulfur Diesel (ULSD) sulfur requirements
5 Assume fleet will be under the MARPOL PROTOCOL the 40 CFR 1043.6 sulfur limit of 0.1% for all ECA and ECA associated area after year 2020, fuel assumed to be ULSD near terminal
ECA Associated area available at: http://www.imo.org/blast/blastDataHelper.asp?data_id=28815&filename=190%2860%29.pdf

Emission Factors Assumptions

1 PM2.5 assumed to be 97% of PM10 for marine diesel firing. PM2.5 assumed to be 100% of PM10 for NG firing.

Natural Gas Emission Factors Notes (Spark Ignition):
1a Emission Factor for NOx based on 40 CFR 1045 Subpart B conventional inboard engines
2a Per the California South Coast Air Quality Management District off-road engine tables and Carl Moyer Program Guidelines, appropriate
NOx & NMHC fractions are 95% and 5%, respectively. Same ratio used by Golden Pass for tugboat Tier II emissions (No. 2 fuel oil)
3a PM10 and PM2.5 emission factors from AP42 Table 3.2-3 Uncontrolled Emission Factors from 4-Stroke Rich-Burn Engines. Includes filterable and condensable
4a CO2e emissions from 40 CFR 98 Subpart C: Table C-1: Default CO2 Emission Factors and High Heat Values for Various Types of Fuel and C-2: Default CH4 and N2O Emission Factors for Various Types of Fuel
5a To determine CO2e emissions in terms of g/kWh for the Natural Gas emissions, a specific brake fuel consumption was assumed. This value was assumed from Table 2-2: Brake Specific Fuel Consumption for Compressor Engines in the Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities (H68 Final Report)
9000 btu/hp-hr
0.012069 mmbtu/kW-hr

Marine Diesel Emission Factors Notes (Compression Ignition):
1b IMO Category 1&2 Tier 1&2 Engine emission factors based on derated speed to add conservatism to the NOx emission factor based on 40 CFR 1042 Subpart J; Cat 1&2 Tier 1 did not have any emission regulations for VOC, emissions are assumed as largest Tier 2 VOC possibility
2b IMO Category 1&2 Tier 3 and 4 Engine emission factors based on derated speed to add conservatism to the NOx emission factor based on 40 CFR 1042 Subpart B
3b IMO Category 3 Engine emission factors based on derated speed to add conservatism to the NOx emission factor based on 40 CFR 1042 Subpart B; Tier 1 Category 3 CO and VOC Emissions were not regulated, Tier 1 emissions assumed equal to Tier 2
4b Per the California South Coast Air Quality Management District off-road engine tables and Carl Moyer Program Guidelines, appropriate
NOx & NMHC fractions are 95% and 5%, respectively. Same ratio used by Golden Pass for tugboat Tier II emissions (No. 2 fuel oil)
5b Liquid Fuel: CH4 and NO2 emissions from Port Inventory Emissions Document Table 2-13: Greenhouse Gas Emission Factors, g/kWh. Using MDO or MGO fuel with SSD propulsion, all 3 GHG emissions added together for 1 emission factor
6b Liquid Fuel: CO2 emissions from Port Inventory Emissions Document Table 2-9: Emission Factors for OGV Main Engines, g/kWh (for Category 3) and Table 3-8: Harbor Craft Emission Factors, g/kWh (for Category 1 and 2). Using MDO or MGO fuel with SSD propulsion, all 3 GHG emissions added together for 1 emission factor
7b PM10, and PM2.5 liquid fuel emissions from IFC Ports Inventory Document from Table 2-9 for SSD/MGO (main engines) and MSD/MGO (auxiliary engines) to match sulfur content of 0.1%

Combustion Engine Assumptions

1 Ship data originates from the Q-Max Vessel Information (Propulsion Trends in LNG Carriers MAN Diesel)
2 Loading rate based on a 12,500 m3/hr (individual calculations based on 1 ship and 1 call) provided by Megan Evans on May 19th
3 Hoteling load is assumed to be 20% of auxiliary engines, does not include loading pump operation.
4 Low Load Adjustment factors have been applied to any operation of the main propulsion engines below a 20% load factor
5 Assumes the use of an Economizer and a constant outlet exhaust temperature of 600°F

Steam Engine Assumptions

1 Ship data originates from the Q-Flex Vessel Information (Propulsion Trends in LNG Carriers MAN Diesel) - Assumed to be same vessel used with Steam Turbine Propulsion
2 Loading rate based on a 12,500 m3/hr (from only one berth at a time) provided by Megan Evans on Feb 21, 2013 at 10:32 am
3 Assumed total output power onboard of 37,000 kW from Steam Turbine and Auxiliary Turbo Generators
4 Number of operating boilers/turbines/generators taken into account with overall onboard power load factor.
5 Hoteling load is assumed to be 5,000 kW for all berth related operations, based on maximum outlet power from the assumed auxiliary engine
6 Emissions rates based on ST engine type, using MDO fuel in Port-Related Emissions Inventories: Ocean Going Vessels: Table 2-9: Emission Factors for OGV Main Engines, g/kWh, page 2-18
7 LNG Carrier Main Engine VOC emissions represented by HC emissions rate located in Port-Related Emissions Inventories: Ocean Going Vessels: Table 2-9: Emission Factors for OGV Main Engines, g/kWh, page 2-14
8 SO2, PM10, and PM2.5 emissions from IFC Ports Inventory Document from Table 2-9 for ST/MGO for 0.1% sulfur content based on MARPOL 2020 sulfur requirements
9 Assumes the use of an Economizer and a constant outlet exhaust temperature of 600°F

Tug Assumptions

1 Tug Data from Alexsandr Iyerusalimskiy Email: LNG Carriers Operation and Description for Final Air Modeling (June 17, 2016)
2 Assumes the use of an Economizer, with a constant outlet exhaust temperature of 600°F during maneuvering operations. The exhaust temperature of 450°F is used during idling
3 90-ton Tug engine information used with additional 22% (110/90) margin added to account for possibilty of 110-ton Tugs used. 110-ton tug info not available
4 Ice Management season is assumed to occur December 1st through May 31st (Total 181 days). Ice Management Season requires 1 additional tug to be operating while a Carrier is at berth to break up the ice

Engine Type Assumptions

Main Propulsion Combustion Engine	Main Propulsion Steam Turbine	Reference
Twin Screw, Twin Engine, Two Stroke Low Speed 91 rpm max. **2 x 17,978kW (MCR) MAN 7S70MC-C, or equal** Specific fuel Consumption = 169g/kWh @ fuel calorific value 42,700kJ/kg Fuel Type: Residual Oil, 2.7% Sulfur 700mm Bore x 2,800mm S **EPA Category 3**	**Single Screw, Steam Turbine** **Kawasaki UA-400 Cross Compound Impulse Turbine,** **28,000kW at 83 rpm MCR. 25,200kW at 80rpm NCR.** Main Boilers (2) - Mitsubishi MB-4E Marine Boiler with oil and gas combination burners. Vertical Two Drum Water Tube. Max. Evaporation 65,000kg/hour each. Assumed Latent Heat of Vaporization of water = 2260 kJ/kg Fuel Type: Residual Oil, 2.7% Sulfur	Combustion Engine: From Compass Port Main Propulsion Diesel Engine Only Steam Engine: From Compass Port Main Propulsion Steam Engine Only
Auxiliary Combustion Engine	**Auxiliary Steam Engine**	**Reference**
3,150kW CAT 3612 Marine Generator Set, or equal Specific fuel Consumption = 191.4g/kWh @ fuel calorific value 42,700kJ/kg Fuel Type: Residual Oil, 2.7% Sulfur 280mm Bore x 300mm Stroke = 18.5dm3 / cylinder **EPA Category 2** **4-Stroke, 9-Cylinder Man Diesel, MAN 9L35/44DF** Engine Output: 4,770 kW, Rated Speed: 750 RPM. Dual Fuel. Engine Heat Rate: 7,530 kJ/kWh **EPA Category 3**	2 x Mitsubishi Multi-Stage Condensing Turbine Generators Generator rated output = 3,150kW at 1800rpm 1 x 3,330kW Wartsila VASA 9R32LND, 4-Stroke, Turbo-charged, Intercooled Diesel Generator, 720rpm	Combustion Engine Category 2: From Compass Port Auxiliary Diesel Engine Only Combustion Engine Category 3: From AECOM Tier III LNG Carrier Hoteling Emissions Calculation, 4-6-2015 Steam Engine: From Compass Port Power Generation Steam Engine Only
90-Ton Tug Combustion Engine		**Reference**
4-Stroke Diesel Engine 3516C Tier 4 2 x 1500kW (Vendor sheet provided 1590-1995 bkW) WITH 22% ADDITIONAL MARGIN 2 x 2433.9 bkW Fuel Type: MGO/DMA 170mm Bore x 215mm Stroke = 69 L / cylinder (Too Large) **EPA Category 2**		90-Ton Tug: Jim Pfeiffer Email, Subject: Tug Info-More Details Necessary? Referenced Nichols Bros Boat Builders website, Hull # S-169 M/V Delta Audrey

MEC-8 LOW LOAD ADJUSTMENT FACTOR

FACTORS TO ADJUST G/kW-HR EMISSION FACTOR AT LOW LOAD CONDITIONS

Reference Table 2-15: Calculated Low Load Multiplicative Adjustment Factor from Port-Related Emissions Inventories

Load	NOx	HC	CO	PM	SO_2	CO_2
1%	11.47	59.28	19.32	19.17	5.99	5.82
2%	4.63	21.18	9.68	7.29	3.36	3.28
3%	2.92	11.68	6.46	4.33	2.49	2.44
4%	2.21	7.71	4.86	3.09	2.05	2.01
5%	1.83	5.61	3.89	2.44	1.79	1.76
6%	1.60	4.35	3.25	2.04	1.61	1.59
7%	1.45	3.52	2.79	1.79	1.49	1.47
8%	1.35	2.95	2.45	1.61	1.39	1.38
9%	1.27	2.52	2.18	1.48	1.32	1.31
10%	1.22	2.20	1.96	1.38	1.26	1.25
11%	1.17	1.96	1.79	1.30	1.21	1.21
12%	1.14	1.76	1.64	1.24	1.18	1.17
13%	1.11	1.60	1.52	1.19	1.14	1.14
14%	1.08	1.47	1.41	1.15	1.11	1.11
15%	1.06	1.36	1.32	1.11	1.09	1.08
16%	1.05	1.26	1.24	1.08	1.07	1.06
17%	1.03	1.18	1.17	1.06	1.05	1.04
18%	1.02	1.11	1.11	1.04	1.03	1.03
19%	1.01	1.05	1.05	1.02	1.01	1.01
20%	1.00	1.00	1.00	1.00	1.00	1.00

MEC-9 INTERNAL COMBUSTION ENGINE FLEETING

2025 FLEETING MIX

Vessel arrival determined below for projected 2025 fleet mix, include both purpose built vessels (80%) and vessels of opportunity (20%). This mix assumes two engine types, spark ignition or compression ignition. The fleet weighting factors are then used to determine an average emission factor based on engine type occurrence at port. The fleet-weighted average emission factors are then used to determine carrier/call specific emissions for the combustion (non-steam turbine) engines.

* Category 3 Engines different for Main Propulsion Engines from Auxiliary Engines, see IC Engine Category for difference in size

MAIN PROPULSION ENGINES

			Assumed (Engine-Specific) Emission Factor									Fleet-Weighted Average Emission Factor							
Engine Type	**Engine Category**	**Standard**	**NOx**	**CO**	**SOx**	**VOC**	**PM2.5**	**PM10**	**GHG (CO_2E)**	**HAPs**	**Fleet Weighting Factor**	**Hybrid NOx (g/kW-hr)**	**Hybrid CO (g/kW-hr)**	**Hybrid SOx (g/kW-hr)**	**Hybrid VOC (g/kW-hr)**	**Hybrid PM2.5 (g/kW-hr)**	**Hybrid PM10 (g/kW-hr)**	**Hybrid GHG (CO2E) (g/kW-hr)**	**Hybrid HAPs (g/kW-hr)**
Spark Ignition	n/a	NG	4.75	75.00	0.000	0.25	0.11	0.11	640.45	0.123	0%	0	0	0	0	0	0	0	0
Compression Ignition	Category 1	Tier 1	13.42	5.00	0.005	1.00	0.78	0.80	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	6.84	5.00	0.005	0.36	0.58	0.60	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 3	5.51	5.00	0.005	0.29	0.11	0.11	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Category 2	Tier 1	10.63	5.00	0.005	1.00	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	7.41	5.00	0.005	0.39	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 3	7.41	5.00	0.005	0.39	0.14	0.14	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 4	1.80	5.00	0.005	0.19	0.06	0.06	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Category 3*	Tier 1	18.51	5.00	0.005	2.00	0.17	0.19	598.18	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	15.84	5.00	0.005	2.00	0.17	0.19	598.18	0.003	20%	3.17	1.00	0.00	0.40	0.03	0.04	119.64	0.00
		Tier 3	3.40	5.00	0.005	2.00	0.17	0.19	598.18	0.003	80%	2.72	4.00	0.00	1.60	0.14	0.15	478.54	0.00
										Total	**100%**	**5.89**	**5.00**	**0.01**	**2.00**	**0.17**	**0.19**	**598.18**	**0.00**

AUXILIARY ENGINES

			Assumed (Engine-Specific) Emission Factor									Fleet-Weighted Average Emission Factor							
Engine Type	**Engine Category**	**Standard**	**NOx**	**CO**	**SOx**	**VOC**	**PM2.5**	**PM10**	**GHG (CO_2E)**	**HAPs**	**Fleet Weighting Factor**	**Hybrid NOx (g/kW-hr)**	**Hybrid CO (g/kW-hr)**	**Hybrid SOx (g/kW-hr)**	**Hybrid VOC (g/kW-hr)**	**Hybrid PM2.5 (g/kW-hr)**	**Hybrid PM10 (g/kW-hr)**	**Hybrid GHG (CO2E) (g/kW-hr)**	**Hybrid HAPs (g/kW-hr)**
Spark Ignition	n/a	NG	4.75	75.00	0.000	0.25	0.11	0.11	640.45	0.123	0%	0	0	0	0	0	0	0	0
Compression Ignition	Category 1	Tier 1	13.42	5.00	0.001	1.00	0.78	0.80	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	6.84	5.00	0.001	0.36	0.58	0.60	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 3	5.51	5.00	0.001	0.29	0.11	0.11	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Category 2	Tier 1	10.63	5.00	0.001	1.00	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	7.41	5.00	0.001	0.39	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 3	7.41	5.00	0.001	0.39	0.14	0.14	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 4	1.80	5.00	0.001	0.19	0.06	0.06	699.39	0.003	25%	0.45	1.25	0.00	0.05	0.02	0.02	174.85	0.00
	Category 3*	Tier 1	12.37	5.00	0.001	2.00	0.17	0.19	655.47	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	9.97	5.00	0.001	2.00	0.17	0.19	655.47	0.003	20%	1.99	1.00	0.00	0.40	0.03	0.04	131.09	0.00
		Tier 3	2.48	5.00	0.001	2.00	0.17	0.19	655.47	0.003	55%	1.36	2.75	0.00	1.10	0.09	0.10	360.51	0.00
										Total	**100%**	**3.81**	**5.00**	**0.00**	**1.55**	**0.14**	**0.16**	**666.45**	**0.00**

MEC-10 INTERNAL COMBUSTION ENGINE CATEGORY

		CAT 1 ENGINE	CAT 2 ENGINE	CAT 3 ENGINE (AUXILIARY)	CAT 3 ENGINE (MAIN)	
	Typical Engine Model		3516C	MAN 9L35/44DF	MAN 7S70MC-C	
	Engine Type		4-Stroke	4-Stroke	4-Stroke	
	Rated Speed	500	1600	750	100	rpm
	85% Derated Speed	425	1360	638	85	rpm
	Engine Output	200	3,150	4700.0	16,700	kW
NEEDED FOR TIER I & II	Displacement	5.0	10.0	n/a	n/a	L/cyl
NEEDED FOR TIER I	Power Density	40.0	n/a	n/a	n/a	kW/L

See Assumptions for Engine Descriptions

MEC-11 INTERNAL COMBUSTION ENGINE EMISSION FACTORS

NOx Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (1a, 2a)	4.75	**4.75**								
Compression Ignition - Tier 1 (1b, 3b, 4b)			13.42	**13.4**	10.63	**10.6**	12.37	**12.4**	18.51	**18.5**
Compression Ignition - Tier 2 (1b, 3b, 4b)			6.84	**6.8**	7.41	**7.4**	9.97	**10.0**	15.84	**15.8**
Compression Ignition - Tier 3 (1b, 3b, 4b)			5.51	**5.5**	7.41	**7.4**	2.48	**2.5**	3.40	**3.4**
Compression Ignition - Tier 4 (2b)					1.800	**1.8**				

CO Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (1a, 2a)	75.00	**75.00**								
Compression Ignition - Tier 1 (1b, 3b, 4b)			5.00	**5.0**	5.00	**5.0**	5.00	**5.0**	5.00	**5.0**
Compression Ignition - Tier 2 (1b, 3b, 4b)			5.00	**5.0**	5.00	**5.0**	5.00	**5.0**	5.00	**5.0**
Compression Ignition - Tier 3 (1b, 3b, 4b)			5.00	**5.0**	5.00	**5.0**	5.00	**5.0**	5.00	**5.0**
Compression Ignition - Tier 4 (2b)					5.000	**5.0**				

VOC Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (1a, 2a)	0.25	**0.25**								
Compression Ignition - Tier 1 (1b, 3b, 4b)			1.00	**1.0**	1.00	**1.0**	2.00	**2.0**	2.00	**2.0**
Compression Ignition - Tier 2 (1b, 3b, 4b)			0.36	**0.4**	0.39	**0.4**	2.00	**2.0**	2.00	**2.0**
Compression Ignition - Tier 3 (1b, 3b, 4b)			0.29	**0.3**	0.39	**0.4**	2.00	**2.0**	2.00	**2.0**
Compression Ignition - Tier 4 (2b)					0.190	**0.2**				

PM2.5 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**lb PMtotal/mm btu Fuel**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (3a)	0.02	**0.11**								
Comrpession Ignition - Tier 1 (1b, 7b)			0.78	**0.8**	0.49	**0.5**	0.17	**0.2**	0.17	**0.2**
Compression Ignition - Tier 2 (1b, 7b)			0.58	**0.6**	0.49	**0.5**	0.17	**0.2**	0.17	**0.2**
Compression Ignition - Tier 3 (1b, 2b, 7b)			0.11	**0.1**	0.14	**0.1**	0.17	**0.2**	0.17	**0.2**
Compression Ignition - Tier 4 (2b)					0.060	**0.1**				

PM10 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**lb PMtotal/mm btu Fuel**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (3a)	0.02	**0.11**								
Comrpession Ignition - Tier 1 (1b, 7b)			0.80	**0.8**	0.50	**0.5**	0.19	**0.2**	0.19	**0.2**
Compression Ignition - Tier 2 (1b, 7b)			0.60	**0.6**	0.50	**0.5**	0.19	**0.2**	0.19	**0.2**
Compression Ignition - Tier 3 (1b, 2b, 7b)			0.11	**0.1**	0.14	**0.1**	0.19	**0.2**	0.19	**0.2**
Compression Ignition - Tier 4 (2b)					0.060	**0.1**				

CO2 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**kg CO2/mmbtu Fuel**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (4a, 5a)	53.06	**640.39**								
Compression Ignition - Tier 1 (6b)			690.00	**690.0**	690.00	**690.0**	646.08	**646.1**	588.79	**588.8**
Compression Ignition - Tier 2 (6b)			690.00	**690.0**	690.00	**690.0**	646.08	**646.1**	588.79	**588.8**
Compression Ignition - Tier 3 (6b)			690.00	**690.0**	690.00	**690.0**	646.08	**646.1**	588.79	**588.8**
Compression Ignition - Tier 4 (6b)					690.00	**690.0**				

CH4 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**kg CH4/mmbtu Fuel**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (4a, 5a)	0.001	**0.01**								
Compression Ignition - Tier 1 (5b)			0.006	**0.0**	0.006	**0.0**	0.006	**0.0**	0.006	**0.0**
Compression Ignition - Tier 2 (5b)			0.006	**0.0**	0.006	**0.0**	0.006	**0.0**	0.006	**0.0**
Compression Ignition - Tier 3 (5b)			0.006	**0.0**	0.006	**0.0**	0.006	**0.0**	0.006	**0.0**
Compression Ignition - Tier 4 (5b)					0.006	**0.0**				

N2O Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**kg N2O/mmbtu Fuel**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition (4a, 5a)	0.0001	**0.0012**								
Compression Ignition - Tier 1 (5b)			0.031	**0.0**	0.031	**0.0**	0.031	**0.0**	0.031	**0.0**
Compression Ignition - Tier 2 (5b)			0.031	**0.0**	0.031	**0.0**	0.031	**0.0**	0.031	**0.0**
Compression Ignition - Tier 3 (5b)			0.031	**0.0**	0.031	**0.0**	0.031	**0.0**	0.031	**0.0**
Compression Ignition - Tier 4 (5b)					0.031	**0.0**				

HAPs Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	**n/a**		**IMO Category 1**		**IMO Category 2**		**IMO Category 3 (Auxiliary)**		**IMO Category 3 (Main)**	
Emission Factor Units	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**	**(g/kW-hr)**
Spark Ignition	0.123	**0.12**								
Compression Ignition - Tier 1			0.006	**0.0**	0.003	**0.0**	0.003	**0.0**	0.003	**0.0**
Compression Ignition - Tier 2			0.006	**0.0**	0.003	**0.0**	0.003	**0.0**	0.003	**0.0**
Compression Ignition - Tier 3			0.006	**0.0**	0.003	**0.0**	0.003	**0.0**	0.003	**0.0**
Compression Ignition - Tier 4 (2b)					0.003	**0.0**				

MEC-12 MAIN ENGINE – INTERNAL COMBUSTION – NORMAL ARRIVAL

Calls Per Year	193.45

Mode	Number of Engines	Power (kW) per Engine	Total Power (kW)		Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
								Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
Cruising IN	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	808			0.16	893			666.45	3,778,760			0.003	16		
				Total					139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
Approach IN	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
				Total					117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Far-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Near-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Cool Down / Vessel Purge	2	16,700	33,400	Main Engines	Shut Down		3.5	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	33,587			5.00	44,100			0.00	11			1.55	13,649			0.14	1,257			0.16	1,389			666.45	5,878,071			0.003	24		
				Total					33,587	21	2.67		44,100	28	3.50		11	0	0.00		13,649	9	1.08		1,257	1	0.10		1,389	1	0.11		5,878,071	3,702	466.51		24	0.02	0.00
LNG Loading	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	52.9%	5,000		3.81	342,720			5.00	450,000			0.00	117			1.55	139,275			0.14	12,825			0.16	14,175			666.45	59,980,320			0.003	250		
				Total					342,720	42	5.29		450,000	55	6.94		117	0	0.00		139,275	17	2.15		12,825	2	0.198		14,175	2	0.22		59,980,320	7,346	925.62		250	0.03	0.00
Hoteling	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	20.0%	1,890		3.81	129,548			5.00	170,100			0.00	44			1.55	52,646			0.14	4,848			0.16	5,358			666.45	22,672,561			0.003	94		
				Total					129,548	16	2.00		170,100	21	2.63		44	0	0.00		52,646	6	0.81		4,848	1	0.07		5,358	1	0.08		22,672,561	2,777	349.89		94	0.01	0.00
Line Purge/Prep	2	16,700	33,400	Main Engines	Shut Down		3.5	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	33,587			5.00	44,100			0.00	11			1.55	13,649			0.14	1,257			0.16	1,389			666.45	5,878,071			0.003	24		
				Total					33,587	21	2.67		44,100	28	3.50		11	0	0.00		13,649	9	1.08		1,257	1	0.10		1,389	1	0.11		5,878,071	3,702	466.51		24	0.02	0.00
Near-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Far-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Departure OUT	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
				Total					117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Cruising OUT	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	808			0.16	893			666.45	3,778,760			0.003	16		
				Total					139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
					Total Call Time (hr)		34.50																																

TOTAL (g/Call)		1,217,119				1,365,464				742				467,831				40,948				45,460				172,302,741				739		
TOTAL (kg/year)		235,448				264,145				144				90,501				7,921				8,794				33,331,499				143		
Weighted Average (lb/hr - g/s)			69.5	8.8			76.4	9.6			0.0	0.0			26.5	3.3			2.3	0.3			2.6	0.3			9561.5	1204.8			0.04	0.01
Total Emissions (tpy)		259.5				291.2				0.2				99.8				8.7				9.7				36741.1				0.2		

MEC-13 MAIN ENGINES – STEAM – NORMAL ARRIVAL

Calls Per Year	3.95

Mode	Number of Boilers Operating	Number of Steam Turbine Operating	Number of Generators Operating	Total Output Power (kiwi)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx Factor (g/kW-hr)	NOx Mass Emitted (g)	NOx Emission Rate	NOx Emission Rate (g/s)	CO Factor (g/kW-hr)	CO Mass Emitted (g)	CO Emission Rate (lb/hr)	CO Emission Rate (g/s)	SOx Factor (g/kW-hr)	SOx Mass Emitted (g)	SOx Emission Rate (lb/hr)	SOx Emission Rate (g/s)
Cruise IN (25nm radius from terminal)	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970		
				Total					45,510	134	16.9		4,551	13	2		12,970	38	4.8
Approach IN	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436		
				Total					29,600	33	4.1		2,960	3	0		8,436	9	1.2
Far-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273		
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5
Near-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273		
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5
Cool Down	1	0	1	37,000	13.5%	5,000	3.5	2.22	38,850			0.304	5,320			0.6498	11,372		
				Total					38,850	24	3.1		5,320	3	0		11,372	7	0.9
Loading	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482		
				Total					199,800	24	3.1		27,360	3	0.42		58,482	7	0.90
Hoteling	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482		
				Total					199,800	24	3.1		27,360	3	0		58,482	7	0.90
Purge Lines	1	0	1	37,000	13.5%	5,000	3.5	2.22	38,850			0.304	5,320			0.6498	11,372		
				Total					38,850	24	3.1		5,320	3	0		11,372	7	0.9
Near-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273		
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5
Far-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273		
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5
Departure OUT	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436		
				Total					29,600	33	4.1		2,960	3	0		8,436	9	1.2
Cruising OUT	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970		
				Total					45,510	134	16.9		4,551	13	2		12,970	38	4.8
					Total Call Time (hr)		32.50												
			TOTAL (g/Call)						701,520				87,782				203,610		
			TOTAL (kg/year)						2,770				347				804		
			Weighted Average (lb/hr - g/s)							34.0	4.3			4.1	0.5			9.8	1.2
			Total Emissions (tpy)						3.1				0.4				0.9		

Mode	VOC Factor (g/kW-hr)	VOC Mass Emitted (g)	VOC Emission Rate (lb/hr)	VOC Emission Rate (g/s)	PM2.5 Factor (g/kW-hr)	PM2.5 Mass Emitted (g)	PM2.5 Emission Rate (lb/hr)	PM2.5 Emission Rate (g/s)	PM10 Factor (g/kW-hr)	PM10 Mass Emitted (g)	PM10 Emission Rate (lb/hr)	PM10 Emission Rate (g/s)	GHG (CO2E) Factor (g/kW-hr)	GHG (CO2E) Mass Emitted (g)	GHG (CO2E) Emission Rate (lb/hr)	GHG (CO2E) Emission Rate (g/s)	HAPs Factor (g/kW-hr)	HAPs Mass Emitted (g)	HAPs Emission Rate (lb/hr)	HAPs Emission Rate (g/s)
Cruise IN (25nm radius from terminal)	0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63		
		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02
Approach IN	0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41		
		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01
Far-Terminal Op.: Maneuvering IN	0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	41		
		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		41	0.09	0.01
Near-Terminal Op.: Maneuvering IN	0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26		
		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01
Cool Down	0.152	2,660			0.1785	3,124			0.2023	3,540			1052.19	18,413,252			0.003	49		
		2,660	2	0		3,124	2	0		3,540	2	0		18,413,252	11,598	1,461		49	0.03	0.00
Loading	0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250		
		13,680	2	0		16,065	2	0.25		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00
Hoteling	0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250		
		13,680	2	0		16,065	2	0		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00
Purge Lines	0.152	2,660			0.1785	3,124			0.2023	3,540			1052.19	18,413,252			0.003	49		
		2,660	2	0		3,124	2	0		3,540	2	0		18,413,252	11,598	1,461		49	0.03	0.00
Near-Terminal Op.: Maneuvering OUT	0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26		
		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01
Far-Terminal Op.: Maneuvering OUT	0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26		
		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01
Departure OUT	0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41		
		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01
Cruising OUT	0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63		
		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02
TOTAL (g/Call)		43,891				55,194				62,553				329,694,114				922		
TOTAL (kg/year)		173				218				247				1,301,601				4		
Weighted Average (lb/hr - g/s)			2.0	0.3			2.7	0.3			3.0	0.4			15940.7	2008.5			0.05	0.01
Total Emissions (tpy)		0.2				0.2				0.3				1434.7				0.0		

MEC-14 MAIN ENGINES – INTERNAL COMBUSTION – WARM ARRIVAL

Calls Per Year	5.98

THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR
(24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)

Mode	Number of Engines	Power (kW) per Engine	Total Power (kW)		Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
								Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
Cruising IN	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	808			0.16	893			666.45	3,778,760			0.003	16		
				Total					139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
Approach IN	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
				Total					117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Far-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Near-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Cool Down / Vessel Purge	2	16,700	33,400	Main Engines	Shut Down		48.0	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	460,616			5.00	604,800			0.00	157			1.55	187,186			0.14	17,237			0.16	19,051			666.45	80,613,550			0.003	335		
				Total					460,616	21	2.67		604,800	28	3.50		157	0	0.00		187,186	9	1.08		17,237	1	0.10		19,051	1	0.11		80,613,550	3,702	466.51		335	0.02	0.00
LNG Loading	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	52.9%	5,000		3.81	342,720			5.00	450,000			0.00	117			1.55	139,275			0.14	12,825			0.16	14,175			666.45	59,980,320			0.003	250		
				Total					342,720	42	5.29		450,000	55	6.94		117	0	0.00		139,275	17	2.15		12,825	2	0.20		14,175	2	0.22		59,980,320	7,346	925.62		250	0.03	0.00
Hoteling	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	20.0%	1,890		3.81	129,548			5.00	170,100			0.00	44			1.55	52,646			0.14	4,848			0.16	5,358			666.45	22,672,561			0.003	94		
				Total					129,548	16	2.00		170,100	21	2.63		44	0	0.00		52,646	6	0.81		4,848	1	0.07		5,358	1	0.08		22,672,561	2,777	349.89		94	0.01	0.00
Line Purge/Prep	2	16,700	33,400	Main Engines	Shut Down		3.5	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	33,587			5.00	44,100			0.00	11			1.55	13,649			0.14	1,257			0.16	1,389			666.45	5,878,071			0.003	24		
				Total					33,587	21	2.67		44,100	28	3.50		11	0	0.00		13,649	9	1.08		1,257	1	0.10		1,389	1	0.11		5,878,071	3,702	466.51		24	0.02	0.00
Near-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Far-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Departure OUT	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
				Total					117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Cruising OUT	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	808			0.16	893			666.45	3,778,760			0.003	16		
				Total					139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
					Total Call Time (hr)		79.00																																

	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
TOTAL (g/Call)		1,644,148				1,926,164				888				641,367				56,928				63,122				247,038,220				1,009		
TOTAL (kg/year)		9,837				11,524				5				3,837				341				378				1,478,006				6		
Weighted Average (lb/hr - g/s)			42.3	5.3			49.0	6.2			0.0	0.0			16.4	2.1			1.5	0.2			1.6	0.2			6261.2	788.9			0.026	0.003
Total Emissions (tpy)		10.8				12.7				0.0				4.2				0.4				0.4				1629.2				0.0		

MEC-15 MAIN ENGINES – STEAM – WARM ARRIVAL

Calls Per Year	0.12

THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)

Mode	Number of Boilers Operating	Number of Steam Turbine Operating	Number of Generators Operating	Total Output Power (kiwi)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
								Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
Cruise IN (25nm radius from terminal)	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970			0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63		
				Total					45,510	134	17		4,551	13	2		12,970	38	5		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02
Approach IN	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436			0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41		
				Total					29,600	33	4		2,960	3	0		8,436	9	1		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01
Far-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	41		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		41	0.09	0.01
Near-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01
Cool Down	1	0	1	37,000	13.5%	5,000	48.0	2.22	532,800			0.304	72,960			0.6498	155,952			0.152	36,480			0.1785	42,840			0.2023	48,552			1052.19	252,524,592			0.003	666		
				Total					532,800	24	3		72,960	3	0		155,952	7	1		36,480	2	0		42,840	2	0		48,552	2	0		252,524,592	11,598	1,461		666	0.03	0.00
Loading	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482			0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250		
				Total					199,800	24	3		27,360	3	0		58,482	7	1		13,680	2	0		16,065	2	0		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00
Hoteling	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482			0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250		
				Total					199,800	24	3		27,360	3	0		58,482	7	1		13,680	2	0		16,065	2	0		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00
Purge Lines	1	0	1	37,000	13.5%	5,000	3.5	2.22	38,850			0.304	5,320			0.6498	11,372			0.152	2,660			0.1785	3,124			0.2023	3,540			1052.19	18,413,252			0.003	49		
				Total					38,850	24	3		5,320	3	0		11,372	7	1		2,660	2	0		3,124	2	0		3,540	2	0		18,413,252	11,598	1,461		49	0.03	0.00
Near-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01
Far-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01
Departure OUT	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436			0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41		
				Total					29,600	33	4		2,960	3	0		8,436	9	1		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01
Cruising OUT	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970			0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63		
				Total					45,510	134	17		4,551	13	2		12,970	38	5		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02
					Total Call Time (hr)		77.00																																

	NOx Factor	NOx Mass	NOx lb/hr	NOx g/s	CO Factor	CO Mass	CO lb/hr	CO g/s	SOx Factor	SOx Mass	SOx lb/hr	SOx g/s	VOC Factor	VOC Mass	VOC lb/hr	VOC g/s	PM2.5 Factor	PM2.5 Mass	PM2.5 lb/hr	PM2.5 g/s	PM10 Factor	PM10 Mass	PM10 lb/hr	PM10 g/s	GHG Factor	GHG Mass	GHG lb/hr	GHG g/s	HAPs Factor	HAPs Mass	HAPs lb/hr	HAPs g/s
TOTAL (g/Call)		1,195,470				155,422				348,190				77,711				94,910				107,565				563,805,454				1,539		
TOTAL (kg/year)		146				19				43				9				12				13				68,841				0		
Weighted Average (lb/hr - g/s)			28.5	3.6			3.7	0.5			8.3	1.0			1.8	0.2			2.3	0.3			2.6	0.3			13431.0	1692.3			0.037	0.005
Total Emissions (tpy)		0.2				0.0				0.0				0.0				0.0				0.0				75.9				0.0		

MEC-16 CARRIER TUGS – NORMAL CARRIER ARRIVAL – NON-ICE MANAGEMENT

Call Per Year	100

Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
LNG Carrier transits state waters	Dispatch/Idle	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
Approach Cruise IN	Dispatch/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	25.0	1.80	164,288	14.49	1.83	5.00	456,356	40.24	5.07	0.00	119	0.01	0.00	0.19	17,342	1.53	0.19	0.06	5,476	0.48	0.06	0.06	5,476	0.48	0.06	699.39	63,834,017	5,629.23	709.27	0.003	253	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
	Total							244,461	21.56	2.72		814,140	71.80	9.05		178	0.02	0.00		30,937	2.73	0.34		8,499	0.75	0.09		8,499	0.75	0.09		95,751,025	8,443.84	1,063.90		354	0.03	0.00
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Departure OUT	Dismissed/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00
LNG Carrier transits state waters	Dismissed	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
				Total Call Time (hr)		39.0																																
				TOTAL (g/Call)				377,714				1,209,502				275				45,961				13,006				13,006				147,669,359				555		
				TOTAL (kg/year)				37,586				120,356				27				4,574				1,294				1,294				14,694,402				55		
				TOTAL (tpy) Short				**41.4**				**132.7**				**0.0**				**5.0**				**1.4**				**1.4**				**16197.5**				**0.1**		
				Weighted Average (lb/hr)					21.35	2.69			68.37	8.61			0.02	0.00			2.60	0.33			0.74	0.09			0.74	0.09			8347.61	1051.78			0.03	0.00

MEC-17 CARRIER TUGS – WARM CARRIER ARRIVAL – NON-ICE MANAGEMENT

Call Per Year	3

THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)

Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
LNG Carrier transits state waters	Dispatch/Idle	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
Approach Cruise IN	Dispatch/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	55.0	1.80	361,434	14.49	1.83	5.00	1,003,984	40.24	5.07	0.00	261	0.01	0.00	0.19	38,151	1.53	0.19	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	699.39	140,434,837	5,629.23	709.27	0.003	557	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
	Total							537,814	21.56	2.72		1,791,107	71.80	9.05		393	0.02	0.00		68,062	2.73	0.34		18,698	0.75	0.09		18,698	0.75	0.09		210,652,256	8,443.84	1,063.90		780	0.03	0.00
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Departure OUT	Dismissed/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00
LNG Carrier transits state waters	Dismissed	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
				Total Call Time (hr)		69.0																																
				TOTAL (g/Call)				671,067				2,186,470				489				83,086				23,205				23,205				262,570,590				981		
				TOTAL (kg/year)				2,065				6,729				2				256				71				71				808,085				3		
				TOTAL (tpy) Short				**2.3**				**7.4**				**0.0**				**0.3**				**0.1**				**0.1**				**890.7**				**0.0**		
				Weighted Average (lb/hr)					21.44	2.70			69.86	8.80			0.02	0.00			2.65	0.33			0.74	0.09			0.74	0.09			8389.45	1057.05			0.03	0.00

MEC-18 CARRIER TUGS – NORMAL CARRIER ARRIVAL – ICE MANAGEMENT

Call Per Year	98

Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
LNG Carrier transits state waters	Dispatch/Idle Ice Clearing	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	75.0%	3,651		1.80	26,286	14.49	1.83	5.00	73,017	40.24	5.07	0.00	19	0.01	0.00	0.19	2,775	1.53	0.19	0.06	876	0.48	0.06	0.06	876	0.48	0.06	699.39	10,213,443	5,629.23	709.27	0.003	40	0.02	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
	Total							30,562	16.84	2.12		92,099	50.76	6.40		22	0.01	0.00		3,500	1.93	0.24		1,037	0.57	0.07		1,037	0.57	0.07		11,915,683	6,567.43	827.48		46	0.03	0.00
Approach Cruise IN	Dispatch/Idle Ice Clearing	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							15,281	33.69	4.24		46,049	101.52	12.79		11	0.02	0.00		1,750	3.86	0.49		519	1.14	0.14		519	1.14	0.14		5,957,842	13,134.86	1,654.96		23	0.05	0.01
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	25.0	1.80	164,288	14.49	1.83	5.00	456,356	40.24	5.07	0.00	119	0.01	0.00	0.19	17,342	1.53	0.19	0.06	5,476	0.48	0.06	0.06	5,476	0.48	0.06	699.39	63,834,017	5,629.23	709.27	0.003	253	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	164,288	14.49	1.83	5.00	456,356	40.24	5.07	0.00	119	0.01	0.00	0.19	17,342	1.53	0.19	0.06	5,476	0.48	0.06	0.06	5,476	0.48	0.06	699.39	63,834,017	5,629.23	709.27	0.003	253	0.02	0.00
		Tug 3	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
	Total							382,025	33.69	4.24		1,151,235	101.52	12.79		277	0.02	0.00		43,747	3.86	0.49		12,968	1.14	0.14		12,968	1.14	0.14		148,946,040	13,134.86	1,654.96		574	0.05	0.01
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Departure OUT	Dismissed/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00
LNG Carrier transits state waters	Dismissed	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
				Total Call Time (hr)		39.0																																
				TOTAL (g/Call)				547,067				1,633,098				397				62,058				18,530				18,530				213,205,617				824		
				TOTAL (kg/year)				53,550				159,858				39				6,075				1,814				1,814				20,869,927				81		
				TOTAL (tpy) Short				**59.0**				**176.2**				**0.0**				**6.7**				**2.0**				**2.0**				**23004.8**				**0.1**		
				Weighted Average (lb/hr)					30.93	3.90			92.32	11.63			0.02	0.00			3.51	0.44			1.05	0.13			1.05	0.13			12052.32	1518.56			0.05	0.01

MEC-19 CARRIER TUGS – WARM CARRIER ARRIVAL – ICE MANAGEMENT

Call Per Year	3

THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)

Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
LNG Carrier transits state waters	Dispatch/Idle	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	75.0%	3,651			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
Approach Cruise IN	Dispatch/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							15,281	33.69	4.24		46,049	101.52	12.79		11	0.02	0.00		1,750	3.86	0.49		519	1.14	0.14		519	1.14	0.14		5,957,842	13,134.86	1,654.96		23	0.05	0.01
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	55.0	1.80	361,434	14.49	1.83	5.00	1,003,984	40.24	5.07	0.00	261	0.01	0.00	0.19	38,151	1.53	0.19	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	699.39	140,434,837	5,629.23	709.27	0.003	557	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	361,434	14.49	1.83	5.00	1,003,984	40.24	5.07	0.00	261	0.01	0.00	0.19	38,151	1.53	0.19	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	699.39	140,434,837	5,629.23	709.27	0.003	557	0.02	0.00
		Tug 3	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
	Total							840,455	33.69	4.24		2,532,716	101.52	12.79		610	0.02	0.00		96,243	3.86	0.49		28,529	1.14	0.14		28,529	1.14	0.14		327,681,287	13,134.86	1,654.96		1,262	0.05	0.01
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total							26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01
Departure OUT	Dismissed/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total							9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00
LNG Carrier transits state waters	Dismissed	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	0.003	0	0.00	0.00
	Total							4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00
					Total Call Time (hr)	69.0																																

	NOx Factor	NOx Mass	NOx Rate	NOx Emission Rate	CO Factor	CO Mass	CO Rate	CO Emission Rate	SOx Factor	SOx Mass	SOx Rate	SOx Emission Rate	VOC Factor	VOC Emitted	VOC Rate	VOC Emission Rate	PM2.5 Factor	PM2.5 Emitted	PM2.5 Rate	PM2.5 Emission Rate	PM10 Factor	PM10 Emitted	PM10 Rate	PM10 Emission Rate	GHG Factor	GHG Mass	GHG Rate	GHG Emission Rate	HAPs Factor	HAPs Emitted	HAPs Rate	HAPs Emission Rate
TOTAL (g/Call)		979,211				2,941,563				710				111,779				33,215				33,215				381,727,422				1,472		
TOTAL (kg/year)		2,964				8,905				2				338				101				101				1,155,647				4		
TOTAL (tpy) Short		**3.3**				**9.8**				**0.0**				**0.4**				**0.1**				**0.1**				**1273.9**				**0.0**		
Weighted Average (lb/hr)			31.29	3.94			93.99	11.84			0.02	0.00			3.57	0.45			1.06	0.13			1.06	0.13			12196.66	1536.74			0.05	0.01