APPENDIX F GAS TREATMENT PLANT AIR QUALITY MODELING REPORT

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GAS TREATMENT PLANT 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. This Project includes a gas treatment plant (GTP) located on the North Slope. The GTP is the focus of this document.

As required by the Federal Energy Regulatory Commission (FERC) regulations, air dispersion modeling was utilized as a tool to demonstrate that the proposed GTP 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:

- USEPA's 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), and
- Alaska Department of Environmental Conservation's (ADEC) Modeling Review Procedures Manual (ADEC 2013).

Note that this report is written to address elements required by FERC for an air quality impact 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 analysis 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 GTP is designed to treat natural gas received from the Prudhoe Bay Unit (PBU) and Point Thomson Unit (PTU). The GTP would be constructed on the North Slope near the Beaufort Sea coast. The facility would be located in the PBU, which is located on State land within the North Slope Borough and is designated for oil and gas development. The GTP would process PBU and PTU gas into natural gas that exceeds pipeline quality gas; however, pipeline quality gas limits were used for this analysis as an upper limit. This gas would be shipped by pipeline to southeast Alaska on the Kenai Peninsula. Among other things processing includes removing CO_2, H_2S, and water (dehydration). The proposed design of GTP would have an average stream day inlet natural gas treating capacity of 3.7 BSCF/D (excluding planned/unplanned downtime) and a 3.9 BSCF/D peak capacity. GTP would be able to accommodate varying compositions of natural gas received from the PBU and PTU.

Because of its proximity to existing gas gathering infrastructure, the GTP is being sited west of Prudhoe Bay, 630 meters (2,070 feet) to the west-southwest of the existing BP Exploration (Alaska), Inc. (BPXA), Central Compression Plant (CCP), and the Central Gas Facility (CGF) as shown in **Figure 1-1**. The layout of the GTP facility was evaluated for all phases of the Project, as it relates to safety, accessibility (Emergency, Constructability, and Maintenance), plot space requirement, schedule, and execution certainty. The facility is restricted to the south by an existing road and pipeline corridor. The facility becomes limited to the north and west by existing bodies of water, where efforts are taken to minimize the impact to those bodies of water.

The GTP facility is comprised of a “main” pad where the natural gas would be treated and a “camp” pad which would house the workers. Building the GTP facility on gravel pads would protect the tundra and permafrost. **Figure 1-2** shows a plot plan of the facility. The following types of emission units would be part of the GTP design:

- gas-fired turbines for power generation and compression,
- gas-fired heaters for process heat and to heat fuel gas received from the sales pipeline,
- flares for emergency control of excess gas,
- diesel fuel-fired reciprocating internal combustion engines for back-up power generation, and
- diesel fuel-fired fire water pumps for supplying water in case of fire.

Figure 1-1: Locations of Existing CCP and CGF Facilities and the Proposed GTP Facility

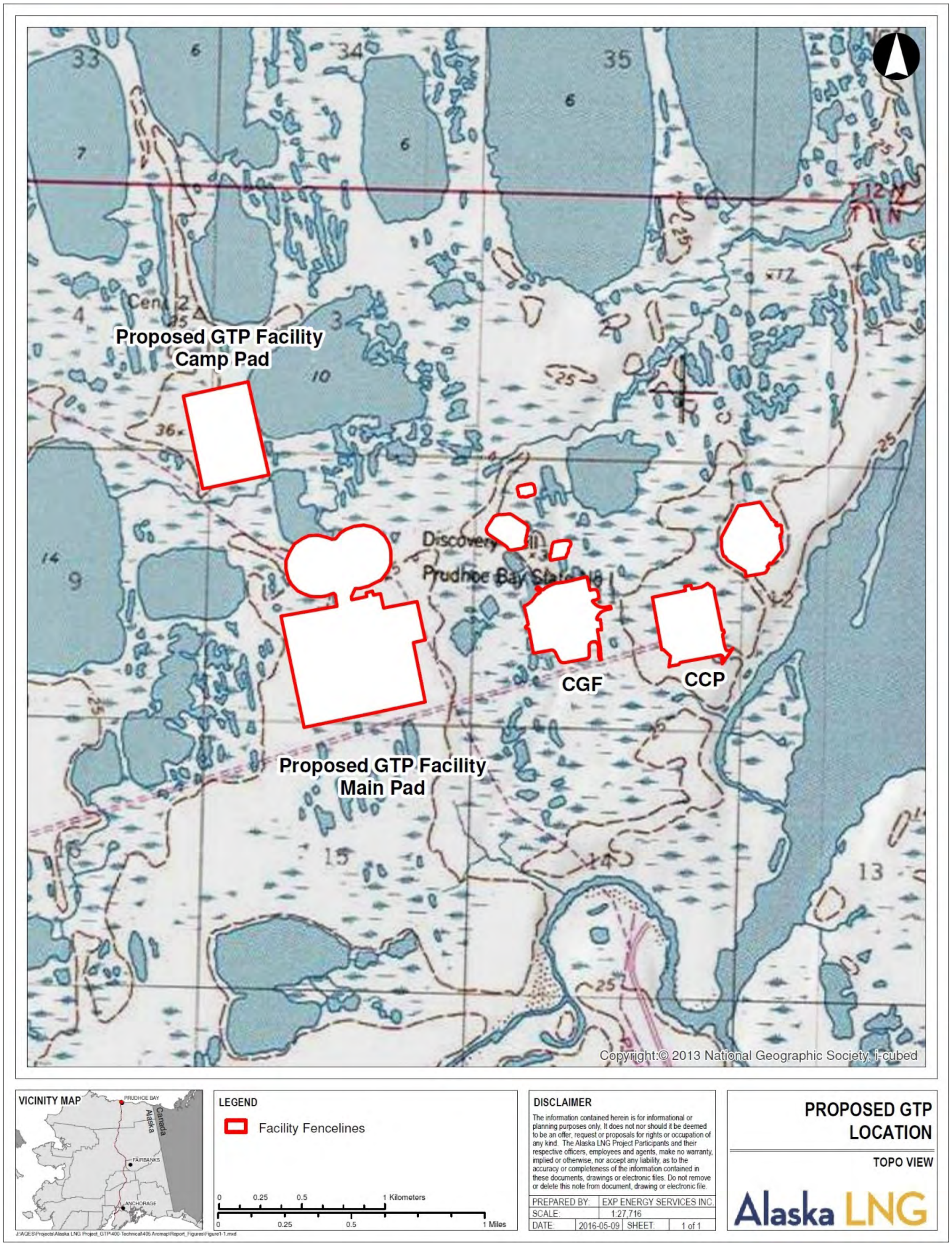
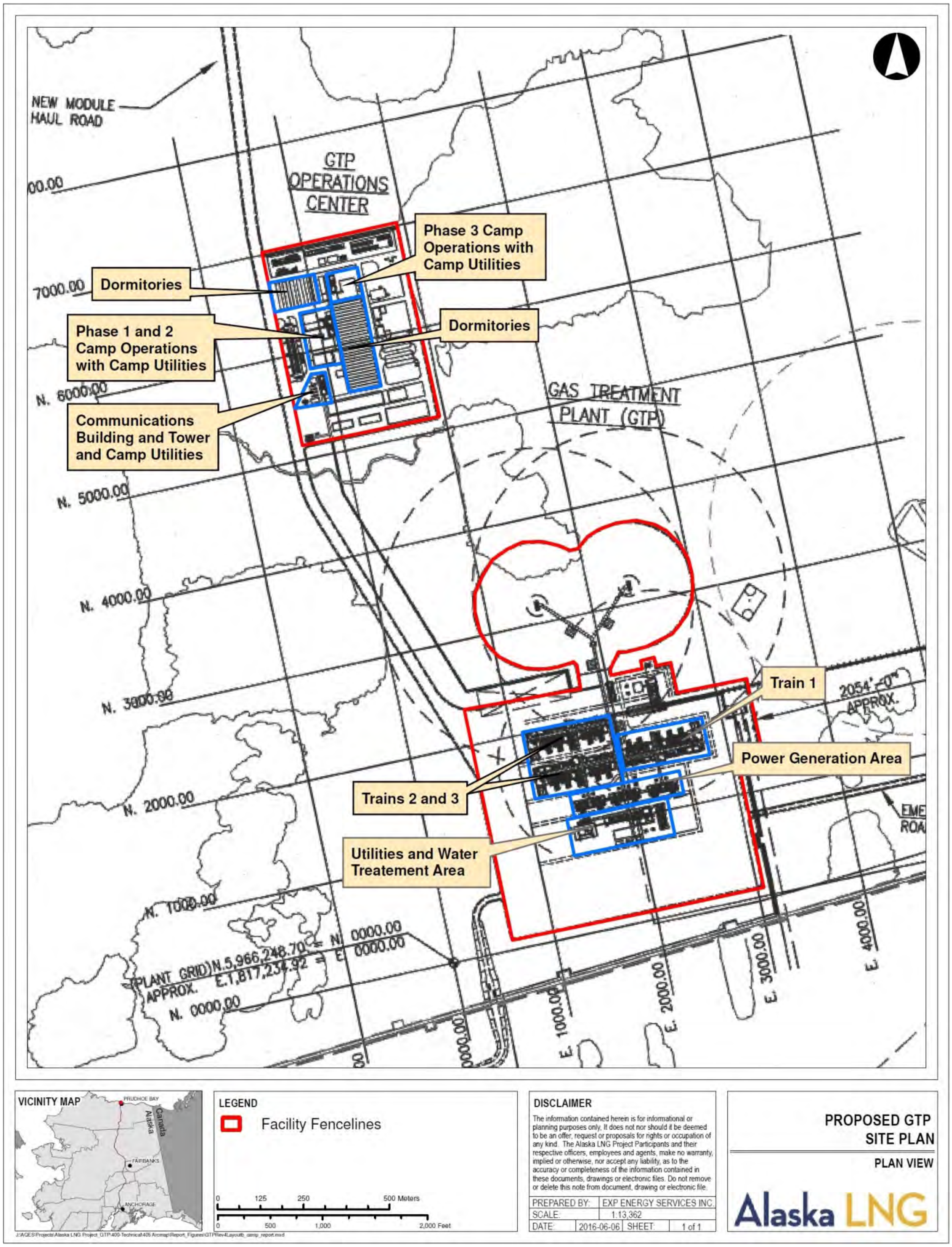


Figure 1-2: Proposed GTP Site Plan



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 GTP 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 and revise the ozone standard. ADEC also has an eight hour AAAQS for ammonia. **Table 2-1** lists both the federal and state ambient air quality standards.

The federal Clean Air Act (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 2015, USEPA 2014a, and 40 C.F.R 81.302). The area surrounding the GTP 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 2015

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 99^{th} 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 98^{th} percentile of the distribution of daily maximum values is less than the 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 98^{th} 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 the 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 a 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 the Project, this means demonstrating that the GTP 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 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 kilometers) or the far-field (beyond approximately 50 kilometers) 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 ($|C|$). 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 kilometers) 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	Plume Perceptability (ΔE)	Plume Contrast (absolute value)
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 kilometers) 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. The regional haze evaluation criteria are change in deciview and change in light extinction due to pollutant loading. As shown in **Table 2-4**, a 5% and 10% change in extinction is approximately equal to 0.5 and 1.0 delta deciview, respectively. The changes (in either metric) 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	Delta Deciview[1] (ddv)	Change in Extinction (%)
Contribute to Visibility Impairment	0.5	5
Cause Visibility Impairment	1.0	10

[1] 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 project sources. Project deposition below 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 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 project sources alone was compared to the DAT of 0.005 kg/ha/yr. However, because project 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 project 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.

Table 2-5: Deposition Analysis Thresholds

Species	Project Deposition (kg/ha/yr)	Cumulative Deposition (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 GTP, NCSLs for AQRV evaluation identified within approximately 50 km for near-field analysis and between approximately 50 kilometers to 300 kilometers for far-field analysis are provided in **Table 2-6** and shown in **Figure 2-1**.

The nearest Class I area is Denali National Park, located approximately 750 kilometers south of the Project area. The New Source Review Workshop Manual (USEPA 1990) and guidance provided by the National Park Service (FLAG 2010) suggest that generally a 100 kilometer range is an acceptable modeling domain unless the source being considered is large and could reasonably affect the outcome of a Class I analysis. In addition to the great distance from Denali, trajectories that might transport emissions from the GTP area toward Denali would need to traverse the Brooks Range, which lies between the North Slope and Denali; consequently, it is highly unlikely that sources located at the North Slope could materially affect ambient air quality at Denali. In light of these facts, neither a Class I increment impact analysis nor an AQRV impact analysis for Denali National Park were conducted.

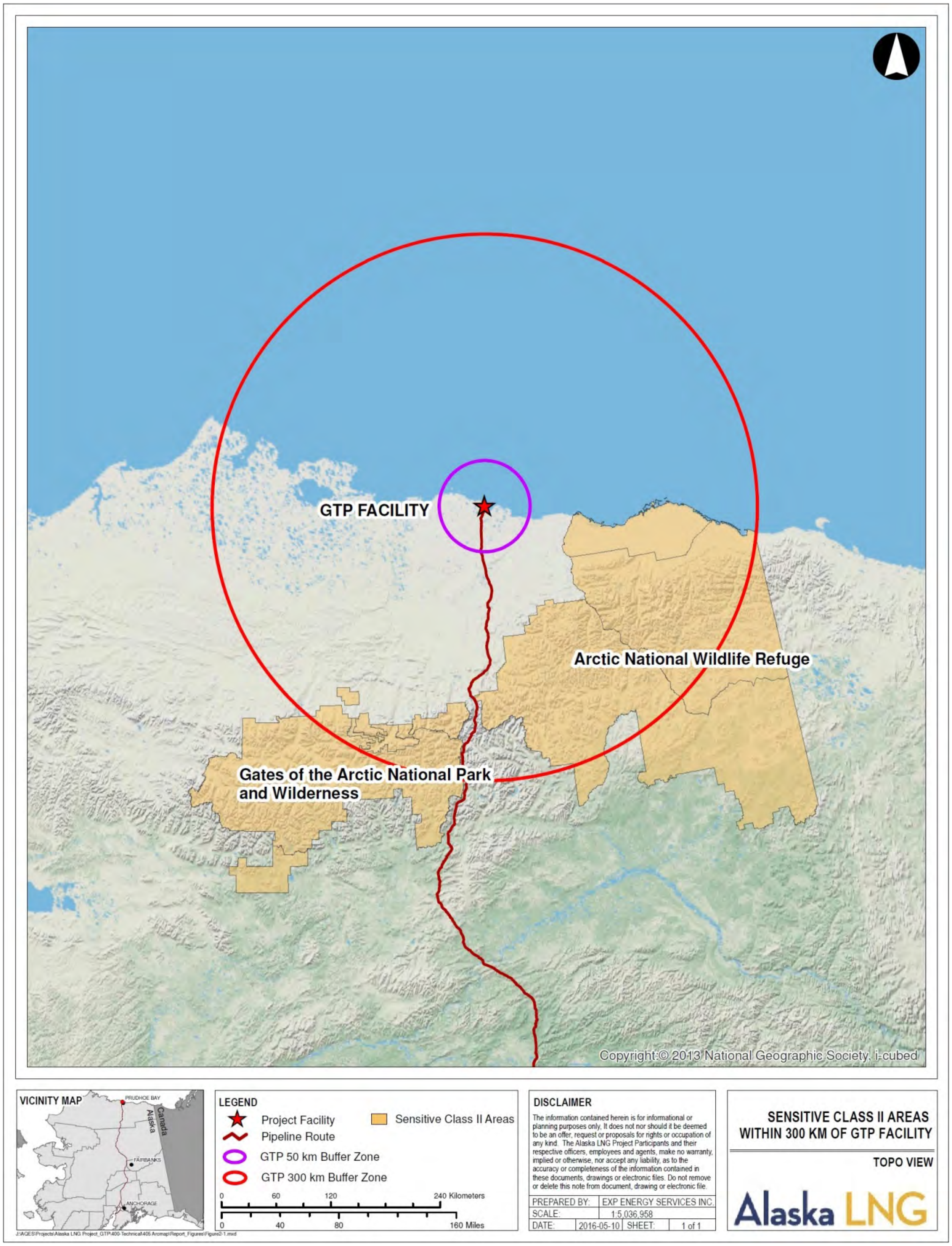
To provide further evidence that an AQRV impact analysis need not be conducted for Denali National park, the FLAG 2010 initial screening procedure for sources greater than 50 kilometers from a Class I Area was conducted. The analysis showed that the ratio of the sum of the GTP's annual SO_2, NO_x, PM_{10}, and H_2SO_4 emissions in tons to the distance to the Class I Area in kilometers is less than 10.

Two Class II areas are located less than 300 kilometers from GTP. They are Arctic National Wildlife Refuge (93 kilometers to the southeast and south) and Gates of the Arctic National Park and Preserve (214 kilometers to the southwest). An AQRV analysis was conducted for GTP and nearby offsite sources for both Class II areas. Further discussion of the modeling methodology is supplied in Section 6.0.

Table 2-6: Class I and Sensitive Class II Areas included in AQRV Evaluation

	Class I Areas (approx. distance from the GTP)	Sensitive Class II Areas Warranting AQRV Evaluation (approx. distance from the GTP)
Within 50 km of LNG Plant (near field)	• None	• None
50 km – 300 km from LNG Plant (far field)	• None	• Arctic National Wildlife Refuge (93 km) • Gates of the Arctic National Park and Preserve (214 km)

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



3.0 BACKGROUND AIR QUALITY

In evaluating cumulative impacts of the GTP with respect to the NAAQS and AAAQS, the appropriate modeled impacts were added to representative ambient background concentrations. The ambient background concentrations shown in **Table 3-1** were added to model-predicted impacts prior to comparison to the NAAQS/AAAQS.

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 Prevention of Significant Deterioration (PSD)-quality should generally be acceptable as the basis for developing background concentrations to support modeling demonstrations.

Background data collected at the BPXA A-Pad monitoring station and the Central Compression Plant (CCP) monitoring station were used. All SO_2, NO_2, and O_3 background values were calculated from data collected at the BPXA A-Pad monitoring station from 2010 through 2014. CO, PM_{10}, and $PM_{2.5}$ background values were calculated from data collected at the CCP monitoring station due to the fact that A-Pad does not measure these pollutants. All data from CCP was collected in 2014. Data collected at these stations are considered conservatively representative of the project area and non-modeled sources since all monitoring stations are located downwind of large stationary sources. **Figure 3-1** shows the locations of the CCP and A-Pad monitoring stations with respect to the GTP. **Table 3-1** summarizes the data.

Note that **Table 3-1** gives a background concentration for 1-hour NO_2. This concentration was used for the far-field CALPUFF modeling. However, a refined approach was used for the near-field AERMOD modeling as is described in **Section 3.2**.

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).

Due to the stringency of the 1-hour NO_2 NAAQS, a refined second-tier technique was used to develop a representative ambient background concentration to combine with near-field cumulative AERMOD-predicted impacts. USEPA guidance provides that the second tier approach can be considered on a case-by-case basis. The second tier approach is a collection of background development procedures based on identifying "the meteorological conditions accompanying the concentrations of concern" (USEPA 2005, USEPA 2011, USEPA 2014b). For the Class I and Sensitive Class II area modeling, the second tier was used.

To identify these meteorological conditions of concern for this evaluation, an analysis was conducted with the meteorological and ambient air quality conditions at the A-Pad monitoring station between 2009 and 2013. These data indicated that measured NO_2 concentrations were strongly dependent on wind speed. **Figure 3-2** illustrates the relationship between hourly average NO_2 and wind speed measurements collected at the A-Pad monitoring station. This figure indicates that NO_2 concentrations decrease with increasing wind speeds. Therefore, low wind speeds are the "meteorological conditions accompanying the concentrations of concern" referenced in USEPA guidance. Developing a background that varies by wind speed is appropriate because the background values are temporally paired with model-predicted concentrations based on meteorological variability. This will reflect the worst-case meteorological conditions in a way that is consistent with the probabilistic form of the 1-hour NO_2 standard.

Background concentrations varying by wind speed were determined by first sorting all hourly averaged NO_2 measurements according to the accompanying wind speed using the categories listed in **Table 3-2**. These wind speed categories are defined in the AERMOD User's Guide (USEPA 2004). Once the data had been sorted, the 98^{th} percentile hourly average NO_2 concentration was calculated from the data in each wind speed category. **Table 3-2** summarizes the resulting NO_2 background concentrations calculated using hourly NO_2 and wind speed data collected at A-Pad monitoring station between 2009 and 2013. Although the form of the 1-hour NO_2 NAAQS is based on three years of monitored data, ADEC considers the use of five years of ambient data more robust than the three years required by USEPA guidelines. Therefore, the same five years of hourly NO_2 and wind speed data were used for this analysis as the five meteorological years for modeling.

Once the background concentrations for each wind speed category were determined, the background values were input to the model. Therefore, an NO_2 background concentration was assigned to all receptors for each hour of the meteorological input, with the selected background value being determined by the wind speed for that hour.

Table 3-1: Background Air Quality Data in the Project Vicinity of the GTP

Air Pollutant	Averaging Period	Concentration	
		ppbv	µg/m^3
Sulfur Dioxide	1-Hour [a]	3.58	9.39
	3-Hour [b]	8.00	20.96
	24-Hour [b]	3.10	8.12
	Annual [b]	0.69	1.8
Carbon Monoxide	1-Hour [b]	1000	1150
	8-Hour [b]	1000	1150
Nitrogen Dioxide	1-Hour [c]	32.80	61.69
	Annual [b]	3.2	6.0
Ozone	8-Hour [d]	56.0	109.9
Particulate Matter less than 10 Microns	24-Hour [b]	NA	50.0
Particulate Matter less than 2.5 Microns	24-Hour [c]	NA	15.0
	Annual [b]	NA	3.7

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.
[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

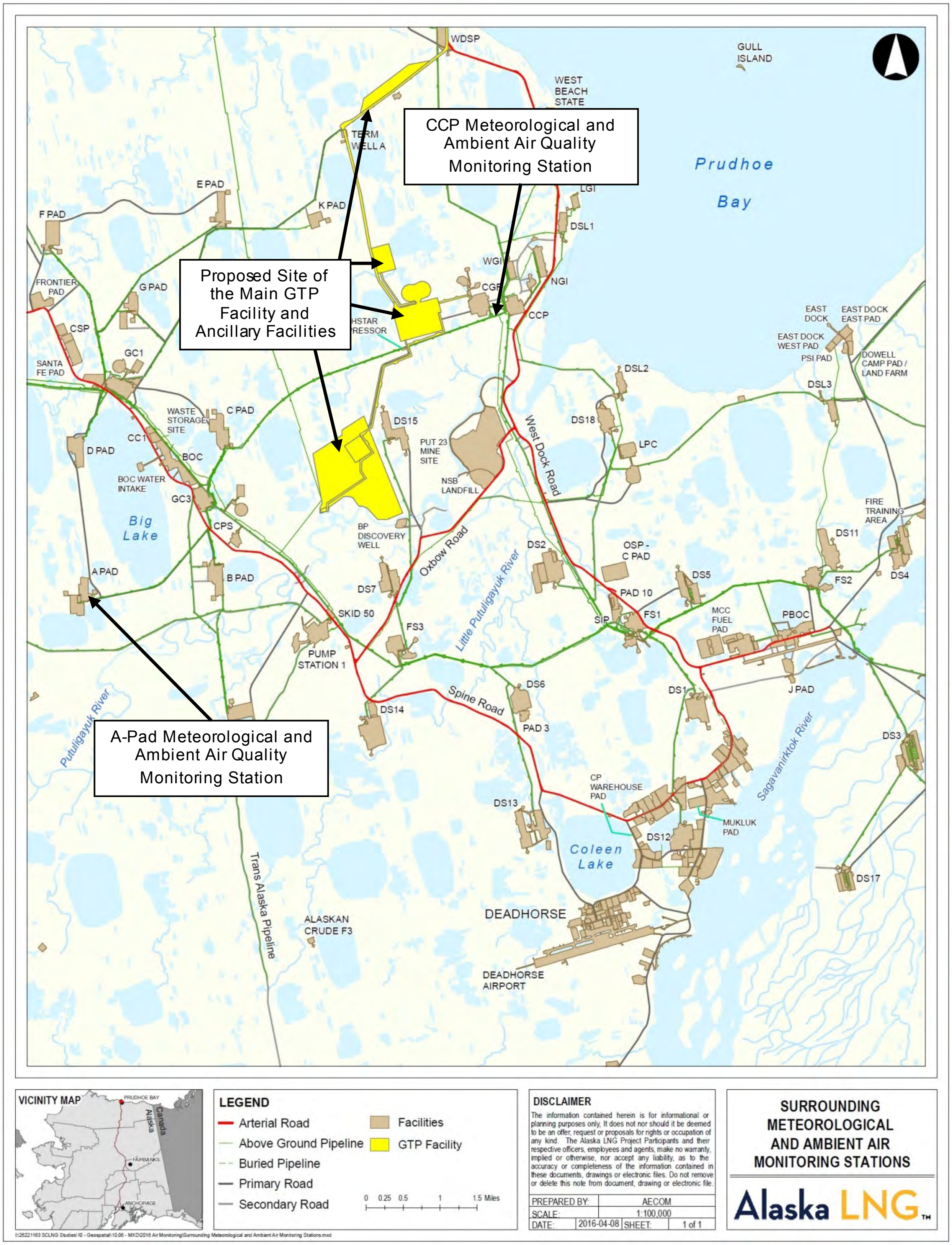


Figure 3-2: Relationship between NO_2 Concentrations and Wind Speed Measured at the A-Pad Monitoring Station from 2009 through 2013

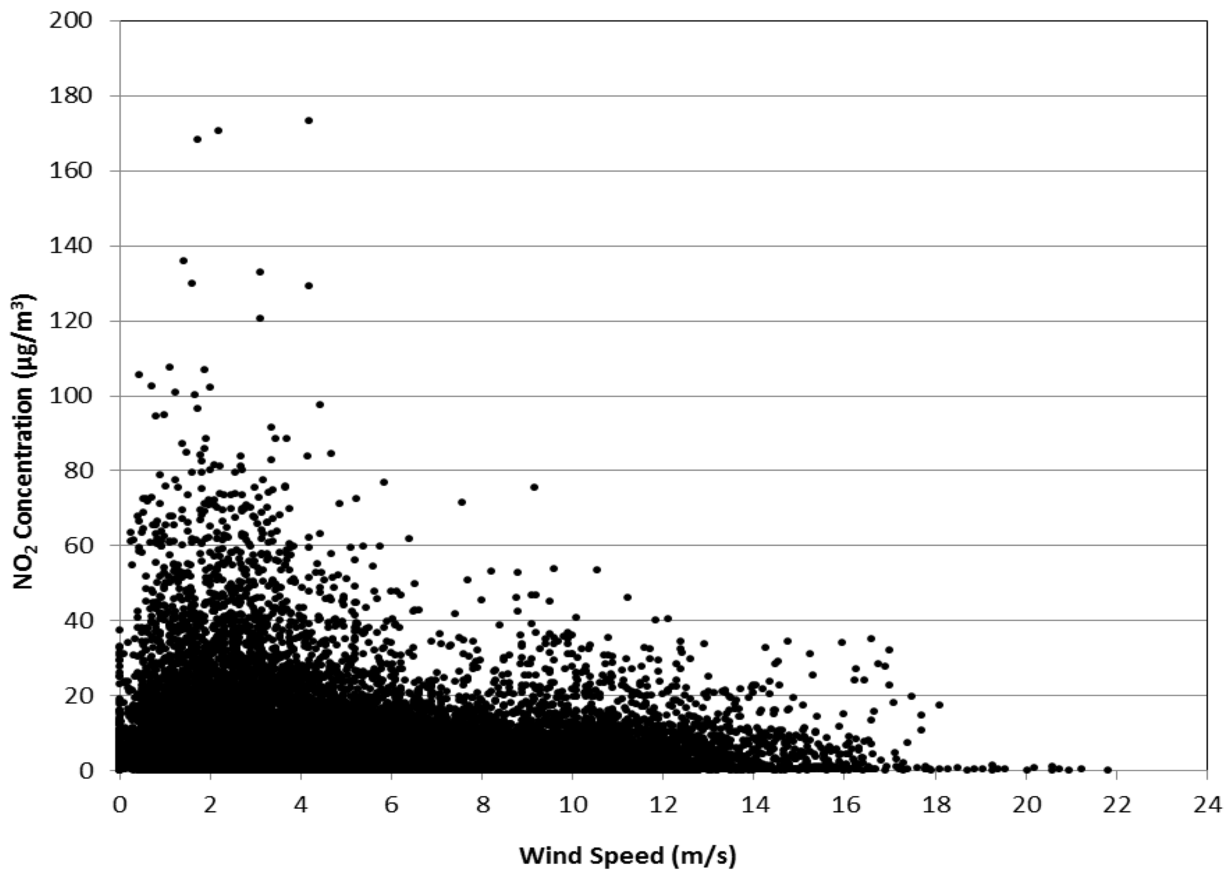


Table 3-2: 1-Hour NO_2 Background Varying by Wind Speed

Wind Speed (W_S) Category [a] (m/s)	NO_2 Concentration	
	ppbv	µg/m^3
W_S < 1.54	25.9	48.8
1.54 ≤ W_S < 3.09	22.3	41.9
3.09 ≤ W_S < 5.14	15.9	29.9
5.14 ≤ W_S < 8.23	10.3	19.4
8.23 ≤ W_S < 10.8	10.7	20.1
W_S ≥ 10.8	13.4	25.2

Abbreviations:
NA = not applicable
µg/m^3 = micrograms per cubic meter
ppbv = parts per billion by volume

Notes:
[a] AERMOD-default wind speed categories.

4.0 EMISSION INVENTORIES

This section provides information regarding the emission inventories used in the dispersion modeling, which serves as an overview of the emission calculation details which are provided in Appendix A.

4.1 PROJECT EMISSION UNITS

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

Table 4-1: Equipment to be Installed at GTP

Description	Number of Units
Turbines	
Power Generation	6
Treated Gas Compression [a]	6
CO_2 Compression [a]	6
Heaters	
Building Heat Medium Heater [b]	3
Buyback Gas Bath Heater	2
Operational Camp Heater [e]	3
Flares [c]	
High Pressure (HP) Hydrocarbon flare	2
Low Pressure (LP) Hydrocarbon flare	2
HP CO_2 Flare	2
LP CO_2 Flare [d]	2
Diesel generator (Liquid Fired – Ultra Low Sulfur Diesel)	
2500 kW Essential Power Generator	1
250 kW Dormitory Emergency Generator	1 (Emergency Use)
150 kW Communication Tower Generator	1 (Emergency Use)
250 hp Main Firewater Pump	3 (Emergency Use)

Notes:

a Each compression turbine has an associated Supplemental Firing (SF) system and Waste Heat Recovery Unit (WHRU) to meet the duty requirements of the Process Heat Medium system. SF duty would vary depending on season and load of each turbine. The SF duties for each operating turbine are a conservative estimate to account for this anticipated seasonal and load variation.

b Building Heat Medium Heater load would vary seasonally. A set of three heaters (225 MMBtu/hr each) are installed but only two heaters (450 MMBtu/hr total) are expected to operate at any one time. The third heater is a spare. This is a 3 x 50% operational configuration.

c Both sets of flares continuously operating with purge gas and pilot gas.

d Each LP CO_2 has 3 tips.

e Operational Camp Heater load would vary seasonally. A set of three heaters (25 MMBtu/hr each) are installed but only two heaters (50 MMBtu/hr total) are expected to operate at any one time. The third heater is a spare. This is a 3 x 50% operational configuration.

4.1.1 Modeled Scenarios

A conservative normal operations scenario was used to predict impacts from GTP sources. 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 GTP is assumed to operate concurrently, even intermittently used equipment.
- Turbines were modeled at maximum emissions rates and minimum exhaust parameters. The additional supplemental firing flow rate and velocity were not included in the velocities modeled.
- Even though flare relief events would only occur during maintenance or upset conditions, they were conservatively modeled as part of normal operations.

Modeling 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 scenario for the GTP is detailed below.

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

EQUIPMENT	SCENARIO TO BE MODELED	NON-MODELED SCENARIOS						
	Normal operations (Conservative)	Start-up	Early Operations – Phase 1	Early Operations – Phase 2	Early Operations – Phase 3	Maintenance – Turbines & Process System	Maintenance – Building Heat Medium Heaters	Maintenance – Operational Camp Heaters
GTP Train 1 - 2 CO_2 Compressor Turbines	Yes	Yes	Yes	Yes	Yes	Offline[a]	Yes	Yes
GTP Train 2 - 2 CO_2 Compressor Turbines	Yes	-	-	Yes	Yes	Yes	Yes	Yes
GTP Train 3 - 2 CO_2 Compressor Turbines	Yes	-	-	-	Yes	Yes	Yes	Yes
GTP Train 1 - 2 Treated Gas Compressor Turbines	Yes	Yes	Yes	Yes	Yes	Offline[a]	Yes	Yes
GTP Train 2 - 2 Treated Gas Compressor Turbines	Yes	-	-	Yes	Yes	Yes	Yes	Yes
GTP Train 3 - 2 Treated Gas Compressor Turbines	Yes	-	-	-	Yes	Yes	Yes	Yes
Power Gen. Turbines Set 1 (2 turbines)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Power Gen. Turbines Set 2 (2 turbines)	Yes	-	-	Yes	Yes	Yes	Yes	Yes
Power Gen. Turbines Set 3 (2 turbines)	Yes	-	-	-	Yes	Yes	Yes	Yes
Building Heat Medium Heater 1	Yes	Yes	Yes	Yes	Yes	Yes	Offline[b]	-
Building Heat Medium Heater 2	Yes	-	-	Yes	Yes	Yes	Yes	-
Building Heat Medium Heater 3 (spare)	-	-	-	-	-	-	Yes	-
Essential Diesel Generator at Main Pad	Yes	Yes	-	-	-	-	-	-
Firewater Pumps (3)	Yes	-	-	-	-	-	-	-
Dormitory Emergency Diesel Generator at Camp Pad	Yes	-	-	-	-	-	-	-
Communications Tower Diesel Generator at Camp Pad	Yes	-	-	-	-	-	-	-
Buyback Gas Bath Heaters (2)	Yes	-	-	-	-	-	-	-
Operational Camp Heaters 1	Yes	-	-	-	-	-	-	Offline[c]
Operational Camp Heaters 2	Yes	-	-	-	-	-	-	Yes
Operational Camp Heaters 3 (spare)	-	-	-	-	-	-	-	Yes

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

	SCENARIO TO BE MODELED	NON-MODELED SCENARIOS						
FACILITY EQUIPMENT	(Conservative) Normal operations	Start-up	Early Operations – Phase 1	Early Operations – Phase 2	Early Operations – Phase 3	Maintenance – Turbines & Process System	Maintenance – Building Heat Medium Heaters	Maintenance – Operational Camp Heaters
LP Hydrocarbon Flares - Pilot/Purge	Yes	Yes	Yes	Yes	Yes	-	Yes	Yes
LP Hydrocarbon Flares - Max. Relief Case	Yes	-	-	-	-	-	-	-
LP Hydrocarbon Flares - Relief Events assoc. with Startup (fewer emissions than max relief case)	-	-	-	-	-	-	-	-
LP Hydrocarbon Flares - Relief Events assoc. with Turbine & Process System Maintenance (fewer emissions than max relief case)	-	-	-	-	-	Yes	-	-
HP Hydrocarbon Flares - Pilot/Purge	Yes	-	Yes	Yes	Yes	-	Yes	Yes
HP Hydrocarbon Flares - Max. Relief Case	Yes	-	-	-	-	-	-	-
HP Hydrocarbon Flares - Relief Events assoc. with Startup (fewer emissions than max relief case)	-	Yes	Yes	Yes	Yes	-	-	-
HP Hydrocarbon Flares - Relief Events assoc. with Turbine & Process System Maintenance (fewer emissions than max relief case)	-	-	-	-	-	Yes	-	-
LP CO_2 Flares - Pilot/Purge	Yes	-	Yes	Yes	Yes	-	Yes	Yes
LP CO_2 Flares - Max. Relief Case	Yes	-	-	-	-	-	-	-
LP CO_2 Flares - Relief Events assoc. with Startup (fewer emissions than max relief case)	-	Yes	Yes	Yes	Yes	-	-	-
LP CO_2 Flares - Relief Events assoc. with Turbine & Process System Maintenance (fewer emissions than max relief case)	-	-	-	-	-	Yes	-	-
HP CO_2 Flares - Pilot/Purge	Yes	Yes	Yes	Yes	Yes	-	Yes	Yes
HP CO_2 Flares - Max. Relief Case	Yes	-	-	-	-	-	-	-
HP CO_2 Flares - Relief Events assoc. with Startup (fewer emissions than max relief case)	-	-	-	-	-	-	-	-
HP CO_2 Flares - Relief Events assoc. with Turbine & Process System Maintenance (fewer emissions than max relief case)	-	-	-	-	-	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.

b. Only two Building Heat Medium Heaters will be operational during normal operations. When on heater goes down for maintenance, the spare will be operating.

c. Only two Operations Camp Heaters will be operational during normal operations. When one heater goes down for maintenance, the spare will be operating.

4.1.1.1 Normal Operations

It was assumed that the GTP would be running at full capacity, producing sales gas using all three production trains. These production trains would burn a blend of PBU and Point Thompson gas with a maximum sulfur content of 1 grain/100scf. A description of the equipment that was modeled is provided below. All emission units were modeled as vertical and uncapped point sources. All point source locations were referenced to NAD83 UTM Zone 6 coordinates. Additional details regarding normal operation of the units as well as the development of emissions and exhaust parameters can be found in Appendix A.

Compression Turbines

There would be a total of twelve gas compression turbines (six Treated Gas and six CO_2 Compression turbines) located at the GTP. The turbines would be organized as two sets of two turbines per train (two Treated Gas compression turbines and two CO_2 Compression turbines total per train) for the 3 trains. The turbines have been designed with spare capacity to allow the GTP to remain in operation during maintenance and upset scenarios. There is potential for the turbines to be operating anywhere from 85% load to 100% load, with either all twelve or fewer turbines operating. Typically, all twelve turbines would operate at 85% load.

To be conservative, the modeled normal operations scenario assumed that all twelve compression turbines operate at 100% load. The turbines would each be fitted with a Waste Heat Recovery Unit (WHRU) and associated Supplemental Firing (SF) system.

For modeling 1-hour SO_2 and 1-hour NO_2, emission rates for all of the turbines were conservatively increased by 10% in the model. This 10% safety factor accounts for short-term load variations in the modeled emissions. This was not applied to any other pollutant or averaging period.

Power Generation Turbines

The GTP main power generation system consists of six turbines total which create a common power supply for the facility. Individual power generation turbine load would fluctuate based on the needs of the process trains, and can range from 60% to 100%. Seasonal load variations would be the most common reason for differences in power generation equipment operation.

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

Heaters

The GTP operation would include the installation of three Building Heat Medium Heaters to heat the process modules, utility modules, common areas, and other enclosed areas. Two of the heaters would operate continuously, and one would be a spare not normally in operation. Each heater has a design duty of 225 MMBtu/hr. The heaters are all sized for 50% of the required heat capacity needed at the facility, 3 x 50%. The load on the two operating heaters would fluctuate based on seasonal heat needs. To be conservative, the modeling assumed that the two heaters operate continuously at 100% load.

Operational heaters would be installed at the operations camp to heat the residences, offices, and other enclosed areas. Three heaters were included in the camp for air modeling purposes. Two of the heaters would operate continuously, and one would be a spare not normally in operation. Each heater has a design duty of 25 MMBtu/hr. The heaters are all sized for 50% of the required heat capacity needed at the facility, 3 x 50%. The load on the two operating heaters would fluctuate based on seasonal heat needs. To be conservative, the modeling assumed that the two heaters operate continuously at 100% load.

Buyback Gas Bath Heaters would also be installed that would heat any treated gas that is rerouted back from the sales gas pipeline, downstream of the Refrigeration System and metering station. The two heaters at the facility would be sized as 2 x 50% of the total fuel capacity. Typically, the heaters would operate in a standby low-load mode. Therefore, the units were modeled as operating continuously at 10% load. To account for infrequent instances where the heaters would operate at maximum load, the units were also modeled as intermittent sources operating at 100% load for 500 hours/year.

Reciprocating Internal Combustion Engines

One essential diesel power generator would be installed at the GTP to assist in the initial black start of the main power generation turbines. The GTP would also include a dormitory emergency diesel generator that would have the ability to provide the worker camp with some energy in the event of an emergency plant shut down.

There would be three main diesel firewater pumps which would be located at the man camp facilities, not within the process trains. The pumps are attached to specific Camp Firewater Storage Tanks that would house water only for a fire emergency system.

The Communications Tower generator would be installed at the GTP to allow for supply of power to the Communication System during emergencies and down operation of the power generation turbines.

While the generators and firewater pumps are not technically a part of everyday normal operations, they were all conservatively included in the modeling as intermittently operated sources, operating for 500 hours per year.

Flares

The GTP would have two sets of emergency flares, one operational and one spare. Each set includes a High Pressure (HP) hydrocarbon flare, a Low Pressure (LP) hydrocarbon flare, an HP CO_2 flare, and a LP CO_2 flare. As part of normal operations, pilot and purge gas would be continuously combusted at each of the eight flares and was included in the dispersion modeling.

Emergency flaring (maximum relief events) would occur infrequently and while not part of everyday normal operations, maximum flaring from each of the four operational flares were conservatively included in the normal operations scenario as intermittent sources, operating for 500 hours per year. The four maximum flaring cases were included in all cumulative and PSD Increment modeling for both near-field and far-field areas.

For the AQRV analyses, however, only the hydrocarbon flares were modeled with a maximum flaring case representing an emergency scenario. The reasoning behind this is that it is unlikely that an emergency or malfunction would occur that would cause process gas to be sent to both sets of flares at the same time. The CO_2 compression system and treated gas compression system operate independently from one another. For instance, if the outlet of the CO_2 compressors is blocked, all of the CO_2 gas located within the compressors and associated piping would be routed to the CO_2 flares. However, the feed gas could still be treated in the Acid Gas Removal System (AGRU) and sent to the treated gas compression system, and the hydrocarbon flares would still operate under normal operations, *i.e.* under pilot/purge. All CO_2 gas produced during the shutdown of the CO_2 compression system while the treated gas was still being processed would be sent directly to the flares.

Each emission unit was modeled at an operating condition specifically chosen to result in conservative model-predicted impacts. The conditions selected were generally 100% load, continuous operation with short-term and annual emissions based on the ambient temperature, leading to a conservative modeling estimate. In the case of CO emissions, the 8-hour emissions were conservatively set to the 1-hour emissions. In the cases of NO_2 and SO_2 emissions the

3-hour and 24-hour emissions were all conservatively set to the 1-hour emissions. The only exceptions to this was the emergency diesel generators, firewater pumps, maximum buyback gas bath heater conditions, and maximum flaring conditions which are deemed intermittent sources. The 1-hour averaged emissions and annual emissions for these sources were based on operations of 500 hours per year.

All liquid fuel fired equipment is assumed to combust Ultra Low Sulfur Diesel fuel, and all other emission units are assumed to combust treated gas. For conservatism and to account for potential start-up scenarios, the treated gas was assumed to have a total sulfur content of 96 ppmv.

Point source parameters and emissions rates used to model the normal operations scenario for the GTP 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 6 coordinates.

Table 4-3: Modeled GTP Source Emissions

Modeled ID	Source Description	Emission Rates (g/s)										
		NO_x (g/sec)		SO_2 (g/sec)			PM_{10} (g/sec)		$PM_{2.5}$ (g/sec)		CO (g/sec)	
		1-hour [a]	Annual	1-hour [a]	3-hour 24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour	8-hour
Turbines												
1A	Train 1a Treated Gas Compressor Turbine Primary Stack	5.56E+00	4.01E+00	1.33E+00	1.33E+00	1.09E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	4.51E+00	4.51E+00
1B	Train 1b Treated Gas Compressor Turbine Primary Stack	5.56E+00	4.01E+00	1.33E+00	1.33E+00	1.09E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	4.51E+00	4.51E+00
2A	Train 2a Treated Gas Compressor Turbine Primary Stack	5.56E+00	4.01E+00	1.33E+00	1.33E+00	1.09E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	4.51E+00	4.51E+00
2B	Train 2b Treated Gas Compressor Turbine Primary Stack	5.56E+00	4.01E+00	1.33E+00	1.33E+00	1.09E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	4.51E+00	4.51E+00
3A	Train 3a Treated Gas Compressor Turbine Primary Stack	5.56E+00	4.01E+00	1.33E+00	1.33E+00	1.09E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	4.51E+00	4.51E+00
3B	Train 3b Treated Gas Compressor Turbine Primary Stack	5.56E+00	4.01E+00	1.33E+00	1.33E+00	1.09E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	4.51E+00	4.51E+00
4A	Train 1a CO2 Compressor Turbine Primary Stack	4.08E+00	3.44E+00	9.51E-01	9.51E-01	8.20E-01	3.94E-01	3.45E-01	3.94E-01	3.45E-01	7.77E+00	7.77E+00
4B	Train 1b CO2 Compressor Turbine Primary Stack	4.08E+00	3.44E+00	9.51E-01	9.51E-01	8.20E-01	3.94E-01	3.45E-01	3.94E-01	3.45E-01	7.77E+00	7.77E+00
5A	Train 2a CO2 Compressor Turbine Primary Stack	4.08E+00	3.44E+00	9.51E-01	9.51E-01	8.20E-01	3.94E-01	3.45E-01	3.94E-01	3.45E-01	7.77E+00	7.77E+00
5B	Train 2b CO2 Compressor Turbine Primary Stack	4.08E+00	3.44E+00	9.51E-01	9.51E-01	8.20E-01	3.94E-01	3.45E-01	3.94E-01	3.45E-01	7.77E+00	7.77E+00
6A	Train 3a CO2 Compressor Turbine Primary Stack	4.08E+00	3.44E+00	9.51E-01	9.51E-01	8.20E-01	3.94E-01	3.45E-01	3.94E-01	3.45E-01	7.77E+00	7.77E+00
6B	Train 3b CO2 Compressor Turbine Primary Stack	4.08E+00	3.44E+00	9.51E-01	9.51E-01	8.20E-01	3.94E-01	3.45E-01	3.94E-01	3.45E-01	7.77E+00	7.77E+00

Table 4-3: Cont. Modeled Source Emissions

Modeled ID	Source Description	Emission Rates (g/s)										
		NO_x (g/sec)		SO_2 (g/sec)			PM_{10} (g/sec)		$PM_{2.5}$ (g/sec)		CO (g/sec)	
		1-hour [(a)]	Annual	1-hour [(a)]	3-hour 24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour	8-hour
Turbines												
7A_1A	Power Generator Turbines	2.69E+00	2.11E+00	7.92E-01	7.92E-01	7.30E-01	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.64E+00	1.64E+00
7A_1B	Power Generator Turbines	2.69E+00	2.11E+00	7.92E-01	7.92E-01	7.30E-01	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.64E+00	1.64E+00
7A_2A	Power Generator Turbines	2.69E+00	2.11E+00	7.92E-01	7.92E-01	7.30E-01	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.64E+00	1.64E+00
7A_2B	Power Generator Turbines	2.69E+00	2.11E+00	7.92E-01	7.92E-01	7.30E-01	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.64E+00	1.64E+00
7A_3A	Power Generator Turbines	2.69E+00	2.11E+00	7.92E-01	7.92E-01	7.30E-01	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.64E+00	1.64E+00
7A_3B	Power Generator Turbines	2.69E+00	2.11E+00	7.92E-01	7.92E-01	7.30E-01	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.64E+00	1.64E+00
Diesel Equipment [(b)]												
9_1	Black Start Diesel Generator (2500 kW)	2.10E-01	2.10E-01	2.70E-04	4.73E-03	2.70E-04	4.20E-02	2.40E-03	4.20E-02	2.40E-03	3.68E+00	3.68E+00
31A	Main Diesel Firewater Pump (250 hp)	1.41E-02	1.41E-02	2.09E-05	3.67E-04	2.09E-05	1.30E-02	7.43E-04	1.30E-02	7.43E-04	2.26E-01	2.26E-01
31B	Main Diesel Firewater Pump (250 hp)	1.41E-02	1.41E-02	2.09E-05	3.67E-04	2.09E-05	1.30E-02	7.43E-04	1.30E-02	7.43E-04	2.26E-01	2.26E-01
31C	Main Diesel Firewater Pump (250 hp)	1.41E-02	1.41E-02	2.09E-05	3.67E-04	2.09E-05	1.30E-02	7.43E-04	1.30E-02	7.43E-04	2.26E-01	2.26E-01
33	Dormitory Emergency Diesel Generator (250 kW)	1.88E-02	1.88E-02	2.81E-05	4.92E-04	2.81E-05	1.74E-02	9.91E-04	1.74E-02	9.91E-04	3.04E-01	3.04E-01
36	Communications Tower Diesel Generator (150 kW)	1.13E-02	1.13E-02	1.69E-05	2.95E-04	1.69E-05	1.04E-02	5.95E-04	1.04E-02	5.95E-04	1.82E-01	1.82E-01

Table 4-3: Cont. Modeled GTP Source Emissions

Modeled ID	Source Description	Emission Rates (g/s)										
		NO_x (g/sec)		SO_2 (g/sec)			PM_{10} (g/sec)		$PM_{2.5}$ (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
Flares												
10E	LP CO2 Flare East Pilot/Purge	5.85E-02	5.85E-02	1.29E-02	1.29E-02	1.29E-02	2.43E-02	2.43E-02	2.43E-02	2.43E-02	2.67E-01	2.67E-01
10W	LP CO2 Flare West Pilot/Purge	5.85E-02	5.85E-02	1.29E-02	1.29E-02	1.29E-02	2.43E-02	2.43E-02	2.43E-02	2.43E-02	2.67E-01	2.67E-01
11E	HP CO2 Flare East Pilot/Purge	2.54E-02	2.54E-02	5.61E-03	5.61E-03	5.61E-03	1.05E-02	1.05E-02	1.05E-02	1.05E-02	1.16E-01	1.16E-01
11W	HP CO2 Flare West Pilot/Purge	2.54E-02	2.54E-02	5.61E-03	5.61E-03	5.61E-03	1.05E-02	1.05E-02	1.05E-02	1.05E-02	1.16E-01	1.16E-01
12E	HP Hydrocarbon Flare East Pilot/Purge	6.72E-02	6.72E-02	1.49E-02	1.49E-02	1.49E-02	2.79E-02	2.79E-02	2.79E-02	2.79E-02	3.07E-01	3.07E-01
12W	HP Hydrocarbon Flare West Pilot/Purge	6.72E-02	6.72E-02	1.49E-02	1.49E-02	1.49E-02	2.79E-02	2.79E-02	2.79E-02	2.79E-02	3.07E-01	3.07E-01
13E	LP Hydrocarbon Flare East Pilot/Purge	1.23E-02	1.23E-02	2.72E-03	2.72E-03	2.72E-03	5.11E-03	5.11E-03	5.11E-03	5.11E-03	5.61E-02	5.61E-02
13W	LP Hydrocarbon Flare West Pilot/Purge	1.23E-02	1.23E-02	2.72E-03	2.72E-03	2.72E-03	5.11E-03	5.11E-03	5.11E-03	5.11E-03	5.61E-02	5.61E-02
10E_M	LP CO2 Flare East (MAXIMUM) [b]	4.71E+00	4.71E+00	3.40E+00	9.92E+00	3.40E+00	7.13E-01	1.95E+00	7.13E-01	1.95E+00	1.88E+02	2.35E+01
11E_M	HP CO2 Flare East (MAXIMUM) [b]	1.54E+00	1.54E+00	1.11E+00	3.25E+00	1.11E+00	2.34E-01	6.40E-01	2.34E-01	6.40E-01	6.16E+01	7.70E+00
12E_M	HP Hydrocarbon Flare East (MAXIMUM) [b]	3.58E+01	3.58E+01	8.90E+00	2.60E+01	8.90E+00	5.43E+00	1.49E+01	5.43E+00	1.49E+01	1.43E+03	1.79E+02
13E_M	LP Hydrocarbon Flare East (MAXIMUM) [b]	2.20E+00	2.20E+00	4.86E-01	1.42E+00	4.86E-01	3.33E-01	9.13E-01	3.33E-01	9.13E-01	8.78E+01	1.10E+01

Table 4-3: Cont. Modeled GTP Source Emissions

Modeled ID	Source Description	Emission Rates (g/s)										
		NO_x (g/sec)		SO_2 (g/sec)			PM_{10} (g/sec)		$PM_{2.5}$ (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
Heaters												
14_1	Building Heat Medium Heater	2.77E+00	2.77E+00	5.20E-01	5.20E-01	5.20E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.85E+00	2.85E+00
14_2	Building Heat Medium Heater	2.77E+00	2.77E+00	5.20E-01	5.20E-01	5.20E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.85E+00	2.85E+00
21A	Buy back Gas Bath Heater Pre-Let Down Heater Standby [b]	1.55E-03	1.55E-03	3.09E-04	3.09E-04	3.09E-04	1.44E-04	1.44E-04	1.44E-04	1.44E-04	1.60E-03	1.60E-03
21B	Buy back Gas Bath Heater Pre-Let Down Heater Standby [b]	1.55E-03	1.55E-03	3.09E-04	3.09E-04	3.09E-04	1.44E-04	1.44E-04	1.44E-04	1.44E-04	1.60E-03	1.60E-03
21A_M	Buy back Gas Bath Heater Pre-Let Down Heater MAXIMUM [b]	1.46E-02	1.46E-02	2.74E-03	4.80E-02	2.74E-03	2.38E-02	1.36E-03	2.38E-02	1.36E-03	2.63E-01	2.63E-01
21B_M	Buy back Gas Bath Heater Post-Let Down Heater MAXIMUM [b]	1.20E-02	1.20E-02	2.26E-03	3.96E-02	2.26E-03	1.96E-02	1.12E-03	1.96E-02	1.12E-03	2.17E-01	2.17E-01
CAMPHT1	Operations Camp Heater	3.21E-01	3.21E-01	6.11E-02	6.11E-02	6.11E-02	2.99E-02	2.99E-02	2.99E-02	2.99E-02	3.31E-01	3.31E-01
CAMPHT2	Operations Camp Heater	3.21E-01	3.21E-01	6.11E-02	6.11E-02	6.11E-02	2.99E-02	2.99E-02	2.99E-02	2.99E-02	3.31E-01	3.31E-01

Notes:

[a] The 10% safety factor for the turbines was included in AERMOD as an input and is not reflected in this Table.

[b] Intermittently operating unit. Emissions set equal to annual emission rate per USEPA guidance (USEPA 2011).

Table 4-4: Modeled GTP Source Physical Parameters

Modeled ID	Source Description	Location			Stack Parameters				In-Stack NO_2/NO_x Ratio [c]
		UTM X [a]	UTM Y [a]	Base Elev. [b]	Ht.	Temp.	Vel.	Dia.	
		(m)	(m)	(m)	(m)	(°K)	(m/s)	(m)	
Turbines									
1A	Train 1a Treated Gas Compressor Turbine Primary Stack	441632.91	7802266.08	1.83	73.15	483.15	15.85	3.05	0.40
1B	Train 1b Treated Gas Compressor Turbine Primary Stack	441598.78	7802260.05	1.83	73.15	483.15	15.85	3.05	0.40
2A	Train 2a Treated Gas Compressor Turbine Primary Stack	441514.39	7802158.49	1.83	73.15	483.15	15.85	3.05	0.40
2B	Train 2b Treated Gas Compressor Turbine Primary Stack	441546.76	7802163.61	1.83	73.15	483.15	15.85	3.05	0.40
3A	Train 3a Treated Gas Compressor Turbine Primary Stack	441489.81	7802265.02	1.83	73.15	483.15	15.85	3.05	0.40
3B	Train 3b Treated Gas Compressor Turbine Primary Stack	441523.94	7802269.80	1.83	73.15	483.15	15.85	3.05	0.40
4A	Train 1a CO2 Compressor Turbine Primary Stack	441721.04	7802288.18	1.83	73.15	483.15	12.50	3.05	0.20
4B	Train 1b CO2 Compressor Turbine Primary Stack	441753.31	7802294.87	1.83	73.15	483.15	12.50	3.05	0.20
5A	Train 2a CO2 Compressor Turbine Primary Stack	441392.32	7802127.98	1.83	73.15	483.15	12.50	3.05	0.20
5B	Train 2b CO2 Compressor Turbine Primary Stack	441426.30	7802135.49	1.83	73.15	483.15	12.50	3.05	0.20
6A	Train 3a CO2 Compressor Turbine Primary Stack	441370.37	7802235.90	1.83	73.15	483.15	12.50	3.05	0.20
6B	Train 3b CO2 Compressor Turbine Primary Stack	441403.41	7802241.70	1.83	73.15	483.15	12.50	3.05	0.20
7A_1A	Power Generator Turbines	441683.89	7802104.89	1.83	73.15	739.26	25.30	3.05	0.40
7A_1B	Power Generator Turbines	441728.16	7802114.50	1.83	73.15	739.26	25.30	3.05	0.40
7A_2A	Power Generator Turbines	441468.06	7802061.38	1.83	73.15	739.26	25.30	3.05	0.40
7A_2B	Power Generator Turbines	441514.13	7802070.80	1.83	73.15	739.26	25.30	3.05	0.40
7A_3A	Power Generator Turbines	441569.32	7802082.04	1.83	73.15	739.26	25.30	3.05	0.40
7A_3B	Power Generator Turbines	441613.40	7802091.54	1.83	73.15	739.26	25.30	3.05	0.40

Table 4-4: Cont. Modeled GTP Source Physical Parameters

Modeled ID	Source Description	Location: UTM X [a]	Location: UTM Y [a]	Location: Base Elev. [b]	Stack Parameters: Ht.	Stack Parameters: Temp.	Stack Parameters: Vel.	Stack Parameters: Dia.	In-Stack NO_2/NO_x Ratio [c]
		(m)	(m)	(m)	(m)	(°K)	(m/s)	(m)	
Diesel Equipment									
9_1	Black Start Diesel Generator (2500 kW)	441618.73	7802154.47	1.83	35.05	743.71	20.73	0.76	0.50
31A	Main Diesel Firewater Pump (250 hp)	440709.65	7803298.16	1.83	23.16	727.59	10.83	0.30	0.50
31B	Main Diesel Firewater Pump (250 hp)	440733.30	7803462.72	1.83	23.16	727.59	10.83	0.30	0.50
31C	Main Diesel Firewater Pump (250 hp)	440738.35	7803589.70	1.83	23.16	727.59	10.83	0.30	0.50
33	Dormitory Emergency Diesel Generator (250 kW)	440714.68	7803289.84	1.83	23.16	728.71	14.63	0.30	0.50
36	Communications Tower Diesel Generator (150 kW)	440690.81	7803243.08	1.83	8.84	727.59	8.72	0.30	0.50
Flares [d]									
10E	LP CO2 Flare East Pilot/Purge	441601.84	7802718.49	1.83	67.26	1273.00	20.00	0.44	0.50
10W	LP CO2 Flare West Pilot/Purge	441335.91	7802643.10	1.83	67.26	1273.00	20.00	0.44	0.50
11E	HP CO2 Flare East Pilot/Purge	441601.72	7802711.65	1.83	66.52	1273.00	20.00	0.29	0.50
11W	HP CO2 Flare West Pilot/Purge	441335.90	7802648.61	1.83	66.52	1273.00	20.00	0.29	0.50
12E	HP Hydrocarbon Flare East Pilot/Purge	441601.90	7802705.72	1.83	67.42	1273.00	20.00	0.47	0.50
12W	HP Hydrocarbon Flare West Pilot/Purge	441335.95	7802655.24	1.83	67.42	1273.00	20.00	0.47	0.50
13E	LP Hydrocarbon Flare East Pilot/Purge	441601.77	7802699.63	1.83	66.07	1273.00	20.00	0.20	0.50
13W	LP Hydrocarbon Flare West Pilot/Purge	441335.94	7802661.87	1.83	66.07	1273.00	20.00	0.20	0.50
10E_M	LP CO2 Flare East (MAXIMUM)	441601.84	7802718.49	1.83	137.36	1273.00	20.00	16.43	0.50
11E_M	HP CO2 Flare East (MAXIMUM)	441601.72	7802711.65	1.83	107.44	1273.00	20.00	9.40	0.50
12E_M	HP Hydrocarbon Flare East (MAXIMUM)	441601.90	7802705.72	1.83	255.97	1273.00	20.00	45.33	0.50
13E_M	LP Hydrocarbon Flare East (MAXIMUM)	441601.77	7802699.63	1.83	115.28	1273.00	20.00	11.22	0.50

Table 4-4: Cont. Modeled GTP Source Physical Parameters

Modeled ID	Source Description	Location			Stack Parameters				In-Stack NO_2/NO_x Ratio [c]
		UTM X [a]	UTM Y [a]	Base Elev. [b]	Ht.	Temp.	Vel.	Dia.	
		(m)	(m)	(m)	(m)	(°K)	(m/s)	(m)	
Heaters									
14_1	Building Heat Medium Heater	441702.17	7802020.12	1.83	70.71	460.93	7.92	2.74	0.50
14_2	Building Heat Medium Heater	441697.18	7802044.48	1.83	70.71	460.93	7.92	2.74	0.50
21A	Buy back Gas Bath Heater Pre-Let Down Heater Standby	441654.10	7802479.72	1.83	6.10	589.26	0.10	0.61	0.50
21B	Buy back Gas Bath Heater Pre-Let Down Heater Standby	441652.81	7802486.16	1.83	6.10	748.15	0.12	0.61	0.50
21A_M	Buy back Gas Bath Heater Pre-Let Down Heater MAXIMUM	441654.10	7802479.72	1.83	6.10	589.26	16.70	0.61	0.50
21B_M	Buy back Gas Bath Heater Post-Let Down Heater MAXIMUM	441652.81	7802486.16	1.83	6.10	748.15	17.52	0.61	0.50
CAMPHT1	Operations Camp Heater	440958.06	7803537.00	1.83	9.75	398.15	8.84	0.76	0.50
CAMPHT2	Operations Camp Heater	440961.23	7803523.24	1.83	9.75	398.15	8.84	0.76	0.50

Notes:

[a] Coordinates are in NAD 83, UTM Zone 6.

[b] Modeling assumed the facility was graded at 1.83 meters, which is the approximate average thickness of the gravel pad (6 feet).

[c] Turbine in-stack NO_2/NO_x ratios are based on vendor provided data. Ratios for all other sources are based on USEPA default of 0.5 (USEPA 2011).

[d] Flare effective stack parameters were calculated using the maximum hourly heat release rate in accordance with the procedures outlined in SCREEN3 Model User's Guide (USEPA 1995) and ADEC Modeling Review Procedures Manual (ADEC 2013).

4.1.2 Non-Modeled Scenarios

In addition to normal operations, there are several other reasonably anticipated operational scenarios that were considered for the GTP dispersion modeling. 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 was 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

Existing facility gas would be required for the start-up of the GTP. The gas would either come from the PBU or the Point Thomson Unit (PTU). The untreated cold gas may need to be filtered for any liquids before being used during start up. A separate line off of the untreated gas feed to the new facility would be fed directly to the flares for immediate start-up and commissioning of the flare pilot system. The untreated gas would then be used to purge the fuel gas system and would need to be warmed before being used by any other equipment at GTP. Directly following the start-up of the fuel gas system, the flare header purge lines would be pressurized and begin a constant flow of untreated gas.

The Black Start Diesel Generator would be started to supply power to essential power users as well as the starting load required by one Main Power Generator Turbine. The Main Power Generation gas turbine drivers would be initially fueled by the untreated gas. The Treated Gas and CO2 Compressor Turbines in the first train would be started using power from the Main Power Generator and using untreated gas. The initial exhaust flow from the compressor turbines would be sent through a bypass stack. The WHRU cannot be utilized until the associated turbine has established stable exhaust flow. The Process Heat Medium system, which consists of large fuel gas burning process heaters, would be started next. This system would establish normal flow through the process heat medium users and through the compressor turbine's WHRUs, slowly increasing the heat medium temperature. A trim cooler has been provided within the process heat medium system to balance the heat input and output of the system. With the process heat medium system established, Train 1 process systems can start accepting feed gas, including the Acid Gas Removal Unit, the Treated Gas Dehydration Unit, and the CO2 Dehydration Unit. All initial off-spec gas production would be sent to the flare until the H2S and CO2 specifications for the pipeline are met.

While the process systems are coming online and before GTP-produced treated gas and CO2 can be fed to the compressors, the compressors would be run in full recycle within the train. Untreated gas would be run within the CO2 Compressor and an inert or third party-provided natural gas would be run within the Treated Gas Compressor. Once the produced, i.e. treated gas, and CO2 are available at the facility (the process equipment is no longer creating off-spec gas), it would be fed to the compressors and mixed with these recycled gases. The mixed gas from the compressors would be sent to the flares, since it would not meet treated gas pipeline or CO2 injection specifications. Flaring the gas from the compressors would be required as long as needed to remove all inert gas from within the compressors.

Note: the turbines are still running on the untreated gas, only the treated gases are being fed to the compressors.

In preparation for the treated gas being fed to the pipeline, propane gas from the nearby CGF facility would be used to fill the Treated Gas Chilling Refrigeration System. Initial emissions from purging and filling of this system would be sent to the flares. The purging and filling of the

Refrigeration System will result in a much smaller volume of gas considered during the maximum flaring case currently modeled in the compliance demonstration. Additionally, the duration of time required to purge the Refrigeration system will be much smaller than the assumed 500 hours for the max flaring rate currently being used.

Start-up of Train 1 would expect to be relieving 525 MMSCFD of off-spec gas through the HP HC Flare. The LP CO2 Flare would be relieving 65 MMSCFD of CO2 plus 30 MMSCFD of assist gas. All other flares would be combusting pilot and purge gas only. Start-up of Train 1 and the facility safety equipment would produce fewer emissions in one year than what has been considered in the potential-to-emit. The use of raw gas during this short time duration would result in higher SO2 and GHG emissions than during normal operations. However, the total amount of SO2 and GHG emitting is still likely to be less than the assumed potential-to-emit.

In this scenario only one train would be starting up. The two remaining trains would be offline. In reality only one train would be starting up at any one time. Under the normal operations scenario which has been modeled, all three trains, and therefore, all six CO2 compressor turbines, all six treated gas turbines, and all six power generator turbines are running at full capacity. The emissions were based on 100% load even though typically the turbines would run at 85% load. The flares were modeled for the normal operations scenario as if all eight were running continuously. In addition, the operational flares were also modeled at maximum emissions for 500 hours per year, which brings an added level of conservatism to the normal operations scenario. The two flares that would be relieving gases during start-up operations would not be emitting continuously. They would be emitting for less than 500 hours. The amount of emissions being sent to the flares would be less than the amount of emissions being sent to all turbines under normal operating conditions.

4.1.2.2 Early Plant Operations

Phase 1: GTP is running at 1/3rd capacity, producing 1.3 billion standard cubic feet per day (BSCF/D) of sales gas in one production train. This production train would be burning untreated feed gas during start-up operations because there is no other fuel available for start-up. The train would continue to burn the untreated feed gas until the compression turbine operations became stable and the treated gas system is able to produce treated gas in a uniform and stable way. The duration of operation on untreated feed gas is assumed to be up to 6 months. Once the treated gas system operations have stabilized the turbines would be switched over to burning the treated gas. The turbines will require adjustments to the combustion equipment and controls prior to using treated gas as fuel. Additionally, the treated gas would be used to fill and pressurize the pipeline which will require a considerable amount of gas. The two Treated Gas and two CO_2 Compression turbines would operate between 85% and 100% and two power generation gas turbines would operate between 60% and 100% capacity depending on demand. The gas compression turbines would each be fitted with a WHRU and associated SF system. One Building Heat Medium Heater would be in continuous operation at 100% load. Diesel emergency equipment would not be in operation, but would be tested periodically. Pilot and purge gas would be combusted at all flares. 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 based on treated gas being available and initially fed to all equipment for purging and startup as discussed in **Section 4.1.2.1**. The flaring that occurs during start-up operations of Train 2 would coincide with the normal purge/pilot fuel gas flaring associated with Train 1 in normal operations, but would not be continuous.

Once Train 2 is fully up and running, GTP would be running at 2/3rds capacity, producing 2.5 BSCFD of sales gas in two production trains. The four Treated Gas turbines, four CO_2 Compression turbines would operate between 85% and 100%, and four power generation gas turbines would operate between 60% and 100% capacity depending on demand. The gas compression turbines would each be fitted with WHRU and SF system. Two Building Heat Medium Heaters would be in continuous operation. Diesel emergency equipment would not be in operation, but would be tested periodically. Pilot and purge gas would be combusted at flares.

Phase 3: Train 3 start-up would commence after approximately the second year of facility operation and would be similar to the start-up of Train 1 based on treated gas being available and initially fed to all equipment for purging and startup as discussed in **Section 4.1.2.1**. The flaring that occurs during start-up operations of Train 3 would coincide with the normal purge/pilot fuel gas flaring associated with Trains 1 and 2 in normal operations, but would not be continuous.

Once Train 3 is fully up and running, GTP would be running at full capacity and considered to be operating normally, producing 3.7 BSCFD of sales gas in three production trains. All six Treated Gas turbines, six CO_2 Compression turbines would operate between 85% to 100%, and six power generation gas turbines would operate between 60% and 100% capacity depending on demand. The gas compression turbines would each be fitted with a WHRU and associated SF system. Two Building Heat Medium Heaters would be in continuous operation. Diesel emergency equipment would be operational and available if needed, though not anticipated to be used. Pilot and purge gas would be combusted at flares.

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 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. There would be no difference in stack parameters 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 because included the normal operations scenario is 500 hours per year of emergency flaring on top of the continuous pilot/purge flaring. 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 was conservatively included in the in the modeled impacts of the normal operations scenario.

4.1.2.3 Maintenance Operations

Compression Turbines

Both the Treated Gas and CO_2 Compressors are equipped with spare capacity higher than what the GTP typically operates at, and the trains are interconnected. Two sets (one for treated gas and the other for CO_2) of 6 x 20% compressors (i.e., 6 compressors each capable of handling 20% of the GTP requirements) would be provided within the three GTP trains. This allows for a total overall compression capacity at the facility of 120%, and allows for one full compressor to be offline with the GTP to still be operating at 100%. Normally, all compressors would be operating at a reduced load, roughly 85%, for the plant to operate at full compression capacity. In the event that one compressor needs to be shut down, the remaining compressors would be able to keep the overall GTP compression capacity at 100%. The compressors are installed as two per train; however the trains have the flexibility to share feed gas across all inlets. The compressor turbines are equipped with waste heat recovery units to supply the process systems with the required heat. When one turbine is offline, it may be required to artificially increase the load through recycling gas for the remaining train-specific compressors to achieve the required heat transfer to the process heat medium system.

For example, consider that all 12 turbines are running at 85% load in a normal operating scenario. If the Train 1 associated Treated Gas Compressor needs to be shut down for emergency or maintenance reasons; the five operating Treated Gas Compressors would increase in load up to 100% to maintain the same facility capacity. Then, additionally, the Train 1 associated CO_2 Compressors may also be artificially loaded up to 100% to add more heat to the Train 1 system. Artificially increasing the CO_2 Compressor load may result in more CO_2 being transferred to the Train 1 compressors, but more than likely, the remaining CO_2 Compressors would stay at their normally operating load and only the Train 1 CO_2 Compressors would increase through manual CO_2 recycling to the inlet of the compressors. In this event, five Treated Gas Compressors are operating at 100% load, one Treated Gas Compressor is not operating at all, four CO_2 Compressors are operating at 85% load, and the two CO_2 Compressors in Train 1 are operating at 100% load for the duration of this emergency or maintenance operation, which are usually short-term operations lasting a few hours to a few days for emergencies and 2 to 8 weeks for maintenance. The GTP potential-to-emit emissions that are modeled in the normal operations scenario include all 12 compressors operating at 100% load for the entire year. Any changes to the load or operation within the normal operating range of the compressor turbines (85% to 100%) would result in fewer emissions from what is assumed as the potential-to-emit, and modeled in the normal operations scenario. Therefore, the normal operations scenario is the most conservative scenario, and these maintenance operations do not need to be modeled since they would result in lower impacts.

Building Heat Medium Heaters

The Building Heat Medium Heaters configuration is 3 x 50%. This means that each of the 3 heaters, are capable of handling 50% of the total building heat requirement for the entire process area. The third heater is assumed to be completely offline when not in use. During normal operations, only two would be running. When maintenance or shutdown of one of the operating heaters is required, the spare heater would need to come online before the original heater is shut down. However, a trim cooler has not been provided within the Building Heat Medium System. This relies on the heaters being controlled to not supply more heat than what is required by the buildings. In the event that the spare heater needs to come online, the heater being shut down would most likely begin to offload at the same time to produce the same total outlet heat. This overlap would result in varying emissions from all three heaters most likely not exceeding a total load equivalent of two heaters operating. Since the GTP potential-to-emit has been calculated based on two heaters operating at 100% for the entire year, there is no need to model such a maintenance situation.

General Maintenance

The power generation turbines and compressor turbines would need maintenance roughly every 3 years. The duration of the maintenance event can 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 inspection.

While the turbines are being shut down, there would be an increase in emissions when the turbines are below the load where the control technology functions as it is shutting down, roughly at 50% turbine load. However, the amount of time spent outside of the control technology functional range would be less than a few hours. Also, at the same time, the exit temperature and exit velocity would be decreasing, which would lead to more conservative dispersion conditions than those modeled during normal operations. While these dispersion conditions can produce more downwash, which could lead to higher impacts in the short-term, the mass of pollutants emitted from the turbines would be decreasing. In all likelihood the normal operations scenario with all the turbines operating at 100% load emissions, exit velocity, and exit temperature would still be considered the worst-case scenario.

Once the equipment is ready to be placed back in service, 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 would be sent to the flare while the equipment is brought back online. The start-up of the equipment would take less time and would be less involved, not requiring as much recycling and flaring as for the initial start-up process described in **Section 4.1.2.1**. Thus, start-up after maintenance work would have lower emissions than the initial start-up process. While emissions from bringing a train back online after routine maintenance may result in higher short-term emissions from equipment purging and gas reintroduction, the downtime while the equipment is offline would allow for the overall emissions to be smaller than the assumed facility potential-to-emit.

Maintenance of equipment systems and trains would be staggered to keep the facility operating at a high capacity. Additionally, maintenance of equipment at the GTP may be synchronized with maintenance at the Liquefaction Facility to keep the treated gas and Liquefied Natural Gas (LNG) production coordinated.

4.1.2.4 Seasonal Effects on Emissions

Power Generation Turbines

Winter operation of the GTP 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 generation turbines being taken offline. A turbine would be taken offline if the load required by the facility drops to a level that would require all six of the 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 emissions control technology on the turbines is rated to maintain NO_x and CO_2 emissions down to approximately 40% load. 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 six 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.

Supplemental Firing

Supplemental Firing has been included in the potential-to-emit calculations at 100% load. The Supplemental Firing emissions assume the heat required by the process system would require all of the heat from the turbine exhaust gas, plus additional heat from supplemental firing. The heat required for the supplemental firing flow is based off of the worst case heat duty required by the process systems at GTP. If any fluctuations in operation or ambient temperature occur that would cause the process systems at GTP to need less heat input, the supplemental firing fuel rate and emissions would be decreased until there is a heat balance within the facility.

This scenario was not modeled because the normal operations scenario is conservatively modeled by assuming maximum supplemental firing.

Building Heat Medium Heaters

There are currently three Building Heat Medium Heaters located within the GTP process area to heat the inside of the buildings. The buildings would be heated to a constant temperature year-round. During the winter, the heat required from heaters is at a maximum. During the summer, machinery within the equipment modules may supply enough heat to buildings to reduce the heat needed from the Building Heat Medium Heaters. However, the Building Heat Medium Heaters most likely would never be turned off completely as the ambient temperature at night could drop enough to require heat within the buildings. Warmer summer ambient temperatures would reduce the load at the Building Heat Medium Heaters which would result in reduced emissions from the heaters. The potential-to-emit has been calculated based on two heaters running at 100% all year long, which leads to more conservative impacts.

Seasonal effects on emissions from the GTP Building Heat Medium Heaters were accounted for in the modeling of the normal operations. The modeled emissions and stack parameters were based on the worst-case (100%) operation.

4.1.3 Construction Emissions

Construction of the GTP would occur over an estimated eight-year span, beginning in the first year following Project authorization. Construction activities would begin with site clearing and stabilization, roadway and surface preparation and construction, and include heavy equipment associated with scrapers, dozers, trenching, and stockpiling any soil. 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.

Depending on the type of activity, construction of the GTP main pad and camp pad 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 would 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 National Ambient Air Quality Standards 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, the Project did not model construction activities, but rather is proposing mitigations and best management practices (BMPs) for controlling construction emissions. Some BMPs that are being developed and submitted for FERC review include:

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

While construction activities will not be included in the dispersion modeling analyses, emissions from the construction operations and construction camp activities will be 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 project sources associated with the GTP, the dispersion analysis also addressed the cumulative ambient air quality impacts from the Project and nearby offsite sources. The following lists the offsite sources included in the analysis:

- BPXA's Central Compression Plant (CCP), and
- BPXA's Central Gas Facility (CGF).

Figure 1-1 shows the locations of these facilities in relation to the GTP. Emissions from the CCP and CGF sources generally consist of gas-fired compressor turbines, gas-fired heaters, and emergency equipment. For conservatism in this modeling demonstration, these offsite sources were modeled at their potential-to-emit.

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

Modeled emissions and stack parameters for the CCP and CGF emission units were developed from the respective facility's most recent Title V operating permits and a review of historical dispersion modeling information submitted to ADEC supporting various permit applications. **Table 4-5** lists the data sources used to develop modeling inputs for the offsite sources. Additional details regarding the development of modeled emissions and parameters for these sources can be found in Appendix A. However, given the proximity of these facilities to the GTP, certain assumptions were revisited based on more recent available data to appropriately characterize impacts and reduce over-predicting impacts from these offsite sources. The following model inputs were revisited:

- Turbine in-stack NO_2/NO_x ratios were developed based on recent available data in USEPA and ADEC databases (final values listed in Appendix A) since they has not been previously developed for this source.
- Effective Building Dimensions (EBDs) were revisited due to complex building arrangements at CGF and CCP which create high aspect ratios of width and/or length to height for the buildings, and due to stacks which are short relative to the adjacent buildings. The USEPA default method of developing EBDs with BPIPPRM is known to over predict impacts for high aspect ratio buildings and this was occurring for the CCP and CGF. Therefore a standard, approach using a wind tunnel evaluation of the CGF and CCP was conducted to refine some EBDs. Scale models of both facilities were evaluated in the wind tunnel and EBDs were developed for the stacks and wind directions that were found through AERMOD modeling to be most likely to produce the greatest over-prediction of ground-level pollutant concentrations. This evaluation was conducted in coordination with CPP Wind.

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 plots their proximity to Sensitive Class II areas as well as the GTP. **Table 4-5** 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 Sensitive Class II areas would be 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 developed following review of Resource Report No. 1 and in consultation with ADEC for the modeling domain containing the Project's GTP. **Figure 4-1** lists the Reasonably Foreseeable Development (RFD) sources included in the modeling and displays their proximity to Sensitive Class II areas as well as the proposed GTP. **Table 4-5** 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 GTP nor are impacts from these sources likely to be collocated in space and time with those from the GTP. 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 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

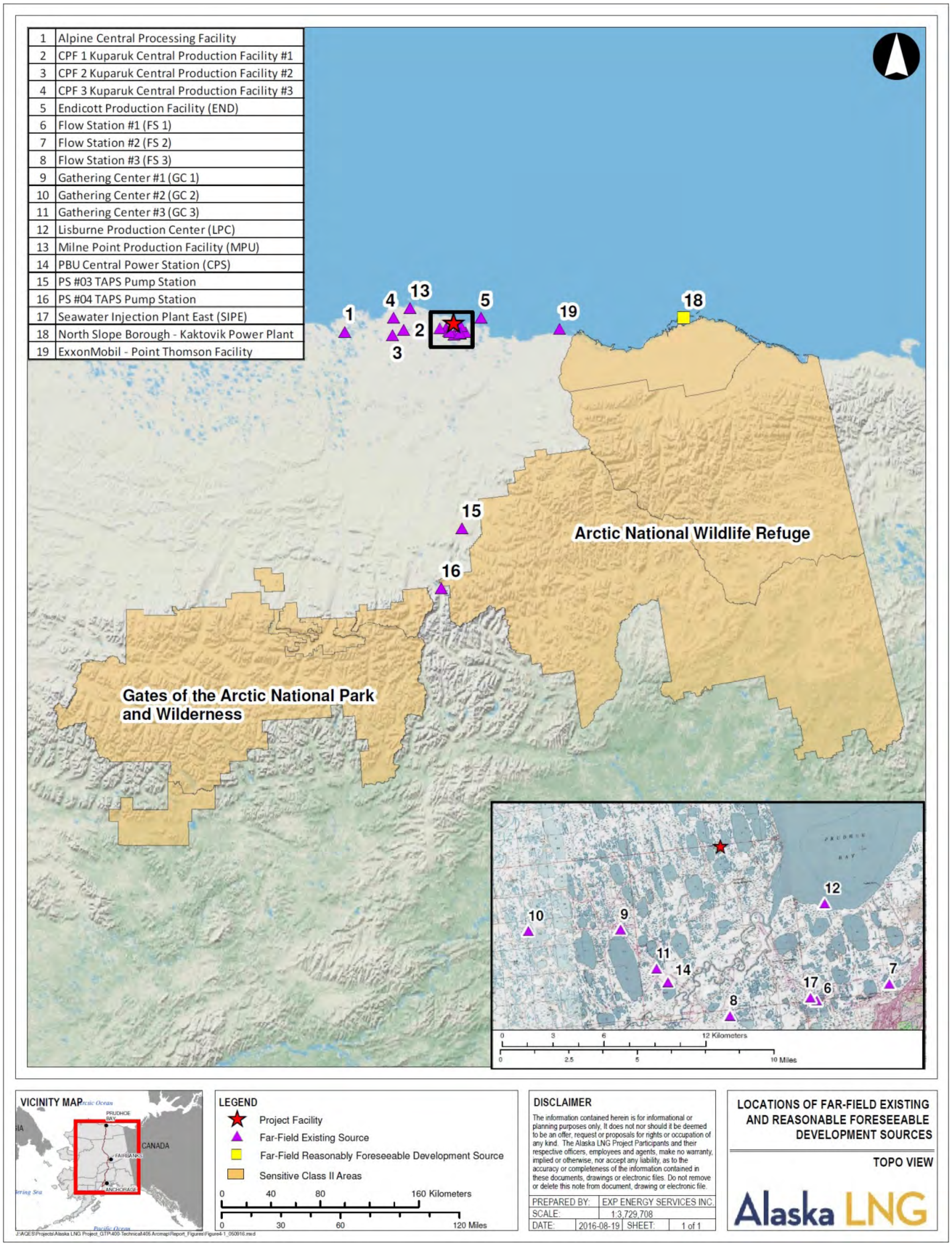


Table 4-5: Sources of Modeling Inputs for Offsite Facilities

Facility	Source of Data Used in Dispersion Modeling			PSD Increment Consumption
	Stack Locations	Emissions	Stack Parameters	
BPXA Central Compression Plant (CCP)	Review of historical dispersion modeling information submitted to ADEC supporting Title V operating permit applications (ENSR 1989, ENSR 2008)	Title V ADEC Air Quality Control Operating Permit No. AQ0166TVP01	Review of historical dispersion modeling information submitted to ADEC supporting Title V operating permit applications (ENSR 1989, ENSR 2008)	NO_2: Partial SO_2: Partial PM_{10}: Partial $PM_{2.5}$: No
BPXA Central Gas Facility (CGF)	Review of historical dispersion modeling information submitted to ADEC supporting Title V operating permit applications (ENSR 1991, ENSR 2008)	Title V ADEC Air Quality Control Operating Permit No. AQ0270TVP01	Review of historical dispersion modeling information submitted to ADEC supporting Title V operating permit applications (ENSR 1991, ENSR 2008)	NO_2: Partial SO_2: Yes PM_{10}: Yes $PM_{2.5}$: No
Far-Field Existing Facilities	2011 National Emissions Inventory (NEI 2011).	2011 National Emissions Inventory (NEI 2011).	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 GTP and background source emissions with the purpose to assess ambient concentrations to a distance of approximately 10 kilometers.

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 impacts from the proposed Project. 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 will be used include:

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

5.2 MODEL OPTIONS

AERMOD model input options for Project 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 horizontal stacks located at CGF and CCP. These adjustments were invoked in AERMOD through the use of the POINTHOR keyword.

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 2016). 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. 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 is also required to generate daytime convective parameters and a complete meteorological dataset.

Required surface meteorological data and upper air data were processed into a model ready input file using AERMET following the procedures and using the individual datasets described below.

5.3.1 Surface Data

The Project area is located approximately six miles northeast of the A-Pad meteorological and air quality monitoring station as shown in **Figure 3-1**. Because there are no significant terrain features between the A-Pad station and GTP, and due to their close proximity and similar surface characteristics, A-Pad is representative of the conditions at GTP. The A-Pad hourly meteorological data were collected and validated as part of an approved Prevention of Significant Deterioration (PSD) monitoring program following ADEC and USEPA quality assurance guidelines. Five years of recent available A-Pad data were used in this modeling (2009-2013) following Alaska and federal permitting guidance. This exceeds the USEPA requirement of at least one year of on-site data discussed in the Modeling Guideline. The processing of this data is provided below. Note that the processed 2009 through 2011 dataset has been approved for use by ADEC for projects located in the Prudhoe Bay area and has been posted on their website for public use. It can be readily accessed at: https://dec.alaska.gov/air/ap/AERMOD_Met_Data.htm. The 2012-2013 dataset has been processed in an identical manner to the 2009-2011 dataset.

Wind speed, wind direction, sigma-theta, sigma-w, dry bulb temperature, delta temperature, and solar insolation were used from the A-Pad measurements. All parameters with the exception of temperature were recorded at a single 10-meter level. Temperature data recorded both at 2 meter and 10-meter levels were used. These five years all meet the 90 percent per calendar quarter data capture and quality assurance PSD requirements for the aforementioned parameters required for AERMOD (USEPA 2000).

A wind rose for the five years of A-Pad meteorological data after processing is shown in **Figure 5-1**. **Table 5-1** lists the joint data capture for each of the five years after the substitutions discussed below.

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

Modeled Period	Year, % Missing				
	2009	2010	2011	2012	2013
Quarter 1	0.74	4.68	6.11	4.17	7.55
Quarter 2	2.79	5.86	4.17	0.73	8.42
Quarter 3	3.99	1.72	3.58	0.18	0.05
Quarter 4	9.24	3.99	0.68	1.18	4.80
Annual	4.21	4.05	3.62	1.56	5.18

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 project area is in Barrow, Alaska, which is located approximately 320 kilometers northwest of the project area. Concurrent upper air data was obtained from the National Oceanic and Atmospheric Administration Earth System Research Laboratory Radiosonde Database[1] and provided as input to AERMET.

[1] http://w w w.esrl.noaa.gov/raobs/

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 to be used as input to AERMET is provided in **Table 5-2**.

Table 5-2: ADEC Approved Surface Characteristics for the North Slope Coastal Plain

Surface Parameter	Winter Value [a]	Summer Value [a]
Albedo	0.8	0.18
Bowen Ratio	1.5	0.80
Surface Roughness Length (meters)	0.004	0.02

Notes:
[a] Winter is defined as occurring from October through May and summer is defined as occurring from June through September. Values and definition of the seasons were provided by ADEC (ADEC 2007a).

These values were applied seasonally over all sectors surrounding the monitoring site. As recommended by ADEC, these values are to be applied on a seasonal basis with summer defined as June through September; and winter defined as October through May.

These values are representative of locations classified as Coastal Wet Tundra. These land use types are specific to the North Slope coastal plain at low elevations near the coast, which are classified as wet sedge tundra and forb tundra dominated by thaw lakes, ice-wedge polygons, frost boils, water tracks, and bogs. Data used to support the values selected were either measured at the Betty Pingo location, or chosen based on a comparison to values measured there. As shown in **Figure 5-2**, the Betty Pingo location is approximately 8 kilometers east of A-Pad, and both lie within a band of homogenous land cover that extends as much as 30 kilometers inland from the coast. Within this band, there is some variation in the size and density of water features; however, the variation is likely too small to affect the surface characteristics from one site to the next within the band.

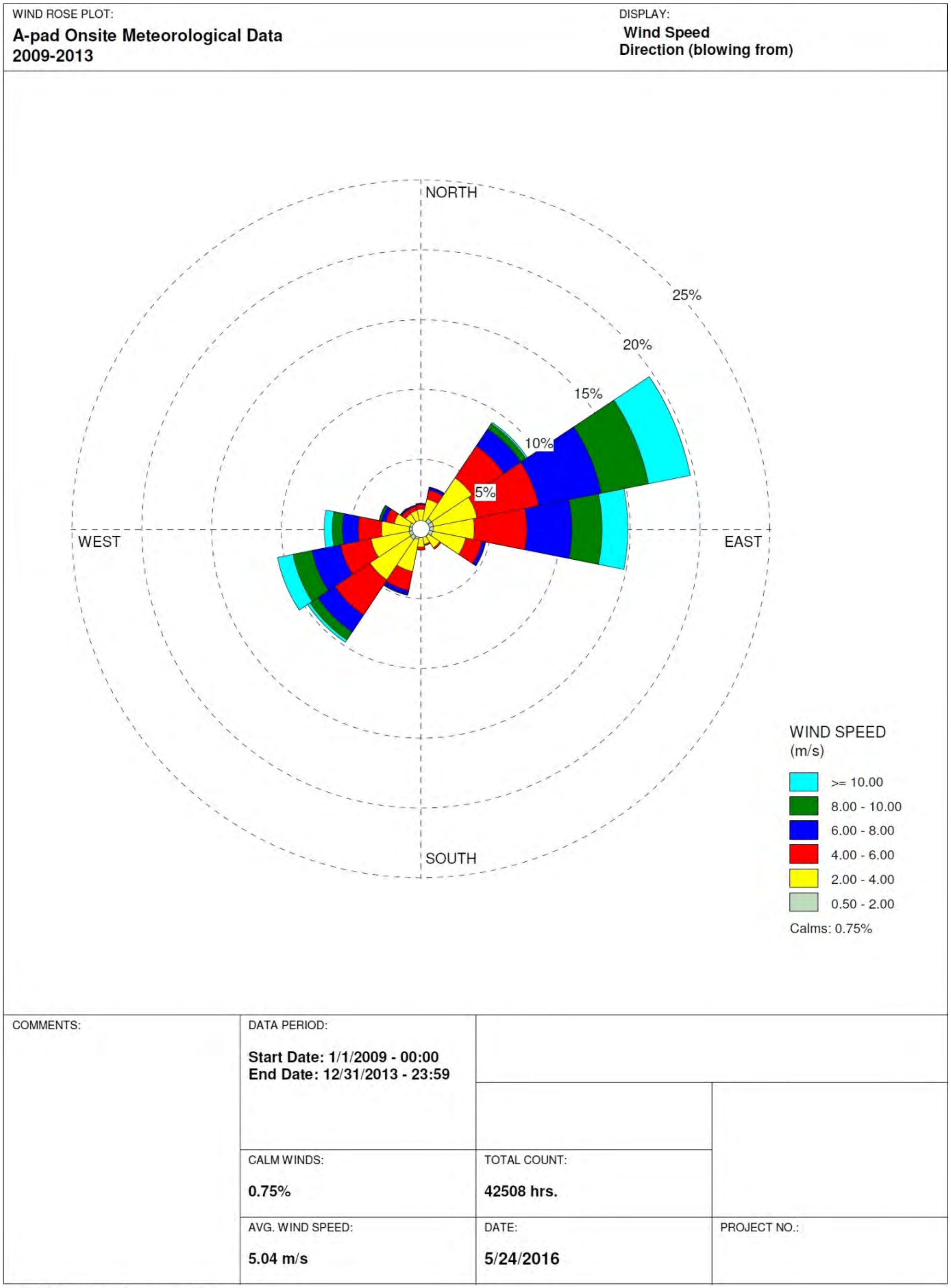
The representativeness of the values provided by ADEC have been re-evaluated in light of 2009 USEPA guidance (USEPA 2009), which revised the size of the domain over which the land use surrounding a monitoring site is evaluated. However, since the land cover within 15 kilometers of the monitoring site is homogenous and classified as Coastal Wet Tundra, the revised guidance does not affect the values recommended, or the way they are used in meteorological data processing.

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

Additional data processing was performed on 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 (Brode 2005) any reported values of site-specific sigma-w below 0.1 m/s were set to missing as discussed below.

The reason for eliminating zero or near-zero values of sigma-w input to AERMOD is to avoid an anomalous problem in the model that can be caused by inappropriate input data. According to information provided by USEPA's AERMOD modeling contractor, in the absence of observed sigma-w data, the sigma-w profile is calculated in AERMOD based on the boundary-layer parameters, convective velocity scale (w*), and friction velocity (u*). A problem can occur if there is an inconsistent observed sigma w value that causes an inconsistency between the observed sigma-w values and the calculated w* values. Such an inconsistency between w* and observed sigma-w can result in extremely large and unrealistic values of the skewness in convective conditions, which is proportional to $(w^*/\text{sigma-w})^3$. This can lead to anomalous plume height and sigma-z values for the updraft and downdraft portions of the direct plume in AERMOD. According to Brode, there is no simple solution to the problem without incorporating a feedback loop between the measured sigma-w and the calculation of w*, which is not part of the current AERMOD model. He suggests that users should avoid inputs of anomalously low (especially below instrument threshold) input values of sigma-w to AERMOD. Given that the USEPA recommended vertical wind speed measurement resolution is 0.1 m/s as listed in **Table 5-1** of USEPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications (USEPA 2000), setting input values of measured sigma-w less than 0.1 m/s to missing is consistent with that advice.

Figure 5-1: Wind Rose of the A-Pad Meteorological Input Data



WRPLOT View - Lakes Environmental Software

Figure 5-2: Land Cover Surrounding the A-Pad and Betty Pingo Monitoring Locations

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 air quality dispersion 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.

The GTP gravel pad edge is a readily identifiable boundary between the sources and the surrounding area and represents a restriction to public access. Furthermore, the GTP would control the gravel pad area and would limit public access. Therefore, that barrier was defined using the gravel pad edge as identified on the facility site plan (Alaska LNG 2016) and was used as the ambient air quality boundary around the facility.

When conducting cumulative modeling, impacts from an offsite source are not included on totals at receptors within that source's ambient boundary. Therefore, modeling for the GTP alone included receptors within offsite sources; however cumulative modeling of the GTP sources plus offsite sources did not include receptors within offsite source ambient boundaries.

Cartesian receptor grids centered on the GTP were defined using Universal Transverse Mercator (UTM) coordinates. The grids were designed to accurately resolve the highest predicted pollutant impacts while at the same time minimizing model execution time. Several receptor grids of varying resolution were defined for the required model analyses. Experience from previous GTP screening dispersion modeling studies indicates that the highest predicted concentrations would occur well within 10 kilometers of the facility. Therefore, the grids consist of receptors placed as follows:

- 25-meter spacing along the edge of the gravel pad of each stationary source,
- 25-meter spacing from the pad edge to at least 100 meters from the pad edge at each stationary source,
- 50-meter spacing from 100 meters to 300 meters from the pad edge at each stationary source,
- 100-meter spacing from 300 meters to 1 kilometer in each cardinal direction from each stationary source,
- 250-meter spacing from 1 kilometer to 5 kilometers in each cardinal direction from each stationary source, and
- 500-meter spacing extending from 5 to 10 kilometers in each direction from the ambient air boundary (or to the significant impact radius, whichever is less).

As discussed above, the area surrounding the project area is considered featureless. Therefore, all receptor elevations and hill heights were set to zero meters and the AERMAP terrain processor were not required for this analysis. **Figure 5-3** depicts the receptor grid in the near field. **Figure 5-4** shows the receptor grid out to the 10 kilometer modeling limit. Note that while there are no receptors located in the identified offsite source boundaries, receptors were included within these facility boundaries when determining GTP-only impacts.

5.5 ELEVATION DATA

The tundra surrounding the project impact area is relatively flat with few topographic features exceeding more than a few feet in elevation. Therefore, the ground level elevation throughout the entire modeling domain was set to 0 meters. This procedure is a standard modeling protocol for sources located within the Alaska North Slope coastal plain.

The base elevations for all source structures were set to the average elevation of the ambient boundary (gravel pad edge) (assumed to be 0 meters; see **Section 5.4**), plus 6 feet to account for the thickness of the gravel pad. Stack base elevations were set equal to the structure base elevations which accounted for the fact that most facility buildings sit approximately 13 feet off of the ground on pilings (i.e., this 13 feet was included as part of the solid structure). This distance is included in the overall building heights used in the BPIP analysis discussed in **Section 5.6**.

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 regulations 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 (Version 04274). Building dimensions were obtained from Project engineers.

In addition to calculating direction-specific building dimensions, the Building Profile Input Program program also calculates the Good Engineering Practice (GEP) stack height. All stack heights were checked to verify that they are within the GEP stack height limit. A GEP stack height is defined as the greater of 65 meters (213 feet), measured from the ground elevation of the stack, or the formula height (H_{GEP}), as determined from the above equation.

The proposed facility layout is shown in **Figure 5-5** and **Figure 5-6** for the main pad and camp pad, respectively. The figure details how the actual buildings and structures were simulated in the building downwash analysis and also depicts the proposed ambient boundary.

Figure 5-3: Near-Field Receptor Grid and Ambient Air Quality Boundary

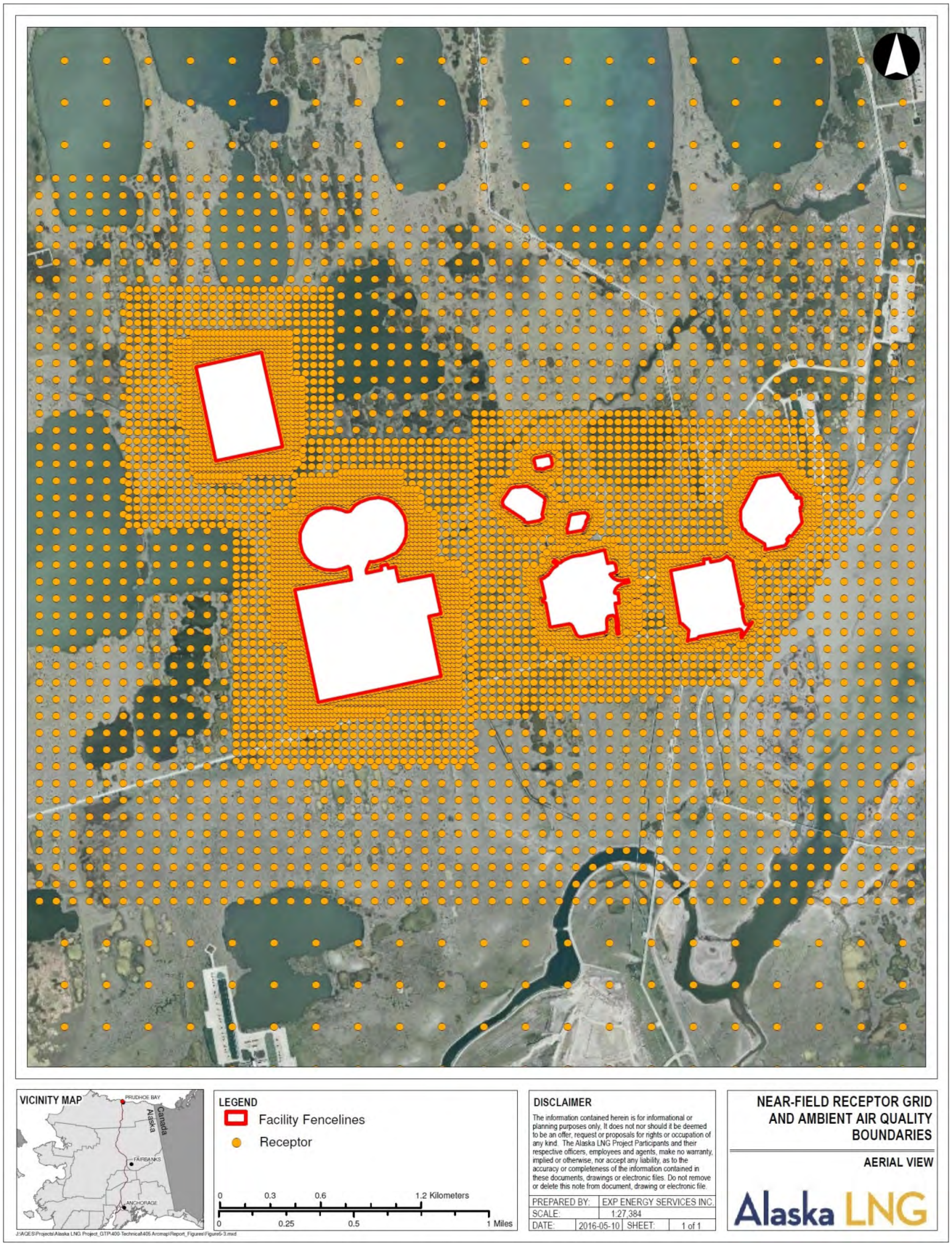
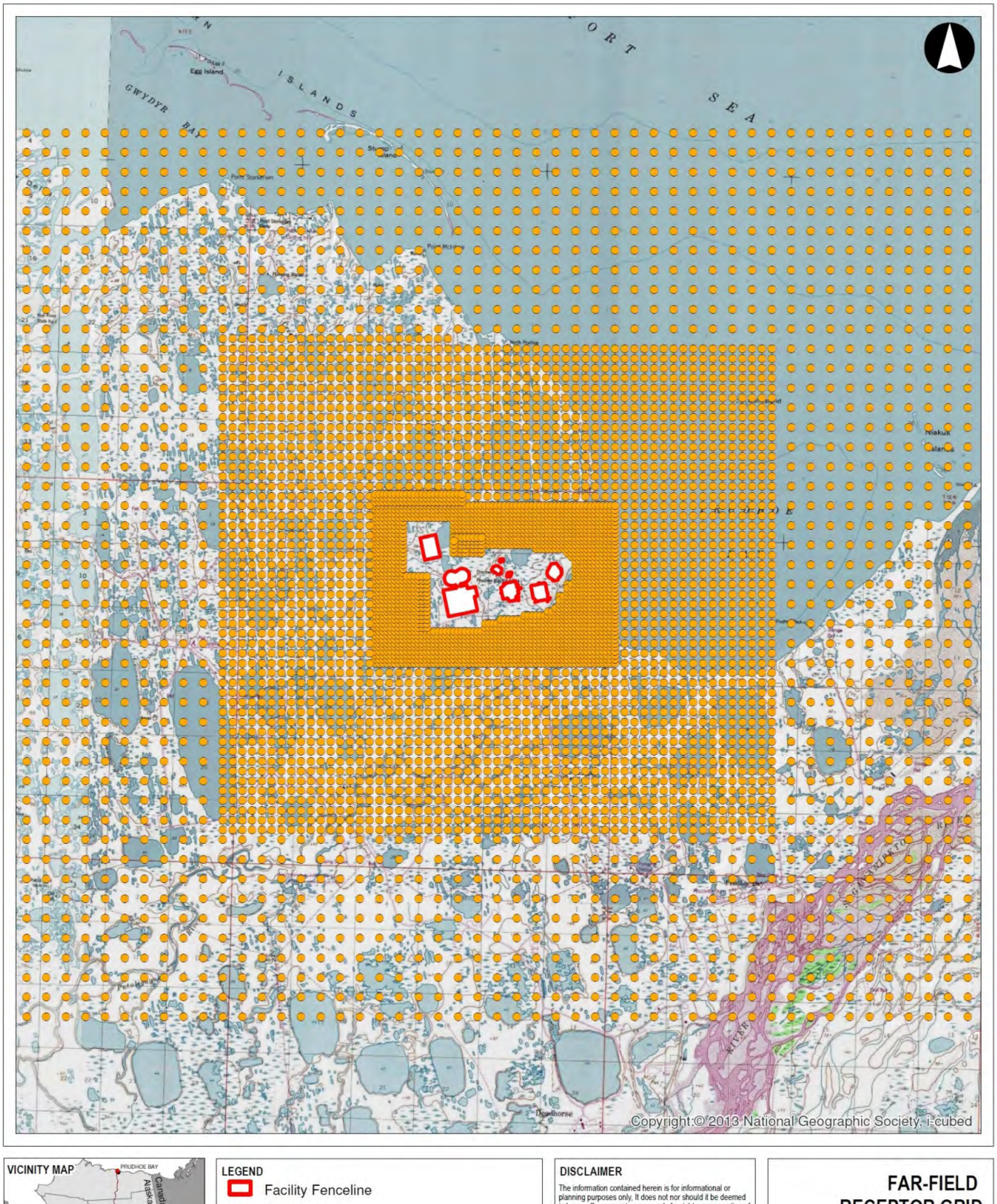


Figure 5-4: Far-Field Receptor Grid



LEGEND

Facility Fenceline

Receptor

0 1.5 3 6 Kilometers

0 1 2 4 Miles

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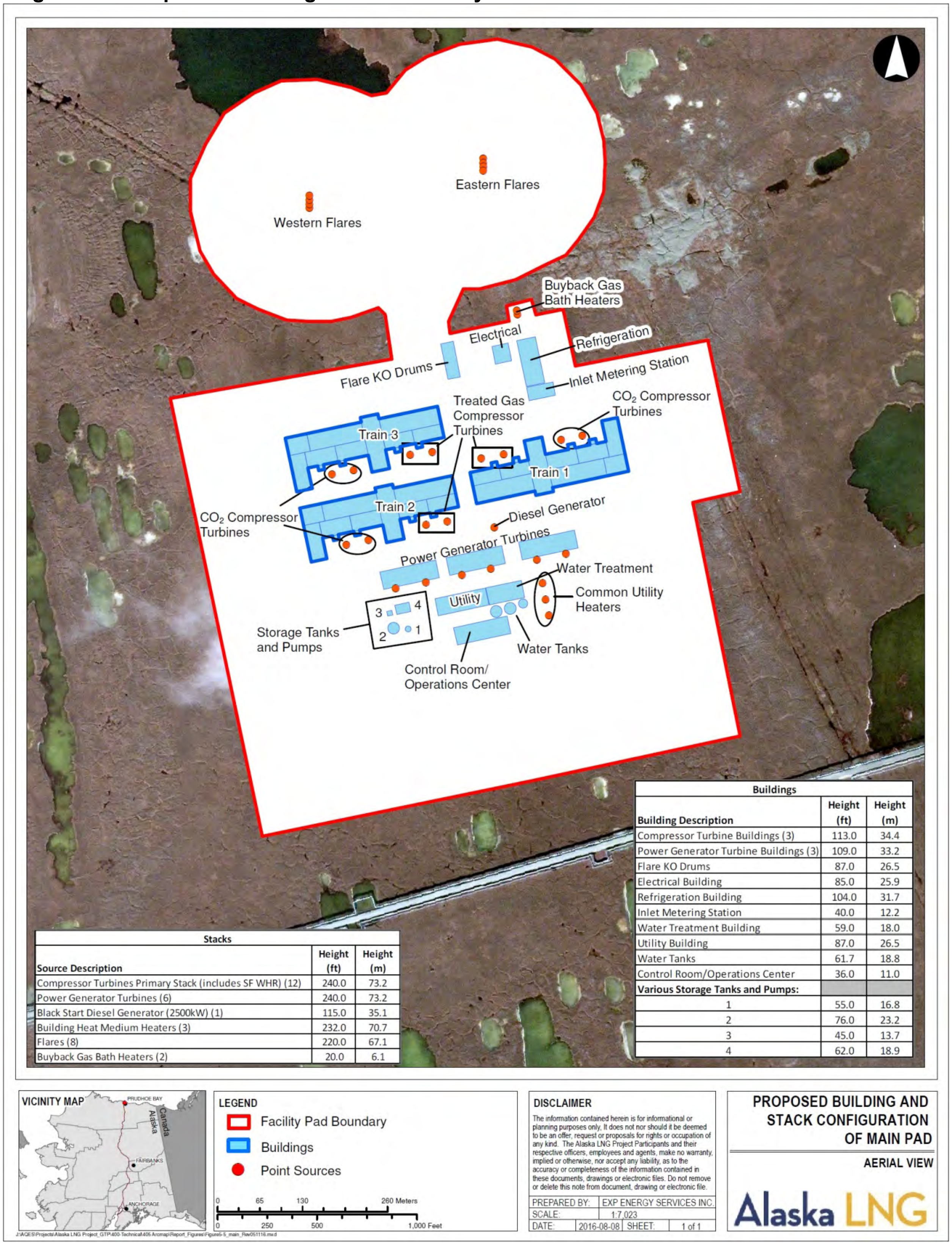
FAR-FIELD RECEPTOR GRID

TOPO VIEW

Alaska LNG

Figure 5-5: Proposed Building and Source Layout as Modeled in BPIP for the GTP Main Pad



Stacks

Source Description	Height (ft)	Height (m)
Compressor Turbines Primary Stack (includes SF WHR) (12)	240.0	73.2
Power Generator Turbines (6)	240.0	73.2
Black Start Diesel Generator (2500kW) (1)	115.0	35.1
Building Heat Medium Heaters (3)	232.0	70.7
Flares (8)	220.0	67.1
Buyback Gas Bath Heaters (2)	20.0	6.1

Buildings

Building Description	Height (ft)	Height (m)
Compressor Turbine Buildings (3)	113.0	34.4
Power Generator Turbine Buildings (3)	109.0	33.2
Flare KO Drums	87.0	26.5
Electrical Building	85.0	25.9
Refrigeration Building	104.0	31.7
Inlet Metering Station	40.0	12.2
Water Treatment Building	59.0	18.0
Utility Building	87.0	26.5
Water Tanks	61.7	18.8
Control Room/Operations Center	36.0	11.0
Various Storage Tanks and Pumps:		
1	55.0	16.8
2	76.0	23.2
3	45.0	13.7
4	62.0	18.9

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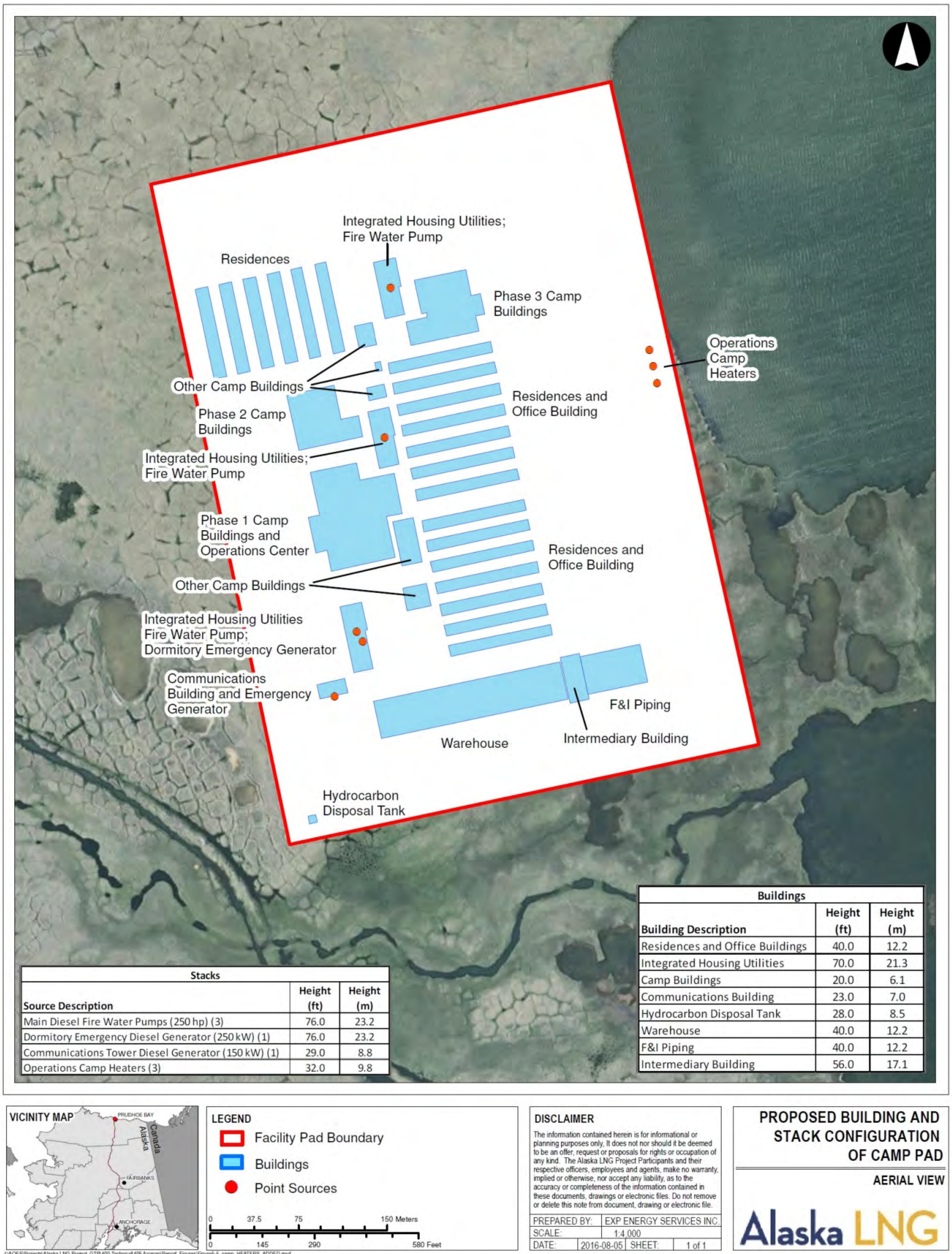
Figure 5-6: Proposed Building and Source Layout as Modeled in BPIP for the GTP Camp Pad



Stacks		
Source Description	Height (ft)	Height (m)
Main Diesel Fire Water Pumps (250 hp) (3)	76.0	23.2
Dormitory Emergency Diesel Generator (250 kW) (1)	76.0	23.2
Communications Tower Diesel Generator (150 kW) (1)	29.0	8.8
Operations Camp Heaters (3)	32.0	9.8

Buildings		
Building Description	Height (ft)	Height (m)
Residences and Office Buildings	40.0	12.2
Integrated Housing Utilities	70.0	21.3
Camp Buildings	20.0	6.1
Communications Building	23.0	7.0
Hydrocarbon Disposal Tank	28.0	8.5
Warehouse	40.0	12.2
F&I Piping	40.0	12.2
Intermediary Building	56.0	17.1

LEGEND

- Facility Pad Boundary
- Buildings
- Point Sources

0 37.5 75 150 Meters
0 145 290 580 Feet

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DATE:	2016-08-05	SHEET:	1 of 1

PROPOSED BUILDING AND STACK CONFIGURATION OF CAMP PAD

AERIAL VIEW

Alaska LNG

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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 both the Tier 1 and Tier 2 approaches are too conservative for this analysis. Therefore, a Tier 3 (PVMRM2) approach was implemented in accordance with the following USEPA guidance memos:

- Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (June 28, 2010);
- Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1 hour NO_2 National Ambient Air Quality Standard (March 1, 2011);
- Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard (September 30, 2014); and
- Proposed Revisions to the Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (July 14, 2015).

The PVMRM2 approach is a non-default, beta model option that is recommended in the proposed revisions to the Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard signed on July 14, 2015.

The PVMRM2 option simulates the NO_x to NO_2 conversion by calculating a ratio of the amount of O_3 available to the amount of NO_x emitted into a plume at the downwind distance of a receptor from a source. This ratio is then multiplied by the AERMOD-predicted NO_x concentrations to determine the NO_2 concentrations in the plume. This method also utilizes dispersion coefficients to differentiate between stable and unstable conditions and simulates how plumes from multiple sources may merge or combine downwind of the sources.

Use of PVMRM2 requires that the in-stack NO_2/NO_x ratio be specified for each NO_x-emitting emission unit. USEPA (2011) provides for a default in-stack ratio of 0.5 in the absence of more appropriate source-specific information. Details regarding the NO_2/NO_x ratio used for each modeled emission unit can be found in **Section 4.1.1.1**. PVMRM2 was applied prior to comparing all modeled NO_2 impacts to applicable standards and thresholds.

To implement the PVMRM2 option, concurrent hourly ozone data is also required. The ozone data file was created by combining five years of ambient measurements (2009 through 2013) from the BPXA A-Pad monitoring station into two conservatively representative composite years of ozone data, a leap year and a non-leap year. The composite years were created by selecting the maximum ozone concentration for a given day and hour across five years of site-specific data collected at A-Pad between January 1, 2009 and December 31, 2013. Hourly concentrations that are either missing or invalid were filled in with the seasonal maximum for the given hour. The seasons were defined as follows:

- Winter – January 1 through May 31 as well as October 1 through December 31 of a given year; and,
- Summer – June 1 through September 30 of a given year.

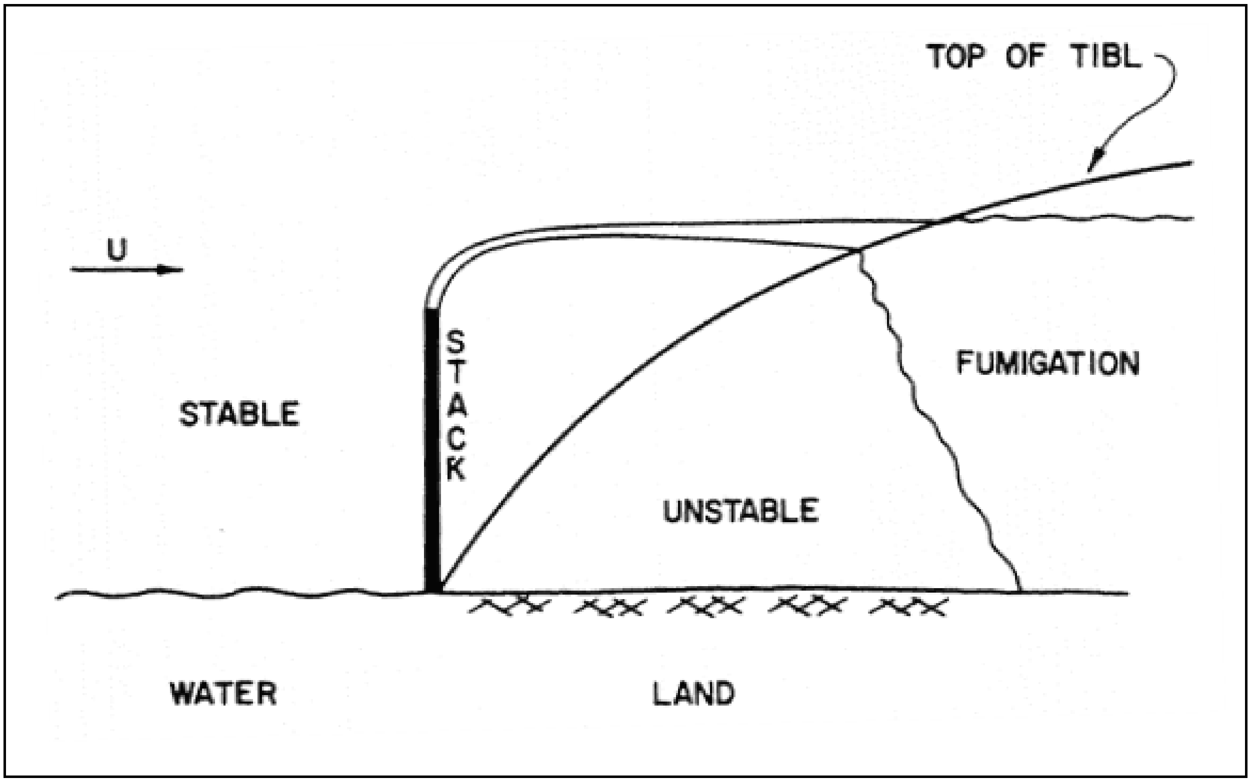
5.8 SHORELINE FUMIGATION

Shoreline fumigation can occur when a plume is emitted from a tall emissions source, 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 in **Figure 5-7** 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.

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. The GTP facility is located in relative close proximity to the shoreline at a distance of approximately 2,150 meters. However, it is expected that the TIBL height at this distance would be well above the plume height for any of the GTP emission sources. In that case, there would be no interaction between the plume and the TIBL and thus no fumigation would occur.

AERMOD does not have the ability to evaluate fumigation impacts. Therefore, understand if fumigation would occur, an analysis using TIBL height equations from the SCREEN3, OCD, and SDM (i.e., dispersion models that include fumigation algorithms) models was conducted and compared to the expected final plume height for the various GTP emission sources. The GTP is approximately 2,150 meters from the shoreline. The tallest stacks are the treated gas compressor turbine stacks, the CO_2 compressor turbine stacks, and the power generator turbine stacks, which are all 73.15 meters tall, as well as the building heat medium heaters which are all at 70.71 meters tall. Calculations of the TIBL height gave a TIBL height over 200 meters at a distance of 2,150 meters inland. This height leads to a reasonable assumption that fumigation would not occur for the GTP emission sources. This was confirmed by a screening fumigation analysis conducted with AERSCREEN (version15181). The analysis indicated that for 73.15 meter tall stacks located at a distance of 2,150 meters from the shoreline, the TIBL height would be well over 200 meters and the final plume height would be below 200 meters. For the remaining sources with shorter stacks, *i.e.*, emergency diesel equipment, flares, operations camp heaters, and buyback gas bath heaters, their plumes will be well below the TIBL as well. As a result, it is conclusive to say that fumigation will not occur at GTP and a detailed fumigation analysis is not needed.

Figure 5-7: Depiction of Typical Shoreline Fumigation (Stunder et al. 1986)



6.0 SENSITIVE CLASS II AREA MODELING METHODOLOGY

This section describes the methodology of modeling GTP and background source emissions with the purpose to assess ground-level ambient concentrations, visibility, and acidic deposition in Sensitive Class II areas (Arctic National Wildlife Refuge and Gates of the Arctic National Park and Preserve/Wilderness).

6.1 MODEL SELECTION

The analyses was performed using the USEPA-approved version of the CALPUFF modeling system (Version 5.8) that was modified by the U.S. Fish and Wildlife Services (USFWS) to account for Polar Stereographic coordinate system (BLM 2012). This modeling system includes the following processors:

- CALPUFF – Version 5.8.4 – Level 130731
- CALMET – Version 5.8 – Level 070623
- 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 which was modified by USFWS to account for Polar Stereographic coordinate system (BLM 2012), 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 were not incorporated into this analysis which would delay submittal.

6.2 MODEL INPUTS

Point source parameters and emissions rates that were used to model GTP sources are provided in **Table 4-3** and **Table 4-4**. In addition to the above sources, the far-field modeling analysis also included existing sources and reasonably foreseeable development sources. **Table 4-5** 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 were referenced to Polar Stereographic coordinate system, centered at 71.3ºN, 155ºW. Building downwash parameters were used for the Project 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 coastal location of the Class II areas and high natural concentration of sea salt, values for the coastally located Tuxedni Wilderness Area natural conditions from FLAG 2010 were used for visibility modeling of the two Sensitive Class II areas. For comparison, FLAG 2010 reports a sea salt concentration of 0.38 $\mu g/m^3$ at Tuxedni and the limited monitoring data (2/2012-12/2012) from Deadhorse indicates a similar concentration of 0.4 $\mu g/m^3$.

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 taken from FLAG 2010 Table 7 and for small particles from FLAG 2010 Table 8. The sea salt relative humidity adjustment factors were taken from FLAG 2010 Table 9.

6.4 MODELING DOMAIN

The modeling domain was limited by the gridded meteorological input data obtained for use on this project (reference **Section 6.6**). The modeling domain is 620 460 kilometers, which is large enough to encompass the GTP, cumulative sources, and receptors at Sensitive Class II areas within 300 kilometers of the GTP. The domain used a Polar Stereographic coordinate system centered at (71.3ºN, 155ºW) with a 10-kilometer grid size. Where possible, the edge of the domain was extended at least 50 kilometers from the nearest receptor to ensure the model captured potential recirculation effects.

The horizontal resolution and geographic projection and datum was based on the Weather Research and Forecasting (WRF) meteorological data grid. The following vertical layers were used:

0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, and 4000 meters

The modeling domain along with source locations, ozone monitoring site, and Sensitive Class II receptors is provided in **Figure 6-1**.

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, and ambient temperature and relative humidity.

Hourly ozone data for 2007-2009 from A-Pad monitor was used in CALPUFF. Missing data were filled with the seasonal maximum values. The ozone station location is depicted in **Figure 6-1**.

The Western Regional Air Partnership (WRAP)[2] and USEPA (in its Best Achievable Retrofit Technology (BART) rule[3]) 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 that the CALPUFF MESOPUFF-II chemistry is

[2] See slide # 9 at
http://www.wrapair.org/forums/ssjf/meetings/050907/WRAP_Regional_Modeling_SSJF2.pdf.
[3] Federal Register, July 6, 2005, Volume 70, pages 39121 and 39123.

based upon. The independent evaluations[4] 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.

Typically, smaller ammonia concentration results in less secondary particle formation from a modeled source's SO_2 and NO_x emissions and would produce less visibility degradation. 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. Despite its importance in atmospheric chemistry and CALPUFF model sensitivity to ammonia levels, ammonia is not routinely measured by any national monitoring network.

The WRAP Modeling Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States 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 [5].

Table 6-1 summarizes predicted and measured ammonia in the western United States and Alaska. Although the values 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). In addition, an analysis of the satellite data over Alaska conducted for this project found a clear indication of seasonality in measured ammonia levels. 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). As shown in **Table 6-2**, 30 years of normal temperature data collected from the stations in the North Slope area suggests that the growing season starts in June and lasts through September (temperatures above freezing). The remaining months have freezing temperatures with little to no vegetation on the ground.

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. Based on seasonality of measured ammonia in the atmosphere and CALPUFF sensitivity of ammonia levels during cold temperatures, a seasonal value of 0.1 ppbv in winter cold months (October – May) and 1.0 ppbv in warmer months (June – September) was used in CALPUFF, as shown in **Table 6-3**.

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

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

Source of Estimate	NH_3 (ppb)	Description	Location	Year(s)
Adams et al. (1999) Plate 3	0.003-0.01	Modeled annual average	North Slope, Alaska	1990s
Chen et al. (2011) Figure 1	Lowest at Yellowstone, WY (monthly average of 0.1-0.4 ppb) and highest at Cedar Bluff, KY (1.7-4.6 ppb) and Bondville, IL (1.2-5.2 ppb)	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 ppm in May-August, 14-95 ppbv during May-October	Measured NH_3 at 7 sites during May-October	Southeast Alaska	2008-2009
Shepard 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
CHANDALAR LAKE	-15	-11	-2	16	38	53	56	48	35	15	-6	-10
CHANDALAR SHELF DOT	-5	-5	1	14	33	48	50	43	32	13	0	-3
COLVILLE VILLAGE	-16	-17	-15	1	22	39	45	43	34	18	-2	-10
DEADHORSE	-16	-18	-16	0	22	39	46	42	33	17	-2	-11
KUPARUK	-15	-16	-14	3	24	41	49	45	35	17	-2	-10
NUIQSUT AP	-15	-17	-15	2	24	43	50	45	36	18	-2	-9
PRUDHOE BAY	-16	-17	-14	2	23	39	46	43	34	16	-3	-11
UMIAT	-21	-20	-17	2	27	49	55	48	35	12	-9	-17
WISEMAN	-10	-6	4	23	42	56	57	50	38	17	-3	-6
Temperature data obtained from the National Climatic Data Center												

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

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

6.6 VISIBILITY MODELING APPROACH

6.6.1 Near-Field Analysis

No near-field visibility modeling is required for GTP because all Class I and Sensitive Class II areas are more than 50 kilometers away from the site.

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 GTP were refined by subtracting the existing 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 existing emission source inventory.

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

6.7 METEOROLOGICAL DATA

6.7.1 Prognostic Meteorological Data

The latest available three-year (2007-2009) Weather Research and Forecasting Model (WRF) dataset developed for the Bureau of Ocean Energy Management (BOEM) (Zhang et al. 2013) were used as the gridded, domain-wide prognostic meteorological dataset. This dataset has been previously used for the far-field dispersion modeling for the ConocoPhillips Alaska, Inc. Greater Mooses Tooth 1 Air Quality Impact Analysis (AECOM 2013). This report is listed on the U.S. Department of the Interior's Bureau of Land Management's (BLM) NEPA register.

6.7.2 MMIF

The WRF meteorological data was processed using the latest version of the Mesoscale Model Interface Program (MMIF), currently Version 3.2 (ENVIRON 2015), to develop a meteorological wind field. The MMIF/CALPUFF modeling domain is shown by the blue line in **Figure 6-1**.

The WRF model output was processed with MMIF with the following options selected:

- Output for CALPUFF version 5.8,
- The WRF vertical layers were interpolated to the FLM/USEPA-recommended (USEPA 2006) vertical layers using the TOP option, as follows:
    - 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000, and
- The Pasquill-Gifford stability classes were calculated with the Golder option.

6.8 RECEPTORS

Receptor placement for Sensitive Class II areas was designed similar to receptors developed by the National Park Service for Class I areas. Receptors were placed every 6 kilometers vertically and every 3 kilometers horizontally. Receptors beyond 300 kilometers of the GTP were not modeled. The receptors are shown in **Figure 6-1**.

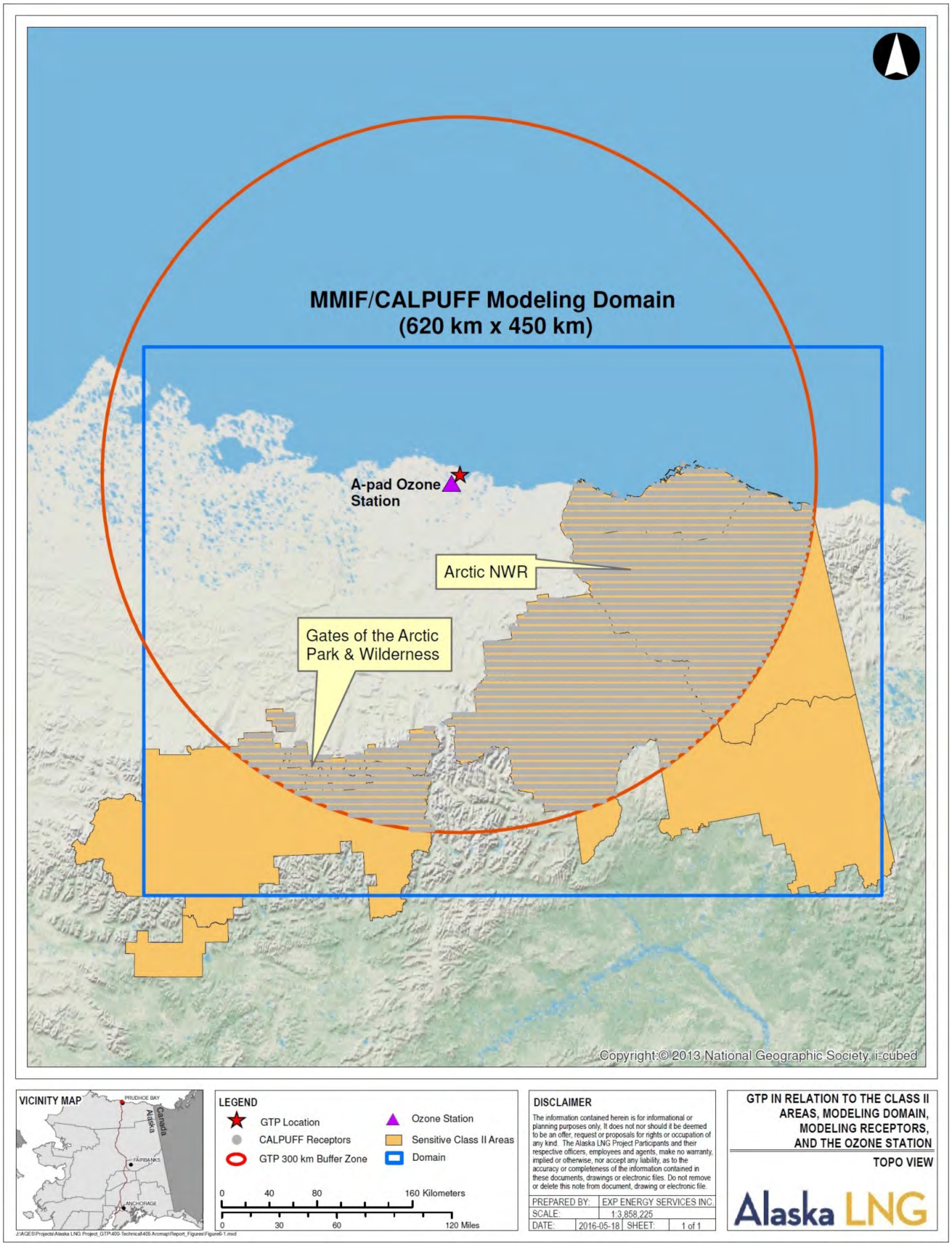
6.9 ELEVATION DATA

The terrain data for Sensitive Class II receptors were extracted from GTOPO30 30-sec data (about 900 meter resolution) using TERREL program (CALMET pre-processor).

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 Sensitive Class II Area modeling analysis. Therefore, consistent with recent USEPA guidance (USEPA 2014b), Tier 2 (ARM) was implemented where Tier 1 results will be 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



7.0 MODELING RESULTS

The results of the ambient air quality modeling analyses for the GTP are presented in this Section. Both near-field 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 previous sections.

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. USAG-P1-SRZZZ-00-000001-001).

7.1 NEAR-FIELD DISPERSION MODEL IMPACTS

This section presents results for modeled receptors within approximately 50 kilometers of the GTP.

7.1.1 Criteria Pollutant Project Only Impacts

Modeled impacts resulting from the normal operations scenario developed for the GTP were compared to applicable standards discussed in **Section 2.0**. Model-predicted concentrations from only the GTP sources are compared to the NAAQS and AAAQS in **Table 7-1** and the PSD Increments in **Table 7-2** for information purposes since it is more appropriate to compare cumulative impacts to these standards. Note that modeling of the facility alone included receptor locations within the ambient boundaries of offsite sources.

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

Air Pollutant	Averaging Period	Modeled Concentration (µg/m^3)	Ambient Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	NAAQS (µg/m^3)	AAAQS (µg/m^3)
Sulfur Dioxide	1-Hour [a]	11.2	9.39	20.6	196	196
	3-Hour [b]	37.7	20.96	58.7	1,300	1,300
	24-Hour [b]	11.2	8.12	19.3	NA	365
	Annual [d]	0.5	1.8	2.3	NA	80
Carbon Monoxide	1-Hour [b]	366.0	1,150	1,516	40,000	40,000
	8-Hour [b]	139.0	1,150	1,289	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	65.0	NA [g]	65.0	188	188
	Annual [d]	2.6	6.0	8.6	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	3.8	50.0	53.8	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	3.3	15.0	18.3	35	35
	Annual [h]	0.2	3.7	3.9	12	12

Abbreviations:

NA = not applicable

µg/m^3 = micrograms per cubic meter

Notes:

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

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

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

[d] Value reported is the maximum annual average concentration for the modeled period.

[e] Value reported is the 98th percentile averaged over the modeled period.

[f] Value reported is the highest, 6th highest concentration over the modeled period.

[g] The 1-hour NO_2 modeling was conducted with wind speed-varying background values applied by hour in AERMOD. Therefore, the AERMOD-predicted 1-hour NO_2 concentration includes the background. These background values are summarized in **Table 3-2**.

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

Table 7-2: Comparison of GTP-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]	37.7	512
	24-Hour [b]	11.2	91
	Annual [c]	0.5	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	2.6	25
Particulate Matter less than 10 Microns	24-Hour [b]	4.8	30
	Annual [c]	0.3	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	4.8	9.0
	Annual [c]	0.3	4.0

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.

7.1.2 Criteria Pollutant Cumulative Impacts

Cumulative model-predicted concentrations from the GTP and offsite sources at Potential to Emit (PTE) were compared to the NAAQS and AAAQS in **Table 7-3**. Cumulative model-predicted concentrations were also compared to PSD Class II increments in **Table 7-4**. All model-predicted impacts are below the applicable standards and increments outlined in **Section 2.0**.

Lead and ammonia emissions are either negligible or not emitted at all from the GTP; therefore, they were not addressed as part of the dispersion modeling analysis.

Predicted cumulative impacts indicate compliance with all applicable standards and thresholds. This was possible even in light of the following conservative assumptions:

- All gas-fired emission units combust a gaseous fuel with up to 5.6 grains sulfur/100 scf, or 96 ppmv sulfur content, which is conservatively representative of PBU raw fuel gas which is likely only to occur during start-up. The GTP would typically operate on treated gas which will have a much lower sulfur content.
- With the exception of intermittently-used emergency equipment, all emission sources are assumed to be operating at all times.
- 500 hours per year of emergency maximum flaring is included in the modeling demonstration in addition to continuous pilot purge and all other equipment operating. While emergency flaring is inevitable, it is unlikely to occur as much as 500 hours per year and is unlikely to occur with all other equipment operating.
- A worst-case background ozone dataset was developed for the NO_2 modeling based on the maximum ozone concentration observed for a given day and hour. Any hours with missing or invalid data were replaced with a seasonal maximum.

Refinement of any of these assumptions would certainly result in lower facility impacts. Electronic input and output files for all model runs used to develop the results will be transmitted digitally with this modeling report.

Table 7-3: Cumulative 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]	39.2	9.39	48.6	196	196
	3-Hour [b]	57.0	20.96	78.0	1,300	1,300
	24-Hour [b]	30.1	8.12	38.2	NA	365
	Annual [d]	2.8	1.8	4.6	NA	80
Carbon Monoxide	1-Hour [b]	423.0	1,150	1,573	40,000	40,000
	8-Hour [b]	302.0	1,150	1,452	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	158.0	NA [g]	158.0	188	188
	Annual [d]	14.0	6.0	20.0	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	18.4	50.0	68.4	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	14.5	15.0	29.5	35	35
	Annual [h]	3.3	3.7	7.0	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 modeled period.

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

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

[d] Value reported is the maximum annual average concentration for the modeled period.

[e] Value reported is the 98th percentile averaged over the modeled period.

[f] Value reported is the highest, 6th highest concentration over the modeled period.

[g] The 1-hour NO_2 modeling was conducted with wind speed-varying background values applied by hour in AERMOD. Therefore, the AERMOD-predicted 1-hour NO_2 concentration includes the background. These background values are summarized in **Table 3-2.**

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

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

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	52.9	512
	24-Hour [b]	27.0	91
	Annual [c]	2.0	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	6.6	25
Particulate Matter less than 10 Microns	24-Hour [b]	12.8	30
	Annual [c]	1.2	17
Particulate Matter less than 2.5 Microns	24-Hour [b, d]	4.8	9.0
	Annual [c, d]	0.3	4.0

Abbreviations:

NA = not applicable

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

Notes:

[a] Neither USEPA or 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.

[d] Based on GTP-only model-predicted concentrations because the offsite sources under consideration (CGF and CCP) are not increment consuming. The CGF and CCP facilities were constructed prior to the $PM_{2.5}$ baseline date.

7.2 SENSITIVE CLASS II AREA DISPERSION MODEL -PREDICTED IMPACTS

This section presents results for modeled receptors within selected Sensitive Class II areas. Two different emissions cases were modeled based on the sulfur content of the fuel gas combusted by GTP emissions sources. The cases include a 16 ppmv sulfur content case typical of long-term GTP operations where the treated gas produced by the GTP is combusted by the source and a 96 ppmv sulfur content case representative of early GTP operation when the facility is combusting untreated gas. The latter case would occur during the first six months following commissioning of the first gas treatment train. The more conservative 96 ppmv sulfur case was modeled in the near-field AERMOD modeling, and these emissions are presented in **Table 4-3**. The 16 ppmv sulfur case was the focus of the Sensitive Class II Area dispersion modeling since it is representative of long-term operations and not a transient event during facility commissioning.

7.2.1 Criteria Pollutant Project Only Impacts

Modeled impacts resulting from the GTP normal operations scenario are compared to applicable standards discussed in **Section 2.0**. Model-predicted concentrations from only the GTP are compared to the NAAQS and AAAQS for each of the selected Sensitive Class II areas in **Table 7-5** through **Table 7-6** and to the PSD Class II increments in **Table 7-7** through **Table 7-8** for informational purposes only since it is more appropriate to compare cumulative impacts to these standards.

7.2.2 Criteria Pollutant Cumulative Impacts

Cumulative CALPUFF-predicted concentrations from the GTP, existing offsite sources, RFD sources, and other non-modeled sources (represented by ambient background concentrations) are compared to the NAAQS and AAAQS for each Sensitive Class II area in **Table 7-9** through **Table 7-10**. The modeling results indicate that the cumulative air quality impacts, combined with representative background air quality data, are well below the NAAQS and AAAQS at all Sensitive Class II areas modeled for all pollutants and averaging periods modeled. Cumulative model-predicted concentrations are compared to PSD Class II Increments in **Table 7-11** through **Table 7-12.** The modeling, which included only increment consuming sources, indicates impacts less than the PSD increment at all Sensitive Class II areas modeled for all pollutants and averaging period.

7.2.3 Ambient Ozone Cumulative Impacts

Because ozone is a regional pollutant, the information provided in **Section 8.0** is also applicable to the Class I and Sensitive Class II areas included in the air quality modeling analysis. Refer to that section for details.

7.2.4 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. Project $PM_{2.5}$ and PM_{10} impacts 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.

7.2.5 AQRV Visibility Assessment

7.2.5.1 Near-Field Analysis

As discussed in Section 5.8, a near-field visibility analysis was not required for GTP.

7.2.5.2 Far-Field Analysis

As shown in **Table 7-13**, the predicted visibility impacts (reported as the 8th highest percent change in visibility extinction) from the GTP emissions sources at all modeled receptors are below the 5% threshold at Gates of the Arctic National Park and Preserve for all years modeled. Predicted GTP-only visibility impacts of less than 5% demonstrate that the project has an insignificant effect on visibility impairment at this Class II Area.

The predicted visibility impacts from the GTP at all modeled Arctic NWR receptors are below the source-only threshold for two of the three years modeled. With the 2008 meteorological input data, the predicted visibility extinction is higher than the threshold and is equal to 5.5%. **Section 7.3.1** provides a discussion of the modeling conservatism and a possibility of lowering the visibility impacts below the 5% threshold.

As shown in **Table 7-14**, cumulative visibility impacts are higher than the 10% threshold at both Sensitive Class II areas examined for all years modeled. Given the results of the GTP-only modeling and limited culpability assessments, these elevated cumulative impacts are attributed to the offsite sources. In order to demonstrate that the background sources cause the visibility impairment, modeling consisting of only the background sources was conducted and the results are presented in **Table 7-15**. The background model-predicted visibility impacts (i.e., those predicted without the presence of the GTP) are essentially equal to the cumulative visibility results. This demonstrates that the offsite sources dominate the cumulative results and the GTP is an insignificant contributor. As a further indication of the culpability of the offsite sources in the visibility impacts; **Figure 7-1** has been developed to show the location of receptors where impacts are above the 10% cumulative visibility threshold over all three modeled years at Arctic NWR. The figure indicates that the majority of the high impacts occur in the northern part of the Class II Area in the region of the Point Thompson Facility and Kaktovik Power Plant. While cumulative impacts are predicted to be higher than the screening level visibility threshold at some receptors, this should not be taken to indicate there is an existing visibility issue, only that the simple way in which the offsite sources were simulated is resulting in modeling conservatism and elevated impacts and that emissions from GTP sources are a negligible portion of those impacts.

7.2.6 AQRV Acidic Deposition Modeling

As shown in **Table 7-16** the maximum sulfur deposition flux predicted from the GTP is well below the DAT at all Sensitive Class II areas modeled. Predicted project-only deposition impacts of less than 0.005 demonstrate that the project has an insignificant effect on sulfur deposition at the modeled Class II areas and a cumulative sulfur deposition analysis was not conducted.

Table 7-17 shows that the maximum model-predicted nitrogen deposition flux from only GTP emissions exceeds the DAT at some locations within the Arctic NWR while it is below the DAT at all receptors within the Gates of the Arctic National Park and Preserve.

The maximum predicted cumulative nitrogen deposition flux is presented in **Table 7-18** and shows that the cumulative nitrogen deposition flux at both modeled Class II Areas is well below the DAT.

7.3 MODELING CONCLUSIONS

This section discusses conclusions based on modeled impacts at near-field receptors as well as at selected Sensitive Class II areas.

7.3.1 Project-Only Source Modeling

Model-predicted impacts due to only emissions from the GTP are below all air quality standards and increments at near-field receptor locations and modeled Sensitive Class II area. This is in spite of the following conservative assumptions that are part of the model simulation:

- All equipment located at the GTP is assumed to operate concurrently, even intermittently used equipment.
- Short-term turbine emissions are based on worst-case, rather than average, ambient temperatures.
- 500 hours per year of maximum relief flaring has been assumed 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 is unlikely to occur with all other equipment operating.

Far-field visibility impairment resulting from only GTP emissions are below the 5% threshold at Gates of the Arctic National Park and Preserve, but are slightly above the source-only threshold at Arctic NWR. While the sulfur deposition flux from only GTP emissions is well below the DAT at both Sensitive Class II areas, the nitrogen deposition flux exceeds the DAT at Arctic NWR. These elevated visibility and deposition impacts are likely artifacts of the conservatism built into the model simulation. If the assumptions listed above were refined to reduce conservatism, it is expected that both visibility and deposition impacts from only GTP emissions would be below their respective screening thresholds.

7.3.2 Cumulative Source Modeling

Cumulative model-predicted impacts demonstrate compliance with the NAAQS/AAAQS, PSD Increments, and DATs in all Sensitive Class II areas. However, the cumulative visibility impacts exceeded the visibility extinction thresholds at some locations within both the Sensitive Class II areas modeled. Based on analyses conducted, it is apparent these elevated cumulative impacts are attributable to the offsite sources. The modeled cumulative impacts from the offsite sources are likely elevated because of the following:

- Elevated visibility impacts due to the Point Thompson Facility and Kaktovik Power Plant occur in the near-field of these facilities. Because of close proximity of these sources (0.0 to 12.4 kilometers) to the Arctic NWR modeled receptors, AERMOD, rather than CALPUFF would be a better suited model for a short-distance transport.
- Due to lack of readily available data, such as exhaust parameters, existing far-field offsite and RFD sources were modeled with a simplified approach using volume sources, which is very conservative. Refined modeling of these sources using actual stack information would likely lead to lower impacts.
- The deposition thresholds used in this modeling analysis are screening thresholds protective of the most sensitive areas. If better data were available on the deposition impacts of the area modeled, there would be a possibility to refine and increase the acceptable thresholds.

Therefore, there are many ways to reduce conservatism in elevated impacts caused by offsite sources, and as those impacts are decreased, impacts from the GTP will also likely decrease and would remain a small percentage of those impacts.

Table 7-5: GTP Facility Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Arctic 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]	0.07	9.39	9.46	196	196
	3-Hour [b]	0.07	20.96	21.03	1300	1300
	24-Hour [b]	0.03	8.12	8.15	NA	365
	Annual [d]	0.002	1.802	1.802	NA	80
Carbon Monoxide	1-Hour [b]	17.2	1,150	1,167	40,000	40,000
	8-Hour [b]	2.0	1,150	1,152	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.91	61.69	62.60	188	188
	Annual [d]	0.02	6.00	6.02	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.26	50.00	50.26	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.02	15.00	15.02	35	35
	Annual [d]	0.17	3.70	3.87	12	15

Table 7-6: GTP Facility Only NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations – Gates of the Arctic National Park & Preserve

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]	0.02	9.39	9.41	196	196
	3-Hour [b]	0.03	20.96	20.99	1300	1300
	24-Hour [b]	0.01	8.12	8.13	NA	365
	Annual [d]	0.0004	1.80	1.80	NA	80
Carbon Monoxide	1-Hour [b]	5.4	1,150	1,155	40,000	40,000
	8-Hour [b]	1.4	1,150	1,151	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	0.25	61.69	61.94	188	188
	Annual [d]	0.003	6.00	6.00	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	0.19	50.00	50.19	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.01	15.00	15.01	35	35
	Annual [d]	0.06	3.70	3.76	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: Comparison of GTP Facility Only Model Predicted Concentrations to Increment Thresholds – Arctic 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]	0.07	512
	24-Hour [b]	0.03	91
	Annual [c]	0.002	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]	0.26	30
	Annual [c]	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.27	9
	Annual [c]	0.02	4

Table 7-8: Comparison of GTP Facility Only Model Predicted Concentrations to Increment Thresholds – Gates of the Arctic National Park & Preserve

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.03	512
	24-Hour [b]	0.01	91
	Annual [c]	0.0004	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]	0.19	30
	Annual [c]	0.01	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.20	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 7-9: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations Scenario – Arctic 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]	4.3	9.39	13.7	196	196
	3-Hour [b]	4.06	20.96	25.02	1300	1300
	24-Hour [b]	1.20	8.12	9.32	NA	365
	Annual [d]	0.052	1.80	1.85	NA	80
Carbon Monoxide	1-Hour [b]	53.04	1,150	1,203	40,000	40,000
	8-Hour [b]	16.16	1,150	1,166	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	16.81	61.69	78.50	188	188
	Annual [d]	0.37	6.00	6.37	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	4.60	50.00	54.60	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.3	15.00	15.3	35	35
	Annual [d]	2.14	3.70	5.84	12	15

Table 7-10: Cumulative NAAQS/AAAQS Air Quality Compliance Analysis – Normal Operations Scenario – Gates of the Arctic National Park & Preserve

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]	0.16	9.39	9.55	196	196
	3-Hour [b]	0.2	20.96	21.1	1300	1300
	24-Hour [b]	0.10	8.12	8.22	NA	365
	Annual [d]	0.003	1.80	1.80	NA	80
Carbon Monoxide	1-Hour [b]	18.08	1,150	1,168	40,000	40,000
	8-Hour [b]	6.56	1,150	1,157	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	2.86	61.69	64.6	188	188
	Annual [d]	0.04	6.00	6.04	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	1.67	50.00	51.7	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	0.08	15.00	15.08	35	35
	Annual [d]	0.73	3.70	4.43	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 Cumulative Model Predicted Concentrations to Increment Thresholds – Arctic NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m^3)	Class II Increments (µg/m^3)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	4.06	512
	24-Hour [b]	1.20	91
	Annual [c]	0.05	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.36	25
Particulate Matter less than 10 Microns	24-Hour [b]	4.27	30
	Annual [c]	0.29	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	4.49	9
	Annual [c]	0.29	4

Table 7-12: Comparison of Cumulative Model Predicted Concentrations to Increment Thresholds – Gates of the Arctic National Park & Preserve

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m^3)	Class II Increments (µg/m^3)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	0.20	512
	24-Hour [b]	0.10	91
	Annual [c]	0.003	20
Carbon Monoxide	1-Hour [a]	NA	NA
	8-Hour [a]	NA	NA
Nitrogen Dioxide	1-Hour [a]	NA	NA
	Annual [c]	0.04	25
Particulate Matter less than 10 Microns	24-Hour [b]	1.58	30
	Annual [c]	0.08	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	1.55	9
	Annual [c]	0.08	4

Abbreviations:

NA = not applicable

µg/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 7-13: GTP-Only Regional Haze Results

Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
Arctic NWR	2007	4	1	3.0	5.0
	2008	15	0	5.5	5.0
	2009	4	1	4.5	5.0
Gates of the Arctic National Park and Preserve	2007	1	1	1.6	5.0
	2008	2	0	2.8	5.0
	2009	5	1	2.8	5.0

Table 7-14: Cumulative Regional Haze Results

Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Cumulative Visibility Extinction Threshold (%)
		5%	10%		
Arctic NWR	2007	142	88	38.7	10.0
	2008	197	131	71.3	10.0
	2009	162	122	49.3	10.0
Gates of the Arctic National Park and Preserve	2007	76	36	23.0	10.0
	2008	94	55	35.9	10.0
	2009	69	44	32.5	10.0

Table 7-15: Regional Haze Results for Offsite Existing and RFD Sources Only

Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Cumulative Visibility Extinction Threshold (%)
		5%	10%		
Arctic NWR	2007	138	87	36.3	10.0
	2008	192	129	66.2	10.0
	2009	156	119	44.6	10.0
Gates of the Arctic National Park and Preserve	2007	70	33	21.3	10.0
	2008	92	50	32.6	10.0
	2009	67	41	29.6	10.0

Table 7-16: GTP-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
Arctic NWR	3-Year Max	0.001	0.005	18%
Gates of the Arctic National Park and Preserve	3-Year Max	0.0003	0.005	6%

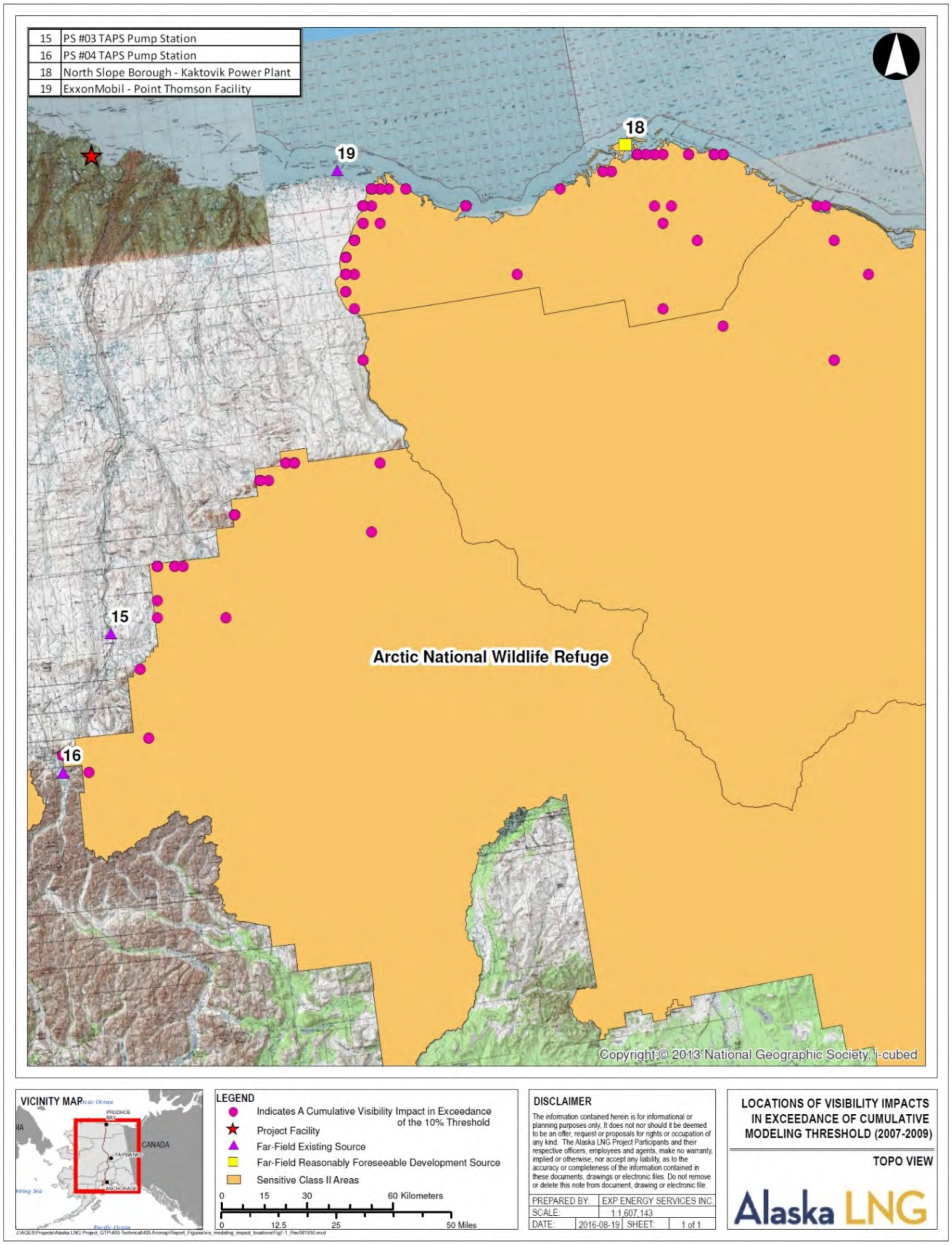
Table 7-17: GTP-Only Nitrogen Deposition Results

Class I/II Area	Year	Nitrogen Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Arctic NWR	3-Year Max	0.007	0.005	140%
Gates of the Arctic National Park and Preserve	3-Year Max	0.002	0.005	43%

Table 7-18: 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
Arctic NWR	3-Year Max	0.107	0.125	85%
Gates of the Arctic National Park and Preserve	3-Year Max	0.031	0.125	24%

Figure 7-1: Locations of Cumulative Visibility Impacts above the 10% Visibility Screening Threshold



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 GTP, therefore, any impacts to ambient ozone as a result of GTP 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 States 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 govern 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 – 0.87 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 States 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.

Polar aerosols, found close to the surface in the Arctic, are usually aged particles with very low concentrations. Arctic aerosols during the winter and early spring are significantly influenced by anthropogenic sources located at mid-latitudes. During this period aerosol number concentrations increase substantially. Polar aerosol contains a complex mixture of different species: carbonaceous and sulfate material from midlatitude pollution sources, sea salt from surrounding oceans and mineral dust from arid regions. VanCuren and Cahill, 2002 have found that dust transported from Asia to midlatitude North America occurs on a frequent, consistent pattern. $PM_{2.5}$ Asian dust is a regular component of the troposphere over the eastern Pacific and western North America. Typical dust monthly concentrations range between 0.1 and 0.5 μg/m^3 in Denali, Alaska. The largest concentrations are observed between March and June, which exhibits a 'conventional' springtime pattern and is similar to the temporal pattern observed at Mauna Loa, Hawaii. Polissar et al. (1998) analyzed the chemical composition data for seven National Park locations in Alaska from 1986 to 1995. Polissar et al. found seasonal variations in the $PM_{2.5}$ concentrations and composition, but that the maxima concentrations occurred in the winter and spring season with minima in the summer for non-marine sulfate but not for black carbon. Sulfate concentrations were always higher in northwestern Alaska, while black carbon peaked in central Alaska during the summer as a result of active forest fires. Polissar et al. concluded that sulfate concentrations were related to variations in long-range midlatitude anthropogenic emissions located to the north and northwest of Alaska.

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

Emissions of ozone precursors from the North Slope Borough are summarized in **Table 8-1** based on the most recent National Emission Inventory (NEI) (USEPA 2016b) 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, the petroleum and related industries are the largest NO_x emissions contributors while the combustion processes associated to industrial processes are the largest VOCs emissions contributors throughout the area. Other anthropogenic VOC emissions in the area are primarily from combustion from electric utilities and other sources. While other sources of NO_x are emitted mostly by stationary sources associated to industrial processes and also mobile sources.

Table 8-1: Anthropogenic Emissions in the North Slope Borough

Emission Inventory Sector	NO_x (TPY)	VOCs (TPY)	Primary $PM_{2.5}$ (TPY)
FUEL COMB. ELEC. UTIL.	60	3,757	91.8
FUEL COMB. INDUSTRIAL	328	33,013	765.3
FUEL COMB. OTHER	41	80	12.5
PETROLEUM & RELATED INDUSTRIES	125,041	1,271	97.2
OTHER INDUSTRIAL PROCESSES	5	55	4.4
SOLVENT UTILIZATION	55	--	--
STORAGE & TRANSPORT	64	--	0.0
WASTE DISPOSAL & RECYCLING	6	6	16.8
HIGHWAY VEHICLES	43	167	6.0
OFF-HIGHWAY	526	9,470	313.6
MISCELLANEOUS	8	1	175.3
Total	**126,177**	**47,821**	**1,483**

Data based on EPA's 2011 National Emissions Inventory (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 North Slope. In general the largest source of $PM_{2.5}$ is related to industrial combustion processes followed by the off-road emissions.

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 March 21, 2011 when regional measurements indicate that 8-hour average ozone concentrations in the Project area could be as high as 0.0561 ppmv. The figures show that for most of the day, air masses get to the GTP from the south, traveling over vast regions of Alaska, possibly transporting ozone and ozone precursors from Anchorage and Fairbanks. 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.

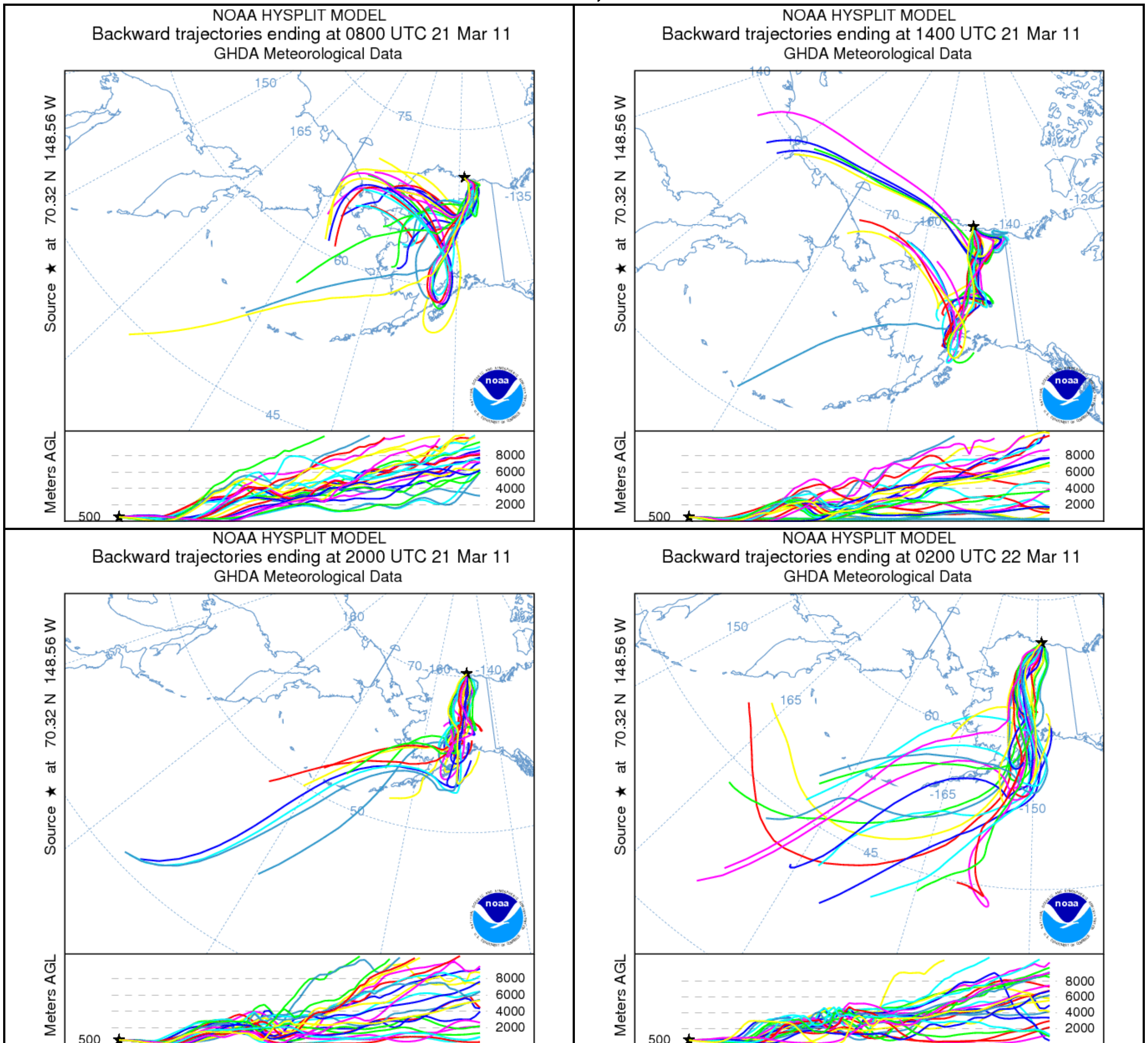
Figure 8-2 shows back trajectories displaying a 72 hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for April 23, 2013 when regional measurements indicate that 8 hour average ozone concentrations in the Project area could be as high as 0.0556 ppmv. The figures show that for most of the day, air masses are transported to the GTP from the west, traveling from as far as Russia. 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 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 $PM_{2.5}$ concentrations near the Project area as indicated by available monitoring data. **Figure 8-3** shows back trajectories displaying a 72 hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for July 11, 2012 when the Nuiqsut monitor indicates that 24 hour $PM_{2.5}$ concentrations could be as high as 8 $\mu g/m^3$. The figures show that for this day during the summer, air masses tend to arrive at the monitor location from the east. The back trajectories suggest that at least some of the measured concentrations are the result of photochemical transformation from precursors' sources along the northern coast of Alaska from existing oil and gas activity. The spatial extent of the trajectories also suggests that at least part of the observed concentrations is the result of particles undergoing long range transport.

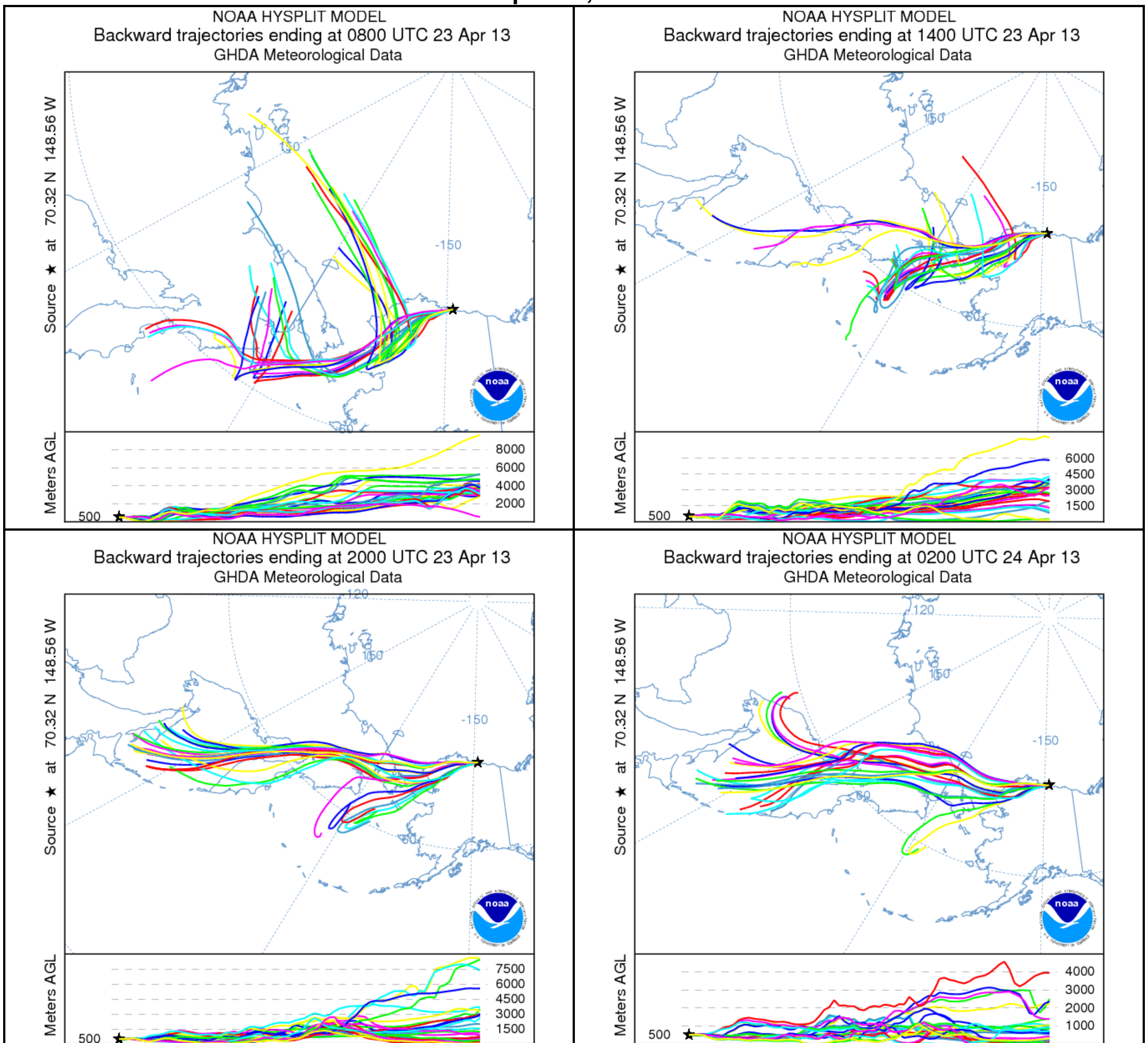
Figure 8-4 shows back trajectories displaying a 72 hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for April, 28 2013 when the Nuiqsut monitor indicates that 24 hour $PM_{2.5}$ concentrations could be as high as 11 $\mu g/m^3$. The figures show that for this day during the early spring, air masses tend to arrive at the monitor location from the west. During spring a more active photochemistry coupled with predominant westerly transport lead to 'Arctic Haze' episodes. The spatial extent of the trajectories during this day in April suggests that most, if not all, of the observed $PM_{2.5}$ concentrations are the result of pollution from Europe and Asia undergoing long range transport.

Figure 8-1: 72 Hour Back trajectories Arriving at the Project Location at (70.317N, 148.557 W) March 21, 2011



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 (70.317N, 148.557 W) April 23, 2013



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 8-3: 72 Hour Back trajectories Arriving at the Project Location at (70.317N, 148.557 W) July 11, 2012

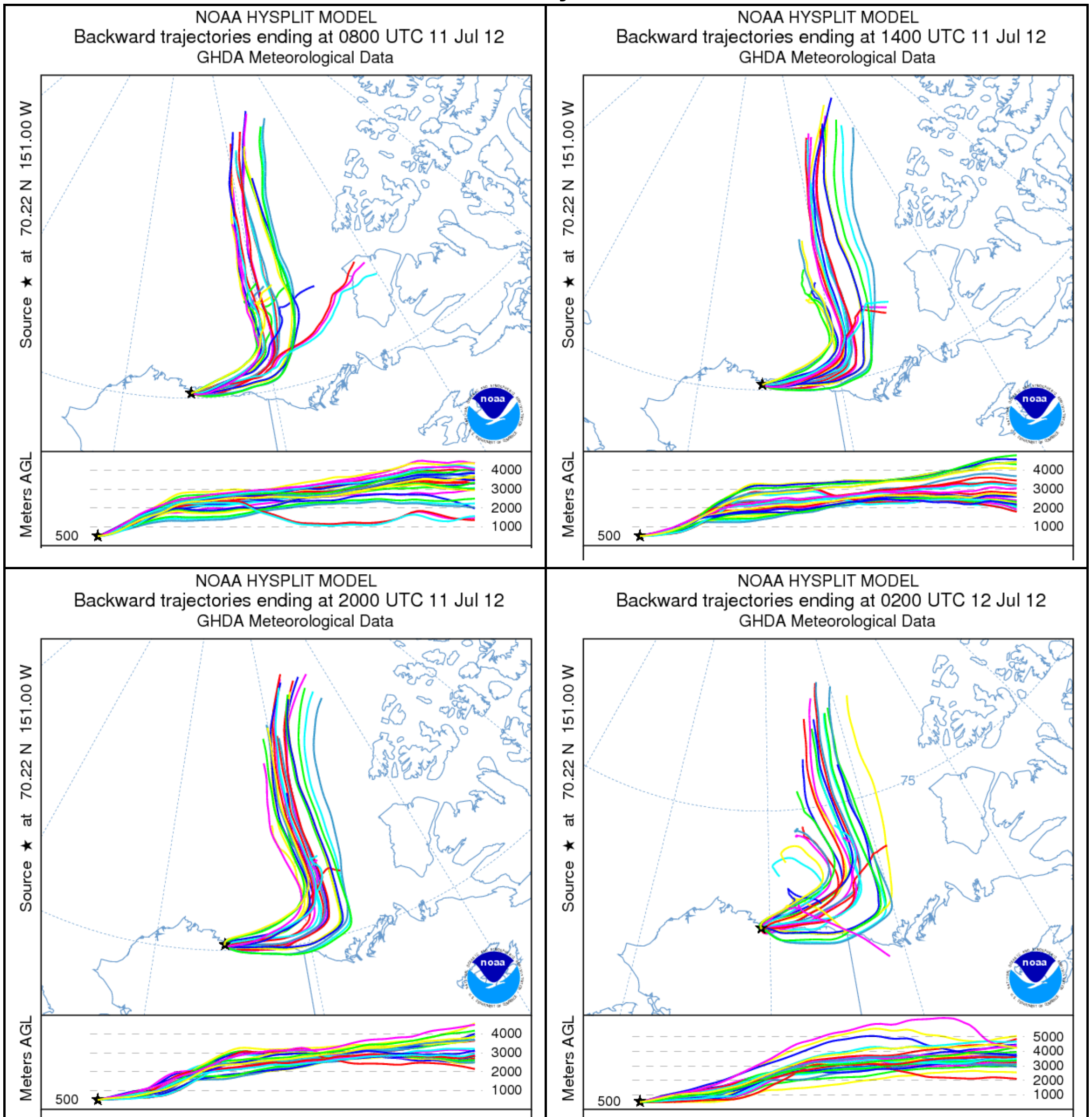


Figure 3.4-3 72 hour back trajectories arriving at the monitor location during July 11, 2012. Top row shows hours 0:00 and 6:00 AKT, while the bottom row shows hours 12:00 and 18:00 AKT. Global Data Assimilation System (GDAS) meteorological data was used to derive the HYSPLIT back trajectories results.

Figure 8-4: 72 hour Back Trajectories Arriving at the Project Location at (70.317N, 148.557 W) April 28, 2013

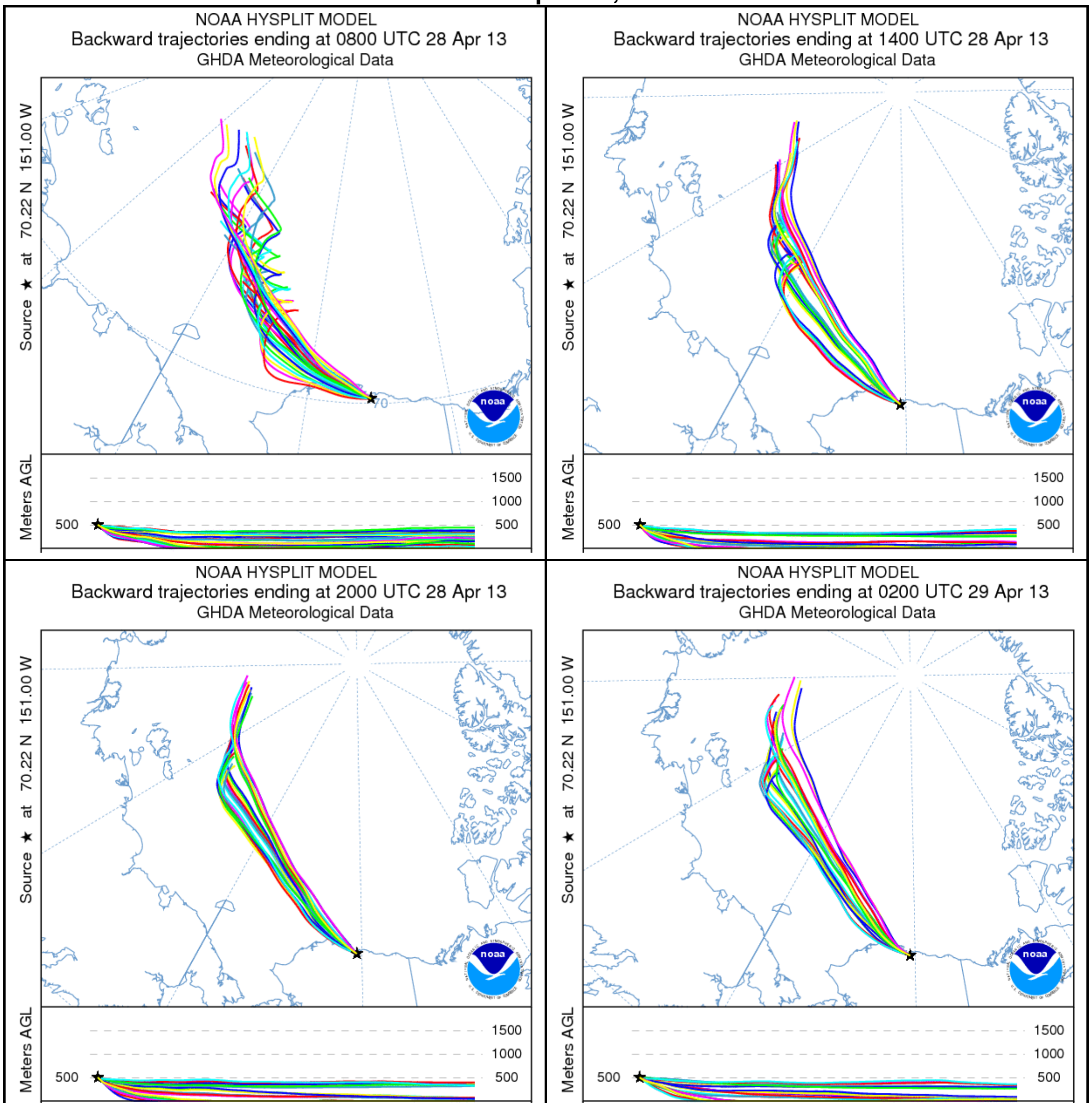


Figure 3.4-3 72 hour back trajectories arriving at the monitor location during April, 28, 2013. Top row shows hours 0:00 and 6:00 AKT, while the bottom row shows hours 12:00 and 18:00 AKT. Global Data Assimilation System (GDAS) meteorological data was used to derive the HYSPLIT back trajectories results.

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. 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 GTP Emissions

8.4.2.1 GTP Emissions

The total potential GTP project emissions of ozone precursors from stationary emissions would be approximately 2,200 tons per year (TPY)of NO_x and 400 TPY of VOC. The potential GTP emissions would represent approximately 2% of the total NO_x and less than 1% of the total VOC emissions in the North Slope Borough (**Table 8-1**). These values reflect the potential to contribute to ozone formation by GTP, but as has been shown in this analysis most of the observed concentrations near the GTP 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 GTP based on applying the PGM model based on single source analyses.

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 5,000 TPY will not lead to ozone impacts larger than approximately 7 ppbv as illustrated in **Figure 8-5**. **Table 8-2** (adapted from Baker et al. 2016) shows the ozone concentrations predicted from studies in which single sources emitted less than 3,000 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 3,000 TPY, the peak ozone impacts estimated by PGM have ranged from 0.9 to 14 ppbv. This range of information provides an approximate estimate of the potential ozone impact associated with the emissions from the GTP. 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 GTP 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 1 μg/m^3 when the emissions of a single source range between 1,000 and 3,000 TPY. The potential to emit NO_x from GTP is approximately 2,200 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 0.2 and 8 μg/m^3. The potential to emit SO_2 from GTP 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 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 from the source. Nitrate impacts are the largest at a distance of about 5 to 10 kilometers 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 from the source.

Figure 8-5: Relationship Between the Change in Daily Maximum 8-Hour Average O_3 and Change in NO_x Precursor Emissions (TPY) (Baker et al. 2016)

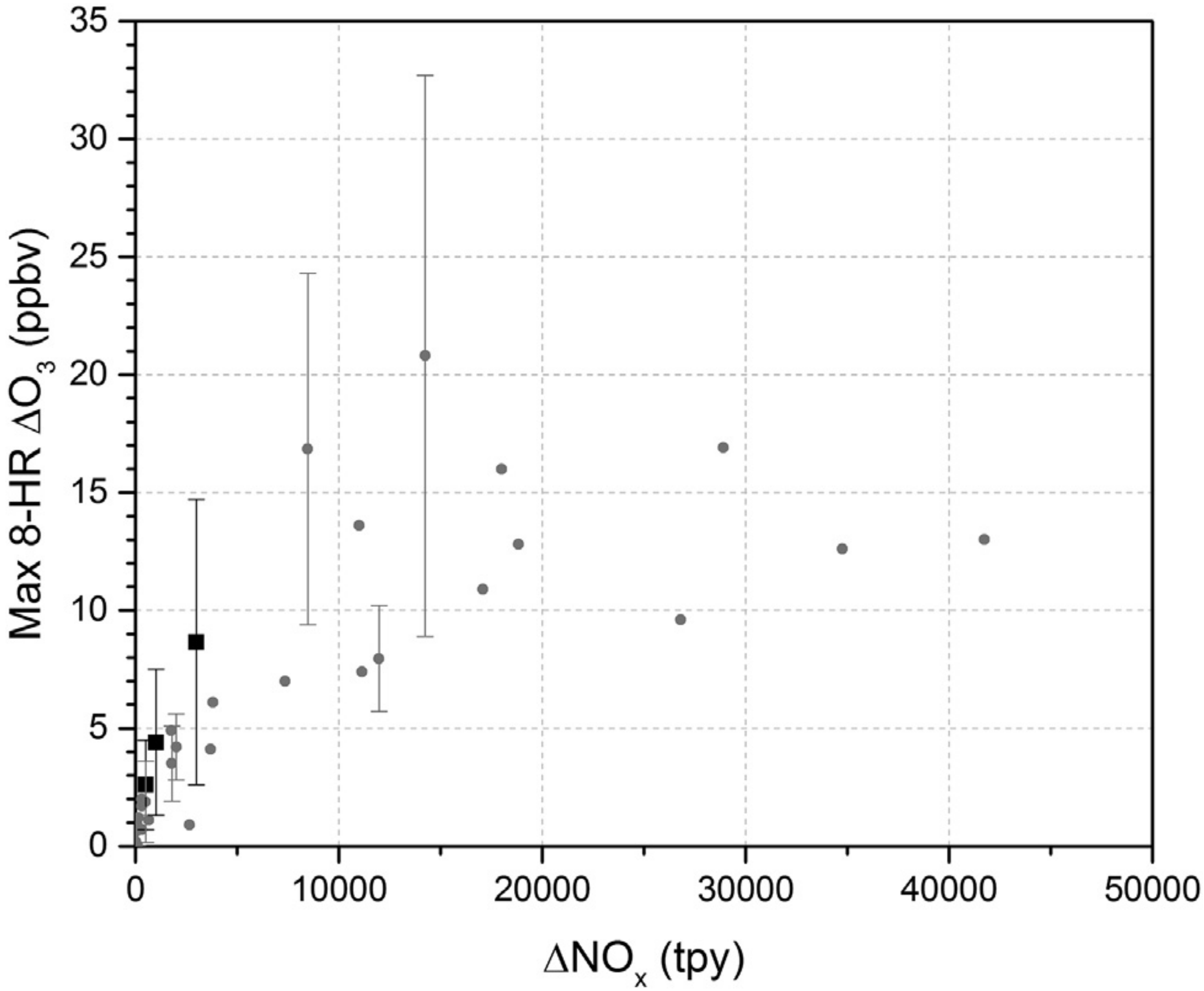


Table 8-2: Compilation of 8-Hour Ozone Impacts (ppbv) from NO_x Emissions (TPY) Reported in Literature (Baker et al. 2016)

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 e EGU	CAMx brute force	4	Not known	2,665	0.9
Castell et al., 2010	Spain	Summer episodes	2003 & 2004	Single e EGU	CAMx brute force	2	65	1,789	1.9-5.1
ENVIRON, 2012a	New Mexico	Full year	2005	Single e EGU	CAMx APCA	4	137.2	3,797	6.1
This work	eastern US	Full year	2011	Hypothetical Source	CAMx OSAT	12	1 and 90	1,000	1.3-7.5
This work	eastern US	Full year	2011	Hypothetical Source	CAMx OSAT	12	90	3,000	2.6-14.7
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 Generation Units

APCA: CAMx Anthropogenic Precursor Culpability Assessment

OSAT: CAMx Ozone Source Apportionment Technology

DDM: Decoupled Direct Method

8.5 SUMMARY OF GTP 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 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 suggest that observed concentrations could be the at least in part the result of pollution transported from midlatitude regions.

Using available tools, a conservative quantification of the potential regional impact of GTP 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) that is known to occur in Alaska.

The analysis presented indicates that emissions from GTP would at most lead to ozone increments of about 7 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 7 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 GTP would at most lead to nitrate increments of about 1 µg/m^3 and sulfate increments of less than 8 µg/m^3 for the 24-hour concentrations. This would be the expected $PM_{2.5}$ 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 10 µg/m^3 in a region where $PM_{2.5}$ concentrations range around 10 µg/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
AERMET	AERMOD Meteorological Processor
AERMOD	American Meteorological Society/USEPA Regulatory Model
AGDC	Alaska Gasline Development Corporation
AGRU	Acid Gas Removal System
APCA	CAMx Anthropogenic Precursor Culpability Assessment
APP	Alaska Pipeline Project
AQRVs	Air Quality Related Values
ARM	Ambient Ratio Method
ARM2	Ambient Ratio Method 2
BART	Best Available Retrofit Technology
BLM	Bureau of Land Management
BMPs	Best Management Practices
BOEM	Bureau of Ocean Energy Management
BPIPPRM	Building Profile Input Program
BPXA	BP Exploration (Alaska), Inc.
BSCF/D	Billion Standard Cubic Feet per Day
CAA	Clean Air Act
CALMET	CALPUFF meteorology preprocessor
CALPOST	CALPUFF post-processor
CALPUFF	Gaussian puff dispersion model used for far-field modeling
CCP	Central Compression Plant
CGF	Central Gas Facility
CO	Carbon Monoxide
CMAQ	Community Multiscale Air Quality
CAMx	Comprehensive Air Quality Model with Extensions
CO_2	Carbon Dioxide
Cp	Plume Contrast
DATs	Deposition Analysis Thresholds
DDM	Decoupled Direct Method
EGU	Electric Generation Units
EMALL	ExxonMobil Alaska LNG LCC
FERC	Federal Energy Regulatory Commission
FLAG	Federal Land Manager's Air Quality related Values Work Group
FLMs	Federal Land Managers
GEP	Good Engineering Practice
GTP	Gas Treatment Plant
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HP	High Pressure
IWAQM	Interagency Workgroup on Air Quality Modeling
LNG	Liquefied Natural Gas
LP	Low Pressure
mg/m^3	Milligrams per Cubic Meter
MMIF	Mesoscale Model Interface Program
MMSCFD	Million Standard Cubic Feet of Gas per Day
N	Nitrogen
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 1983

NCSLs	National Conservation System Lands
NEPA	National Environmental Policy Act
NEI	National Emissions Inventory
NGA	Natural Gas Act
NO	Nitrogen Oxide/ Nitric Oxide
NO_2	Nitrogen Dioxide
North Slope	Alaska's north slope
NO_x	Nitrogen Oxides
HNO_3	Nitric Acid
NSR	New Source Review
NWS	National Weather Service
O_3	Ozone
OCD	Offshore and Coastal Dispersion Model; Includes fumigation algorithms
ODEs	Ozone Depletion Events
OH	Hydroxyl Radical
OLM	Ozone Limiting Method
OSAT	CAMx Ozone Source Apportionment Technology
Pb	Lead
PBU	Prudhoe Bay Unit
PGM	Photochemical Grid Models
PLUVUE II	Plume visibility model used for near-field visual impact modeling
PM	Particulate Matter
$PM_{2.5}$	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
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
PTE	Potential-to-Emit
PTU	Point Thomson Unit
PVMRM	Plume Volume Molar Ratio Method
PVMRM2	Plume Volume Molar Ratio Method 2
Report	FERC air quality modeling report
RFD	Reasonable Foreseeable Development
RMC	Regional Modeling Center
S	Sulfur Dioxide
SCREEN3	A screening dispersion model that includes fumigation algorithms
SDM	Shoreline Dispersion Model; Includes fumigation algorithms
SF	Supplemental Firing
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TPY	Ton per Year
TIBL	Thermal Internal Boundary Layer
$\mu g/m^3$	Micrograms per Cubic Meter
USDOI	U.S. Department of the Interior
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Services
UTM	Universal Transverse Mercator
VISCREEN	A screening model used for near-field visual impact modeling
VOC	Volatile Organic Compound
WHRU	Waste Heat Recovery Unit

WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting
📬E	Plume Perceptibility

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11.0 APPENDICES

APPENDIX A – GTP FACILITY AIR EMISSIONS INVENTORY

Public

EMISSIONS CALCULATION REPORT FOR THE ALASKA LNG GAS TREATMENT PLANT

USAG-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 GTP. 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 calculations are represented by document sections prefixed with EC (Emission Calculation). The tables located within this report reference both the summary tables and the individual equipment calculation sections.

2.0 GAS TREATMENT PLANT FACILITY DESCRIPTION

The Gas Treatment Plant (GTP) would be designed to treat natural gas received from the PBU and the Point Thomson Unit (PTU). The GTP would be constructed on the North Slope near the Beaufort Sea coast and in the PBU. According to the current design, the GTP would have an annual average inlet gas treating capacity of up to 3.7 billion standard cubic feet per day (BSCFD), and would be able to accommodate varying compositions of gas received from the PBU and PTU.

Primary emission sources at the GTP would include gas turbines, boilers/heaters, diesel internal combustion engines and flares. The design for the GTP would consist of three parallel natural gas treatment trains, each sized to process a roughly one-third portion of the inlet untreated feed gas. The process would remove most of the CO_2 and H_2S from the feed gas to meet the specification of the Liquefaction Facility, and some of the water (to a dew point specification for the Mainline). The gas then would be compressed in stages and routed to a gas chilling unit which utilizes a refrigerant to cool the gas. Cooling the gas would help to maintain the stability of the thaw-sensitive soils along sections of the Mainline.

The GTP would include facilities to collect the CO_2 and H_2S by-product streams from the three treatment units. These streams would also contain water and some hydrocarbons. The by-product streams from each train would be compressed and treated to remove water. The gaseous by-product stream (CO_2) would then be transported to the PBU via an approximately one mile pipeline.

The fuel gas to be used for equipment operation at the GTP facility would be the produced treated gas that has had CO_2 and H_2S reduced to Mainline specifications. The treated gas product specifications have a maximum limit of 4 ppmv H_2S, 1 grain sulfur/100 standard cubic feet of gas, and 50 ppmv CO_2. A level of 16 ppmv of sulfur was assumed for the GTP emission calculations described in this Report in order to provide a conservative estimate of the sulfur content that accounts for H_2S and mercaptans that could be present in the treated gas. While this is the case for normal operation, a 96 ppmv total sulfur assumption was applied to early operations and startup of the equipment in the first train, based on the assumed utilization of untreated gas from the CGF prior to commencement of GTP treated gas production.

Table 2-1 lists the major air emissions emitting equipment at the GTP. Information on mobile and non-road equipment of the operational GTP and the associated emissions calculations is provided in **Section 9.0** of this Report. **Table 2-2** shows ambient temperature data for the Prudhoe Bay Area which was used in developing emissions data for certain equipment (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 temperature data are based on measurements from Prudhoe Bay (1986-1999), Deadhorse Airport station (1999-2010), and Umiat Air Field (1949-2001). Data from these locations was assumed to be representative for the GTP facility location. The COOP information from all locations show annual average temperatures around 10°F; Prudhoe Bay is 11.7°F, Deadhorse Airport is 12.1°F, and Umiat Air Field is 10.7°F. A mean temperature value of 10°F was selected as a calculation basis, since it is representative and has been historically used for calculating emissions from sources operating within the PBU. **Table 2-2** lists the values that were used to represent minimum and maximum probable temperatures during normal operations at the site. Extreme temperature values that have rarely been recorded were not used in the emissions calculations. A representative low ambient temperature of -40°F was selected based on the very small reasonably foreseeable probability of the ambient temperature remaining below -40°F for any extended period of time. A review of the 25-year daily average of the regional temperature data which shows only a 0.6% likelihood that the ambient temperature would be below -40°F.

Similarly a value of 70°F was selected for the representative highest ambient temperature, based on the review of the 25-year daily average regional data which shows less than 0.1% probability of an ambient temperature higher than 70°F.

Table 2-1 GTP Emitting Equipment Type and Count

Equipment Type	Facility Count
Compressor Turbines	12
Power Generation Turbines	6
Reciprocating Internal Combustion Engines (Emergency/Non-Emergency)	6
Fuel Gas Heaters/Boilers	5
Flares	8

Table 2-2 Ambient Temperatures Used for GTP Emissions Calculations

	Temperature (°F)
Lowest Ambient	-40
Highest Ambient	70
Annual Average Ambient	10

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 GTP facility on the North Slope (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 GTP 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*

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

of Air Pollutant Emission Factors (USEPA 2009), may be used if suitable vendor data are not available.

Emission rates required for the dispersion modeling analyses presented in this Project submittal 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 modeling 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 the 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 GTP.

4.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS: COMPRESSION TURBINES

4.1 OPERATIONS DESCRIPTION

The compression turbines at the GTP would be designed with spare capacity to allow the GTP to remain in operation during maintenance and upset scenarios. The Treated Gas and CO_2 Compressors would be sized for a 6 x 20% configuration, meaning each compressor would have a maximum capacity representing 20% of the total facility design throughput. This would result in full facility compression capability of roughly 120%, and would allow for one turbine to shut down completely with the facility still able to operate at the 100% design throughput. The turbines would be organized as two sets of two turbines per train (four compression turbines total per train) for the 3 trains.

There would be potential for the turbines to be operating anywhere from 85% load to 100% load, with either all 12 or fewer turbines operating. The normal operating assumption is that all turbines would be operating at reduced capacity. This method of operation is accepted as the simplest way to provide the necessary heat to the trains from the waste heat recovery units (WHRUs) located on the turbine exhaust side. Flexibility would be designed into the trains to allow gas to be passed between trains and compressed by any compressor in any train; however, the heat medium would be specific to each train, as the heat medium systems for the individual trains are not interconnected.

The compressor turbines at the GTP would all be equipped with WHRUs, as well as supplemental firing to ensure the ability to meet each individual trains' heat requirements. The WHRUs would operate by transferring the heat from the hot turbine exhaust gas to the process train heat medium fluid. Supplemental firing is the addition of fuel gas combustion in the turbine exhaust gas to add more heat ahead of the process heat medium fluid heat exchanger in cases when the turbine exhaust does not supply enough heat.

The amount of supplemental firing and the flow rate of the process heat medium fluid through the WHRU would be determined by the needs of the process train, not by the turbine exhaust. The WHRU would be designed to always accept the full exhaust flow from the compressor turbines. Downstream of the WHRU, the system exhaust stack would be the actual emission point. There would be a WHRU bypass stack included in the design that would only be used when there is a need for the WHRU to be shut down. This is provided mostly to account for the possibility of an unexpected tube rupture within the WHRU. All maintenance shutdowns would be assumed to be coordinated with turbine downtime, further reducing the likelihood that the bypass stack would be used.

The WHRU would be designed to transfer the heat duty of the exhaust gas and supplemental firing that corresponds to an exhaust temperature loss from about 1,650°F down to 410°F which would be the exhaust temperature regardless of turbine operating conditions. This design condition would be based on the heat needs of the process trains. The supplemental firing flow rate would be determined by how much fuel gas combustion is required to raise the exhaust gas temperature (typically in the 900°F to 1,100°F range) to 1,650°F.

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 GTP. See **Section 2.0** and **Table 2-2** for a discussion on selection of a representative ambient temperature range at the GTP site. The vendor created the operating and emissions profiles based on the design specifications for the fuel gas to be utilized at the GTP facility, as well as specific 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 GTP 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	Vendor Data

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 GTP 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 annual tons per year per pollutant was needed for determining 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.

4.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates used 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 compression turbines include the assumed operating load, ambient temperature, and the contribution of 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 emission rates for all pollutants. The selected emissions and operating conditions provided conservative estimates 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 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 4-2 Assumed GTP 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 (10°F)
CO			
VOC			
PM_{10}			
$PM_{2.5}$			
SO_2			
Total GHG			
Total HAPs			

Supplemental Firing Considerations-Annual Emissions Calculations

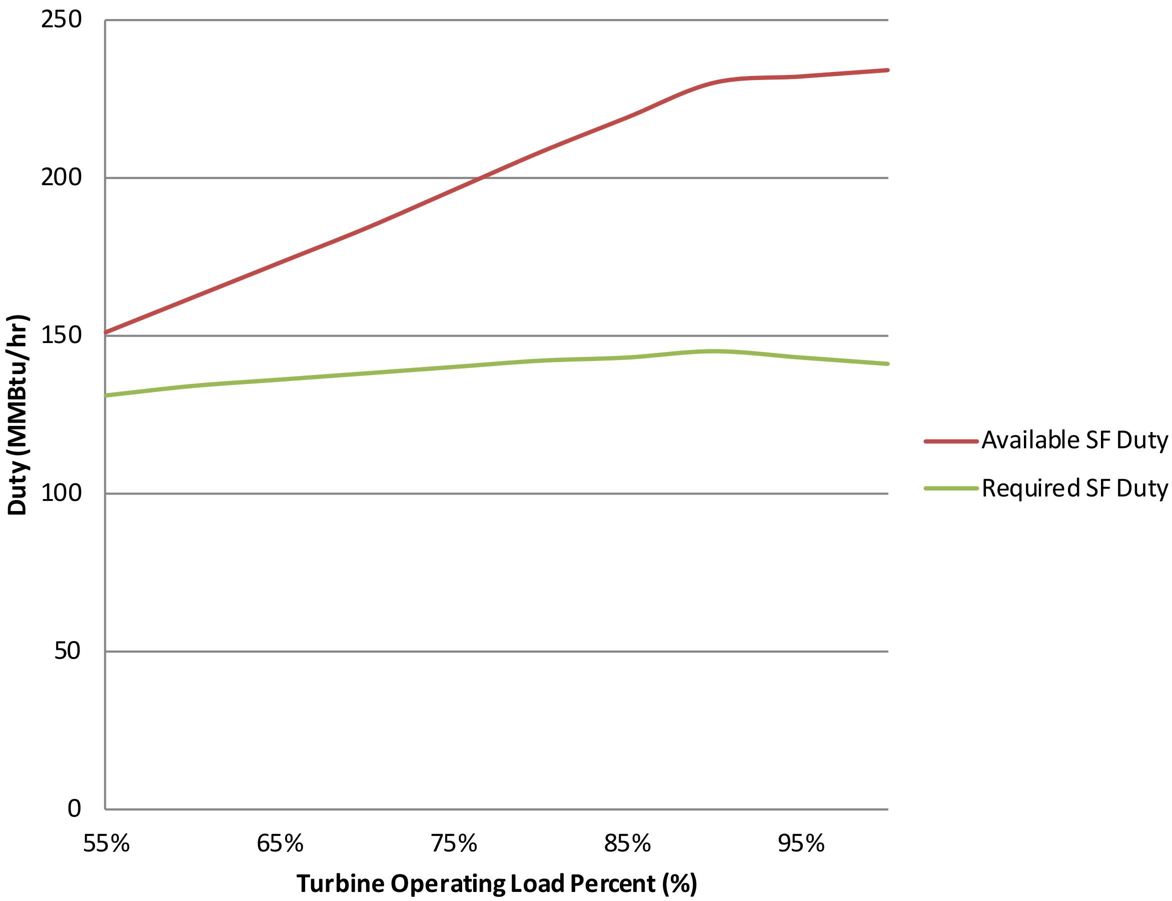
The annual emissions for the supplemental firing were assumed as a constant rate for the year. The rate selected was based on the maximum supplemental firing duty required to meet the process heat needs for each process train with an additional margin to add conservativism to account for annual variability. The supplemental firing emissions were added to the turbine emissions that were based on 100% turbine load operation at 10°F.

The supplemental firing duty would be the duty to increase the turbine exhaust temperature to the required inlet WHRU temperature of 1650°F. This duty was determined based on the fuel gas higher heating value at the GTP. The vendor-provided emission factors related pounds of pollutant to the heat duty of the supplemental firing additional heat.

The required supplemental firing duty is not a linear relationship with turbine load because both turbine exhaust flow rate and temperature impact supplemental firing duty. The heat recovery from both turbines occurs simultaneously and in parallel. Heat recovery is required from both the treated gas compressor turbines and CO_2 compressor turbines to be able to supply the necessary heat to the process train. Since the turbines are different types of machines, they do not necessarily have the same worst-case operations. For determining the emissions, the operation of the turbines was decoupled from each other.

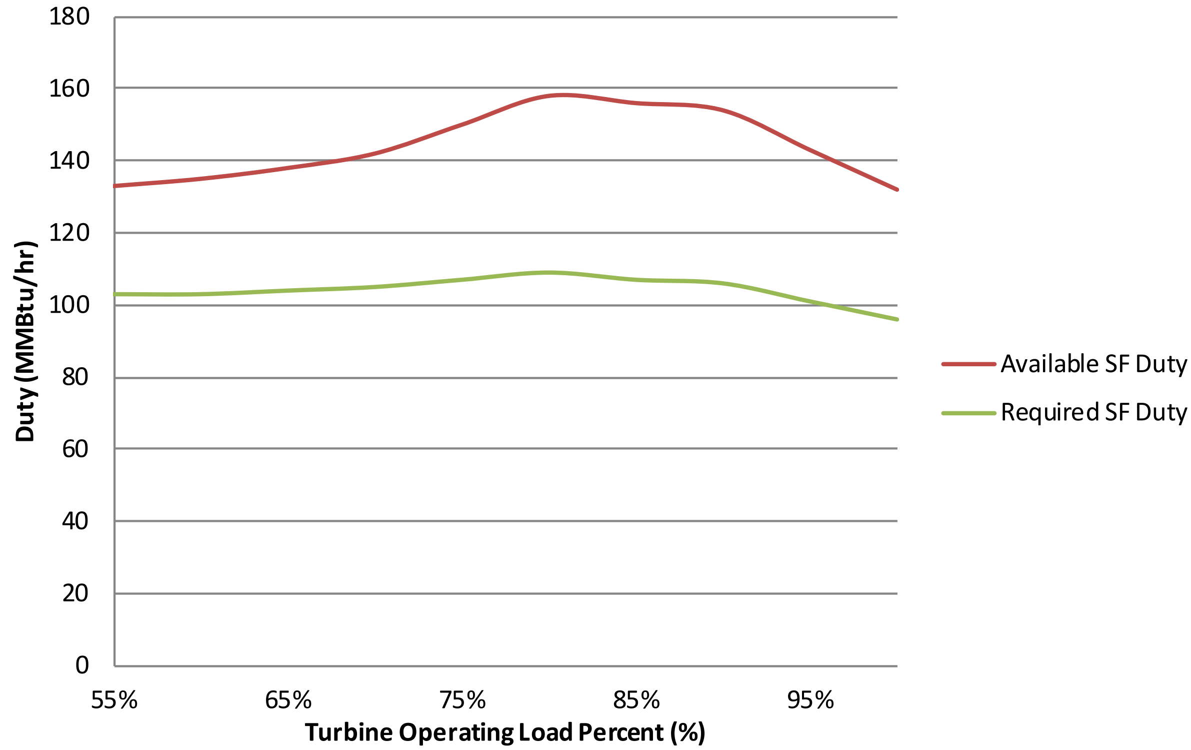
To determine the maximum required supplemental firing duty for the treated gas compressor turbines, the load of the CO_2 compressor turbines were held constant at the normal annual operating load of 85% at 10°F, while the load of the treated gas compressor turbine was varied between 55% and 100% in order to find the peak supplemental firing rate. As shown in **Figure 1**, the maximum required supplemental firing duty occurs at approximately 90% turbine load in combination with the CO_2 compressor turbine operating at 85% load. A margin was added to the maximum required duty and this duty was used for the entire operating year regardless of load and at the annual ambient temperature. The same method was applied to determine the maximum required supplemental firing for the CO_2 compressor turbine, which occurs at approximately 80% turbine load with the treated gas compressor turbine held constant at 85% (see **Figure 2**). For each criteria pollutant, the supplemental firing emissions rate was added to the turbine exhaust emission rate to provide the total pollutant emission rate at the stack.

Figure 1: Treated Gas Compressor Turbine Load vs Supplemental Firing Needs at Ambient Average Temperature (10°F)



Note: CO_2 Compressor Turbine operating at a constant load of 85%.

Figure 2: CO_2 Compressor Turbine Load vs Supplemental Firing Needs at Ambient Average Temperature (10°F)



Note: Treated Gas Compressor Turbine operating at a constant load of 85%.

<u>Final Calculated Annual Emissions</u>

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 GTP Compression Turbines/Supplemental Firing PTE Summary

Pollutant		Treated Gas Compressor Turbine (per turbine)	CO_2 Compressor Turbine (per turbine)	Reference to Calculation
NO_x	ton/year	139	120	Sections EC-1 and EC-4
CO	ton/year	122	121	
VOC	ton/year	16.2	12.1	
PM_{10}	ton/year	15.9	12.0	
$PM_{2.5}$	ton/year	15.9	12.0	
SO_2	ton/year	6.32	4.76	
GHG	tonnes/year	267,551	201,361	
HAPs	ton/year	2.51	1.89	

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 GTP 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 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 in support of 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 lowest operating load with the maximum ambient temperature.
- The exhaust temperature used was the minimum temperature across the range of turbine loads and ambient temperatures, this corresponded with the WHRU outlet temperature that is much lower than the turbine exhaust 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 that were assumed for modeling long-term (i.e., annual average) turbine impacts.

Table 4-4 GTP Short-Term Modeling Parameters for Compression Turbines with WHRU

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 (-40°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Constant for all Turbine Loads and Ambient Temperatures (Based on Process Heat Medium Needs, Minimum Exhaust Temperature of 410°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 4-5 Long-Term Modeling Parameters for GTP Compression Turbines with WHRU

Pollutant	Annual Emissions		Annual Average 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 (10°F)	Average Operating Load (85%)	Maximum Ambient Temperature (70°F)	Constant for all Turbine Loads and Ambient Temperatures (Based on Process Heat Medium Needs, Minimum Exhaust Temperature of 410°F considered)	
CO						
PM_{10}						
$PM_{2.5}$						
SO_2						

Supplemental Firing Considerations Modeling Emissions Calculations

The emissions used for modeling short-term impacts assumed the maximum available supplemental firing duty at the lowest ambient average temperature (-40°F). Available supplemental firing was used for short-term emissions because there is a greater potential for short-term excursions from the required duty. The available supplemental firing duty is the maximum duty of the system and cannot be exceeded without causing damage to the equipment. The supplemental firing emissions were added to the turbine emissions that are based on 100% turbine load operation at -40°F. The lowest ambient temperature provides the most conservative (highest emissions) supplemental firing duty and turbine duty. At warmer ambient temperatures, the exhaust from the turbine is warmer and the system material is warmer, therefore the maximum heat able to be added to the system by supplemental firing would be lower in the summer.

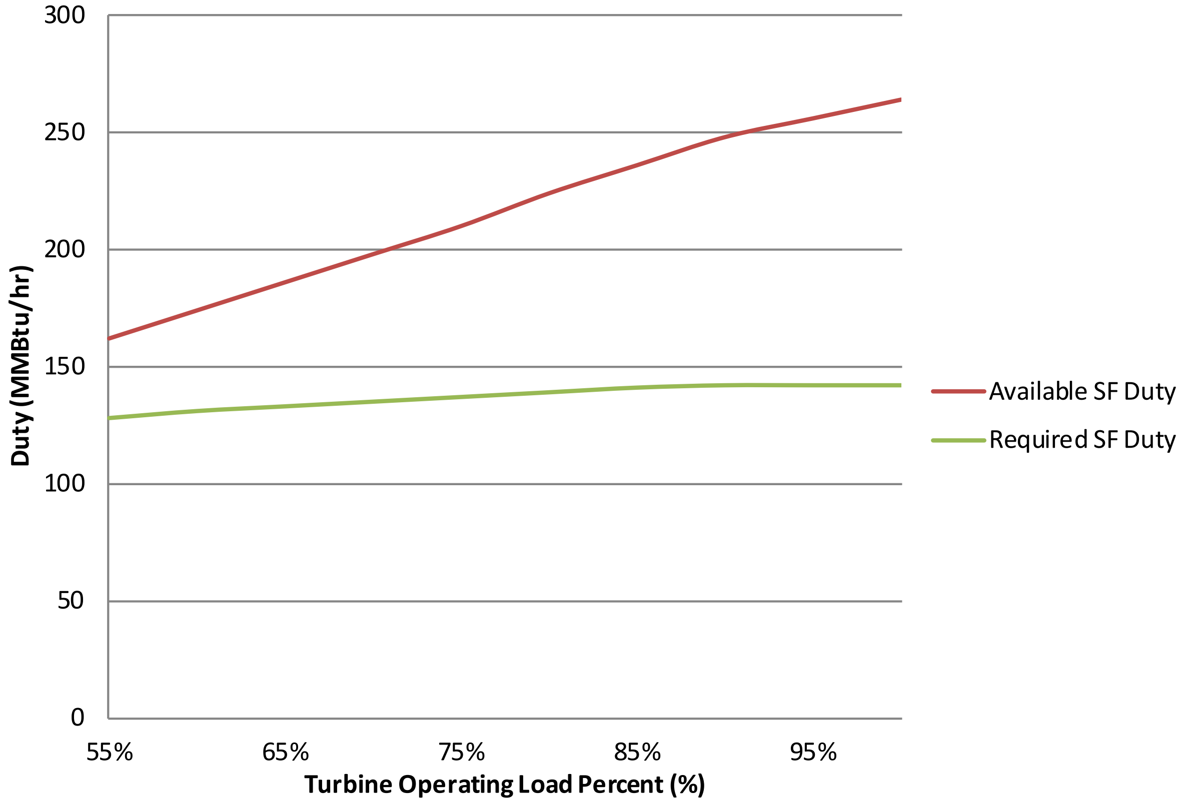
The supplemental firing duty would be the duty to increase the turbine exhaust temperature to the required inlet WHRU temperature of 1650°F. This duty was determined based on the fuel gas higher heating value at the GTP. The vendor-provided emission factors related pounds of pollutant to the heat duty of the supplemental firing additional heat.

The required supplemental firing duty is not a linear relationship with turbine load because both turbine exhaust flow rate and temperature impact supplemental firing duty. The heat recovery from both turbines occurs simultaneously and in parallel. Heat recovery is required from both the treated gas compressor turbines and CO_2 compressor turbines to be able to supply the necessary heat to the process train. Since the turbines are different types of machines, they do not necessarily have the same worst-case operations. For determining the emissions, the operation of the turbines was decoupled from each other.

Similarly to how the annual/long-term emissions were calculated, the turbine supplemental firing duties were determined individually as the load of the other turbine was held at a constant normal annual operating load. To determine the maximum available supplemental firing duty for the treated gas compressor turbines, the CO_2 compressor turbines were held at their normal operating load of 85% at -40°F, while the load of the treated gas compressor turbine was varied between 55% and 100% in order to find the peak supplemental firing rate. As shown in **Figure 3**, the maximum available supplemental firing duty occurs at 100% treated gas compressor turbine load in combination with the CO_2 compressor turbine operating at 85% consistently. The maximum possible supplemental firing duty was selected to model a maximum short-term value, a margin was not added to this value as the maximum available duty cannot be exceeded. The same method was applied to determine the maximum available supplemental firing for the CO_2 compressor turbine, while varying its load as the treated gas compressor turbine is held constant at 85%. As shown in **Figure 4**, the maximum available supplemental firing duty occurs at 80% for the CO_2 compressor turbine. For each criteria pollutant, the supplemental firing emissions rate was added to the turbine exhaust emission rate to provide the total pollutant emission rate at the stack.

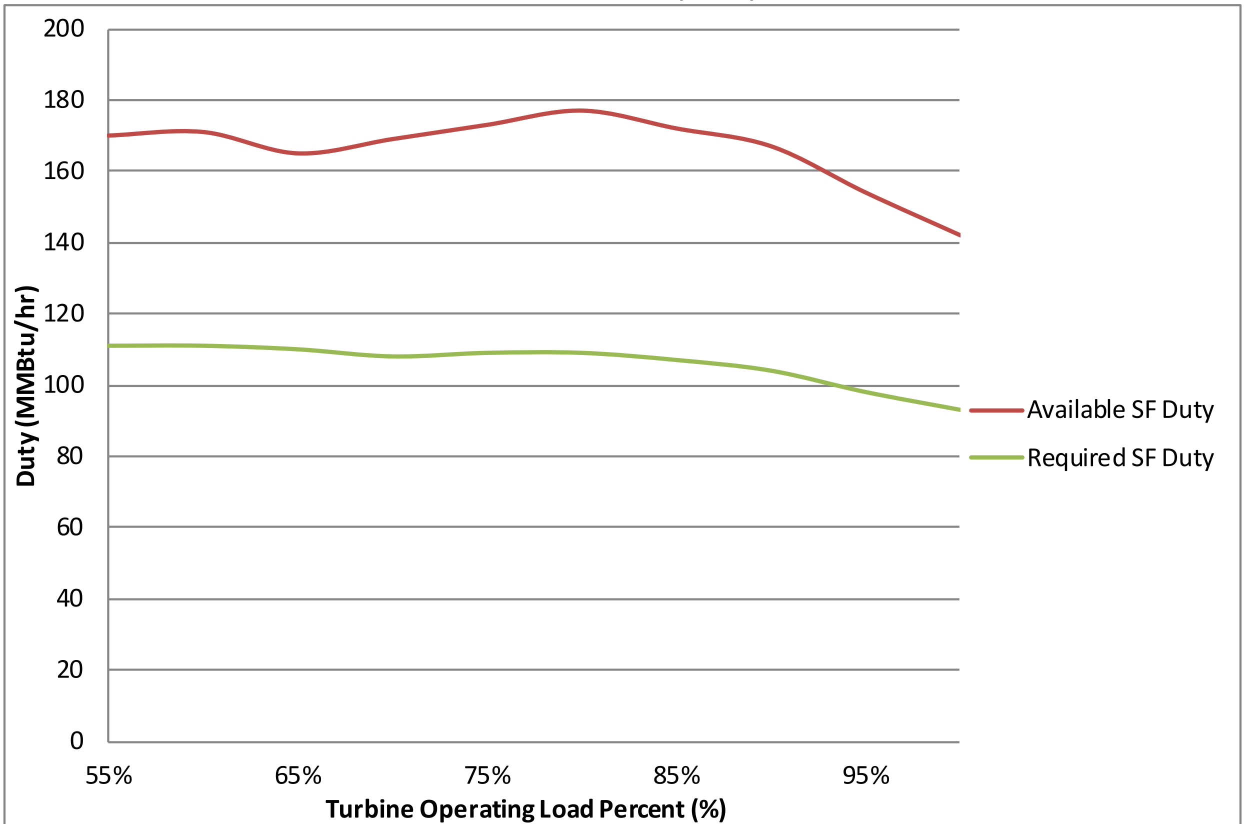
For both annual and short-term modeling, the velocity used to represent the exhaust flow out of the turbine and WHRU stack combination did not include the additional flow from the supplemental firing fuel combustion. Without the flow caused by the supplemental firing, the exit velocities are minimized resulting in conservative model-predicted impacts. As previously described in **Section 4.3.2**, the minimum, and most conservative, exhaust temperature corresponds with the WHRU outlet temperature which is constant regardless of turbine operating loads and supplemental firing duty.

Figure 3: Treated Gas Compressor Turbine Load vs Supplemental Firing Needs at Lowest Ambient Temperature (-40°F)



Note: CO_2 Compressor Turbine operating at a constant load of 85%.

Figure 4: Treated Gas Compressor Turbine Load vs Supplemental Firing Needs at Lowest Ambient Temperature (-40°F)



Note: Treated Gas Compressor operating at a constant load of 85%.

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 GTP Compression Turbines with WHRU

Pollutant		Treated Gas Compressor Turbine (per turbine)			CO_2 Compressor Turbine (per turbine)			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	5.56	483	15.85	4.08	483	12.5	Sections EC-2 and EC-4
	Long-Term	4.01			3.44			
CO	Short-Term	4.51			7.77			
PM_{10}	Short-Term	0.55			0.39			
	Long-Term	0.46			0.34			
$PM_{2.5}$	Short-Term	0.55			0.39			
	Long-Term	0.46			0.34			
SO_2 @ 16 ppmv	Short-Term (Hourly)	0.22			0.16			
	Short-Term (Daily)	0.22			0.16			
	Long-Term	0.18			0.14			
SO_2 @ 96 ppmv	Short-Term (Hourly)	1.33			0.95			
	Short-Term (Daily)	1.33			0.95			
	Long-Term	1.09			0.82			

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 GTP Compression Turbines with WHRU

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 GTP main power generation system would consist of six turbines total, which would create a common power supply for the facility. Individual power generation turbine load would fluctuate based on the needs of the process trains, and could range from 60% to 100%. Seasonal load variations would be the most common reason for differences in power generation equipment operation. For example, air cooler fans would have a much higher energy demand during the summer months than in winter, thus requiring a higher power generation turbine output. During, typical winter operation, it is estimated that only five or fewer of the six power generation turbines would be required. However, during the summer months, all six turbines would be expected to be operating.

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 GTP. See **Section 2.0** and **Table 2-2** for a discussion on selection of a representative ambient temperature range at the GTP site. The vendor created the operating and emissions profiles based on the design specifications for the fuel gas to be utilized at the GTP facility, as well as the specific ambient temperatures and typical ambient pressure at 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 GTP 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	Vendor Data

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 GTP 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 to New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the power generation turbines include operating load and ambient temperature.

Operating Load and Ambient Temperature Selection

Table 5-2 provides the assumed operating hours, as well as the assumed turbine loads and ambient temperatures corresponding to the maximum annual emission rates for all pollutants. The selected emissions and operating conditions provided a conservative estimate of the power generation 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 in load, which typically results in fewer 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 GTP 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 (10°F)
CO			
VOC			
PM_{10}			
$PM_{2.5}$			
SO_2			
Total GHGs			
Total HAPs			

Supplemental Firing Considerations Annual Emissions Calculations

Supplemental firing was not utilized in the design of the GTP power generation turbines.

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 GTP Power Generation Turbines PTE Summary

Pollutant		Power Generation Turbine (per turbine)	Reference to Calculation
NO_x	ton/year	73.2	Sections EC-1 and EC-4
CO	ton/year	104	
VOC	ton/year	3.75	
PM_{10}	ton/year	11.8	
$PM_{2.5}$	ton/year	11.8	
SO_2	ton/year	4.23	
GHG	tonnes/year	179,600	
HAPs	ton/year	1.74	

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 GTP 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 for modeling 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 that were assumed in the dispersion modeling to evaluate maximum 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 was the minimum velocity across the range of turbine loads and ambient temperatures, this corresponded to operation at the lowest operating load with 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 lowest operating load with 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 5-5 provides similar information relating to the emission rates and stack parameters that were assumed for modeling long-term (i.e., annual average) turbine impacts.

Table 5-4 Short-Term Modeling Parameters for GTP Power Generation Turbine

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 (-40°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Minimum Operating Load (60%)	Minimum Ambient Temperature (-40°F)
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 GTP Power Generation Turbine

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 (10°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Minimum Operating Load (60%)	Minimum Ambient Temperature (-40°F)
CO						
PM_{10}						
$PM_{2.5}$						
SO_2						

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

Supplemental firing was not utilized in the design of the GTP power generation 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 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 GTP 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	2.69	739	25.3	Sections EC-2 and EC-4
	Long-Term	2.11			
CO	Short-Term	1.64			
PM_{10}	Short-Term	0.37			
	Long-Term	0.34			
$PM_{2.5}$	Short-Term	0.37			
	Long-Term	0.34			
SO_2 @ 16 ppmv	Short-Term (Hourly)	0.13			
	Short-Term (Daily)	0.13			
	Long-Term	0.12			
SO_2 @ 96 ppmv	Short-Term (Hourly)	0.79			
	Short-Term (Daily)	0.79			
	Long-Term	0.73			

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 GTP 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 following reciprocating diesel internal combustion engines are expected to be installed at the GTP.

Black Start Diesel Generator

The Black Start Diesel Generator would be provided to assist in the black start of the main power generation turbines. The Black Start Diesel Generator would be capable of providing rapid start power for the black start of one of the power generation turbines. The Black Start Diesel Generator would only be used if all power generation turbines are shut down at once and then brought back online.

Dormitory Emergency Diesel Generator

The Dormitory Emergency Diesel Generator would have the ability to provide the worker camp with partial power if line power is lost. This generator would only feed the man camp with limited capacity, but would be sized to provide power to essential functions.

Diesel Firewater Pump Engines

There would be three Main Diesel Firewater Pumps which would be located at the man camp facilities, not within the process trains. The pumps would be attached to specific Camp Firewater Storage Tanks that would house water only for a fire emergency system.

Communications Tower Generator

The Communications Tower Generator would be provided to allow for supply of power to the Communication System during loss of line power. The communications tower would be located at the man camp.

6.2 EMISSIONS DATA SOURCES

Common industry standards for specific equipment types were used to provide emission factors that were 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 (USEPA 2010) 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 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 60.4202 Rule (a-2) based on the size and build date of the equipment, 40 CFR Part 89 Subpart B, 89.112: Control of

Emissions from New and In-Use Nonroad Compression-Ignition Engines (USEPA 2005) was used. The Tier 2 level of emission control was assumed for these units since the equipment would not be installed until 2025. (See **Table 6-2**)

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 6-3**)

Table 6-1 Data Sources for GTP 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 3.4 (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 GTP 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 GTP Emergency Diesel Equipment Emissions Estimation

Pollutant	Data Source Description
NO_x	40 CFR Part 89 Subpart B, 89.112 (95% of NO_x+NMHC) (USEPA 2005)
CO	40 CFR Part 89 Subpart B, 89.112 (USEPA 2005)
VOC	40 CFR Part 89 Subpart B, 89.112 (5% of NO_x+NMHC) (USEPA 2005)
PM_{10}[1]	40 CFR Part 89 Subpart B, 89.112 (USEPA 2005)
$PM_{2.5}$	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 3.4 (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 GTP 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 6-3 Data Sources for GTP 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 GTP 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 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.

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 with New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the diesel-driven engines include annual operating hours and operating load.

<u>**Operating Hours and Operating Load**</u>

Diesel firewater pump engines and emergency generators would typically be run 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 NO_x and SO_2 impacts from such sources against the short-term ambient standards. Accordingly, the NO_x and SO_2 modeling impacts for these sources may use "annualized" emissions, i.e., total annual emissions can be assumed to be spread over all hours of the year to calculate a much lower equivalent hourly rate.

Table 6-4 provides the assumed operational characteristics chosen for the calculation of the annual emission rates for intermittent diesel equipment to provide a conservative estimate of PTE values for PSD Applicability and FERC Impact Assessment. This approach was conservative for the following reasons:

- The assumption of 500 hours of operation per year was much higher than the projected actual operation per year (more likely less than 100 hours of operation per year).
- Maximum load for full duration of each operating period, without any variations in load that would typically result in lower emissions.

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

Table 6-4 Assumed GTP Intermittent Diesel Equipment Annual Operations

Pollutant	Annual Operating Hours	Selected Load
NO_x	Maximum Intermittent Operating Hours (500 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 intermittent diesel equipment to be included in the facility's PTE summary are shown in **Table 6-5**.

Table 6-5 GTP Intermittent Diesel Equipment PTE Summary

Pollutant		Black Start Diesel Generator	Main Diesel Firewater Pump (per pump)	Dormitory Emergency Diesel Generator	Communications Tower Generator	Reference to Calculation
NO_x	ton/year	7.30	0.49	0.65	0.39	Sections EC-1 and EC-5
CO	ton/year	7.30	0.45	0.60	0.36	
VOC	ton/year	0.40	0.03	0.03	0.02	
PM_{10}	ton/year	0.08	0.03	0.03	0.02	
$PM_{2.5}$	ton/year	0.08	0.03	0.03	0.02	
SO_2	ton/year	0.01	7.28E-04	9.76E-04	5.86E-04	
GHG	tonnes/year	1,055	64.9	87.1	52.2	
HAPs	ton/year	0.01	1.77E-03	2.37E-03	1.42E-03	

6.3.2 Criteria Pollutant Modeling

Conservative estimates of the maximum short-term and long-term emissions from intermittent diesel equipment at the GTP were needed to support required dispersion modeling for evaluation of GTP 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. 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 6-6 shows the diesel equipment operating load assumptions that were used in determining short-term emission rates for modeling. However, as discussed in **Section 6.3.1** and allowed by USEPA guidance (USEPA 2011), the "hourly" emission rates that were used in modeling the intermittent engines for 1-hour NO_2 and 1-hour SO_2 were 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 modeled 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 6-7 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 6-6 Short-Term Modeling Parameters for GTP Intermittent Diesel Engines

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 6-7 Long-Term Modeling Parameters for GTP Intermittent Diesel Engines

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 6-8**.

Table 6-8 Modeling Emissions Summary for GTP Intermittent Diesel Equipment

Pollutant		Black Start Diesel Generator			Main Diesel Fire Water Pump (per pump)			Dormitory Emergency Diesel Generator			Communication Tower Generator			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	0.21 (Annualized)	744	20.7	0.01 (Annualized)	728	10.8	0.02 (Annualized)	729	14.6	0.01 (Annualized)	728	8.72	Sections EC-2 and EC-5
	Long-Term	0.21			0.01			0.02			0.01			
CO	Short-Term	3.68			0.23			0.30			0.18			
PM_{10}	Short-Term	0.04			0.01			0.02			0.01			
	Long-Term	2.40E-03			7.43E-04			9.91E-04			5.95E-04			
$PM_{2.5}$	Short-Term	0.04			0.01			0.02			0.01			
	Long-Term	2.40E-03			7.43E-04			9.91E-04			5.95E-04			
SO_2	Short-Term (Hourly)	2.70E-04 (Annualized)			2.09E-05 (Annualized)			2.81E-05 (Annualized)			1.69E-05 (Annualized)			
	Short-Term (Daily)	4.73E-03			3.67E-04			4.92E-04			2.95E-04			
	Long-Term	2.70E-04			2.09E-05			2.81E-05			1.69E-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 analyses were speciated as described in the following subsection.

<u>**PM Speciation Breakdown**</u>

Table 6-9 shows the assumed breakdown and basis for the short-term GTP diesel engine emissions of the PM_{10} and $PM_{2.5}$ into filterable and condensable fractions, as required for AQRV modeling.

Table 6-9 AQRV PM Speciation for GTP 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)
Pump	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2[1] (USEPA 2009)

Note 1: Some of the equipment at the GTP would be less than 600 hp. Since no filterable/condensable PM information is provided in AP-42 Section 3.3, the data in AP-42 Section 3.4: Large Stationary Diesel Equipment (greater than 600 hp), was used to estimate the AQRV PM Speciation for these engines.

7.0 DEVELOPMENT OF EMISSIONS AND STACK PARAMETERS: FUEL GAS HEATERS

7.1 OPERATIONS DESCRIPTION

The fuel gas heaters listed below are expected to be installed at the GTP.

Building Heat Medium Heaters

The Building Heat Medium Heaters would provide heat to the process modules, utility modules, common areas, and other enclosed areas. The building heat medium system would be separate from the process heat medium systems; it therefore would require separate heat input since it would not be connected to any waste heat recovery system. The building heat medium system would be kept separate from the process heat medium system to employ a different type of heat medium that is more commonly used for buildings.

Three Building Heat Medium Heaters would be part of the design; however, one of these units would be assumed to be a full spare that would never run during normal operations. The heaters would be all sized for 50% of the required heat capacity needed at the facility, i.e., 3 x 50%. The load on the remaining two heaters would fluctuate based on seasonal heat needs.

Operations Camp Heaters

The Operations Camp Heaters would provide heat to the man camp enclosed areas. The operations camp system would be separate from all other facility heat systems because of the type of heat medium that could be used and because of the distance between the camp and process areas.

Three Operations Camp Heaters would be part of the design; however, one of these units would be assumed to be a full spare that would never run during normal operations. The heaters would be all sized for 50% of the required heat capacity needed at the camp, i.e., 3 x 50%. The load on the remaining two heaters would fluctuate based on seasonal heat needs.

Buyback Gas Bath Heaters

The Buyback Gas Bath Heaters would heat any treated gas that would be rerouted back from the sales pipeline downstream of the metering station. This gas may be required by the facility if treated gas is ever unavailable to feed the fuel gas system. Typically, the Buyback Gas Bath Heaters would operate in a standby low-load mode. Maintaining the heaters in standby mode would be required in case buyback gas is needed quickly. The heaters would be sized to be able to heat the entire low pressure and high pressure fuel gas demand of the facility. There would be two heaters sized as 2 x 50% of the total fuel capacity.

7.2 EMISSIONS DATA SOURCE

Common industry standards as well as publicly available, currently operating, gas-fired heater information were used to determine the emission factors to be used for the GTP fired heaters. A compilation of public sources was used to determine the appropriate emission factors to be used with an ultra-low NO_x burner or low NO_x burner. It was assumed that the heater emission factors for NO_x and VOC in the USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009) were overly conservative for the either of these proposed burner types. Also, greenhouse gas emission factors were taken from 40 Part 98 *Mandatory Greenhouse Gas Reporting, Subpart C, General Stationary Fuel Combustion Sources* (USEPA 2011). **Table 7-1** lists the sources of the emission factors that were used to calculate gas heater emissions for all pollutants.

Table 7-1 Data Sources for GTP Fired Heaters Emissions Estimation

Pollutant	Data Source Description
NO_x	Average emission factor used by recent Alaska DEC for only heater point source emissions reporting (ADEC 2011)
CO	AP-42 equipment emission factors, Section 1.4 (USEPA 2009)
VOC	Average emission factor used by recent Alaska DEC for only heater point source emissions reporting (ADEC 2011)
PM_{10}[1]	AP-42 equipment emission factors, Section 1.4 (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 Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 1.4 (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 GTP 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.

7.3 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.

7.3.1 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 gas-fired heaters include operating hours and operating load.

Operating Load and Ambient Temperature Selection

Table 7-2 provides the assumed operational characteristics chosen for the calculation of annual emission rates for the gas-fired heaters to provide a conservative estimate of PTE per pollutant for PSD Applicability and FERC Impact Assessment. For the continuously operating Building Heat Medium Heaters and the Operations Camp Heaters, operational characteristics representing the maximum possible annual emissions were selected. However, only two of the three heaters would ever be operating at the same time and emissions were calculated accordingly. The annual emissions estimated in this manner for the Building Heat Medium and Operations Camp heaters are conservative, because the assumption of continuous operation at maximum load throughout the year does not reflect any load variations that would typically result in lower emissions.

The Buyback Gas Bath Heaters were represented by dual operating modes (standby and full load conditions) to provide conservative, but realistic, annual emission rate estimate. Fuel gas to the burners was supplied continuously, whether at the reduced standby rate or at maximum capacity. The full-capacity operating condition was conservatively assumed to occur 500 hours/year for each heater for purposes of the annual emissions estimates. The hourly emission rates for the 500 hours/year full-capacity case were annualized over the entire year (500 hours/8,760 hours) and then added to the emissions for the lower continuous, standby load operation that was assumed to occur for the remaining hours of the year.

The buyback gas heater emissions were conservative because of the following:

- Operation at standby load was assumed as constant operation for a full year.

The buyback gas heater maximum emissions were conservative because of the following:

- The assumption of 500 hours per year of operation at full-capacity is much higher than the projected actual annual hours (most likely only a few hours per year).
- Assumed operation at maximum load for all 500 hours does not account for any operational load variations that would typically result in lower emissions.

The emission factors that used for these gas-fired heaters are not dependent on ambient temperature.

Table 7-2 Assumed GTP Fired Heaters Annual Operations

Pollutant	Building Heat Medium Heaters and Operations Camp Heaters		Buyback Gas Bath Heaters (Standby)		Buyback Gas Bath Heaters (Full-Capacity)	
	Annual Operating Hours	Selected Load	Annual Operating Hours	Selected Load	Annual Operating Hours	Selected Load
NO_x	Continuous Full-Time Operation (8,760 hours)	Maximum Operating Load (100%)	Continuous Full-Time Operation (8,760 hours)	Standby Operating Load (1%)	Maximum Intermittent Operating Hours (500 hours)	Full-Capacity 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 heaters to be included in the facility's PTE summary are shown in **Table 7-3**.

Table 7-3 GTP Fired Heaters PTE Summary

Pollutant		Building Heat Medium Heaters (per Heater)	Operations Camp Heaters (per Heater)	Buyback Gas Bath Heater Primary Heater (per Heater)		Buyback Gas Bath Heater Secondary Heater (per Heater)		Reference to Calculation
				Standby	Full-Capacity	Standby	Full-Capacity	
NO_x	ton/year	96.3	11.2	0.05	0.51	0.05	0.42	Section EC-1 and EC-6
CO	ton/year	99.1	11.5	0.06	0.52	0.06	0.43	
VOC	ton/year	7.22	0.84	4.04E-03	0.04	4.04E-03	0.03	
PM_{10}	ton/year	8.97	1.04	0.01	0.05	0.01	0.04	
$PM_{2.5}$	ton/year	8.97	1.04	0.01	0.05	0.01	0.04	
SO_2	ton/year	3.02	0.35	1.80E-03	0.02	1.80E-03	0.01	
GHG	tonnes/year	127,835	14,829	71.6	672	71.6	556	
HAPs	ton/year	2.22	0.26	1.24E-03	0.01	1.24E-03	0.01	

7.3.2 Criteria Pollutant Modeling

Conservative estimates of the short-term and long-term emissions from the gas-fired heaters were needed to support required dispersion modeling for evaluation of GTP 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 of NO_x and SO_2 from the maximum operation of the Buyback Gas Bath Heaters were annualized in accordance with USEPA guidance (USEPA 2011) on modeling emissions from intermittent sources.

Operating Load Selection

Table 7-4 shows the gas-fired heaters operating load assumptions that were used in determining short-term emission rates for the criteria pollutant modeling analyses for all pollutants and averaging times. As discussed in **Section 7.3.1** and allowed by USEPA guidance (USEPA 2011), the Buyback Gas Bath Heaters maximum "hourly" emission rates used in the modeling for 1-hour NO_2 and 1-hour SO_2 were 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 equipment that would actually operate at full load for only a few 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. Additionally, as previously stated for the Building Heat Medium Heaters and the Operations Camp Heaters, only two of the three heaters were included as simultaneous operational emission sources in the dispersion modeling. Assuming all three heaters operating at 100% capacity would not be a reasonably foreseeable operation mode.

The modeled exhaust velocities and exhaust temperatures for the individual heaters were those corresponding to the assumed load operations for determining emissions. These values are not be dependent on ambient temperature.

Table 7-5 shows the selection of modeling parameters for evaluating annual average impacts. All annual emission rates for the maximum Buyback Gas Bath Heater operation were based on the maximum emission rate derated by a factor of 500 hours/8,760 hours.

Table 7-4 Short-Term Modeling Parameters for GTP Fired Heaters

Pollutant	Emission Type	Building Heat Medium Heaters and Operations Camp Heaters			Buyback Gas Bath Heater (Standby)			Buyback Gas Bath Heater (Full-Capacity)		
		Emissions	Exhaust Velocity	Exhaust Temperature	Emissions	Exhaust Velocity	Exhaust Temperature	Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load
NO_x	1-Hour	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Standby Operating Load (1%)	Standby Operating Load (1%)	Standby Operating Load (1%)	100% (Annualized)	Full-Capacity Operating Load (100%)	Full-Capacity 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 7-5 Long-Term Modeling Parameters for GTP Fired Heaters

Pollutant	Building Heat Medium Heaters and Operations Camp Heaters			Buyback Gas Bath Heater (Standby)			Buyback Gas Bath Heater (Full-Capacity)		
	Emissions	Exhaust Velocity	Exhaust Temperature	Emissions	Exhaust Velocity	Exhaust Temperature	Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load	Selected Load
NO_x	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Standby Operating Load (10%)	Standby Operating Load (1%)	Standby Operating Load (1%)	Full-Capacity Operating Load (100%)	Full-Capacity Operating Load (100%)	Full-Capacity 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 heaters to be included in the facility's modeling compliance demonstration are shown in **Table 7-6** and **Table 7-7**.

Table 7-6 Modeling Emissions Summary GTP Fired Heaters

Pollutant		Building Heat Medium Heaters (per Heater)			Operations Camp Heaters (per Heater)			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	2.77	461	7.92	0.32	398	8.84	Section EC-2 and EC-6
	Long-Term	2.77			0.32			
CO	Short-Term	2.85			0.33			
PM_{10}	Short-Term	0.26			0.03			
	Long-Term	0.26			0.03			
$PM_{2.5}$	Short-Term	0.26			0.03			
	Long-Term	0.26			0.03			
SO_2 @ 16 ppmv	Short-Term (Hourly)	0.09			0.01			
	Short-Term (Daily)	0.09			0.01			
	Long-Term	0.09			0.01			
SO_2 @ 96 ppmv	Short-Term (Hourly)	0.52			0.06			
	Short-Term (Daily)	0.52			0.06			
	Long-Term	0.52			0.06			

Table 7-7 Modeling Emissions Summary GTP Fired Heaters

Pollutant		Buyback Gas Bath Heater (Primary Heater)						Buyback Gas Bath Heater (Secondary Heater)						Reference to Calculation
		Standby			Full-Capacity			Standby			Full-Capacity			
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO_x	Short-Term	1.55E-03	589	0.10	0.01 (Annualized)	589	16.7	1.55E-03	748	0.12	0.01 (Annualized)	748	17.5	Section EC-2 and EC-6
	Long-Term	1.55E-03			0.01			1.55E-03			0.01			
CO	Short-Term	1.60E-03			0.26			1.60E-03			0.22			
PM_{10}	Short-Term	1.44E-04			0.02			1.44E-04			0.02			
	Long-Term	1.44E-04			1.36E-03			1.44E-04			1.12E-03			
$PM_{2.5}$	Short-Term	1.44E-04			0.02			1.44E-04			0.02			
	Long-Term	1.44E-04			1.36E-03			1.44E-04			1.12E-03			
SO_2 @ 16 ppmv	Short-Term (Hourly)	5.17E-05			4.57E-04 (Annualized)			5.17E-05			3.77E-04 (Annualized)			
	Short-Term (Daily)	5.17E-05			8.01E-03			5.17E-05			6.61E-03			
	Long-Term	5.17E-05			4.57E-04			5.17E-05			3.77E-04			
SO_2 @ 96 ppmv	Short-Term (Hourly)	3.09E-04			2.74E-03			3.09E-04			2.26E-03			
	Short-Term (Daily)	3.09E-04			4.80E-02			3.09E-04			3.96E-02			
	Long-Term	3.09E-04			2.74E-03			3.09E-04			2.26E-03			

7.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling, in that it includes additional attention to acid deposition and visibility impacts. Emissions of gaseous pollutants in the AQRV impact assessment were the same as those used in the other short-term impact modeling described in **Section 7.3.2**. The short-term particulate matter emissions used for the AQRV analysis were speciated as described in the following subsection.

PM Speciation Breakdown

Table 7-8 shows the assumed breakdown and basis for the short-term fired heater emissions of the PM_{10} and $PM_{2.5}$ into filterable and condensable fractions, as required for AQRV modeling.

Table 7-8 AQRV PM Speciation for GTP Fired Heaters

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}	
Heater	Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (USEPA 2009)
Boiler	Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (USEPA 2009)

8.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMTERS: FLARES

8.1 OPERATIONS DESCRIPTION

The flare system at the GTP Facility would consist of four different types of flares, high and low pressure CO_2 flares and high and low pressure hydrocarbon flares. The multiple flare services would be provided in an effort to minimize the required sizes of the flares and the flare headers. High pressure and low pressure flares would be separated based on the relief pressure of the largest single relief gas flow rate. The separation of high pressure from low pressure would reduce the amount of equipment required to have a high design pressure to account for high back pressures. Additionally, the hydrocarbon services would be separated from the CO_2 services due to the complications of low-BTU flaring. The flaring events involving a gas with a heating value greater than 200 BTU/scf would be routed to the hydrocarbon flare, while all gas streams with lower heating values would be routed to the CO_2 flares, where they could be mixed with assist gas to increase the streams' heating value for flaring. The USEPA's *AP-42 Compilation of Air Pollutant Emission Factors,* Chapter 13, Section 5 (USEPA 2009) on Industrial Flares requires the gas flared to have a fuel heating value of at least 200 BTU/ft^3 to ensure complete combustion. The relief streams from the CO_2 area within the GTP would not meet the required fuel heating value and would need to have fuel gas added to the stream in order to ensure combustion. The fuel gas addition would be designed to increase the relief flow fuel value up to 300 BTU/ft^3 for conservatism.

Four common flare headers would be split into two flare systems, each sized to handle 100% of the anticipated GTP's requirements. One flare system would be operational and the other system would be held in reserve. This would allow for the facility to keep operating during any individual flare maintenance or shutdown event. The reserve flare system would be fed with fuel gas to keep the flare headers purged of oxygen and to keep the flare pilots operational.

8.2 EMISSIONS DATA SOURCE

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

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

Table 8-1 Data Sources for GTP 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's default accepted ratio of 0.5 (USEPA 2011)

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 GTP 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 include annual operating hours and emergency relief rates.

Operating Hours and Operating Load

Emissions from the flare systems were calculated uniquely because this equipment 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 condition, for limited emergency or upset conditions, was conservatively assumed to occur 500 hours/year. The emissions from the 500 hours/year maximum case were annualized over the entire year using a derating factor of 500 hours/8,760 hours, which 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 fuels would be combusted in the flares. The Fd factor only accounts for gas with butane (C4 or 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 was assumed to be similar to standard values used for the other external combustion devices (boilers/heaters). Specifically, an oxygen concentration of 3% and a water concentration of 10% were used in the calculation.

Table 8-2 provides the assumed operational characteristics selected for the calculation of maximum annual pollutant emissions, based on continuous pilot/purge operation, and intermittent maximum/emergency relief operation for 500 hours per year.

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

- 500 hours of operation per year was assumed and is much higher than the projected actual operation per year (more likely less than 1 hour of such operation per year).
- Maximum load for full duration of operation without any variations which would typically result in lower emissions.

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

Table 8-2 Assumed GTP Flare Annual Operations

Pollutant	Annual Operating Hours (Pilot/Purge) All Flares	Annual Operating Hours (Maximum) All Flares	Selected Load All Flares
NO_x	Continuous Full-Time Operation (8,760)	Maximum Intermittent Operating Hours (500)	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			

Final Calculated Annual Emissions

The annual emissions calculated for the flares to be included in the facility's PTE summary are shown in **Table 8-3**.

Table 8-3 GTP Flare PTE Summary

Pollutant		LP CO_2 Flare (Per Flare)		HP CO_2 Flare (Per Flare)		HP Hydrocarbon Flare (Per Flare)		LP Hydrocarbon Flare (Per Flare)		Reference to Calculation
		Purge/ Pilot	Max	Purge/ Pilot	Max	Purge/ Pilot	Max	Purge/ Pilot	Max	
NO_x	ton/year	2.03	164	0.88	53.6	2.34	1,246	0.43	76.4	Sections EC-1 and EC-7
CO	ton/year	9.27	746	4.02	244	10.7	5,681	1.95	348	
VOC	ton/year	17.05	1,372	7.40	450	19.6	10,446	3.59	641	
PM_{10}	ton/year	0.84	67.9	0.37	22.3	0.97	517	0.18	31.7	
$PM_{2.5}$	ton/year	0.84	67.9	0.37	22.3	0.97	517	0.18	31.7	
SO_2	ton/year	0.08	19.7	0.03	6.46	0.09	51.6	0.02	2.82	
GHG	tonnes/year	3,178	255,748	1,379	83,775	3,652	1,946,853	669	119,420	
HAPs	ton/year	0.09	6.97	0.04	2.28	0.10	53.1	0.02	3.26	

8.3.2 Criteria Pollutant Modeling

Conservative estimates of the short-term and long-term emissions from flaring were needed to support required dispersion modeling for evaluation of GTP 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 maximum/emergency emissions for NO_x and SO_2 were annualized in accordance with USEPA guidance (USEPA 2011) for emissions calculations to support modeling of intermittent sources.

Operating Load Selection

The flares required two separate emissions calculations: one for the purge/pilot emissions that occur continuously for 8,760 hours/year, and another for the emergency maximum flaring case that was assumed to occur 500 hours per year. Emissions for the latter operating mode were annualized over the entire year (derated by a factor of 500 hours/8,760 hours). All emissions were modeled at the same location.

Table 8-3 details the flare operational characteristics assumed for the calculation of short-term modeled flare emission rates.

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

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

In accordance with USEPA Guidance (USEPA 1995), flares also required additional consideration for the calculation of their modeled heights and diameters. It is understood that flares are different from most other combustion 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 height that better represents 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 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-7**.

Table 8-4 and **Table 8-5** summarize the information that was used for development of short-term and long-term flaring emission estimates, respectively. All annual emission rates for the maximum operation scenarios were based on the maximum emission rate derated by a factor of 500 hours/8,760 hours.

Table 8-4 Short-Term Modeling Parameters for GTP Flares

Pollutant	Emission Type	Purge/Pilot Emissions	Maximum Relief Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load		
NO_x	1-Hour	Purge/Pilot Operating Load (100%)	100% (Annualized)	USEPA and ADEC Standard (20 m/s)	USEPA and ADEC Standard (1,273°K)
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 8-5 Long-Term Modeling Parameters for GTP Flares

Pollutant	Purge/Pilot Emissions	Maximum Relief 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				

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 8-6** and **Table 8-7**.

Table 8-6 Modeling Emissions Summary for GTP CO_2 Flares

Pollutant		LP CO_2 Flare (Per Flare)				HP CO_2 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	0.06	4.71 (Annualized)	1,273	20	0.03	1.54 (Annualized)	1,273	20	Sections EC-2 and EC-7
	Long-Term	0.06	4.71			0.03	1.54			
CO	1-hour	0.27	188			0.12	61.6			
	8-hour	0.27	23.5			0.12	7.70			
PM_{10}	Short-Term	0.02	0.71			0.01	0.23			
	Long-Term	0.02	1.95			0.01	0.64			
$PM_{2.5}$	Short-Term	0.02	0.71			0.01	0.23			
	Long-Term	0.02	1.95			0.01	0.64			
SO_2 @ 16 ppmv	Short-Term (Hourly)	2.16E-03	0.57 (Annualized)			9.37E-04	0.19 (Annualized)			
	Short-Term (Daily)	2.16E-03	1.66			9.37E-04	0.54			
	Long-Term	2.16E-03	0.57			9.37E-04	0.19			
SO_2 @ 96 ppmv	Short-Term (Hourly)	0.01	3.40 (Annualized)			0.01	1.11 (Annualized)			
	Short-Term (Daily)	0.01	9.92			0.01	3.25			
	Long-Term	0.01	3.40			0.01	1.11			

Table 8-7 Modeling Emissions Summary for GTP Hydrocarbon Flare

Pollutant		HP Hydrocarbon Flare (Per Flare) Purge/Pilot Emission (g/s)	HP Maximum Emissions (g/s)	HP Exhaust Temp (°K)	HP Exhaust Velocity (m/s)	LP Hydrocarbon Flare (Per Flare) Purge/Pilot Emission (g/s)	LP Maximum Emissions (g/s)	LP Exhaust Temp (°K)	LP Exhaust Velocity (m/s)	Reference to Calculation
NO_x	Short-Term	0.07	35.85 (Annualized)	1,273	20	0.01	2.20 (Annualized)	1,273	20	Sections EC-2 and EC-7
	Long-Term	0.07	35.85			0.01	2.20			
CO	1-hour	0.31	1,432			0.06	87.8			
	8-hour	0.31	179			0.06	11.0			
PM_{10}	Short-Term	0.03	5.43			0.01	0.33			
	Long-Term	0.03	14.9			0.01	0.91			
$PM_{2.5}$	Short-Term	0.03	5.43			0.01	0.33			
	Long-Term	0.03	14.9			0.01	0.91			
SO_2 @ 16 ppmv	Short-Term (Hourly)	2.48E-03	1.49 (Annualized)			4.54E-04	0.08 (Annualized)			
	Short-Term (Daily)	2.48E-03	4.34			4.54E-04	0.24			
	Long-Term	2.48E-03	1.49			4.54E-04	0.08			
SO_2 @ 96 ppmv	Short-Term (Hourly)	0.02	8.90 (Annualized)			2.72E-03	0.49 (Annualized)			
	Short-Term (Daily)	0.02	26.0			2.72E-03	1.42			
	Long-Term	0.02	8.90			2.72E-03	0.49			

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 for the AQRV analysis as described in the following subsection.

PM Speciation Breakdown

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

Table 8-8 AQRV PM Speciation for GTP 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)

9.0 GTP 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 GTP 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

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 GTP 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

During normal operation of the Gas Treatment Plant, there would be no marine transportation emission sources associated with the facility.

9.1.3 Final Mobile 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**.

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 facilities themselves. 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 GTP, 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 GTP for comparison with ambient air quality standards and increment limits explicitly included emissions from existing facilities at PBU. 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 Modeling

It is anticipated that the two existing sources near the proposed GTP location in the PBU would be capable of causing significant pollutant concentration gradients at the GTP site, i.e., the Central Compression Plant (CCP) and Central Gas Facility (CGF) operated by BP Exploration (Alaska), Inc. (BPXA). Contributions from other North Slope emissions sources were assumed to be captured in locally monitored background pollutant concentrations that were a part of the cumulative impact analysis. USEPA has recently proposed modifications to the Guideline on Air Quality Models (USEPA 2011) that explicitly allow for representation of nearby sources in cumulative impact analyses at their actual operating conditions. Accordingly, emissions from CCP and CGF were included explicitly with GTP emissions in modeling to evaluate compliance with the NAAQS and Class II PSD Increments. For conservatism and because most of the larger units at these facility operate nearly continuously at 100% load (e.g., actual emissions close to maximum allowable), the maximum allowable (100% load) emissions for all CCP and CGF emission units were used in the NAAQS compliance analyses. The emissions data for CCP and CGF were determined from documents associated with the most recent Title V permit renewals for these facilities. The simulations that were conducted to test compliance with the Class II PSD increments used actual emission rates for the same units as reported to the 2011 NEI Database (NEI 2011), except that equipment that commenced operation prior to the North Slope PSD baseline dates were excluded.

Modeling of CCP and CGF NO_x emissions required specification of appropriate in-stack NO_2/NO_x ratios (ISRs) for each emission unit. Review of source test data provided by ADEC and BPXA for the turbines at these and similar units at other North Slope facilities showed that ISRs decrease with increasing engine load and that ISRs are higher for the turbines equipped with air staging NO_x controls than for uncontrolled turbines. Based on the substantial body of available relevant source tests, the in-stack ratios shown in **Table 10-1** were found to be appropriate for uncontrolled and controlled turbines at operating loads between 80% and 100%.

Table 10-1 In-Stack NO2/NOx Ratios for Use in Modeling CCP and CGF Turbines for Different Operating Loads

NO_x Control	Applicable Technologies	Ratio at 80-89% Load	Ratio at 90- 99% Load	Ratio at 100% Load
Uncontrolled	Forced Diffusion	0.2	0.1	0.1
Air Staging Control	Lean Head End (LHE) Liner	0.5	0.4	0.35

Databases compiled by USEPA and ADEC based on stack testing results indicate that in-stack ratios for heaters/boilers, reciprocating engines and flares are generally less dependent upon operating load. Values selected for modeling involving these equipment types at CCP and CGF are summarized in **Table 10-2**.

Table 10-2 In-Stack NO_2/NO_x Ratios Assumed for Other CCP and CGF Combustion Equipment

Equipment	Ratio
Heaters/boilers	0.10
Internal Combustion Engines	0.10
Flares	0.50

Speciation of particulate matter emissions from CGF and CCP emission units was accomplished 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 10-3**.

Table 10-3 PM Speciation Assumed for CCP and CGF Equipment

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	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)
Pump	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 (Smaller than 600 hp, but no condensable info in AP-42 3.3) (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)

10.2 EMISSIONS DATA FOR FAR-FIELD IMPACT ANALYSES

PSD Applicability determinations required dispersion modeling to evaluate GTP impacts at Class I areas located within 300 kilometers of these facilities, 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 areas in northern Alaska for which GTP impacts were assessed include:

- Arctic National Wildlife Refuge (Class II)
- Gates of the Arctic National Park and Preserve (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 location, 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 GTP.

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 GTP site.

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 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 (NPS 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 GTP 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 facilities 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 10-3**).

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.

The conservative USEPA default NO_2/NO_x ratio of 0.5 (USEPA 2011) was used for all volume sources in the far-field NO_2 modeling for the GTP.

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 10-4**. 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 10-4 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 GTP. 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 GTP 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-14**.

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
CCP	Central Compression Plant
CH_4	Methane
CGF	Central Gas Facility
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 GAS TREATMENT PLANT 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			SO_2 @ 96 ppmvd[1]			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	lb/hr	lb/day	tpy	tonnes/yr	tonnes/yr	tonnes/yr	tonnes/yr	lb/hr	tpy	lb/hr	tpy
1A	Train 1a Treated Gas Compressor Turbine Primary Stack (includes SF WHR)	8760	44.13	139.46	35.77	286.20	121.96	5.20	16.17	4.34	104.07	15.92	4.34	104.07	15.92	1.77	42.37	6.32	10.58	253.82	37.84	267274.60	5.04	0.50	267550.64	0.40	1.74	0.57	2.51
1B	Train 1b Treated Gas Compressor Turbine Primary Stack (includes SF WHR)	8760	44.13	139.46	35.77	286.20	121.96	5.20	16.17	4.34	104.07	15.92	4.34	104.07	15.92	1.77	42.37	6.32	10.58	253.82	37.84	267274.60	5.04	0.50	267550.64	0.40	1.74	0.57	2.51
2A	Train 2a Treated Gas Compressor Turbine Primary Stack (includes SF WHR)	8760	44.13	139.46	35.77	286.20	121.96	5.20	16.17	4.34	104.07	15.92	4.34	104.07	15.92	1.77	42.37	6.32	10.58	253.82	37.84	267274.60	5.04	0.50	267550.64	0.40	1.74	0.57	2.51
2B	Train 2b Treated Gas Compressor Turbine Primary Stack (includes SF WHR)	8760	44.13	139.46	35.77	286.20	121.96	5.20	16.17	4.34	104.07	15.92	4.34	104.07	15.92	1.77	42.37	6.32	10.58	253.82	37.84	267274.60	5.04	0.50	267550.64	0.40	1.74	0.57	2.51
3A	Train 3a Treated Gas Compressor Turbine Primary Stack (includes SF WHR)	8760	44.13	139.46	35.77	286.20	121.96	5.20	16.17	4.34	104.07	15.92	4.34	104.07	15.92	1.77	42.37	6.32	10.58	253.82	37.84	267274.60	5.04	0.50	267550.64	0.40	1.74	0.57	2.51
3B	Train3b Treated Gas Compressor Turbine Primary Stack (includes SF WHR)	8760	44.13	139.46	35.77	286.20	121.96	5.20	16.17	4.34	104.07	15.92	4.34	104.07	15.92	1.77	42.37	6.32	10.58	253.82	37.84	267274.60	5.04	0.50	267550.64	0.40	1.74	0.57	2.51
4A	Train 1a CO2 Compressor Turbine Primary Stack (includes SF WHR)	8760	32.35	119.58	61.66	493.27	120.61	3.56	12.14	3.12	74.96	11.99	3.12	74.96	11.99	1.26	30.24	4.76	7.55	181.14	28.50	201153.16	3.79	0.38	201360.91	0.30	1.31	0.43	1.89
4B	Train 1b CO2 Compressor Turbine Primary Stack (includes SF WHR)	8760	32.35	119.58	61.66	493.27	120.61	3.56	12.14	3.12	74.96	11.99	3.12	74.96	11.99	1.26	30.24	4.76	7.55	181.14	28.50	201153.16	3.79	0.38	201360.91	0.30	1.31	0.43	1.89
5A	Train 2a CO2 Compressor Turbine Primary Stack (includes SF WHR)	8760	32.35	119.58	61.66	493.27	120.61	3.56	12.14	3.12	74.96	11.99	3.12	74.96	11.99	1.26	30.24	4.76	7.55	181.14	28.50	201153.16	3.79	0.38	201360.91	0.30	1.31	0.43	1.89
5B	Train 2b CO2 Compressor Turbine Primary Stack (includes SF WHR)	8760	32.35	119.58	61.66	493.27	120.61	3.56	12.14	3.12	74.96	11.99	3.12	74.96	11.99	1.26	30.24	4.76	7.55	181.14	28.50	201153.16	3.79	0.38	201360.91	0.30	1.31	0.43	1.89
6A	Train 3a CO2 Compressor Turbine Primary Stack (includes SF WHR)	8760	32.35	119.58	61.66	493.27	120.61	3.56	12.14	3.12	74.96	11.99	3.12	74.96	11.99	1.26	30.24	4.76	7.55	181.14	28.50	201153.16	3.79	0.38	201360.91	0.30	1.31	0.43	1.89
6B	Train 3b CO2 Compressor Turbine Primary Stack (includes SF WHR)	8760	32.35	119.58	61.66	493.27	120.61	3.56	12.14	3.12	74.96	11.99	3.12	74.96	11.99	1.26	30.24	4.76	7.55	181.14	28.50	201153.16	3.79	0.38	201360.91	0.30	1.31	0.43	1.89
7A_1A	Power Generation Turbines	8760	21.36	73.22	13.00	104.03	55.72	0.93	3.75	2.91	69.91	11.78	2.91	69.91	11.78	1.05	25.19	4.23	6.29	150.91	25.36	179414.96	3.38	0.34	179600.26	0.27	1.20	0.40	1.74
7A_1B	Power Generation Turbines	8760	21.36	73.22	13.00	104.03	55.72	0.93	3.75	2.91	69.91	11.78	2.91	69.91	11.78	1.05	25.19	4.23	6.29	150.91	25.36	179414.96	3.38	0.34	179600.26	0.27	1.20	0.40	1.74
7A_2A	Power Generation Turbines	8760	21.36	73.22	13.00	104.03	55.72	0.93	3.75	2.91	69.91	11.78	2.91	69.91	11.78	1.05	25.19	4.23	6.29	150.91	25.36	179414.96	3.38	0.34	179600.26	0.27	1.20	0.40	1.74
7A_2B	Power Generation Turbines	8760	21.36	73.22	13.00	104.03	55.72	0.93	3.75	2.91	69.91	11.78	2.91	69.91	11.78	1.05	25.19	4.23	6.29	150.91	25.36	179414.96	3.38	0.34	179600.26	0.27	1.20	0.40	1.74
7A_3A	Power Generation Turbines	8760	21.36	73.22	13.00	104.03	55.72	0.93	3.75	2.91	69.91	11.78	2.91	69.91	11.78	1.05	25.19	4.23	6.29	150.91	25.36	179414.96	3.38	0.34	179600.26	0.27	1.20	0.40	1.74
7A_3B	Power Generation Turbines	8760	21.36	73.22	13.00	104.03	55.72	0.93	3.75	2.91	69.91	11.78	2.91	69.91	11.78	1.05	25.19	4.23	6.29	150.91	25.36	179414.96	3.38	0.34	179600.26	0.27	1.20	0.40	1.74
9_1	Black Start Diesel Generator (2500 kW)	500	29.20	7.30	29.20	233.61	7.30	1.59	0.40	0.33	8.01	0.08	0.33	8.01	0.08	0.04	0.90	0.01				1050.97	0.04	0.01	1054.58	0.00	0.00	0.05	0.01
31A	Main Diesel Firewater Pump (250 hp)	500	1.96	0.49	1.79	14.33	0.45	0.10	0.03	0.10	2.48	0.03	0.10	2.48	0.03	0.00	0.07	7.28E-04				64.72	0.00	0.00	64.94	0.00	0.00	0.01	1.77E-03
31B	Main Diesel Firewater Pump (250 hp)	500	1.96	0.49	1.79	14.33	0.45	0.10	0.03	0.10	2.48	0.03	0.10	2.48	0.03	0.00	0.07	7.28E-04				64.72	0.00	0.00	64.94	0.00	0.00	0.01	1.77E-03
31C	Main Diesel Firewater Pump (250 hp)	500	1.96	0.49	1.79	14.33	0.45	0.10	0.03	0.10	2.48	0.03	0.10	2.48	0.03	0.00	0.07	7.28E-04				64.72	0.00	0.00	64.94	0.00	0.00	0.01	1.77E-03
33	Dormitory Emergency Diesel Generator (250 kW)	500	2.62	0.65	2.41	19.29	0.60	0.14	0.03	0.14	3.31	0.03	0.14	3.31	0.03	0.00	0.09	9.76E-04				86.78	0.00	0.00	87.08	0.00	0.00	0.01	2.37E-03
36	Communications Tower (150 kW)	500	1.57	0.39	1.45	11.57	0.36	0.08	0.02	0.08	1.98	0.02	0.08	1.98	0.02	0.00	0.06	5.86E-04				52.07	0.00	0.00	52.25	0.00	0.00	0.01	1.42E-03
10E_1	LP CO2 Flare East Pilot/Purge (3 Flares)	8760	0.46	2.03	2.12	16.94	9.27	3.89	17.05	0.19	4.63	0.84	0.19	4.63	0.84	0.02	0.41	0.08	0.10	2.46	0.45	3174.74	0.06	0.01	3178.02	0.01	0.03	0.02	0.09
10W_1	LP CO2 Flare West Pilot/Purge (3 Flares)	8760	0.46	2.03	2.12	16.94	9.27	3.89	17.05	0.19	4.63	0.84	0.19	4.63	0.84	0.02	0.41	0.08	0.10	2.46	0.45	3174.74	0.06	0.01	3178.02	0.01	0.03	0.02	0.09
11E	HP CO2 Flare East Pilot/Purge	8760	0.20	0.88	0.92	7.35	4.02	1.69	7.40	0.08	2.01	0.37	0.08	2.01	0.37	0.01	0.18	0.03	0.04	1.07	0.20	1377.54	0.03	0.00	1378.96	0.00	0.01	0.01	0.04
11W	HP CO2 Flare West Pilot/Purge	8760	0.20	0.88	0.92	7.35	4.02	1.69	7.40	0.08	2.01	0.37	0.08	2.01	0.37	0.01	0.18	0.03	0.04	1.07	0.20	1377.54	0.03	0.00	1378.96	0.00	0.01	0.01	0.04
12E	HP Hydrocarbon Flare East Pilot/Purge	8760	0.53	2.34	2.43	19.46	10.66	4.47	19.59	0.22	5.32	0.97	0.22	5.32	0.97	0.02	0.47	0.09	0.12	2.83	0.52	3648.04	0.07	0.01	3651.81	0.01	0.04	0.02	0.10
12W	HP Hydrocarbon Flare West Pilot/Purge	8760	0.53	2.34	2.43	19.46	10.66	4.47	19.59	0.22	5.32	0.97	0.22	5.32	0.97	0.02	0.47	0.09	0.12	2.83	0.52	3648.04	0.07	0.01	3651.81	0.01	0.04	0.02	0.10
13E	LP Hydrocarbon Flare East Pilot/Purge	8760	0.10	0.43	0.45	3.56	1.95	0.82	3.59	0.04	0.97	0.18	0.04	0.97	0.18	0.00	0.09	0.02	0.02	0.52	0.09	668.00	0.01	0.00	668.69	0.00	0.01	0.00	0.02
13W	LP Hydrocarbon Flare West Pilot/Purge	8760	0.10	0.43	0.45	3.56	1.95	0.82	3.59	0.04	0.97	0.18	0.04	0.97	0.18	0.00	0.09	0.02	0.02	0.52	0.09	668.00	0.01	0.00	668.69	0.00	0.01	0.00	0.02
10E_M	LP CO2 Flare East MAX (3 Flares)	500	327.42	163.71	1492.65	1492.65	746.33	2744.55	1372.28	135.88	135.88	67.94	135.88	135.88	67.94	39.44	39.44	19.72	236.27	236.27	118.13	255484.14	4.82	0.48	255748.00	5.52	2.76	13.95	6.97
11E_M	HP CO2 Flare East MAX	500	107.25	53.63	488.95	488.95	244.47	899.03	449.52	44.51	44.51	22.26	44.51	44.51	22.26	12.92	12.92	6.46	77.40	77.40	38.70	83688.93	1.58	0.16	83775.36	1.81	0.90	4.57	2.28
12E_M	HP Hydrocarbon Flare East MAX	500	2492.45	1246.23	11362.64	11362.64	5681.32	20892.60	10446.30	1034.37	1034.37	517.19	1034.37	1034.37	517.19	103.25	103.25	51.63	618.55	618.55	309.28	1944844.19	36.65	3.67	1946852.81	42.01	21.00	106.19	53.09
13E_M	LP Hydrocarbon Flare East MAX	500	152.88	76.44	696.97	696.97	348.48	1281.52	640.76	63.45	63.45	31.72	63.45	63.45	31.72	5.64	5.64	2.82	33.80	33.80	16.90	119294.15	2.25	0.22	119417.36	2.58	1.29	6.51	3.26
14_1	Building Heat Medium Heater	8760	21.98	96.27	22.63	181.01	99.10	1.65	7.22	2.05	49.13	8.97	2.05	49.13	8.97	0.69	16.53	3.02	4.13	99.04	18.07	127702.97	2.41	0.24	127834.86	0.02	0.09	0.51	2.22
14_2	Building Heat Medium Heater	8760	21.98	96.27	22.63	181.01	99.10	1.65	7.22	2.05	49.13	8.97	2.05	49.13	8.97	0.69	16.53	3.02	4.13	99.04	18.07	127702.97	2.41	0.24	127834.86	0.02	0.09	0.51	2.22
14_3	Building Heat Medium Heater (spare)	0																											
21A	Buyback Gas Bath Heater Primary Heater Standby	8760	0.01	0.05	0.01	0.10	0.06	0.00	0.00	0.00	0.03	0.01	0.00	0.03	0.01	0.00	0.01	0.00	0.00	0.06	0.01	71.51	0.00	0.00	71.59	0.00	0.00	0.00	0.00
21B	Buyback Gas Bath Heater Secondary Heater Standby	8760	0.01	0.05	0.01	0.10	0.06	0.00	0.00	0.00	0.03	0.01	0.00	0.03	0.01	0.00	0.01	0.00	0.00	0.06	0.01	71.51	0.00	0.00	71.59	0.00	0.00	0.00	0.00
21A_M	Buyback Gas Bath Heater Primary Heater MAX	500	2.03	0.51	2.09	16.68	0.52	0.15	0.04	0.19	4.53	0.05	0.19	4.53	0.05	0.06	1.53	0.02	0.38	9.14	0.10	671.75	0.01	0.00	672.45	0.00	0.00	0.05	0.01
21B_M	Buyback Gas Bath Heater Secondary Heater MAX	500	1.67	0.42	1.72	13.79	0.43	0.13	0.03	0.16	3.74	0.04	0.16	3.74	0.04	0.05	1.26	0.01	0.31	7.55	0.08	555.13	0.01	0.00	555.70	0.00	0.00	0.04	0.01
CAMPHT1	Operations Camp Heater	8760	2.55	11.17	2.62	21.00	11.50	0.19	0.84	0.24	5.70	1.04	0.24	5.70	1.04	0.08	1.94	0.35	0.49	11.64	2.12	14813.54	0.28	0.03	14828.84	0.00	0.01	0.06	0.26
CAMPHT2	Operations Camp Heater	8760	2.55	11.17	2.62	21.00	11.50	0.19	0.84	0.24	5.70	1.04	0.24	5.70	1.04	0.08	1.94	0.35	0.49	11.64	2.12	14813.54	0.28	0.03	14828.84	0.00	0.01	0.06	0.26
CAMPHT3	Operations Camp Heater (spare)	0																											
	Tank Emissions	8760						0.01	0.04																				
	Fugitive Emissions	8760						10.80	47.32														111.25		2,781				
	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														
Total Emissions (Without Maximum Flare)			**681.7**	**2,241.5**	**767.2**	**6,137.8**	**2,079.9**	**96.7**	**354.4**	**69.1**	**1,658.2**	**264.1**	**69.1**	**1,658.2**	**264.0**	**26.3**	**630.1**	**99.1**	**157.0**	**3,767.2**	**593.3**	**4,194,739.6**	**190.4**	**7.9**	**4,201,860.1**	**5.9**	**25.8**	**9.8**	**42.4**
Total Emissions (With Maximum Flare)			**3,761.7**	**3,781.5**	**14,808.4**	**20,179.0**	**9,100.5**	**25,914.4**	**13,263.3**	**1,347.3**	**2,936.4**	**903.2**	**1,347.3**	**2,936.4**	**903.2**	**187.5**	**791.4**	**179.7**	**1,123.0**	**4,733.2**	**1,076.3**	**6,598,051.0**	**235.7**	**12.4**	**6,607,653.6**	**57.8**	**51.8**	**141.0**	**108.0**

8 CO Standard Requirement
24 Intermittent unit hours/day operation
24 Non-intermittent unit hours/day operation
0.5 Flare hours/day operation

Notes:
1 Commissioning Only Raw Gas

EC-2 GAS TREATMENT PLANT MODELED EMISSIONS SUMMARY

Modeled ID	Emission Unit	Configuration	Coordinates (UTM, NAD 83, Zone 6)		Base Elevation	Modeled Height		Temperature		Velocity		Diameter		In-Stack Ratio	NOx			CO		PM_{10}		$PM_{2.5}$		SO_2 @16 ppmvd			SO_2 @96 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	1-hour	3&24-hour	Annual
Turbines																													
1A	Train 1a Treated Gas Compressor Turbine Primary Stack[1]	Vert./no Cap	441632.91	7802266.08	1.83	240.00	73.15	410.00	483.15	52.00	15.85	10.00	3.05	0.40	5.56E+00	5.56E+00	4.01E+00	4.51E+00	4.51E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	2.22E-01	2.22E-01	1.82E-01	1.33E+00	1.33E+00	1.09E+00
1B	Train 1b Treated Gas Compressor Turbine Primary Stack[1]	Vert./no Cap	441598.78	7802260.05	1.83	240.00	73.15	410.00	483.15	52.00	15.85	10.00	3.05	0.40	5.56E+00	5.56E+00	4.01E+00	4.51E+00	4.51E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	2.22E-01	2.22E-01	1.82E-01	1.33E+00	1.33E+00	1.09E+00
2A	Train 2a Treated Gas Compressor Turbine Primary Stack[1]	Vert./no Cap	441514.39	7802158.49	1.83	240.00	73.15	410.00	483.15	52.00	15.85	10.00	3.05	0.40	5.56E+00	5.56E+00	4.01E+00	4.51E+00	4.51E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	2.22E-01	2.22E-01	1.82E-01	1.33E+00	1.33E+00	1.09E+00
2B	Train 2b Treated Gas Compressor Turbine Primary Stack[1]	Vert./no Cap	441546.76	7802163.61	1.83	240.00	73.15	410.00	483.15	52.00	15.85	10.00	3.05	0.40	5.56E+00	5.56E+00	4.01E+00	4.51E+00	4.51E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	2.22E-01	2.22E-01	1.82E-01	1.33E+00	1.33E+00	1.09E+00
3A	Train 3a Treated Gas Compressor Turbine Primary Stack[1]	Vert./no Cap	441489.81	7802265.02	1.83	240.00	73.15	410.00	483.15	52.00	15.85	10.00	3.05	0.40	5.56E+00	5.56E+00	4.01E+00	4.51E+00	4.51E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	2.22E-01	2.22E-01	1.82E-01	1.33E+00	1.33E+00	1.09E+00
3B	Train 3b Treated Gas Compressor Turbine Primary Stack[1]	Vert./no Cap	441523.94	7802269.80	1.83	240.00	73.15	410.00	483.15	52.00	15.85	10.00	3.05	0.40	5.56E+00	5.56E+00	4.01E+00	4.51E+00	4.51E+00	5.46E-01	4.58E-01	5.46E-01	4.58E-01	2.22E-01	2.22E-01	1.82E-01	1.33E+00	1.33E+00	1.09E+00
4A	Train 1a CO2 Compressor Turbine Primary Stack[1]	Vert./no Cap	441721.04	7802288.18	1.83	240.00	73.15	410.00	483.15	41.00	12.50	10.00	3.05	0.20	4.08E+00	4.08E+00	3.44E+00	7.77E+00	7.77E+00	3.94E-01	3.45E-01	3.94E-01	3.45E-01	1.59E-01	1.59E-01	1.37E-01	9.51E-01	9.51E-01	8.20E-01
4B	Train 1b CO2 Compressor Turbine Primary Stack[1]	Vert./no Cap	441753.31	7802294.87	1.83	240.00	73.15	410.00	483.15	41.00	12.50	10.00	3.05	0.20	4.08E+00	4.08E+00	3.44E+00	7.77E+00	7.77E+00	3.94E-01	3.45E-01	3.94E-01	3.45E-01	1.59E-01	1.59E-01	1.37E-01	9.51E-01	9.51E-01	8.20E-01
5A	Train 2a CO2 Compressor Turbine Primary Stack[1]	Vert./no Cap	441392.32	7802127.98	1.83	240.00	73.15	410.00	483.15	41.00	12.50	10.00	3.05	0.20	4.08E+00	4.08E+00	3.44E+00	7.77E+00	7.77E+00	3.94E-01	3.45E-01	3.94E-01	3.45E-01	1.59E-01	1.59E-01	1.37E-01	9.51E-01	9.51E-01	8.20E-01
5B	Train 2b CO2 Compressor Turbine Primary Stack[1]	Vert./no Cap	441426.30	7802135.49	1.83	240.00	73.15	410.00	483.15	41.00	12.50	10.00	3.05	0.20	4.08E+00	4.08E+00	3.44E+00	7.77E+00	7.77E+00	3.94E-01	3.45E-01	3.94E-01	3.45E-01	1.59E-01	1.59E-01	1.37E-01	9.51E-01	9.51E-01	8.20E-01
6A	Train 3a CO2 Compressor Turbine Primary Stack[1]	Vert./no Cap	441370.37	7802235.90	1.83	240.00	73.15	410.00	483.15	41.00	12.50	10.00	3.05	0.20	4.08E+00	4.08E+00	3.44E+00	7.77E+00	7.77E+00	3.94E-01	3.45E-01	3.94E-01	3.45E-01	1.59E-01	1.59E-01	1.37E-01	9.51E-01	9.51E-01	8.20E-01
6B	Train 3b CO2 Compressor Turbine Primary Stack[1]	Vert./no Cap	441403.41	7802241.70	1.83	240.00	73.15	410.00	483.15	41.00	12.50	10.00	3.05	0.20	4.08E+00	4.08E+00	3.44E+00	7.77E+00	7.77E+00	3.94E-01	3.45E-01	3.94E-01	3.45E-01	1.59E-01	1.59E-01	1.37E-01	9.51E-01	9.51E-01	8.20E-01
7A_1A	Power Generator Turbines	Vert./no Cap	441683.89	7802104.89	1.83	240.00	73.15	871.00	739.26	83.00	25.30	10.00	3.05	0.40	2.69E+00	2.69E+00	2.11E+00	1.64E+00	1.64E+00	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.32E-01	1.32E-01	1.22E-01	7.92E-01	7.92E-01	7.30E-01
7A_1B	Power Generator Turbines	Vert./no Cap	441728.16	7802114.50	1.83	240.00	73.15	871.00	739.26	83.00	25.30	10.00	3.05	0.40	2.69E+00	2.69E+00	2.11E+00	1.64E+00	1.64E+00	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.32E-01	1.32E-01	1.22E-01	7.92E-01	7.92E-01	7.30E-01
7A_2A	Power Generator Turbines	Vert./no Cap	441468.06	7802061.38	1.83	240.00	73.15	871.00	739.26	83.00	25.30	10.00	3.05	0.40	2.69E+00	2.69E+00	2.11E+00	1.64E+00	1.64E+00	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.32E-01	1.32E-01	1.22E-01	7.92E-01	7.92E-01	7.30E-01
7A_2B	Power Generator Turbines	Vert./no Cap	441514.13	7802070.80	1.83	240.00	73.15	871.00	739.26	83.00	25.30	10.00	3.05	0.40	2.69E+00	2.69E+00	2.11E+00	1.64E+00	1.64E+00	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.32E-01	1.32E-01	1.22E-01	7.92E-01	7.92E-01	7.30E-01
7A_3A	Power Generator Turbines	Vert./no Cap	441569.32	7802082.04	1.83	240.00	73.15	871.00	739.26	83.00	25.30	10.00	3.05	0.40	2.69E+00	2.69E+00	2.11E+00	1.64E+00	1.64E+00	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.32E-01	1.32E-01	1.22E-01	7.92E-01	7.92E-01	7.30E-01
7A_3B	Power Generator Turbines	Vert./no Cap	441613.40	7802091.54	1.83	240.00	73.15	871.00	739.26	83.00	25.30	10.00	3.05	0.40	2.69E+00	2.69E+00	2.11E+00	1.64E+00	1.64E+00	3.67E-01	3.39E-01	3.67E-01	3.39E-01	1.32E-01	1.32E-01	1.22E-01	7.92E-01	7.92E-01	7.30E-01
Diesel Equipment																													
9_1	Black Start Diesel Generator (2500 kW)[2]	Vert./no Cap	441618.73	7802154.47	1.83	115.00	35.05	879.00	743.71	68.00	20.73	2.50	0.76	0.50	0.210006	3.6793045	0.210006	3.6793045	3.679305	0.0420492	2.40E-03	0.042049	0.0024	2.70E-04	4.73E-03	2.70E-04	N/A	N/A	N/A
31A	Main Diesel Firewater Pump (250 hp)[2]	Vert./no Cap	440709.65	7803298.16	1.83	76.00	23.16	850.00	727.59	35.54	10.83	1.00	0.30	0.50	0.0141208	0.2473958	0.0141208	0.2256944	0.225694	0.0130208	7.43E-04	0.013021	0.000743	2.09468E-05	3.67E-04	2.09468E-05	N/A	N/A	N/A
31B	Main Diesel Firewater Pump (250 hp)[2]	Vert./no Cap	440733.30	7803462.72	1.83	76.00	23.16	850.00	727.59	35.54	10.83	1.00	0.30	0.50	0.0141208	0.2473958	0.0141208	0.2256944	0.225694	0.0130208	7.43E-04	0.013021	0.000743	2.09468E-05	3.67E-04	2.09468E-05	N/A	N/A	N/A
31C	Main Diesel Firewater Pump (250 hp)[2]	Vert./no Cap	440738.35	7803589.70	1.83	76.00	23.16	850.00	727.59	35.54	10.83	1.00	0.30	0.50	0.0141208	0.2473958	0.0141208	0.2256944	0.225694	0.0130208	7.43E-04	0.013021	0.000743	2.09468E-05	3.67E-04	2.09468E-05	N/A	N/A	N/A
33	Dormitory Emergency Diesel Generator (250 kW)[2]	Vert./no Cap	440714.68	7803289.84	1.83	76.00	23.16	852.00	728.71	48.00	14.63	1.00	0.30	0.50	0.0188277	0.3298611	0.0188277	0.3038194	0.303819	0.0173611	9.91E-04	0.017361	0.000991	2.80901E-05	4.92E-04	2.80901E-05	N/A	N/A	N/A
36	Communications Tower Diesel Generator (150 kW)[2]	Vert./no Cap	440690.81	7803243.08	1.83	29.00	8.84	850.00	727.59	28.60	8.72	1.00	0.30	0.50	0.0112966	0.1979167	0.0112966	0.1822917	0.182292	0.0104167	5.95E-04	0.010417	0.000595	1.68541E-05	2.95E-04	1.68541E-05	N/A	N/A	N/A
Flares																													
10E	LP CO2 Flare East Pilot/Purge **(3 Flare Tips)**	Vert./no Cap	441601.84	7802718.49	1.83	220.67	67.26	1831.73	1273.00	65.62	20.00	1.44	0.44	0.50	5.85E-02	5.85E-02	5.85E-02	2.67E-01	2.67E-01	2.43E-02	2.43E-02	2.43E-02	2.43E-02	2.16E-03	2.16E-03	2.16E-03	1.29E-02	1.29E-02	1.29E-02
10W	LP CO2 Flare West Pilot/Purge **(3 Flare Tips)**	Vert./no Cap	441335.91	7802643.10	1.83	220.67	67.26	1831.73	1273.00	65.62	20.00	1.44	0.44	0.50	5.85E-02	5.85E-02	5.85E-02	2.67E-01	2.67E-01	2.43E-02	2.43E-02	2.43E-02	2.43E-02	2.16E-03	2.16E-03	2.16E-03	1.29E-02	1.29E-02	1.29E-02
11E	HP CO2 Flare East Pilot/Purge	Vert./no Cap	441601.72	7802711.65	1.83	218.23	66.52	1831.73	1273.00	65.62	20.00	0.95	0.29	0.50	2.54E-02	2.54E-02	2.54E-02	1.16E-01	1.16E-01	1.05E-02	1.05E-02	1.05E-02	1.05E-02	9.37E-04	9.37E-04	9.37E-04	5.61E-03	5.61E-03	5.61E-03
11W	HP CO2 Flare West Pilot/Purge	Vert./no Cap	441335.90	7802648.61	1.83	218.23	66.52	1831.73	1273.00	65.62	20.00	0.95	0.29	0.50	2.54E-02	2.54E-02	2.54E-02	1.16E-01	1.16E-01	1.05E-02	1.05E-02	1.05E-02	1.05E-02	9.37E-04	9.37E-04	9.37E-04	5.61E-03	5.61E-03	5.61E-03
12E	HP Hydrocarbon Flare East Pilot/Purge	Vert./no Cap	441601.90	7802705.72	1.83	221.18	67.42	1831.73	1273.00	65.62	20.00	1.54	0.47	0.50	6.72E-02	6.72E-02	6.72E-02	3.07E-01	3.07E-01	2.79E-02	2.79E-02	2.79E-02	2.79E-02	2.48E-03	2.48E-03	2.48E-03	1.49E-02	1.49E-02	1.49E-02
12W	HP Hydrocarbon Flare West Pilot/Purge	Vert./no Cap	441335.95	7802655.24	1.83	221.18	67.42	1831.73	1273.00	65.62	20.00	1.54	0.47	0.50	6.72E-02	6.72E-02	6.72E-02	3.07E-01	3.07E-01	2.79E-02	2.79E-02	2.79E-02	2.79E-02	2.48E-03	2.48E-03	2.48E-03	1.49E-02	1.49E-02	1.49E-02
13E	LP Hydrocarbon Flare East Pilot/Purge	Vert./no Cap	441601.77	7802699.63	1.83	216.78	66.07	1831.73	1273.00	65.62	20.00	0.66	0.20	0.50	1.23E-02	1.23E-02	1.23E-02	5.61E-02	5.61E-02	5.11E-03	5.11E-03	5.11E-03	5.11E-03	4.54E-04	4.54E-04	4.54E-04	2.72E-03	2.72E-03	2.72E-03
13W	LP Hydrocarbon Flare West Pilot/Purge	Vert./no Cap	441335.94	7802661.87	1.83	216.78	66.07	1831.73	1273.00	65.62	20.00	0.66	0.20	0.50	1.23E-02	1.23E-02	1.23E-02	5.61E-02	5.61E-02	5.11E-03	5.11E-03	5.11E-03	5.11E-03	4.54E-04	4.54E-04	4.54E-04	2.72E-03	2.72E-03	2.72E-03
10E_M	LP CO2 Flare East MAX[2] **(3 Flare Tips)**	Vert./no Cap	441601.84	7802718.49	1.83	450.65	137.36	1831.73	1273.00	65.62	20.00	53.89	16.43	0.50	4.71E+00	1.72E+00	4.71E+00	1.88E+02	2.35E+01	7.13E-01	1.95E+00	7.13E-01	1.95E+00	5.67E-01	1.66E+00	5.67E-01	3.40E+00	9.92E+00	3.40E+00
11E_M	HP CO2 Flare East MAX[2]	Vert./no Cap	441601.72	7802711.65	1.83	352.51	107.44	1831.73	1273.00	65.62	20.00	30.84	9.40	0.50	1.54E+00	5.63E-01	1.54E+00	6.16E+01	7.70E+00	2.34E-01	6.40E-01	2.34E-01	6.40E-01	1.86E-01	5.43E-01	1.86E-01	1.11E+00	3.25E+00	1.11E+00
12E_M	HP Hydrocarbon Flare East MAX[2]	Vert./no Cap	441601.90	7802705.72	1.83	839.79	255.97	1831.73	1273.00	65.62	20.00	148.73	45.33	0.50	3.58E+01	1.31E+01	3.58E+01	1.43E+03	1.79E+02	5.43E+00	1.49E+01	5.43E+00	1.49E+01	1.49E+00	4.34E+00	1.49E+00	8.90E+00	2.60E+01	8.90E+00
13E_M	LP Hydrocarbon Flare East MAX[2]	Vert./no Cap	441601.77	7802699.63	1.83	378.22	115.28	1831.73	1273.00	65.62	20.00	36.83	11.22	0.50	2.20E+00	8.03E-01	2.20E+00	8.78E+01	1.10E+01	3.33E-01	9.13E-01	3.33E-01	9.13E-01	8.12E-02	2.37E-01	8.12E-02	4.86E-01	1.42E+00	4.86E-01
Heaters and Incinerators																													
14_1	Building Heat Medium Heater	Vert./no Cap	441702.17	7802020.12	1.83	232.00	70.71	370.00	460.93	26.00	7.92	9.00	2.74	0.50	2.77E+00	2.77E+00	2.77E+00	2.85E+00	2.85E+00	2.58E-01	2.58E-01	2.58E-01	2.58E-01	8.68E-02	8.68E-02	8.68E-02	5.20E-01	5.20E-01	5.20E-01
14_2	Building Heat Medium Heater	Vert./no Cap	441697.18	7802044.48	1.83	232.00	70.71	370.00	460.93	26.00	7.92	9.00	2.74	0.50	2.77E+00	2.77E+00	2.77E+00	2.85E+00	2.85E+00	2.58E-01	2.58E-01	2.58E-01	2.58E-01	8.68E-02	8.68E-02	8.68E-02	5.20E-01	5.20E-01	5.20E-01
14_3	Building Heat Medium Heater **(Spare)**	Vert./no Cap	441692.46	7802069.05	1.83	232.00	70.71	370.00	460.93	26.00	7.92	9.00	2.74	0.50															
21A	Buyback Gas Bath Heater Primary Heater Standby	Vert./no Cap	441654.10	7802479.72	1.83	20.00	6.10	601.00	589.26	0.33	0.10	2.00	0.61	0.50	1.55E-03	1.55E-03	1.55E-03	1.60E-03	1.60E-03	1.44E-04	1.44E-04	1.44E-04	1.44E-04	5.17E-05	5.17E-05	5.17E-05	3.09E-04	3.09E-04	3.09E-04
21B	Buyback Gas Bath Heater Secondary Heater Standby	Vert./no Cap	441652.81	7802486.16	1.83	20.00	6.10	887.00	748.15	0.41	0.12	2.00	0.61	0.50	1.55E-03	1.55E-03	1.55E-03	1.60E-03	1.60E-03	1.44E-04	1.44E-04	1.44E-04	1.44E-04	5.17E-05	5.17E-05	5.17E-05	3.09E-04	3.09E-04	3.09E-04
21A_M	Buyback Gas Bath Heater Primary Heater MAX[2]	Vert./no Cap	441654.10	7802479.72	1.83	20.00	6.10	601.00	589.26	54.79	16.70	2.00	0.61	0.50	1.46E-02	2.55E-01	1.46E-02	2.63E-01	2.63E-01	2.38E-02	1.36E-03	2.38E-02	1.36E-03	4.57E-04	8.01E-03	4.57E-04	2.74E-03	4.80E-02	2.74E-03
21B_M	Buyback Gas Bath Heater Secondary Heater MAX[2]	Vert./no Cap	441652.81	7802486.16	1.83	20.00	6.10	887.00	748.15	57.49	17.52	2.00	0.61	0.50	1.20E-02	2.11E-01	1.20E-02	2.17E-01	2.17E-01	1.96E-02	1.12E-03	1.96E-02	1.12E-03	3.77E-04	6.61E-03	3.77E-04	2.26E-03	3.96E-02	2.26E-03
CAMPHT1	Operations Camp Heater	Vert./no Cap	440958.06	7803537.00	1.83	32.00	9.75	257.00	398.15	29.00	8.84	2.50	0.76	0.50	3.21E-01	3.21E-01	3.21E-01	3.31E-01	3.31E-01	2.99E-02	2.99E-02	2.99E-02	2.99E-02	1.02E-02	1.02E-02	1.02E-02	6.11E-02	6.11E-02	6.11E-02
CAMPHT2	Operations Camp Heater	Vert./no Cap	440961.23	7803523.24	1.83	32.00	9.75	257.00	398.15	29.00	8.84	2.50	0.76	0.50	3.21E-01	3.21E-01	3.21E-01	3.31E-01	3.31E-01	2.99E-02	2.99E-02	2.99E-02	2.99E-02	1.02E-02	1.02E-02	1.02E-02	6.11E-02	6.11E-02	6.11E-02
CAMPHT3	Operations Camp Heater **(Spare)**	Vert./no Cap	440964.41	7803508.69	1.83	32.00	9.75	257.00	398.15	29.00	8.84	2.50	0.76	0.50															
Total Emissions (Without Maximum Flare)															**80.78**	**85.89**	**64.17**	**96.67**	**96.67**	**8.71**	**7.57**	**8.71**	**7.57**	**3.29**	**3.31**	**2.85**	**19.69**	**19.78**	**17.07**
Total Emissions (With Maximum Flare)															**125.09**	**102.06**	**108.47**	**1865.82**	**317.81**	**15.42**	**25.96**	**15.42**	**25.96**	**5.61**	**10.08**	**5.17**	**33.59**	**60.35**	**30.96**

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.

8,760 hours Annual hours

0.5 hours Per day maximum flare operation

1 Supplemental Firing emissions have been included in the total emissions from the turbine source. To be conservative, the additional supplemental firing flow rate and velocity have not been included in the stack parameter selection

2 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								
1A	Train 1a Treated Gas Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.573E-01	1.573E-01	3.891E-01	3.891E-01
1B	Train 1b Treated Gas Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.573E-01	1.573E-01	3.891E-01	3.891E-01
2A	Train 2a Treated Gas Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.573E-01	1.573E-01	3.891E-01	3.891E-01
2B	Train 2b Treated Gas Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.573E-01	1.573E-01	3.891E-01	3.891E-01
3A	Train 3a Treated Gas Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.573E-01	1.573E-01	3.891E-01	3.891E-01
3B	Train 3b Treated Gas Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.573E-01	1.573E-01	3.891E-01	3.891E-01
4A	Train 1a CO2 Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.133E-01	1.133E-01	2.802E-01	2.802E-01
4B	Train 1b CO2 Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.133E-01	1.133E-01	2.802E-01	2.802E-01
5A	Train 2a CO2 Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.133E-01	1.133E-01	2.802E-01	2.802E-01
5B	Train 2b CO2 Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.133E-01	1.133E-01	2.802E-01	2.802E-01
6A	Train 3a CO2 Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.133E-01	1.133E-01	2.802E-01	2.802E-01
6B	Train 3b CO2 Compressor Turbine Primary Stack[1]	Turbine	Gas	0.000E+00	1.133E-01	1.133E-01	2.802E-01	2.802E-01
7A_1A	Power Generator Turbines	Turbine	Gas	0.000E+00	1.057E-01	1.057E-01	2.614E-01	2.614E-01
7A_1B	Power Generator Turbines	Turbine	Gas	0.000E+00	1.057E-01	1.057E-01	2.614E-01	2.614E-01
7A_2A	Power Generator Turbines	Turbine	Gas	0.000E+00	1.057E-01	1.057E-01	2.614E-01	2.614E-01
7A_2B	Power Generator Turbines	Turbine	Gas	0.000E+00	1.057E-01	1.057E-01	2.614E-01	2.614E-01
7A_3A	Power Generator Turbines	Turbine	Gas	0.000E+00	1.057E-01	1.057E-01	2.614E-01	2.614E-01
7A_3B	Power Generator Turbines	Turbine	Gas	0.000E+00	1.057E-01	1.057E-01	2.614E-01	2.614E-01
Diesel Equipment								
9_1	Black Start Diesel Generator (2500 kW)[2]	Generator	Diesel	0.000E+00	3.623E-02	3.640E-02	5.823E-03	5.651E-03
31A	Main Diesel Firewater Pump (250 hp)[2]	Pump	Diesel	0.000E+00	1.122E-02	1.127E-02	1.803E-03	1.750E-03
31B	Main Diesel Firewater Pump (250 hp)[2]	Pump	Diesel	0.000E+00	1.122E-02	1.127E-02	1.803E-03	1.750E-03
31C	Main Diesel Firewater Pump (250 hp)[2]	Pump	Diesel	0.000E+00	1.122E-02	1.127E-02	1.803E-03	1.750E-03
33	Dormitory Emergency Diesel Generator (250 kW)[2]	Generator	Diesel	0.000E+00	1.496E-02	1.503E-02	2.404E-03	2.333E-03
36	Communications Tower Diesel Generator (150 kW)[2]	Generator	Diesel	0.000E+00	8.974E-03	9.017E-03	1.443E-03	1.400E-03
Flares								
10E	LP CO2 Flare East Pilot/Purge **(3 Flare Tips)**	Flare	Gas	0.000E+00	6.072E-03	6.072E-03	1.821E-02	1.821E-02
10W	LP CO2 Flare West Pilot/Purge **(3 Flare Tips)**	Flare	Gas	0.000E+00	6.072E-03	6.072E-03	1.821E-02	1.821E-02
11E	HP CO2 Flare East Pilot/Purge	Flare	Gas	0.000E+00	2.634E-03	2.634E-03	7.903E-03	7.903E-03
11W	HP CO2 Flare West Pilot/Purge	Flare	Gas	0.000E+00	2.634E-03	2.634E-03	7.903E-03	7.903E-03
12E	HP Hydrocarbon Flare East Pilot/Purge	Flare	Gas	0.000E+00	6.977E-03	6.977E-03	2.093E-02	2.093E-02
12W	HP Hydrocarbon Flare West Pilot/Purge	Flare	Gas	0.000E+00	6.977E-03	6.977E-03	2.093E-02	2.093E-02
13E	LP Hydrocarbon Flare East Pilot/Purge	Flare	Gas	0.000E+00	1.278E-03	1.278E-03	3.833E-03	3.833E-03
13W	LP Hydrocarbon Flare West Pilot/Purge	Flare	Gas	0.000E+00	1.278E-03	1.278E-03	3.833E-03	3.833E-03
10E_M	LP CO2 Flare East MAX[2] **(3 Flare Tips)**	Flare	Gas	0.000E+00	1.783E-01	1.783E-01	5.350E-01	5.350E-01
11E_M	HP CO2 Flare East MAX[2]	Flare	Gas	0.000E+00	5.842E-02	5.842E-02	1.753E-01	1.753E-01
12E_M	HP Hydrocarbon Flare East MAX[2]	Flare	Gas	0.000E+00	1.358E+00	1.358E+00	4.073E+00	4.073E+00
13E_M	LP Hydrocarbon Flare East MAX[2]	Flare	Gas	0.000E+00	8.327E-02	8.327E-02	2.498E-01	2.498E-01
Heaters and Incinerators								
14_1	Building Heat Medium Heater	Heater	Gas	0.000E+00	6.448E-02	6.448E-02	1.934E-01	1.934E-01
14_2	Building Heat Medium Heater	Heater	Gas	0.000E+00	6.448E-02	6.448E-02	1.934E-01	1.934E-01
14_3	Building Heat Medium Heater **(Spare)**							
21A	Buyback Gas Bath Heater Primary Heater Standby	Heater	Gas	0.000E+00	3.611E-05	3.611E-05	1.083E-04	1.083E-04
21B	Buyback Gas Bath Heater Secondary Heater Standby	Heater	Gas	0.000E+00	3.611E-05	3.611E-05	1.083E-04	1.083E-04
21A_M	Buyback Gas Bath Heater Primary Heater MAX[2]	Heater	Gas	0.000E+00	5.943E-03	5.943E-03	1.783E-02	1.783E-02
21B_M	Buyback Gas Bath Heater Secondary Heater MAX[2]	Heater	Gas	0.000E+00	4.911E-03	4.911E-03	1.473E-02	1.473E-02
CAMPHT1	Operations Camp Heater	Heater	Gas	0.000E+00	7.480E-03	7.480E-03	2.244E-02	2.244E-02
CAMPHT2	Operations Camp Heater	Heater	Gas	0.000E+00	7.480E-03	7.480E-03	2.244E-02	2.244E-02
CAMPHT3	Operations Camp Heater **(Spare)**							
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.
8,760 hours	Annual hours
0.5 hours	Per day maximum flare operation

1 Supplemental Firing emissions have been included in the total emissions from the turbine source. To be conservative, the additional supplemental firing flow rate and velocity have not been included in the stack parameter selection

2 Intermittent equipment 1-hr NOx and SO2 emissions can be annualized

EC-3 GAS TREATMENT PLANT FUEL SPECIFICATIONS

GTP Fuel Gas Specification

Component	% By Volume	MW
Hydrogen	0.0000	
Methane	91.1100	
Ethane	5.7600	
Ethylene	0.0000	
Propane	1.9700	
Propylene	0.0000	
Butane	0.3000	
Butylene	0.0000	
Butadiene	0.0000	
Pentane	0.0700	
Cyclopentane	0.0000	
Hexane	0.0074	
Heptane	0.0045	
CO	0.0000	
CO2	0.0050	
Nitrogen	0.7700	28.0130
Water	0.0000	18.0200
Oxygen	0.0000	32.0000
Lean Gas - S (Note 1)	0.0016	64.0660
Rich Gas - S (Note 1)	0.0096	64.0660
Ammonia	0.0000	
Argon	0.0000	
Properties		
Temp	82.0000	
MW	17.6700	
Fuel Heating Value at 82ºF:		
Net (Btu/lbm)	21040.0000	
Net (Btu/scf)	980.0000	
Gross (Btu/lbm)	23129.0000	
Gross (Btu/scf)	1077.0000	
scf defined at 14.676 psia, 60F		

Conversion of 1 grain/100 scf of H2S to Sulfur
GPSA Calculation:

32 Sulfur Molecular Weight
34.08 H2S Molecular Weight
1.065

90 ppm H2S of Rich Gas
95.85 ppm S equivalent

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

GTP 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 GAS TREATMENT PLANT FUEL GAS-DRIVEN TURBINES

EMISSION FACTORS	Standard Factors: AP42 Table 3.1-1 and 3.1-2a	Standard Factors: 40 CFR Part 98 (Natural Gas)	Special/Vendor	Ambient Temp Basis (F)	Load % Basis	Treated Gas/Power Gen Turbine Vendor	Ambient Temp Basis (F)	Load % Basis	CO2 Turbine Vendor		Supplemental Firing Vendor
NOx (lb/MMBtu)	0.338		Short-Term ppmvd @ 15% NOx	-40.00	100%	15.00	-40.00	100%	15.00	NOx (lb/MMBtu)	0.08
CO (lb/MMBtu)	0.087		Short-Term ppmvd @ 15% CO	-40.00	100%	15.00	-40.00	85%	67.00	CO (lb/MMBtu)	0.08
VOC (lb/MMBtu)	0.002		Annual ppmvd @ 15% NOx	10.00	100%	12.00	10.00	100%	15.00	VOC (lb/MMBtu)	0.015
PM10 (lb/MMBtu)	0.007		Annual ppmvd @ 15% CO	10.00	100%	15.00	10.00	100%	25.00	PM10 (lb/MMBtu)	0.005
PM2.5 (lb/MMBtu)	0.007									PM2.5 (lb/MMBtu)	0.005
CO2 (kg CO2/MMBtu)		53.060									
CH4 (kg CH4/MMBtu)		0.001									
N2O (kg N2O/MMBtu)		0.0001									

Notes:

1.) AP42 Section 3.1 Emission Factors have been convert to AlaskaLNG fuel gas HHV by ratio of project fuel gas/1020 (btu/scf)

EMISSIONS CALCULATIONS	Treated Gas Compressor Turbines		CO2 Compressor Turbines		Main Power Generation Turbines		References/Comments
Turbine Parameters	Short-Term	Annual	Short-Term	Annual	Short-Term	Annual	
Total Installed	6	6	6	6	6	6	From GTP Cookbook
Ambient Temperature Basis (F)	-40	10	-40	10	-40	10	
Load % Basis	100%	100%	100%	100%	100%	100%	
Operation (hr/yr)	8,760	8,760	8,760	8,760	8,760	8,760	
Device Power (hp)	61,094	56,197	37,339	34,458	59,089	54,264	
Device Power (kW)	45,558	41,906	27,844	25,695	44,063	40,465	From GTP Cookbook - Inlet Power
Turbine Heat Input HHV (MMBtu/hr)	418	386	311	291	418	386	From GTP Cookbook
Fuel Flow Rate (lbmol/hr)	1,024	943	760	712	1,024	943	From GTP Cookbook
Exhaust Flow MW (lb/lbmol)	28.6	28.6	28.6	28.6	28.6	28.6	From GTP Cookbook
Exhaust Flow Rate WET (lb/hr)	1,042,433	968,343	724,483	684,305	1,042,433	968,343	From GTP Cookbook
Exhaust Flow Rate (lbmol/hr)	36,449	33,858	25,332	23,927	36,449	33,858	
Exhaust H2O Concentration	6.2%	5.8%	6.3%	6.4%	6.2%	5.8%	From GTP Cookbook
Exhaust Flow Rate DRY (lbmol/hr)	34,196	31,901	23,738	22,405	34,196	31,901	
Exhaust O2 Concentration DRY	15.6%	15.3%	14.8%	14.8%	15.6%	15.3%	From Vendor Info
Exhaust Flow Rate (acfh)	23,152,716	21,507,158	16,090,962	15,198,597	35,420,995	32,903,479	

EMISSIONS CALCULATIONS	Treated Gas Compressor Turbines		CO2 Compressor Turbines		Main Power Generation Turbines		References/Comments
Turbine Emission Factors	Short-Term	Annual	Short-Term	Annual	Short-Term	Annual	
NOx (ppmvd @15% O2)	15.00	12.00	15.00	15.00	15.00	12.00	Adjusted to Actual O2 Amount
CO (ppmvd @15% O2)	15.00	15.00	67.00	25.00	15.00	15.00	Adjusted to Actual O2 Amount
VOC (lb/MMBtu)	0.002	0.002	0.002	0.002	0.002	0.002	
PM10 (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	
PM2.5 (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	
SO2	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Facto	No Emission Facto	No Emission Facto	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	53.060	53.060	53.060	53.060	53.060	
CH4 (kg CH4/MMBtu)	0.001	0.001	0.001	0.001	0.001	0.001	
N2O (kg N2O/MMBtu)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
Turbine Emission Calculations (Maximum 1-hour)							
NOx (lb/hr)	21.360	16.718	17.049	15.961	21.360	16.718	
CO (lb/hr)	13.004	12.722	46.361	16.194	13.004	12.722	
VOC (lb/hr)	0.927	0.856	0.690	0.645	0.927	0.856	
PM10 (lb/hr)	2.913	2.690	2.167	2.028	2.913	2.690	
PM2.5 (lb/hr)	2.913	2.690	2.167	2.028	2.913	2.690	
SO2 @ 16 ppm (lb/hr)	1.050	0.967	0.779	0.730	1.050	0.967	
SO2 @ 96 ppm (lb/hr)	6.288	5.791	4.667	4.372	6.288	5.791	
CO2 (lb/hr)	48,896.000	45,152.765	36,379.560	34,040.038	48,896.000	45,152.765	
CH4 (lb/hr)	0.922	0.851	0.686	0.642	0.922	0.851	
N2O (lb/hr)	0.092	0.085	0.069	0.064	0.092	0.085	
CO2e (lb/hr)	48,946.499	45,199.399	36,417.132	34,075.194	48,946.499	45,199.399	
Supplemental Firing Parameters							
Ambient Temp Basis (F)	-40	10	-40	10			
Load % Basis	100%	85%	80%	85%			
Operation (hr/yr)	8,760	8,760	8,760	8,760			
Heat Input LHV (MMBtu/hr)	259	172	174	129			From GTP Cookbook
Heat Input HHV (MMBtu/hr)	284.64	189.02	191.22	141.77			
Fuel Flow Rate (lbmol/hr)	698	464	469	348			Based on HHV
Supplemental Firing Emission Factors							
NOx (lb/MMBtu)	0.08	0.08	0.08	0.08			
CO (lb/MMBtu)	0.08	0.08	0.08	0.08			
VOC (lb/MMBtu)	0.02	0.02	0.02	0.02			
PM10 (lb/MMBtu)	0.01	0.01	0.01	0.01			
PM2.5 (lb/MMBtu)	0.01	0.01	0.01	0.01			
SO2	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			
CH4 (kg CH4/MMBtu)	0.001	0.001	0.001	0.001			
N2O (kg N2O/MMBtu)	0.0001	0.0001	0.0001	0.0001			
Supplemental Firing Emission Calculations (Maximum 1-hour)							
NOx (lb/hr)	22.771	15.122	15.298	11.341			
CO (lb/hr)	22.771	15.122	15.298	11.341			
VOC (lb/hr)	4.270	2.835	2.868	2.127			
PM10 (lb/hr)	1.423	0.945	0.956	0.709			
PM2.5 (lb/hr)	1.423	0.945	0.956	0.709			
SO2 @ 16 ppm (lb/hr)	0.716	0.475	0.481	0.356			
SO2 @ 96 ppm (lb/hr)	4.288	2.848	2.881	2.136			
CO2 (lb/hr)	33,295.569	22,111.343	22,368.452	16,583.507			
CH4 (lb/hr)	0.628	0.417	0.422	0.313			
N2O (lb/hr)	0.063	0.042	0.042	0.031			
CO2e (lb/hr)	33,329.956	22,134.180	22,391.554	16,600.635			
Total Emission Calculations (Maximum 1-hour)							
NOx (lb/hr)	44.131	31.840	32.347	27.302	21.360	16.718	
CO (lb/hr)	35.775	27.844	61.659	27.536	13.004	12.722	
VOC (lb/hr)	5.196	3.691	3.558	2.772	0.927	0.856	
PM10 (lb/hr)	4.336	3.635	3.123	2.737	2.913	2.690	
PM2.5 (lb/hr)	4.336	3.635	3.123	2.737	2.913	2.690	
SO2 @ 16 ppm (lb/hr)	1.765	1.442	1.260	1.086	1.050	0.967	
SO2 @ 96 ppm (lb/hr)	10.576	8.638	7.548	6.508	6.288	5.791	
CO2 (lb/hr)	82,191.569	67,264.108	58,748.011	50,623.545	48,896.000	45,152.765	
CH4 (lb/hr)	1.549	1.268	1.107	0.954	0.922	0.851	
N2O (lb/hr)	0.155	0.127	0.111	0.095	0.092	0.085	
CO2e (lb/hr)	82,276.456	67,333.578	58,808.686	50,675.829	48,946.499	45,199.399	
Total Emission Calculations (Annual)							
NOx (tpy)	193.295	139.458	141.681	119.584	93.559	73.223	
CO (tpy)	156.693	121.955	270.065	120.607	56.957	55.721	
VOC (tpy)	22.760	16.168	15.584	12.140	4.060	3.749	
PM10 (tpy)	18.992	15.922	13.681	11.987	12.759	11.782	
PM2.5 (tpy)	18.992	15.922	13.681	11.987	12.759	11.782	
SO2 @ 16 ppm (tpy)	7.733	6.316	5.518	4.758	4.597	4.234	
SO2 @ 96 ppm (tpy)	46.323	37.835	33.058	28.504	27.542	25.363	
CO2 (tonnes/yr)	326,589.015	267,274.603	233,435.807	201,153.161	194,288.741	179,414.962	
CH4 (tonnes/yr)	6.155	5.037	4.399	3.791	3.662	3.381	
N2O (tonnes/yr)	0.616	0.504	0.440	0.379	0.366	0.338	
CO2e (tonnes/yr)	326,926.314	267,550.642	233,676.898	201,360.910	194,489.401	179,600.260	
Stack Parameters							
Stack Height (ft)	240	240	240	240	240	240	From GTP Cookbook
Exhaust Temp Ambient Temp Basis (F)	--	--	--	--	-40	-40	
Exhaust Temp Load % Basis	--	--	--	--	60%	60%	
Exhaust Temperature (F)	410	410	410	410	871	871	From GTP Cookbook
Exhaust Velocity Ambient Temp Basis (F)	70	70	70	70	70	70	
Exhaust Velocity Load % Basis	60%	85%	60%	85%	60%	60%	
Exhaust Velocity (ft/s)	52.00	63.00	41.00	48.00	83	83	From GTP Cookbook (Calculated without SF for the Treated Gas and CO2 Turbines)
Stack Diameter (ft)	10	10	10	10	10	10	From GTP Cookbook
NO2/NOx Ratio	0.4	0.4	0.2	0.2	0.4	0.4	From GTP Cookbook

EC-5 GAS TREATMENT PLANT 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	**Black Start Diesel Generator**	**Main Diesel Firewater Pump**	**Dormitory Emergency Diesel Generator**	**Communications Tower Diesel Generator**	**References/ Comments**
Total Installed	1	3	1	1	From GTP Cookbook
Load % Basis	100%	100%	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	500	500	500	500	Intermittent Assumption
Rated Power (hp)	4,060	250	335	201	
Rated Power (kW)	2,500	186	250	150	From GTP Cookbook
BSFC (Btu/hp-hr)	7,000	7,000	7,000	7,000	AP42 Table 3.3-1
Rated Duty (MMBtu/hr)	28.42	1.75	2.35	1.41	For HAPs calculation and CO2e
Fuel Flow Rate (gal/hr)	186.60	14.47	19.40	11.64	Ratio Assumed for FWP and Com Tower Gen
Exhaust Flow Rate (acfm)	20,134.00	1,674.84	2,246.00	1,347.60	Ratio Assumed for FWP and Com Tower Gen
Emission Factors					
Not-to-Exceed Factor	25%	25%	25%	25%	
NOx (g/hp-hr)	2.610	2.850	2.834	2.834	
CO (g/hp-hr)	2.610	2.600	2.610	2.610	
VOC (g/hp-hr)	0.142	0.150	0.149	0.149	
PM10 (g/hp-hr)	0.030	0.150	0.149	0.149	
PM2.5 (g/hp-hr)	0.030	0.150	0.149	0.149	
SO2	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	73.960	73.960	73.960	73.960	
CH4 (kg CH4/MMBtu)	0.003	0.003	0.003	0.003	
N2O (kg N2O/MMBtu)	0.001	0.001	0.001	0.001	
Emission Calculations (Maximum 1-hour)					
NOx (lb/hr)	29.201	1.964	2.618	1.571	
CO (lb/hr)	29.201	1.791	2.411	1.447	
VOC (lb/hr)	1.585	0.103	0.138	0.083	
PM10 (lb/hr)	0.334	0.103	0.138	0.083	
PM2.5 (lb/hr)	0.334	0.103	0.138	0.083	
SO2 (lb/hr)	0.038	0.003	0.004	0.002	
CO2 (lb/hr)	4,633.944	285.341	382.649	229.589	
CH4 (lb/hr)	1.234	0.096	0.128	0.077	
N2O (lb/hr)	0.000	0.000	0.000	0.000	
CO2e (lb/hr)	4,664.797	287.733	385.857	231.514	
Emission Calculations (Annual)					
NOx (tpy)	7.300	0.491	0.655	0.393	
CO (tpy)	7.300	0.448	0.603	0.362	
VOC (tpy)	0.396	0.026	0.034	0.021	
PM10 (tpy)	0.083	0.026	0.034	0.021	
PM2.5 (tpy)	0.083	0.026	0.034	0.021	
SO2 (tpy)	0.009	0.001	0.001	0.001	
CO2 (tonnes/yr)	1,050.972	64.715	86.784	52.071	
CH4 (tonnes/yr)	0.043	0.003	0.004	0.002	
N2O (tonnes/yr)	0.009	0.001	0.001	0.000	
CO2e (tonnes/yr)	1,054.578	64.937	87.082	52.249	
Stack Parameters					
Stack Height (ft)	115	76	76	29	From GTP Cookbook (FWP and Com Gen Assumed)
Exhaust Temperature (F)	879	850	852	850	From GTP Cookbook (FWP and Com Gen Assumed)
Exhaust Velocity (ft/s)	68	36	48	29	From GTP Cookbook (FWP and Com Gen Assumed)
Stack Diameter (ft)	2.5	1	1	1	From GTP Cookbook (FWP and Com Gen Assumed)
NO2/NOx Ratio	0.5	0.5	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-6 GAS TREATMENT PLANT FUEL GAS HEATERS

EMISSION FACTORS	Standard Factors: AP42 Tables 1.4-1 and 1.4-2 Large Controlled (Low NOx Burners)			40 CFR Part 98 (Natural Gas)	Average Emission Factors from Currently Operating Facilities (Low NOx Burners)
NOx (lb/MMSCF)	147.824	NOx (lb/MMBtu)	0.137		0.080
CO (lb/MMSCF)	88.694	CO (lb/MMBtu)	0.082		0.060
VOC (lb/MMSCF)	5.807	VOC (lb/MMBtu)	0.005		0.006
PM10 (lb/MMSCF)	8.025	PM10 (lb/MMBtu)	0.007		0.007
PM2.5 (lb/MMSCF)	8.025	PM2.5 (lb/MMBtu)	0.007		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	Building Heat Medium Heater	Buyback Gas Bath Heater Primary Heater Standby	Buyback Gas Bath Heater Secondary Heater Standby	Buyback Gas Bath Heater Primary Heater Maximum	Buyback Gas Bath Heater Secondary Heater Maximum	Operations Camp Heater	References/ Comments
Total Installed	3	1	1	1	1	3	From GTP Cookbook (2 op, 1 spare For Building Heat Medium Heater)
Load	100%	100%	100%	100%	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	8,760	8,760	8,760	500	500	8,760	Intermittent Assumption
Rated Duty LHV (MMBtu/hr)	250.00	0.14	0.14	23.04	19.04	29.00	From GTP Cookbook
Rated Duty HHV (MMBtu/hr)	274.74	0.15	0.15	25.32	20.92	31.87	
Fuel Flow Rate (lbmol/hr)	672.00	0.40	0.40	62.00	51.20	79.00	From GTP Cookbook
Fuel Flow Rate (MMSCF/hr)	0.25	0.00	0.00	0.02	0.02	0.03	
Emission Factors							
NOx (lb/MMBtu)	0.080	0.080	0.080	0.080	0.080	0.080	Based on HHV
CO (lb/MMBtu)	0.082	0.082	0.082	0.082	0.082	0.082	Based on HHV
VOC (lb/MMBtu)	0.006	0.006	0.006	0.006	0.006	0.006	Based on HHV
PM10 (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	Based on HHV
PM2.5 (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	Based on HHV
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
Emission Calculations (Maximum 1-hour)							
NOx (lb/hr)	21.980	0.012	0.012	2.026	1.674	2.550	
CO (lb/hr)	22.626	0.013	0.013	2.085	1.723	2.625	
VOC (lb/hr)	1.648	0.001	0.001	0.152	0.126	0.191	
PM10 (lb/hr)	2.047	0.001	0.001	0.189	0.156	0.237	
PM2.5 (lb/hr)	2.047	0.001	0.001	0.189	0.156	0.237	
SO2 @ 16 ppm (lb/hr)	0.689	0.000	0.000	0.064	0.052	0.081	
SO2 @ 96 ppm (lb/hr)	4.127	0.002	0.002	0.381	0.314	0.485	
CO2 (lb/hr)	32138.580	17.998	17.998	2961.892	2447.674	3728.075	
CH4 (lb/hr)	0.606	0.000	0.000	0.056	0.046	0.070	
N2O (lb/hr)	0.061	0.000	0.000	0.006	0.005	0.007	
CO2e (lb/hr)	32171.773	18.016	18.016	2964.951	2450.202	3731.926	
Emission Calculations (Annual)							
NOx (tpy)	96.271	0.054	0.054	0.506	0.418	11.167	
CO (tpy)	99.102	0.055	0.055	0.521	0.431	11.496	
VOC (tpy)	7.220	0.004	0.004	0.038	0.031	0.838	
PM10 (tpy)	8.966	0.005	0.005	0.047	0.039	1.040	
PM2.5 (tpy)	8.966	0.005	0.005	0.047	0.039	1.040	
SO2 @ 16 ppm (tpy)	3.017	0.002	0.002	0.016	0.013	0.355	
SO2 @ 96 ppm (tpy)	18.074	0.011	0.011	0.095	0.079	2.125	
CO2 (tonnes/yr)	127702.967	71.514	71.514	671.753	555.129	14813.544	
CH4 (tonnes/yr)	2.407	0.001	0.001	0.013	0.010	0.279	
N2O (tonnes/yr)	0.241	0.000	0.000	0.001	0.001	0.028	
CO2e (tonnes/yr)	127834.858	71.588	71.588	672.446	555.702	14828.844	
Stack Parameters							
Stack Height (ft)	232	20	20	20	20	32	From GTP Cookbook
Exhaust Temperature (F)	370	601	887	601	887	257	From GTP Cookbook
Exhaust Velocity (ft/s)	26	0.33	0.41	54.79	57.49	29	From GTP Cookbook
Stack Diameter (ft)	9	2	2	2	2	2.5	From GTP Cookbook
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 GAS TREATMENT PLANT 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	LP CO2 East/West Purge Pilot	HP CO2 East/West Purge Pilot	HP HC East/West Purge Pilot	LP HC East/West Purge Pilot	LP CO2 East/West Maximum	HP CO2 East/West Maximum	HP HC East/West Maximum	LP HC East/West Maximum	References/ Comments
Exhaust Flow Calculation									
Fuel Flow Rate (scfh)	6,326	2,745	7,269	1,331	29,125,000	9,541,667	76,250,000	4,166,667	From GTP Cookbook
Fuel Flow Rate (lbmol/hr)	16.71	7.25	19.20	3.52	76,950.51	25,209.83	201,458.43	11,008.66	
Fuel MW(lb/lbmol)	17.67	17.67	17.67	17.67	35.64	35.92	20.57	17.66	Purge/Pilot based on Fuel Gas, Maximum Case from GTP Cookbook
Fuel Flow Rate (lb/hr)	295.31	128.14	339.34	62.14	2,742,516.31	905,536.91	4,143,999.84	194,412.89	
Fuel HHV (Btu/lb)	23,129.00	23,129.00	23,129.00	23,129.00	3,511.38	3,483.57	17,690.00	23,129.00	Purge/Pilot based on Fuel Gas, Maximum Case from GTP Cookbook
Fuel Flow HHV (MMBtu/hr)	6.83	2.96	7.85	1.44	9,630.01	3,154.50	73,307.36	4,496.58	
Fd Factor (dscf/MMBtu)	8,710.00	8,710.00	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%	3%	3%	Assumed Dry Oxygen Concentration
Exhaust Flow (dscfh) (@HHV)	69,462.26	30,140.03	79,817.88	14,615.70	97,935,038.13	32,080,577.30	745,519,441.15	45,729,169.51	
Exhaust Water Concentration	10%	10%	10%	10%	10%	10%	10%	10%	Assumed Water Content
Exhaust Flow (scfh) (@HHV)	77,180.28	33,488.92	88,686.53	16,239.67	108,816,709.04	35,645,085.89	828,354,934.61	50,810,188.34	
Ratio of Exhaust to Fuel	12.20	12.20	12.20	12.20	3.74	3.74	10.86	12.19	
Exhaust Flow (L/h) (@HHV)	2,185,745.63	948,406.35	2,511,602.62	459,907.52	3,081,689,199.88	1,009,468,832.33	23,459,011,748.12	1,438,944,533.90	
Effective Height and Diameter Calculation									
Fuel LHV (Btu/lb)	21,040.00	21,040.00	21,040.00	21,040.00	3,194.00	3,169.00	16,100.00	21,040.00	Purge/Pilot based on Fuel Gas, Maximum Case from GTP Cookbook
Heat Release Rate (MMBtu/hr)	6.21	2.70	7.14	1.31	8,759.60	2,869.65	66,718.40	4,090.45	Based on LHV
Buoyancy flux	7.22	3.13	8.30	1.52	10,178.65	3,334.53	77,526.78	4,753.10	SCREEN3 Model User's Guide
Actual Stack Height (m)	67.056	67.056	67.056	67.056	67.056	67.056	67.056	67.056	From GTP Cookbook converted to m
GEP stack height (m)	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	EPA GEP Stack Height Guideline
Effective Stack Height (m)	67.26	66.52	67.42	66.07	137.36	107.44	255.97	115.28	SCREEN3 Model User's Guide
Effective Stack Diameter (m)	0.44	0.29	0.47	0.20	16.43	9.40	45.33	11.22	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	LP CO2 East/West Purge Pilot	HP CO2 East/West Purge Pilot	HP HC East/West Purge Pilot	LP HC East/West Purge Pilot	LP CO2 East/West Maximum	HP CO2 East/West Maximum	HP HC East/West Maximum	LP HC East/West Maximum	References/ Comments
Total Installed	6 (2 x 3 flare tips)	2	2	2	3	1	1	1	From GTP Cookbook
Load	100%	100%	100%	100%	100%	100%	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	8,760	8,760	8,760	8,760	500	500	500	500	Maximum Case Intermittent
Rated Duty HHV (MMBtu/hr)	6.83	2.96	7.85	1.44	9,630.01	3,154.50	73,307.36	4,496.58	For HAPs Calculation
Emission Factors									
NOx (lb/MMBtu)	0.068	0.068	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	0.310	0.310	Based on HHV
VOC (lb/MMBtu)	0.570	0.570	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	40.000	40.000	
PM2.5 (µg/L Exhaust)	40.000	40.000	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	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	53.060	53.060	Based on HHV
CH4 (kg CH4/MMBtu)	0.001	0.001	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	0.000	0.000	Based on HHV
Emission Calculations (Maximum 1-hour)									
NOx (lb/hr)	0.464	0.202	0.534	0.098	654.841	214.506	4,984.900	305.767	
CO (lb/hr)	2.117	0.919	2.433	0.446	2,985.303	977.896	22,725.281	1,393.938	
VOC (lb/hr)	3.893	1.689	4.474	0.819	5,489.105	1,798.066	41,785.194	2,563.048	
PM10 (lb/hr)	0.193	0.084	0.221	0.041	271.760	89.020	2,068.742	126.894	
PM2.5 (lb/hr)	0.193	0.084	0.221	0.041	271.760	89.020	2,068.742	126.894	
SO2 @ 16 ppm (lb/hr)	0.017	0.007	0.020	0.004	78.879	25.841	206.506	11.284	
SO2 @ 96 ppm (lb/hr)	0.103	0.045	0.118	0.022	472.532	154.807	1,237.101	67.601	
CO2 (lb/hr)	798.977	346.680	918.091	168.115	1,126,480.648	369,001.230	8,575,206.987	525,991.775	
CH4 (lb/hr)	0.015	0.007	0.017	0.003	21.230	6.954	161.613	9.913	
N2O (lb/hr)	0.002	0.001	0.002	0.000	2.123	0.695	16.161	0.991	
CO2e (lb/hr)	799.803	347.038	919.039	168.288	1,127,644.069	369,382.332	8,584,063.401	526,535.015	
Emission Calculations (Annual)									
NOx (tpy)	2.034	0.883	2.338	0.428	163.710	53.627	1,246.225	76.442	
CO (tpy)	9.274	4.024	10.657	1.951	746.326	244.474	5,681.320	348.485	
VOC (tpy)	17.052	7.399	19.595	3.588	1,372.276	449.516	10,446.298	640.762	
PM10 (tpy)	0.844	0.366	0.970	0.178	67.940	22.255	517.185	31.723	
PM2.5 (tpy)	0.844	0.366	0.970	0.178	67.940	22.255	517.185	31.723	
SO2 @ 16 ppm (tpy)	0.075	0.033	0.086	0.016	19.720	6.460	51.627	2.821	
SO2 @ 96 ppm (tpy)	0.450	0.195	0.517	0.095	118.133	38.702	309.275	16.900	
CO2 (tonnes/yr)	3,174.745	1,377.538	3,648.045	668.005	255,484.135	83,688.930	1,944,844.186	119,294.152	
CH4 (tonnes/yr)	0.060	0.026	0.069	0.013	4.815	1.577	36.654	2.248	
N2O (tonnes/yr)	0.006	0.003	0.007	0.001	0.482	0.158	3.665	0.225	
CO2e (tonnes/yr)	3,178.024	1,378.961	3,651.812	668.695	255,747.997	83,775.363	1,946,852.808	119,417.358	
Stack Parameters									
Stack Height (m)	67.26	66.52	67.42	66.07	137.36	107.44	255.97	115.28	
Exhaust Temperature (K)	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	
Exhaust Velocity (m/s)	20	20	20	20	20	20	20	20	
Stack Diameter (m)	0.44	0.29	0.47	0.20	16.43	9.40	45.33	11.22	
NO2/NOx Ratio	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-8 GAS TREATMENT PLANT MISCELLANEOUS SOURCES

EMISSIONS CALCULATIONS	Tank	Fugitive	References/ Comments
Methane (lb/hr)		27.998	From GTP Cookbook
NMHC (lb/hr)	0.009	10.803	From GTP Cookbook
CO2e (lb/hr)		699.961	
Emissions Calculation (Annual)			
Operation (hr/yr)	8,760	8,760	From GTP Cookbook
Methane (tonnes/yr)		111.252	
CO2e (tonnes/yr)		2781.3	
NMHC (tpy)	0.04	47.32	

EC-9 GAS TREATMENT PLANT HAZARDOUS AIR POLLUTANTS (HAPS) EMISSIONS SUMMARY

Emission Unit ID	1A	1B	2A	2B	3A	3B	4A	4B	5A	5B	6A	6B	7A_1A	7A_1B	7A_2A	7A_2B	7A_3A	7A_3B	9_1	31A	31B	31C
CT Mfg / Model	Train 1a Treated Gas Compressor Turbine Primary Stack (includes SF	Train 1b Treated Gas Compressor Turbine Primary Stack (includes SF	Train 2a Treated Gas Compressor Turbine Primary Stack (includes SF	Train 2b Treated Gas Compressor Turbine Primary Stack (includes SF	Train 3a Treated Gas Compressor Turbine Primary Stack (includes SF	Train 3b Treated Gas Compressor Turbine Primary Stack (includes	Train 1a CO2 Compressor Turbine Primary Stack (includes	Train 1b CO2 Compressor Turbine Primary Stack (includes	Train 2a CO2 Compressor Turbine Primary Stack (includes	Train 2b CO2 Compressor Turbine Primary Stack (includes	Train 3a CO2 Compressor Turbine Primary Stack (includes	Train 3b CO2 Compressor Turbine Primary Stack (includes SF	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Black Start Diesel Generator (2500 kW)	Main Diesel Firewater Pump (250 hp)	Main Diesel Firewater Pump (250 hp)	Main Diesel Firewater Pump (250 hp)
Source Category	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	ICE	ICE	ICE	ICE
ISO Power (kW)	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
10°F Heat Consumption (MMBtu/hr)	558	558	558	558	558	558	420	420	420	420	420	420	386	386	386	386	386	386	28.42	1.75	1.75	1.75
Load Basis for CT EF	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>600hp	<600hp	<600hp	<600hp
Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	D	D	D	D
hrs/yr	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	500	500	500	500
1,1,2,2-Tetrachloroethane	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
1,3-Butadiene	0.001050937	0.001050937	0.001050937	0.001050937	0.001050937	0.001050937	0.000791028	0.000791028	0.000791028	0.000791028	0.000791028	0.000791028	0.000726992	0.000726992	0.000726992	0.000726992	0.000726992	0.000726992	0	1.71063E-05	1.71063E-05	1.71063E-05
1,3-Dichloropropene	0	0	0	0	0	0	0	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	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	0	0	0	0	0	0	0
Acetaldehyde	0.0977616	0.0977616	0.0977616	0.0977616	0.0977616	0.0977616	0.073584	0.073584	0.073584	0.073584	0.073584	0.073584	0.0676272	0.0676272	0.0676272	0.0676272	0.0676272	0.0676272	0.000179046	0.000335563	0.000335563	0.000335563
Acrolein	0.015641856	0.015641856	0.015641856	0.015641856	0.015641856	0.015641856	0.01177344	0.01177344	0.01177344	0.01177344	0.01177344	0.01177344	0.010820352	0.010820352	0.010820352	0.010820352	0.010820352	0.010820352	5.59874E-05	4.04688E-05	4.04688E-05	4.04688E-05
Antimony	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Benzene	0.02932848	0.02932848	0.02932848	0.02932848	0.02932848	0.02932848	0.0220752	0.0220752	0.0220752	0.0220752	0.0220752	0.0220752	0.02028816	0.02028816	0.02028816	0.02028816	0.02028816	0.02028816	0.00551348	0.000408188	0.000408188	0.000408188
Beryllium	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Cadmium	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Chlorobenzene	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Chromium	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Dibutylphthalate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethylbenzene	0.07820928	0.07820928	0.07820928	0.07820928	0.07820928	0.07820928	0.0588672	0.0588672	0.0588672	0.0588672	0.0588672	0.0588672	0.05410176	0.05410176	0.05410176	0.05410176	0.05410176	0.05410176	0	0	0	0
Ethylene Dibromide	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Formaldehyde	1.7352684	1.7352684	1.7352684	1.7352684	1.7352684	1.7352684	1.306116	1.306116	1.306116	1.306116	1.306116	1.306116	1.2003828	1.2003828	1.2003828	1.2003828	1.2003828	1.2003828	0.000560585	0.00051625	0.00051625	0.00051625
HCl	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Manganese	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
n-Hexane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nickel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PAHs	0.005376888	0.005376888	0.005376888	0.005376888	0.005376888	0.005376888	0.00404712	0.00404712	0.00404712	0.00404712	0.00404712	0.00404712	0.003719496	0.003719496	0.003719496	0.003719496	0.003719496	0.003719496	0.00150626	0.0000735	0.0000735	0.0000735
Phenol	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
POM (Total)	0.003177252	0.003177252	0.003177252	0.003177252	0.003177252	0.003177252	0.00239148	0.00239148	0.00239148	0.00239148	0.00239148	0.00239148	0.002197884	0.002197884	0.002197884	0.002197884	0.002197884	0.002197884	0.001502942	7.36147E-05	7.36147E-05	7.36147E-05
POM 2-Methylnaphthalene	0	0	0	0	0	0	0	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	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	0	0	0	0	0	0	0
POM Acenaphthene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.32514E-05	6.2125E-07	6.2125E-07	6.2125E-07
POM Acenaphthylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6.55792E-05	2.21375E-06	2.21375E-06	2.21375E-06
POM Anthracene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8.73915E-06	8.18125E-07	8.18125E-07	8.18125E-07
POM Benz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.41931E-06	0.000000735	0.000000735	0.000000735
POM Benzo(a)pyrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.82599E-06	8.225E-08	8.225E-08	8.225E-08
POM Benzo(b)fluoranthene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7.88655E-06	4.33563E-08	4.33563E-08	4.33563E-08
POM Benzo(g,h,i)perylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.95038E-06	2.13938E-07	2.13938E-07	2.13938E-07
POM Benzo(k)fluoranthene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.54889E-06	6.78125E-08	6.78125E-08	6.78125E-08
POM Chrysene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.08707E-05	1.54438E-07	1.54438E-07	1.54438E-07
POM Dibenz(a,h)anthracene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.45833E-06	2.55063E-07	2.55063E-07	2.55063E-07
POM Fluoranthene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.86332E-05	3.32938E-06	3.32938E-06	3.32938E-06
POM Fluorene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000090944	1.28625E-05	1.28625E-05	1.28625E-05
POM Indeno(1,2,3-c,d)pyrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.94147E-06	1.64063E-07	1.64063E-07	1.64063E-07
POM Naphthalene	0.003177252	0.003177252	0.003177252	0.003177252	0.003177252	0.003177252	0.00239148	0.00239148	0.00239148	0.00239148	0.00239148	0.00239148	0.002197884	0.002197884	0.002197884	0.002197884	0.002197884	0.002197884	0.00092365	0.0000371	0.0000371	0.0000371
POM Phenanthrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000289884	1.28625E-05	1.28625E-05	1.28625E-05
POM Pyrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.63596E-05	2.09125E-06	2.09125E-06	2.09125E-06
Propional[dehyde]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propylene Oxide	0.07087716	0.07087716	0.07087716	0.07087716	0.07087716	0.07087716	0.0533484	0.0533484	0.0533484	0.0533484	0.0533484	0.0533484	0.04902972	0.04902972	0.04902972	0.04902972	0.04902972	0.04902972	0	0	0	0
Selenium	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Tetrachloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Toluene	0.3177252	0.3177252	0.3177252	0.3177252	0.3177252	0.3177252	0.239148	0.239148	0.239148	0.239148	0.239148	0.239148	0.2197884	0.2197884	0.2197884	0.2197884	0.2197884	0.2197884	0.001996505	0.000178938	0.000178938	0.000178938
Trichloroethylene	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
Vinylidene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Xylenes(m,p,o)	0.15641856	0.15641856	0.15641856	0.15641856	0.15641856	0.15641856	0.1177344	0.1177344	0.1177344	0.1177344	0.1177344	0.1177344	0.10820352	0.10820352	0.10820352	0.10820352	0.10820352	0.10820352	0.001371265	0.000124688	0.000124688	0.000124688
CDD/CDF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOURCE TOTAL (tpy)	**2.511**	**2.511**	**2.511**	**2.511**	**2.511**	**2.511**	**1.890**	**1.890**	**1.890**	**1.890**	**1.890**	**1.890**	**1.737**	**1.737**	**1.737**	**1.737**	**1.737**	**1.737**	**0.013**	**0.002**	**0.002**	**0.002**

Emission Unit ID	33	36	10E	10W	11E	11W	12E	12W	13E	13W	10E_M	11E_M	12E_M	13E_M	14_1	14_2	14_3	21A	21B	21A_M	21B_M	CAMPHT1	CAMPHT2	CAMPHT3	Total
CT Mfg / Model	Dormitory Emergency Diesel Generator (250 kW)	Communications Tower (150 kW)	LP CO2 Flare East Pilot/Purge (3 Flares)	LP CO2 Flare West Pilot/Purge (3 Flares)	HP CO2 Flare East Pilot/Purge	HP CO2 Flare West Pilot/Purge	HP Hydrocarbon Flare East Pilot/Purge	HP Hydrocarbon Flare West Pilot/Purge	LP Hydrocarbon Flare East Pilot/Purge	LP Hydrocarbon Flare West Pilot/Purge	LP CO2 Flare East MAX	HP CO2 Flare East MAX	HP Hydrocarbon Flare East MAX	LP Hydrocarbon Flare East MAX	Building Heat Medium Heater	Building Heat Medium Heater	Building Heat Medium Heater (spare)	Buyback Gas Bath Heater Pre-Let Down Heater Standby	Buyback Gas Bath Heater Post-Let Down Heater Standby	Buyback Gas Bath Heater Pre-Let Down Heater MAX	Buyback Gas Bath Heater Post-Let Down Heater MAX	Operations Camp Heater	Operations Camp Heater	Operations Camp Heater (spare)	
Source Category	ICE	ICE	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Heater	Heater	Heater	Heater	Heater	Heater	Heater	Heater	Heater	Heater	
ISO Power (kW)	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	
10°F Heat Consumption (MMBtu/hr)	2.35	1.41	6.83	6.83	2.96	2.96	7.85	7.85	1.44	1.44	9630.01	3154.50	73307.36	4496.58	274.74	274.744898	274.744898	0.153857143	0.153857143	25.3204898	20.92457143	31.87	31.87	31.87	
Load Basis for CT EF	<600hp	<600hp	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0	0	
Fuel	D	D	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	
hrs/yr	500	500	8760	8760.00	8760.00	8760.00	8760.00	8760.00	8760.00	8760.00	500.00	500.00	500.00	500.00	8760.00	8760	0	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	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	0	0	0	0	0	0	0	0	0	0	0	0.00
1,3-Butadiene	2.29399E-05	1.37639E-05	0	0	0	0	0	0	0	0	0	0	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	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	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	0	0	0	0	0	0	0	0	0	0	0	0.00
Acetaldehyde	0.000449997	0.000269998	0.001261188	0.001261188	0.000547236	0.000547236	0.00144921	0.00144921	0.000265369	0.000265369	0.10149274	0.033245974	0.772602049	0.047390381	0	0	0	0	0	0	0	0	0	0	2.40
Acrolein	5.42695E-05	3.25617E-05	0.0002933	0.0002933	0.000127264	0.000127264	0.000337025	0.000337025	6.17138E-05	6.17138E-05	0.023602963	0.007731622	0.179674895	0.011021019	0	0	0	0	0	0	0	0	0	0	0.45
Antimony	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	0	0.00
Benzene	0.000547388	0.000328433	0.004663463	0.004663463	0.002023501	0.002023501	0.005358705	0.005358705	0.000981249	0.000981249	0.37528711	0.122932787	2.856830832	0.175234198	0.002477524	0.002477524	0	1.38741E-06	1.38741E-06	1.30325E-05	1.07699E-05	0.000287393	0.000287393	0	4.00
Beryllium	0	0	0	0	0	0	0	0	0	0	0	0	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	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	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	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	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	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	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	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	0	0	0	0	0	0	0	0	0	0	0	0.00
Ethylbenzene	0	0	0.042352456	0.042352456	0.01837695	0.01837695	0.048666477	0.048666477	0.008911473	0.008911473	3.408267841	1.116446187	25.94505485	1.591435106	0	0	0	0	0	0	0	0	0	0	33.44
Ethylene Dibromide	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	0	0.00
Formaldehyde	0.000692303	0.000415382	0.034286718	0.034286718	0.014877185	0.014877185	0.039398277	0.039398277	0.007214343	0.007214343	2.759186362	0.903826588	21.00399524	1.288357091	0.088484004	0.088484004	0	4.9551E-05	4.9551E-05	0.00046545	0.000384643	0.010264145	0.010264145	0	51.80
HCl	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0.000589898	0.000589898	0	3.30343E-07	3.30343E-07	3.10303E-06	2.56431E-06	6.84282E-05	6.84282E-05	0	0.00
Manganese	0	0	0	0	0	0	0	0	0	0	0	0	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	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	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	0	0	0	0	0	0	0	0	0	0	0	0.00
n-Hexane	0	0	0.000850569	0.000850569	0.000369066	0.000369066	0.000977374	0.000977374	0.00017897	0.00017897	0.068448592	0.022421703	0.521057196	0.031960954	2.123616468	2.123616468	0	0.001189225	0.001189225	0.011170804	0.009231429	0.24633951	0.24633951	0	5.41
Nickel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
PAHs	9.85651E-05	5.91391E-05	0.000410619	0.000410619	0.00017817	0.00017817	0.000471836	0.000471836	8.63993E-05	8.63993E-05	0.033044148	0.010824271	0.251544853	0.015429426	0	0	0	0	0	0	0	0	0	0	0.39
Phenol	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	0	0.00
POM (Total)	9.87189E-05	5.92313E-05	3.16303E-07	3.16303E-07	1.37246E-07	1.37246E-07	3.63459E-07	3.63459E-07	6.65541E-08	6.65541E-08	2.54542E-05	8.33802E-06	0.000193767	1.18854E-05	0.000824076	0.000824076	0	4.61483E-07	4.61483E-07	4.33487E-06	3.58229E-06	9.55929E-05	9.55929E-05	0	0.05
POM 2-Methylnaphthalene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.82795E-05	2.82795E-05	0	1.58365E-08	1.58365E-08	1.48758E-07	1.22932E-07	3.28042E-06	3.28042E-06	0	0.00
POM 3-Methylcholanthrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM 7,12-Dimethylbenz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.88931E-05	1.88931E-05	0	1.05801E-08	1.05801E-08	9.93829E-08	8.21289E-08	2.1916E-06	2.1916E-06	0	0.00
POM Acenaphthene	8.3311E-07	4.99866E-07	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Acenaphthylene	2.96869E-06	1.78121E-06	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Anthracene	1.09712E-06	6.58274E-07	0	0	0	0	0	0	0	0	0	0	0	0	2.88812E-06	2.88812E-06	0	1.61735E-09	1.61735E-09	1.51923E-08	1.25547E-08	3.35022E-07	3.35022E-07	0	0.00
POM Benz(a)anthracene	9.85651E-07	5.91391E-07	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Benzo(a)pyrene	1.10299E-07	6.61794E-08	0	0	0	0	0	0	0	0	0	0	0	0	1.44406E-06	1.44406E-06	0	8.08673E-10	8.08673E-10	7.59615E-09	6.27737E-09	1.67511E-07	1.67511E-07	0	0.00
POM Benzo(b)fluoranthene	5.81417E-08	3.4885E-08	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Benzo(g,h,i)perylene	2.86895E-07	1.72137E-07	0	0	0	0	0	0	0	0	0	0	0	0	1.44406E-06	1.44406E-06	0	8.08673E-10	8.08673E-10	7.59615E-09	6.27737E-09	1.67511E-07	1.67511E-07	0	0.00
POM Benzo(k)fluoranthene	9.0938E-08	5.45628E-08	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Chrysene	2.07104E-07	1.24262E-07	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Dibenz(a,h)anthracene	3.42044E-07	2.05227E-07	0	0	0	0	0	0	0	0	0	0	0	0	1.44406E-06	1.44406E-06	0	8.08673E-10	8.08673E-10	7.59615E-09	6.27737E-09	1.67511E-07	1.67511E-07	0	0.00
POM Fluoranthene	4.46476E-06	2.67886E-06	0	0	0	0	0	0	0	0	0	0	0	0	3.48981E-06	3.48981E-06	0	1.95429E-09	1.95429E-09	1.83574E-08	1.51703E-08	4.04818E-07	4.04818E-07	0	0.00
POM Fluorene	1.72489E-05	1.03493E-05	0	0	0	0	0	0	0	0	0	0	0	0	3.24913E-06	3.24913E-06	0	1.81951E-09	1.81951E-09	1.70913E-08	1.41241E-08	3.76899E-07	3.76899E-07	0	0.00
POM Indeno(1,2,3-c,d)pyrene	2.20011E-07	1.32007E-07	0	0	0	0	0	0	0	0	0	0	0	0	2.16609E-06	2.16609E-06	0	1.21301E-09	1.21301E-09	1.13942E-08	9.41606E-09	2.51266E-07	2.51266E-07	0	0.00
POM Naphthalene	4.97519E-05	2.98511E-05	0.00032263	0.00032263	0.000139991	0.000139991	0.000370728	0.000370728	6.78852E-05	6.78852E-05	0.025963259	0.008504784	0.197642385	0.012123121	0.000719623	0.000719623	0	4.02989E-07	4.02989E-07	3.78541E-06	3.12822E-06	8.34762E-05	8.34762E-05	0	0.30
POM Phenanthrene	1.72489E-05	1.03493E-05	0	0	0	0	0	0	0	0	0	0	0	0	2.00965E-05	2.00965E-05	0	1.1254E-08	1.1254E-08	1.05713E-07	8.73601E-08	2.33119E-06	2.33119E-06	0	0.00
POM Pyrene	2.80441E-06	1.68265E-06	0	0	0	0	0	0	0	0	0	0	0	0	5.89658E-06	5.89658E-06	0	3.30208E-09	3.30208E-09	3.10176E-08	2.56326E-08	6.84003E-07	6.84003E-07	0	0.00
Propional[dehyde]	0	0	0	0	0	0	0	0	0	0	0	0	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	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	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	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	0	0	0	0	0	0	0	0	0	0	0	0.00
Toluene	0.000239959	0.000143975	0.001701137	0.001701137	0.000738132	0.000738132	0.001954748	0.001954748	0.00035794	0.00035794	0.136897185	0.044843406	1.042114392	0.063921909	0.004011235	0.004011235	0	2.24629E-06	2.24629E-06	2.11002E-05	1.7437E-05	0.000465303	0.000465303	0	5.97
Trichloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	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	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	0	0	0	0	0	0	0	0	0	0	0	0.00
Xylenes(m,p,o)	0.000167209	0.000100325	0.000850569	0.000850569	0.000369066	0.000369066	0.000977374	0.000977374	0.00017897	0.00017897	0.068448592	0.022421703	0.521057196	0.031960954	0	0	0	0	0	0	0	0	0	0	2.94
CDD/CDF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
SOURCE TOTAL (tpy)	**0.002**	**0.001**	**0.087**	**0.087**	**0.038**	**0.038**	**0.100**	**0.100**	**0.018**	**0.018**	**6.975**	**2.285**	**53.094**	**3.257**	**2.220**	**2.220**	**0.000**	**0.001**	**0.001**	**0.012**	**0.010**	**0.258**	**0.258**	**0.000**	**107.92**

EC-10 GAS TREATMENT PLANT EMISSION FACTOR SUMMARY

	Treated Gas Compressor Turbine Primary Stack		Treated Gas Compressor Turbine Primary Stack		CO2 Compressor Turbine Primary Stack		CO2 Compressor Turbine Primary Stack		Turbine Supplemental Firing		Power Generator Turbine		Power Generator Turbine	
Pollutant	**Emission Factor**	**Units**	**Emission Factor**	**Units**	**Emission Factor**	**Units**	**Emission Factor**	**Units**	**Emission Factor**	**Units**	**Emission Factor**	**Units**	**Emission Factor**	**Units**
NOx	15.00	ppmvd @15% O2	12.00	ppmvd @15% O2	15.00	ppmvd @15% O2	15.00	ppmvd @15% O2	0.08	lb/MMBtu	15.00	ppmvd @15% O2	12.00	ppmvd @15% O2
CO	15.00	ppmvd @15% O2	15.00	ppmvd @15% O2	67.00	ppmvd @15% O2	25.00	ppmvd @15% O2	0.08	lb/MMBtu	15.00	ppmvd @15% O2	15.00	ppmvd @15% O2
VOC	0.002	lb/MMBtu	0.002	lb/MMBtu	0.002	lb/MMBtu	0.002	lb/MMBtu	0.015	lb/MMBtu	0.002	lb/MMBtu	0.002	lb/MMBtu
PM10	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu	0.005	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu
PM2.5	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu	0.005	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu
Fuel Sulfur Normal Operation	16.00	ppmv	16.00	ppmv	16.00	ppmv	16.00	ppmv	16.00	ppmv	16.00	ppmv	16.00	ppmv
Fuel Sulfur Maximum	96.00	ppmv	96.00	ppmv	96.00	ppmv	96.00	ppmv	96.00	ppmv	96.00	ppmv	96.00	ppmv
CO2	53.06	kg/MMBtu	53.060	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu
CH4	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu
N2O	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	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	4.30E-07	lb/MMBtu	4.30E-07	lb/MMBtu	4.30E-07	lb/MMBtu	4.30E-07	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	4.00E-05	lb/MMBtu	4.00E-05	lb/MMBtu	4.00E-05	lb/MMBtu	4.00E-05	lb/MMBtu
Acrolein	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu	6.40E-06	lb/MMBtu
Antimony														
Arsenic														
Benzene	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	1.20E-05	lb/MMBtu	1.20E-05	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	3.20E-05	lb/MMBtu	3.20E-05	lb/MMBtu	3.20E-05	lb/MMBtu	3.20E-05	lb/MMBtu
Ethylene Dibromide														
Ethylene Dichloride														
Formaldehyde	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu	7.10E-04	lb/MMBtu
HCl														
Lead														
Manganese														
Mercury														
Methanol														
Methylene Chloride														
n-Hexane														
Nickel														
PAHs	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.20E-06	lb/MMBtu
Phenol														
Phosphorus														
POM 2-Methylnaphthalene														
POM 3-Methylcholanthrene														
POM 7,12-Dimethylbenz(a)anthracene														
POM Acenaphthene														
POM Acenaphthylene														
POM Anthracene														
POM Benz(a)anthracene														
POM Benzo(a)pyrene														
POM Benzo(b)fluoranthene														
POM Benzo(g,h,i)perylene														
POM Benzo(k)fluoranthene														
POM Chrysene														
POM Dibenz(a,h)anthracene														
POM Fluoranthene														
POM Fluorene														
POM Indeno(1,2,3-c,d)pyrene														
POM Naphthalene	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu	1.30E-06	lb/MMBtu
POM Phenanthrene														
POM Pyrene														
Propional*[dehyde]*														
Propylene Oxide	2.90E-05	lb/MMBtu	2.90E-05	lb/MMBtu	2.90E-05	lb/MMBtu	2.90E-05	lb/MMBtu	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	1.30E-04	lb/MMBtu	1.30E-04	lb/MMBtu	1.30E-04	lb/MMBtu	1.30E-04	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	6.40E-05	lb/MMBtu	6.40E-05	lb/MMBtu	6.40E-05	lb/MMBtu	6.40E-05	lb/MMBtu
CDD/CDF														

	Black Start Diesel Generator		Main Diesel Firewater Pump		Dormitory Emergency Diesel Generator		Communications Tower		Flares		Common Utility Heater		Buyback Gas Bath Heater		Operations Camp Heater	
Pollutant	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units	Emission Factor	Units
NOx	3.26	g/hp-hr	3.56	g/hp-hr	3.54	g/hp-hr	3.54	g/hp-hr	0.068	lb/MMBtu	0.080	lb/MMBtu	0.080	lb/MMBtu	0.080	lb/MMBtu
CO	3.26	g/hp-hr	3.25	g/hp-hr	3.26	g/hp-hr	3.26	g/hp-hr	0.310	lb/MMBtu	0.082	lb/MMBtu	0.082	lb/MMBtu	0.082	lb/MMBtu
VOC	0.177	g/hp-hr	0.188	g/hp-hr	0.186	g/hp-hr	0.186	g/hp-hr	0.570	lb/MMBtu	0.006	lb/MMBtu	0.006	lb/MMBtu	0.006	lb/MMBtu
PM10	0.037	g/hp-hr	0.188	g/hp-hr	0.186	g/hp-hr	0.186	g/hp-hr	40.00	µg/L	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu
PM2.5	0.037	g/hp-hr	0.188	g/hp-hr	0.186	g/hp-hr	0.186	g/hp-hr	40.00	µg/L	0.007	lb/MMBtu	0.007	lb/MMBtu	0.007	lb/MMBtu
Fuel Sulfur Normal Operation	15.00	ppmv	15.00	ppmv	15.00	ppmv	15.00	ppmv	16.00	ppmv	16.00	ppmv	16.00	ppmv	16.00	ppmv
Fuel Sulfur Maximum									96.00	ppmv	96.00	ppmv	96.00	ppmv	96.00	ppmv
CO2	73.96	kg/MMBtu	73.96	kg/MMBtu	73.96	kg/MMBtu	73.96	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu	53.06	kg/MMBtu
CH4	0.003	kg/MMBtu	0.003	kg/MMBtu	0.003	kg/MMBtu	0.003	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu	0.001	kg/MMBtu
N2O	0.0006	kg/MMBtu	0.0006	kg/MMBtu	0.0006	kg/MMBtu	0.0006	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu	0.0001	kg/MMBtu
1,1,2,2-Tetrachloroethane																
1,1,2-Trichloroethane																
1,3-Butadiene			3.91E-05	lb/MMBtu	3.91E-05	lb/MMBtu	3.91E-05	lb/MMBtu								
1,3-Dichloropropene																
1,4-Dichlorobenzene																
2,2,4-Trimethylpentane																
Acetaldehyde	2.52E-05	lb/MMBtu	7.67E-04	lb/MMBtu	7.67E-04	lb/MMBtu	7.67E-04	lb/MMBtu	4.22E-05	lb/MMBtu						
Acrolein	7.88E-06	lb/MMBtu	9.25E-05	lb/MMBtu	9.25E-05	lb/MMBtu	9.25E-05	lb/MMBtu	9.80E-06	lb/MMBtu						
Antimony																
Arsenic																
Benzene	7.76E-04	lb/MMBtu	9.33E-04	lb/MMBtu	9.33E-04	lb/MMBtu	9.33E-04	lb/MMBtu	1.56E-04	lb/MMBtu	2.06E-06	lb/MMBtu	2.06E-06	lb/MMBtu	2.06E-06	lb/MMBtu
Beryllium																
Biphenyl																
Cadmium																
Carbon Tetrachloride																
Chlorobenzene																
Chloroform																
Chromium																
Cobalt																
Dibutylphthalate																
Ethylbenzene									1.42E-03	lb/MMBtu						
Ethylene Dibromide																
Ethylene Dichloride																
Formaldehyde	7.89E-05	lb/MMBtu	1.18E-03	lb/MMBtu	1.18E-03	lb/MMBtu	1.18E-03	lb/MMBtu	1.15E-03	lb/MMBtu	7.35E-05	lb/MMBtu	7.35E-05	lb/MMBtu	7.35E-05	lb/MMBtu
HCl																
Lead											4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu
Manganese																
Mercury																
Methanol																
Methylene Chloride																
n-Hexane									2.84E-05	lb/MMBtu	1.76E-03	lb/MMBtu	1.76E-03	lb/MMBtu	1.76E-03	lb/MMBtu
Nickel																
PAHs	2.12E-04	lb/MMBtu	1.68E-04	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	2.35E-08	lb/MMBtu	2.35E-08	lb/MMBtu
POM 3-Methylcholanthrene											1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM 7,12-Dimethylbenz(a)anthracene											1.57E-08	lb/MMBtu	1.57E-08	lb/MMBtu	1.57E-08	lb/MMBtu
POM Acenaphthene	4.68E-06	lb/MMBtu	1.42E-06	lb/MMBtu	1.42E-06	lb/MMBtu	1.42E-06	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Acenaphthylene	9.23E-06	lb/MMBtu	5.06E-06	lb/MMBtu	5.06E-06	lb/MMBtu	5.06E-06	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Anthracene	1.23E-06	lb/MMBtu	1.87E-06	lb/MMBtu	1.87E-06	lb/MMBtu	1.87E-06	lb/MMBtu			2.40E-09	lb/MMBtu	2.40E-09	lb/MMBtu	2.40E-09	lb/MMBtu
POM Benz(a)anthracene	6.22E-07	lb/MMBtu	1.68E-06	lb/MMBtu	1.68E-06	lb/MMBtu	1.68E-06	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Benzo(a)pyrene	2.57E-07	lb/MMBtu	1.88E-07	lb/MMBtu	1.88E-07	lb/MMBtu	1.88E-07	lb/MMBtu			1.20E-09	lb/MMBtu	1.20E-09	lb/MMBtu	1.20E-09	lb/MMBtu
POM Benzo(b)fluoranthene	1.11E-06	lb/MMBtu	9.91E-08	lb/MMBtu	9.91E-08	lb/MMBtu	9.91E-08	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Benzo(g,h,i)perylene	5.56E-07	lb/MMBtu	4.89E-07	lb/MMBtu	4.89E-07	lb/MMBtu	4.89E-07	lb/MMBtu			1.20E-09	lb/MMBtu	1.20E-09	lb/MMBtu	1.20E-09	lb/MMBtu
POM Benzo(k)fluoranthene	2.18E-07	lb/MMBtu	1.55E-07	lb/MMBtu	1.55E-07	lb/MMBtu	1.55E-07	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Chrysene	1.53E-06	lb/MMBtu	3.53E-07	lb/MMBtu	3.53E-07	lb/MMBtu	3.53E-07	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Dibenz(a,h)anthracene	3.46E-07	lb/MMBtu	5.83E-07	lb/MMBtu	5.83E-07	lb/MMBtu	5.83E-07	lb/MMBtu			1.20E-09	lb/MMBtu	1.20E-09	lb/MMBtu	1.20E-09	lb/MMBtu
POM Fluoranthene	4.03E-06	lb/MMBtu	7.61E-06	lb/MMBtu	7.61E-06	lb/MMBtu	7.61E-06	lb/MMBtu			2.90E-09	lb/MMBtu	2.90E-09	lb/MMBtu	2.90E-09	lb/MMBtu
POM Fluorene	1.28E-05	lb/MMBtu	2.94E-05	lb/MMBtu	2.94E-05	lb/MMBtu	2.94E-05	lb/MMBtu			2.70E-09	lb/MMBtu	2.70E-09	lb/MMBtu	2.70E-09	lb/MMBtu
POM Indeno(1,2,3-c,d)pyrene	4.14E-07	lb/MMBtu	3.75E-07	lb/MMBtu	3.75E-07	lb/MMBtu	3.75E-07	lb/MMBtu			1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu	1.80E-09	lb/MMBtu
POM Naphthalene	1.30E-04	lb/MMBtu	8.48E-05	lb/MMBtu	8.48E-05	lb/MMBtu	8.48E-05	lb/MMBtu	1.08E-05	lb/MMBtu	5.98E-07	lb/MMBtu	5.98E-07	lb/MMBtu	5.98E-07	lb/MMBtu
POM Phenanthrene	4.08E-05	lb/MMBtu	2.94E-05	lb/MMBtu	2.94E-05	lb/MMBtu	2.94E-05	lb/MMBtu			1.67E-08	lb/MMBtu	1.67E-08	lb/MMBtu	1.67E-08	lb/MMBtu
POM Pyrene	3.71E-06	lb/MMBtu	4.78E-06	lb/MMBtu	4.78E-06	lb/MMBtu	4.78E-06	lb/MMBtu			4.90E-09	lb/MMBtu	4.90E-09	lb/MMBtu	4.90E-09	lb/MMBtu
Propional*[dehyde]*																
Propylene Oxide																
Selenium																
Styrene																
Tetrachloroethylene																
Toluene	2.81E-04	lb/MMBtu	4.09E-04	lb/MMBtu	4.09E-04	lb/MMBtu	4.09E-04	lb/MMBtu	5.69E-05	lb/MMBtu	3.33E-06	lb/MMBtu	3.33E-06	lb/MMBtu	3.33E-06	lb/MMBtu
Trichloroethylene																
Vinyl Chloride																
Vinylidene Chloride																
Xylenes(m,p,o)	1.93E-04	lb/MMBtu	2.85E-04	lb/MMBtu	2.85E-04	lb/MMBtu	2.85E-04	lb/MMBtu	2.84E-05	lb/MMBtu						
CDD/CDF																

EC-11 GAS TREATMENT PLANT ANNUAL FUEL CONSUMPTION

Gas-Fired Equipment (Fuel Gas Users)	Rated Duty (HHV)	Daily Average Fuel Flow
	MMBtu/hr	MMSCFD
Train 1a Treated Gas Compressor Turbine	386.0	8.60
Supplemental Firing	189.0	4.21
Train 1b Treated Gas Compressor Turbine	386.0	8.60
Supplemental Firing	189.0	4.21
Train 2a Treated Gas Compressor Turbine	386.0	8.60
Supplemental Firing	189.0	4.21
Train 2b Treated Gas Compressor Turbine	386.0	8.60
Supplemental Firing	189.0	4.21
Train 3a Treated Gas Compressor Turbine	386.0	8.60
Supplemental Firing	189.0	4.21
Train3b Treated Gas Compressor Turbine	386.0	8.60
Supplemental Firing	189.0	4.21
Train 1a CO2 Compressor Turbine	291.0	6.48
Supplemental Firing	141.8	3.16
Train 1b CO2 Compressor Turbine	291.0	6.48
Supplemental Firing	141.8	3.16
Train 2a CO2 Compressor Turbine	291.0	6.48
Supplemental Firing	141.8	3.16
Train 2b CO2 Compressor Turbine	291.0	6.48
Supplemental Firing	141.8	3.16
Train 3a CO2 Compressor Turbine	291.0	6.48
Supplemental Firing	141.8	3.16
Train 3b CO2 Compressor Turbine	291.0	6.48
Supplemental Firing	141.8	3.16
Power Generation Turbines	386.0	8.60
Power Generation Turbines	386.0	8.60
Power Generation Turbines	386.0	8.60
Power Generation Turbines	386.0	8.60
Power Generation Turbines	386.0	8.60
Power Generation Turbines	386.0	8.60
LP CO2 Flare East Pilot/Purge (3 Flares)	6.8	0.15
LP CO2 Flare West Pilot/Purge (3 Flares)	6.8	0.15
HP CO2 Flare East Pilot/Purge	3.0	0.07
HP CO2 Flare West Pilot/Purge	3.0	0.07
HP Hydrocarbon Flare East Pilot/Purge	7.8	0.17
HP Hydrocarbon Flare West Pilot/Purge	7.8	0.17
LP Hydrocarbon Flare East Pilot/Purge	1.4	0.03
LP Hydrocarbon Flare West Pilot/Purge	1.4	0.03
LP CO2 Flare East Assist Gas (For Max Case)	9,558.4	213.00
HP CO2 Flare East Assist Gas (For Max Case)	3,141.3	70.00
Building Heat Medium Heater	274.7	6.12
Building Heat Medium Heater	274.7	6.12
Building Heat Medium Heater (spare)	0.0	0.00
Buyback Gas Bath Heater Pre-Let Down Heater Standby	0.2	0.00
Buyback Gas Bath Heater Post-Let Down Heater Standby	0.2	0.00
Buyback Gas Bath Heater Pre-Let Down Heater MAX	25.3	0.56
Buyback Gas Bath Heater Post-Let Down Heater MAX	20.9	0.47
Operations Camp Heater	31.9	0.71
Operations Camp Heater	31.9	0.71
Operations Camp Heater (spare)	0.0	0.00
Total Fuel Gas Consumption	**21,760**	**485**
Liquid-Driven Equipment (Diesel Users)	**Rated Duty (HHV)**	**Daily Average Diesel Flow**
	MMBtu/hr	**gal/day**
Black Start Diesel Generator (2500 kW)	28.42	4,729
Main Diesel Firewater Pump (250 hp)	1.75	291
Main Diesel Firewater Pump (250 hp)	1.75	291
Main Diesel Firewater Pump (250 hp)	1.75	291
Dormitory Emergency Diesel Generator (250 kW)	2.35	390
Communications Tower (150 kW)	1.41	234
Mobile Equipment Emissions (Normal Operation)	6.53	1,087
Non-Road/Portable Equipment Emissions (Normal Operation)	27.32	4,546
Total Diesel Consumption	**71.3**	**11,860**
Gas-Fired Equipment (Fuel Gas Users)		
LP CO2 Flare East (Max Case CO2)		
HP CO2 Flare East (Max Case CO2)		
HP Hydrocarbon Flare East (Max Case)		
LP Hydrocarbon Flare East (Max Case)		
Tank Emissions		
Fugitive Emissions		

EC-12 GAS TREATMENT PLANT 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 GAS TREATMENT PLANT 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 GAS TREATMENT PLANT OFFSITE SOURCE EMISSIONS SUMMARY

Central Compression Plant – Actual Emissions

		Location			Emissions (g/sec)[2]														
Model ID	Point Sources Description	UTM X[1]	UTM Y[1]	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
801	MS5371PATP Gas Compressor	443519.8	7802232.4	1.5	1.75E+01	1.75E+01	3.02E-01	3.02E-01	2.33E-01	2.33E-01	2.33E-01	2.05E+00	Turbine	Gas	0.000E+00	8.69E-02	8.69E-02	2.15E-01	2.15E-01
802	MS5371PATP w/LHE Gas Compressor	443528.2	7802187.7	1.5	1.01E+01	1.01E+01	2.58E-01	2.58E-01	2.01E-01	2.01E-01	2.01E-01	3.82E+00	Turbine	Gas	0.000E+00	7.43E-02	7.43E-02	1.84E-01	1.84E-01
803	MS5371PATP Gas Compressor	443514.5	7802259.0	1.5	1.68E+01	1.68E+01	2.89E-01	2.89E-01	2.23E-01	2.23E-01	2.23E-01	1.96E+00	Turbine	Gas	0.000E+00	8.32E-02	8.32E-02	2.06E-01	2.06E-01
804	MS5371PATP Gas Compressor	443533.1	7802161.0	1.5	1.69E+01	1.69E+01	2.91E-01	2.91E-01	2.24E-01	2.24E-01	2.24E-01	1.98E+00	Turbine	Gas	0.000E+00	8.38E-02	8.38E-02	2.07E-01	2.07E-01
805	MS5371PATP Gas Compressor	443565.0	7802139.3	1.5	1.66E+01	1.66E+01	2.87E-01	2.87E-01	2.21E-01	2.21E-01	2.21E-01	1.94E+00	Turbine	Gas	0.000E+00	8.25E-02	8.25E-02	2.04E-01	2.04E-01
806	MS5371PATP Gas Compressor	443509.6	7802285.8	1.5	1.71E+01	1.71E+01	2.95E-01	2.95E-01	2.27E-01	2.27E-01	2.27E-01	2.00E+00	Turbine	Gas	0.000E+00	8.48E-02	8.48E-02	2.10E-01	2.10E-01
807	MS5371PATP Gas Compressor	443536.7	7802290.6	1.5	1.66E+01	1.66E+01	2.86E-01	2.86E-01	2.20E-01	2.20E-01	2.20E-01	1.94E+00	Turbine	Gas	0.000E+00	8.22E-02	8.22E-02	2.03E-01	2.03E-01
808	MS5371PATP Gas Compressor	443538.1	7802134.2	1.5	1.65E+01	1.65E+01	2.84E-01	2.84E-01	2.19E-01	2.19E-01	2.19E-01	1.93E+00	Turbine	Gas	0.000E+00	8.17E-02	8.17E-02	2.02E-01	2.02E-01
809	MS5371PATP Gas Compressor	443554.7	7802192.6	1.5	1.76E+01	1.76E+01	3.04E-01	3.04E-01	2.34E-01	2.34E-01	2.34E-01	2.06E+00	Turbine	Gas	0.000E+00	8.75E-02	8.75E-02	2.16E-01	2.16E-01
810	MS5371PATP Gas Compressor	443546.3	7802237.4	1.5	1.62E+01	1.62E+01	2.78E-01	2.78E-01	2.15E-01	2.15E-01	2.15E-01	1.89E+00	Turbine	Gas	0.000E+00	8.02E-02	8.02E-02	1.98E-01	1.98E-01
811	MS5371PATP Gas Compressor	443559.8	7802165.8	1.5	1.61E+01	1.61E+01	2.77E-01	2.77E-01	2.13E-01	2.13E-01	2.13E-01	1.88E+00	Turbine	Gas	0.000E+00	7.97E-02	7.97E-02	1.97E-01	1.97E-01
812	MS5371PATP Gas Compressor	443541.4	7802264.2	1.5	1.62E+01	1.62E+01	2.78E-01	2.78E-01	2.16E-01	2.16E-01	2.16E-01	1.89E+00	Turbine	Gas	0.000E+00	8.02E-02	8.02E-02	1.98E-01	1.98E-01
813	MS5371PATP Gas Compressor	443504.6	7802312.4	1.5	1.69E+01	1.69E+01	2.90E-01	2.90E-01	2.24E-01	2.24E-01	2.24E-01	1.97E+00	Turbine	Gas	0.000E+00	8.36E-02	8.36E-02	2.07E-01	2.07E-01
833	MS5382C Tandem Compressor	443485.3	7802343.2	1.5	1.53E+01	1.53E+01	2.82E-01	2.82E-01	2.18E-01	2.18E-01	2.18E-01	1.92E+00	Turbine	Gas	0.000E+00	8.13E-02	8.13E-02	2.01E-01	2.01E-01
834	MS5382C Tandem Compressor	443534.2	7802360.8	1.5	1.56E+01	1.56E+01	2.89E-01	2.89E-01	2.24E-01	2.24E-01	2.24E-01	1.96E+00	Turbine	Gas	0.000E+00	8.32E-02	8.32E-02	2.06E-01	2.06E-01
832	Broach Glycol Heater	443681.2	7802224.5	1.5	9.03E-02	9.03E-02	8.34E-03	8.34E-03	5.75E-03	5.75E-03	5.75E-03	6.88E-02	Heater	Gas	0.000E+00	2.09E-03	2.09E-03	6.26E-03	6.26E-03
814	Broach Glycol Heater	443671.6	7802218.8	1.5	1.04E-01	1.04E-01	8.05E-03	8.05E-03	5.47E-03	5.47E-03	5.47E-03	8.75E-02	Heater	Gas	0.000E+00	2.01E-03	2.01E-03	6.04E-03	6.04E-03
815	Broach Glycol Heater	443677.4	7802219.5	1.5	1.23E-01	1.23E-01	9.49E-03	9.49E-03	6.33E-03	6.33E-03	6.33E-03	1.04E-01	Heater	Gas	0.000E+00	2.37E-03	2.37E-03	7.12E-03	7.12E-03
702	Eclipse Glycol Heater	443627.8	7802442.7	1.5	1.15E-03	1.15E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.15E-03	Heater	Gas	0.000E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
701	Eclipse Glycol Heater	443631.9	7802424.7	1.5	1.56E-01	1.56E-01	1.18E-02	1.18E-02	8.05E-03	8.05E-03	8.05E-03	1.31E-01	Heater	Gas	0.000E+00	2.95E-03	2.95E-03	8.85E-03	8.85E-03
816	Solar T-4001 Emergency Generator	443613.0	7802290.5	1.5	4.89E-03	4.89E-03	0.00E+00	0.00E+00	2.88E-04	2.88E-04	2.88E-04	0.00E+00	Generator	Diesel	0.000E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
817	GM Emergency Generator	443631.5	7802253.2	1.5	1.64E-02	1.64E-02	5.75E-04	5.75E-04	5.75E-04	5.75E-04	5.75E-04	3.74E-03	Generator	Diesel	0.000E+00	4.96E-04	4.98E-04	7.97E-05	7.73E-05
818	Cummins Emergency Fire Water Pump	443652.0	7802214.1	1.5	8.92E-03	8.92E-03	5.75E-04	5.75E-04	2.88E-04	2.88E-04	2.88E-04	2.01E-03	Pump	Diesel	0.000E+00	4.96E-04	4.98E-04	7.97E-05	7.73E-05
819	John Zink HP/IP Flare Arm A (A-J, 10x)	443963.3	7802701.1	1.5	9.96E-02	9.96E-02	4.06E-02	4.06E-02	7.48E-03	7.48E-03	7.48E-03	5.42E-01	Flare	Gas	0.000E+00	1.01E-02	1.01E-02	3.04E-02	3.04E-02
820	John Zink HP/IP Flare Arm B (A-J, 10x)	443968.3	7802699.1	1.5	9.96E-02	9.96E-02	4.06E-02	4.06E-02	7.48E-03	7.48E-03	7.48E-03	5.42E-01	Flare	Gas	0.000E+00	1.01E-02	1.01E-02	3.04E-02	3.04E-02
821	John Zink HP/IP Flare Arm C (A-J, 10x)	443971.3	7802697.1	1.5	9.96E-02	9.96E-02	4.06E-02	4.06E-02	7.48E-03	7.48E-03	7.48E-03	5.42E-01	Flare	Gas	0.000E+00	1.01E-02	1.01E-02	3.04E-02	3.04E-02
822	John Zink HP/IP Flare Arm D (A-I, 9x)	443968.3	7802687.1	1.5	9.96E-02	9.96E-02	4.06E-02	4.06E-02	7.48E-03	7.48E-03	7.48E-03	5.42E-01	Flare	Gas	0.000E+00	1.01E-02	1.01E-02	3.04E-02	3.04E-02
823	John Zink STV Flare (A-E, 5x)	443946.3	7802702.1	1.5	2.42E-01	2.42E-01	9.74E-02	9.74E-02	6.50E-02	6.50E-02	6.50E-02	1.31E+00	Flare	Gas	0.000E+00	2.43E-02	2.43E-02	7.30E-02	7.30E-02
824	Line Emergency Backup Flare	443970.3	7802879.1	1.5	5.18E-02	5.18E-02	2.09E-02	2.09E-02	1.39E-02	1.39E-02	1.39E-02	2.80E-01	Flare	Gas	0.000E+00	5.22E-03	5.22E-03	1.56E-02	1.56E-02
825	Line Emergency Backup Flare	443967.3	7802880.1	1.5	5.18E-02	5.18E-02	2.09E-02	2.09E-02	1.39E-02	1.39E-02	1.39E-02	2.80E-01	Flare	Gas	0.000E+00	5.22E-03	5.22E-03	1.56E-02	1.56E-02
					2.43E+02	2.43E+02	4.63E+00	4.63E+00	3.46E+00	3.46E+00	3.46E+00								

PTE Emissions since actuals weren't available

Decommissioned equipment = 0

horizontal release

Notes:

1 UTM Coordinates from current Air Quality Model

2 All emissions based on Worst-Case 24 hour emissions during normal facility operation. All emissions considered as operating 8,760 hours/year

Emergency equipment included in normal operation assumption at an annual operation of 8,760 hours/year. Normally not operational, and only operational at max condition while other equipment is not operating normally.

Model ID	Point Sources Description	Stack Parameters: Stack Ht. (m)	Exit Temp. (K)	Exit Vel. (m/s)	Stack Diam. (m)	NO2 Ratio	install/ mod date from permit	Baseline Dates: 2/1988 Consumes NO_2 Increment	6/1979 Consumes SO_2 Increment	11/1978 Consumes PM_{10} Increment	11/2012 Consumes $PM_{2.5}$ Increment
801	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	10/91	Yes	Yes	Yes	No
802	MS5371PATP w/LHE Gas Compressor	31.10	754.0	63.30	2.40	0.35	2000	Yes	Yes	Yes	No
803	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	1/91	Yes	Yes	Yes	No
804	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	2/90	Yes	Yes	Yes	No
805	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	10/90	Yes	Yes	Yes	No
806	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	3/91	Yes	Yes	Yes	No
807	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	5/91	Yes	Yes	Yes	No
808	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	9/91	Yes	Yes	Yes	No
809	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	7/91	Yes	Yes	Yes	No
810	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	8/90	Yes	Yes	Yes	No
811	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	2/91	Yes	Yes	Yes	No
812	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	8/91	Yes	Yes	Yes	No
813	MS5371PATP Gas Compressor	31.10	750.0	62.90	2.40	0.10	1991	Yes	Yes	Yes	No
833	MS5382C Tandem Compressor	34.40	774.0	41.30	3.10	0.10	1990	Yes	Yes	Yes	No
834	MS5382C Tandem Compressor	34.40	774.0	41.30	3.10	0.10	1990	Yes	Yes	Yes	No
832	Broach Glycol Heater	42.40	422.0	4.30	1.10	0.10	1990	Yes	Yes	Yes	No
814	Broach Glycol Heater	20.10	422.0	6.50	1.10	0.10	4/74	No	No	No	No
815	Broach Glycol Heater	20.10	422.0	6.50	1.10	0.10	4/74	No	No	No	No
702	Eclipse Glycol Heater	21.10	611.0	3.70	0.90	0.10	Pre-1977	No	No	No	No
701	Eclipse Glycol Heater	21.10	611.0	3.70	0.90	0.10	Pre-1977	No	No	No	No
816	Solar T-4001 Emergency Generator	16.80	727.0	43.00	1.00	0.10	4/74	No	No	No	No
817	GM Emergency Generator	12.80	616.0	42.00	0.60	0.10	11/84	No	Yes	Yes	No
818	Cummins Emergency Fire Water Pump	12.20	602.0	58.00	0.10	0.10	Pre-1977	No	No	No	No
819	John Zink HP/IP Flare Arm A (A-J, 10x)	3.10	1273.0	20.00	0.20	0.50	Pre-1977	No	No	No	No
820	John Zink HP/IP Flare Arm B (A-J, 10x)	3.10	1273.0	20.00	0.20	0.50	Pre-1977	No	No	No	No
821	John Zink HP/IP Flare Arm C (A-J, 10x)	3.10	1273.0	20.00	0.20	0.50	Pre-1977	No	No	No	No
822	John Zink HP/IP Flare Arm D (A-I, 9x)	3.10	1273.0	20.00	0.20	0.50	Pre-1977	No	No	No	No
823	John Zink STV Flare (A-E, 5x)	4.00	1273.0	20.00	0.40	0.50	Pre-1977	No	No	No	No
824	Line Emergency Backup Flare	4.00	1273.0	20.00	0.40	0.50	Pre-1977	No	No	No	No
825	Line Emergency Backup Flare	4.30	1273.0	20.00	0.40	0.50	Pre-1977	No	No	No	No

PTE Emissions since actuals w eren't available
Decommissioned equipment = 0
horizontal release

Notes:

1 UTM Coordinates from current Air Quality Model

2 All emissions based on Worst-Case 24 hour emissions during normal facility operation. All emissions considered as operating 8,760 hours/year

Emergency equipment included in normal operation assumption at an annual operation of 8,760 hours/year. Normally not operational, and only operational at max condition w hile other equipment is not operating normally.

Central Gas Facility – Actual Emissions

		Location			Emissions (g/sec)[2]														
Model ID	Point Sources Description	UTM X[1]	UTM Y[1]	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
1116	GE Frame 6 Tandem Compressor	442852.2	7802155.5	1.5	1.962E+01	1.96E+01	3.03E-01	3.03E-01	2.34E-01	2.34E-01	2.34E-01	1.03E+00	Turbine	Gas	0.000E+00	8.72E-02	8.72E-02	2.16E-01	2.16E-01
1117	GE Frame 6 Tandem Compressor	442843.9	7802198	1.5	2.543E+01	2.54E+01	3.93E-01	3.93E-01	3.03E-01	3.03E-01	3.03E-01	1.33E+00	Turbine	Gas	0.000E+00	1.13E-01	1.13E-01	2.80E-01	2.80E-01
1118	GE Frame 6 Tandem Compressor	442928.2	7802125.6	1.5	2.304E+01	2.30E+01	3.56E-01	3.56E-01	2.74E-01	2.74E-01	2.74E-01	1.21E+00	Turbine	Gas	0.000E+00	1.02E-01	1.02E-01	2.53E-01	2.53E-01
1119	GE Frame 6 Tandem Compressor	442920.3	7802168.1	1.5	2.526E+01	2.53E+01	3.90E-01	3.90E-01	3.01E-01	3.01E-01	3.01E-01	1.32E+00	Turbine	Gas	0.000E+00	1.12E-01	1.12E-01	2.78E-01	2.78E-01
1101	Cooper-Rolls/RB211-24C Booster Compressor	442847.1	7802240.3	1.5	1.607E+01	1.61E+01	1.85E-01	1.85E-01	1.43E-01	1.43E-01	1.43E-01	1.57E+00	Turbine	Gas	0.000E+00	5.32E-02	5.32E-02	1.32E-01	1.32E-01
1102	Cooper-Rolls/RB211-24C Booster Compressor	442902	7802206.9	1.5	1.648E+01	1.65E+01	1.89E-01	1.89E-01	1.46E-01	1.46E-01	1.46E-01	1.61E+00	Turbine	Gas	0.000E+00	5.45E-02	5.45E-02	1.35E-01	1.35E-01
1103	Cooper-Rolls/RB211-24C MI Compressor	442891	7802280.2	1.5	8.080E+00	8.08E+00	9.29E-02	9.29E-02	7.05E-02	7.05E-02	7.05E-02	7.87E-01	Turbine	Gas	0.000E+00	2.67E-02	2.67E-02	6.62E-02	6.62E-02
1104	Cooper-Rolls/RB211-24C MI Compressor	442838	7802275.7	1.5	9.260E+00	9.26E+00	1.06E-01	1.06E-01	8.31E-02	8.31E-02	8.31E-02	9.02E-01	Turbine	Gas	0.000E+00	3.06E-02	3.06E-02	7.58E-02	7.58E-02
1105	GE MS5382C w/LHE Refrigerant Compressor	442828.7	7802360.3	1.5	5.520E+00	5.52E+00	1.52E-01	1.52E-01	1.17E-01	1.17E-01	1.17E-01	1.03E+00	Turbine	Gas	0.000E+00	4.38E-02	4.38E-02	1.08E-01	1.08E-01
1106	GE MS5382C w/LHE Refrigerant Compressor	442812.3	7802423.7	1.5	8.021E+00	8.02E+00	2.21E-01	2.21E-01	1.72E-01	1.72E-01	1.72E-01	1.50E+00	Turbine	Gas	0.000E+00	6.36E-02	6.36E-02	1.57E-01	1.57E-01
1115	GE MS5382C w/LHE Booster Compressor	442956.6	7802282.2	1.5	1.013E+01	1.01E+01	2.79E-01	2.79E-01	2.16E-01	2.16E-01	2.16E-01	1.90E+00	Turbine	Gas	0.000E+00	8.04E-02	8.04E-02	1.99E-01	1.99E-01
1107	Chiyoda-John Zink Hot Oil Heater	442677.1	7802305.2	1.5	9.481E-01	9.48E-01	8.83E-02	8.83E-02	6.10E-02	6.10E-02	6.10E-02	7.23E-01	Heater	Gas	0.000E+00	2.21E-02	2.21E-02	6.62E-02	6.62E-02
1108	Chiyoda-John Zink Hot Oil Heater	442678.3	7802299.2	1.5	1.062E+00	1.06E+00	9.90E-02	9.90E-02	6.76E-02	6.76E-02	6.76E-02	8.09E-01	Heater	Gas	0.000E+00	2.47E-02	2.47E-02	7.42E-02	7.42E-02
1109	Chiyoda-John Zink Hot Oil Heater	442679.9	7802292.9	1.5	9.079E-01	9.08E-01	8.46E-02	8.46E-02	5.78E-02	5.78E-02	5.78E-02	6.92E-01	Heater	Gas	0.000E+00	2.11E-02	2.11E-02	6.34E-02	6.34E-02
1110	GM Emergency Electrical Generator	442945.3	7802334.6	1.5	7.393E-02	7.39E-02	2.01E-03	2.01E-03	1.73E-03	1.73E-03	1.73E-03	1.70E-02	Generator	Diesel	0.000E+00	1.73E-03	1.74E-03	2.79E-04	2.71E-04
1111	GM Emergency Electrical Generator	442944.3	7802339.6	1.5	8.457E-02	8.46E-02	2.59E-03	2.59E-03	2.01E-03	2.01E-03	2.01E-03	1.93E-02	Generator	Diesel	0.000E+00	2.23E-03	2.24E-03	3.59E-04	3.48E-04
1121	GM Emergency Electrical Generator	442942.4	7802343.2	1.5	8.400E-02	8.40E-02	2.59E-03	2.59E-03	0.00E+00	0.00E+00	0.00E+00	1.93E-02	Generator	Diesel	0.000E+00	2.23E-03	2.24E-03	3.59E-04	3.48E-04
1122	Caterpillar Emergency Fire Water Pump	442781.6	7802322.5	1.5	6.616E-03	6.62E-03	5.75E-04	5.75E-04	0.00E+00	0.00E+00	0.00E+00	1.44E-03	Pump	Diesel	0.000E+00	4.96E-04	4.98E-04	7.97E-05	7.73E-05
11131	John Zink Flare HP-Primary Pit	442765.3	7802719.1	1.5	7.067E-01	7.07E-01	2.88E-01	2.88E-01	5.37E-02	5.37E-02	5.37E-02	3.85E+00	Flare	Gas	0.000E+00	7.21E-02	7.21E-02	2.16E-01	2.16E-01
11130	John Zink Flare LP-Primary Pit	442770.3	7802719.1	1.5	5.304E-01	5.30E-01	2.16E-01	2.16E-01	4.03E-02	4.03E-02	4.03E-02	2.89E+00	Flare	Gas	0.000E+00	5.41E-02	5.41E-02	1.62E-01	1.62E-01
NGL	John Zink Flare NGL-Primary Pit	442609.1	7803086.8	1.5	1.550E-01	1.55E-01	6.32E-02	6.32E-02	1.18E-02	1.18E-02	1.18E-02	8.43E-01	Flare	Gas	0.000E+00	1.58E-02	1.58E-02	4.74E-02	4.74E-02

Notes:

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		Stack Parameters						Baseline Dates			
								2/1988	6/1979	11/1978	11/2012
Model ID	Point Sources Description	Stack Ht. (m)	Exit Temp. (K)	Exit Vel. (m/s)	Stack Diam. (m)	NO2 Ratio	install/ mod date from permit	Consumes NO_2 Increment	Consumes SO_2 Increment	Consumes PM_{10} Increment	Consumes $PM_{2.5}$ Increment
1116	GE Frame 6 Tandem Compressor	36.80	741.0	43.83	3.20	0.10	4/1998	Yes	Yes	Yes	No
1117	GE Frame 6 Tandem Compressor	36.80	741.0	43.83	3.20	0.10	4/1998	Yes	Yes	Yes	No
1118	GE Frame 6 Tandem Compressor	36.80	741.0	43.83	3.20	0.10	4/1998	Yes	Yes	Yes	No
1119	GE Frame 6 Tandem Compressor	36.80	741.0	43.83	3.20	0.10	4/1998	Yes	Yes	Yes	No
1101	Cooper-Rolls/RB211-24C Booster Compressor	31.30	639.0	41.30	2.44	0.10	1986	No	Yes	Yes	No
1102	Cooper-Rolls/RB211-24C Booster Compressor	31.30	639.0	41.30	2.44	0.10	1986	No	Yes	Yes	No
1103	Cooper-Rolls/RB211-24C MI Compressor	34.30	639.0	41.30	2.44	0.10	1986	No	Yes	Yes	No
1104	Cooper-Rolls/RB211-24C MI Compressor	34.30	639.0	41.30	2.44	0.10	1986	No	Yes	Yes	No
1105	GE MS5382C w/LHE Refrigerant Compressor	28.20	521.0	31.63	2.60	0.35	7/1998	Yes	Yes	Yes	No
1106	GE MS5382C w/LHE Refrigerant Compressor	28.20	760.0	36.81	3.05	0.35	8/1998	Yes	Yes	Yes	No
1115	GE MS5382C w/LHE Booster Compressor	43.50	760.0	36.81	3.05	0.35	9/1999	Yes	Yes	Yes	No
1107	Chiyoda-John Zink Hot Oil Heater	49.40	541.0	11.90	2.20	0.10	1986	No	Yes	Yes	No
1108	Chiyoda-John Zink Hot Oil Heater	49.40	541.0	11.90	2.20	0.10	1986	No	Yes	Yes	No
1109	Chiyoda-John Zink Hot Oil Heater	49.40	541.0	11.90	2.20	0.10	1986	No	Yes	Yes	No
1110	GM Emergency Electrical Generator	9.90	608.0	41.10	0.56	0.10	1986	No	Yes	Yes	No
1111	GM Emergency Electrical Generator	9.90	608.0	41.10	0.56	0.10	1986	No	Yes	Yes	No
1121	GM Emergency Electrical Generator	9.90	608.0	41.10	0.56	0.10	1992	Yes	Yes	Yes	No
1122	Caterpillar Emergency Fire Water Pump	13.10	685.0	44.10	0.20	0.10	1986	No	Yes	Yes	No
11131	John Zink Flare HP-Primary Pit	11.90	1273.0	20.00	1.40	0.50	1986	No	Yes	Yes	No
11130	John Zink Flare LP-Primary Pit	11.50	1273.0	20.00	1.32	0.50	1986	No	Yes	Yes	No
NGL	John Zink Flare NGL-Primary Pit	8.32	1273.0	20.00	0.65	0.50	1986	No	Yes	Yes	No

Notes:

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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)	$PM_{2.5}$-FIL (annual)	PM_{10}-FIL (annual)	PM-CON (annual)	PMF/SOIL[d]	EC - PM2.5[e,g,h]	EC - PM10	SOA - PM2.5[f,g,h]	SOA - PM10
	vol01	Alpine Central Processing Facility	-150.925150	70.339817	2.5	3.16E+01	3.16E+01	8.93E-01	8.93E-01	9.29E-01	9.29E-01	5.39E-01	5.39E-01	5.39E-01	7.68E+00	4.52E-01	4.88E-01	3.74E-01	0.00E+00	4.52E-01	4.88E-01	3.74E-01	3.74E-01
	vol02	CPF 1, Kuparuk Central Production Facility #1	-149.650187	70.323106	23.9	5.56E+01	5.56E+01	1.58E+00	1.58E+00	1.62E+00	1.62E+00	1.73E+00	1.73E+00	1.73E+00	7.26E+00	8.10E-01	8.51E-01	6.70E-01	0.00E+00	8.10E-01	8.51E-01	6.70E-01	6.70E-01
	vol03	CPF 2, Kuparuk Central Production Facility #2	-149.901463	70.292654	33.0	4.57E+01	4.57E+01	1.41E+00	1.41E+00	1.41E+00	1.41E+00	1.59E+00	1.59E+00	1.59E+00	4.70E+00	7.25E-01	7.25E-01	6.18E-01	0.00E+00	7.25E-01	7.25E-01	6.18E-01	6.18E-01
	vol04	CPF 3, Kuparuk Central Production Facility #3	-149.848840	70.415592	14.5	2.90E+01	2.90E+01	1.16E+00	1.16E+00	1.16E+00	1.16E+00	2.29E+00	2.29E+00	2.29E+00	1.60E+01	6.06E-01	6.06E-01	5.18E-01	0.00E+00	6.06E-01	6.06E-01	5.18E-01	5.18E-01
	vol05	Endicott Production Facility (END)	-147.956948	70.352565	0.9	4.32E+01	4.32E+01	1.03E+00	1.03E+00	1.03E+00	1.03E+00	5.75E+00	5.75E+00	5.75E+00	4.31E+00	5.64E-01	5.69E-01	4.65E-01	0.00E+00	5.64E-01	5.69E-01	4.65E-01	4.65E-01
	vol06	Flow Station #1 (FS 1)	-148.433841	70.256482	11.6	3.74E+01	3.74E+01	1.21E+00	1.21E+00	1.21E+00	1.21E+00	5.21E-01	5.21E-01	5.21E-01	1.63E+01	4.09E-01	4.09E-01	3.67E-01	0.00E+00	4.09E-01	4.09E-01	3.67E-01	3.67E-01
	vol07	Flow Station #2 (FS 2)	-148.317525	70.261168	10.0	3.69E+01	3.69E+01	9.37E-01	9.37E-01	9.37E-01	9.37E-01	1.15E+00	1.15E+00	1.15E+00	1.22E+01	4.07E-01	4.07E-01	3.45E-01	0.00E+00	4.07E-01	4.07E-01	3.45E-01	3.45E-01
	vol08	Flow Station #3 (FS 3)	-148.571567	70.253433	12.9	5.33E+01	5.33E+01	1.09E+00	1.09E+00	1.09E+00	1.09E+00	6.78E-01	6.78E-01	6.78E-01	1.46E+01	4.86E-01	4.86E-01	4.08E-01	0.00E+00	4.86E-01	4.86E-01	4.08E-01	4.08E-01
	vol09	Gathering Center #1 (GC 1)	-148.727930	70.305000	9.8	4.94E+01	4.94E+01	1.32E+00	1.32E+00	1.32E+00	1.32E+00	5.51E-01	5.51E-01	5.51E-01	1.63E+01	4.63E-01	4.63E-01	4.22E-01	0.00E+00	4.63E-01	4.63E-01	4.22E-01	4.22E-01
	vol10	Gathering Center #2 (GC 2)	-148.872656	70.309157	10.4	2.70E+01	2.70E+01	8.48E-01	8.48E-01	8.48E-01	8.48E-01	3.72E-01	3.72E-01	3.72E-01	7.84E+00	3.54E-01	3.54E-01	3.21E-01	0.00E+00	3.54E-01	3.54E-01	3.21E-01	3.21E-01
	vol11	Gathering Center #3 (GC 3)	-148.678320	70.282390	12.1	2.41E+01	2.41E+01	6.04E-01	6.04E-01	6.04E-01	6.04E-01	3.23E-01	3.23E-01	3.23E-01	7.45E+00	2.64E-01	2.64E-01	2.34E-01	0.00E+00	2.64E-01	2.64E-01	2.34E-01	2.34E-01
	vol12	Lisburne Production Center (LPC)	-148.404921	70.307162	6.3	4.06E+01	4.06E+01	1.61E+00	1.61E+00	1.71E+00	1.71E+00	2.29E+00	2.29E+00	2.29E+00	2.00E+01	9.88E-01	1.09E+00	6.23E-01	0.00E+00	9.88E-01	1.09E+00	6.23E-01	6.23E-01
	vol13	Milne Point Production Facility (MPU)	-149.468279	70.475146	8.3	2.12E+01	2.12E+01	3.72E-01	3.72E-01	4.09E-01	4.09E-01	1.59E-01	1.59E-01	1.59E-01	3.11E+00	2.01E-01	2.38E-01	1.71E-01	0.00E+00	2.01E-01	2.38E-01	1.71E-01	1.71E-01
	vol14	PBU Central Pow er Station (CPS)	-148.662253	70.274635	12.1	6.79E+01	6.79E+01	1.22E+00	1.22E+00	1.22E+00	1.22E+00	9.03E-01	9.03E-01	9.03E-01	8.65E+00	6.70E-01	6.70E-01	5.54E-01	0.00E+00	6.70E-01	6.70E-01	5.54E-01	5.54E-01
	vol15	PS #03, TAPS Pump Station	-148.831033	68.842217	476.3	1.62E+00	1.62E+00	9.78E-02	9.78E-02	9.78E-02	9.78E-02	6.90E-02	6.90E-02	6.90E-02	6.31E+00	5.38E-02	5.38E-02	4.40E-02	0.00E+00	5.38E-02	5.38E-02	4.40E-02	4.40E-02
	vol16	PS #04, TAPS Pump Station	-149.357925	68.422325	1217.2	2.19E+00	2.19E+00	1.20E-01	1.20E-01	1.21E-01	1.21E-01	9.52E-02	9.52E-02	9.52E-02	8.46E+00	4.31E-02	4.40E-02	7.71E-02	0.00E+00	4.31E-02	4.40E-02	7.71E-02	7.71E-02
	vol17	Seaw ater Injection Plant East (SIPE)	-148.442730	70.258410	11.6	2.04E+01	2.04E+01	2.68E-01	2.68E-01	2.68E-01	2.68E-01	2.07E-01	2.07E-01	2.07E-01	2.92E+00	1.44E-01	1.44E-01	1.24E-01	0.00E+00	1.44E-01	1.44E-01	1.24E-01	1.24E-01
	vol18	North Slope Borough - Kaktovik Pow er Plant	-143.63	70.13	7.6	3.52E+00	3.52E+00	5.47E-02	5.47E-02	5.47E-02	5.47E-02	4.34E-01	4.34E-01	4.34E-01	7.25E-01				0.00E+00	1.57E-02	1.57E-02	3.89E-02	3.89E-02
	vol19	ExxonMobil - Point Thomson Facility[h]	-146.30	70.20	2.7	6.93E+00	6.93E+00	6.04E-01	6.04E-01	6.62E-01	6.62E-01	8.63E-01	8.63E-01	8.63E-01	2.99E+00				0.00E+00	1.74E-01	1.90E-01	4.30E-01	4.71E-01

RFD Sources - 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

g The Kaktovik Pow er Plant and the Point Thomson Facility 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%

h Point Thomson is an existing facility, but actual emissions w ere not available through NEI 2011, so PTE rates w ere used

			Stack Parameters[c]					1988	1978	2012	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
	vol01	Alpine Central Processing Facility	10.0	2.33	2.33		0.5	Y	Y	Y	Y	1984	2012
	vol02	CPF 1, Kuparuk Central Production Facility #1	10.0	2.33	2.33		0.5	Y	Y	N	Y	1979	2001
	vol03	CPF 2, Kuparuk Central Production Facility #2	10.0	2.33	2.33		0.5	Y	Y	N	Y	1981	1993
	vol04	CPF 3, Kuparuk Central Production Facility #3	10.0	2.33	2.33		0.5	Y	Y	N	Y	1984	2003
	vol05	Endicott Production Facility (END)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1986	2010
	vol06	Flow Station #1 (FS 1)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1973	2006
	vol07	Flow Station #2 (FS 2)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1975	2002
	vol08	Flow Station #3 (FS 3)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1977	1990
	vol09	Gathering Center #1 (GC 1)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1977	1993
	vol10	Gathering Center #2 (GC 2)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1976	1999
	vol11	Gathering Center #3 (GC 3)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1977	1990
	vol12	Lisburne Production Center (LPC)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1984	2003
	vol13	Milne Point Production Facility (MPU)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1985	2004
	vol14	PBU Central Pow er Station (CPS)	10.0	2.33	2.33		0.5	Y	Y	N	Y	1970	1999
	vol15	PS #03, TAPS Pump Station	10.0	2.33	2.33		0.5	Y	Y	N	Y	1978	2006
	vol16	PS #04, TAPS Pump Station	10.0	2.33	2.33		0.5	Y	Y	N	Y	1978	2010
	vol17	Seaw ater Injection Plant East (SIPE)	10.0	2.33	2.33		0.5	N	Y	N	Y	1981	1983
	vol18	North Slope Borough - Kaktovik Pow er Plant	10.0	2.33	2.33		0.5	Y	Y	Y	Y		
	vol19	ExxonMobil - Point Thomson Facility[h]	10.0	2.33	2.33		0.5	Y	Y	Y	Y		

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