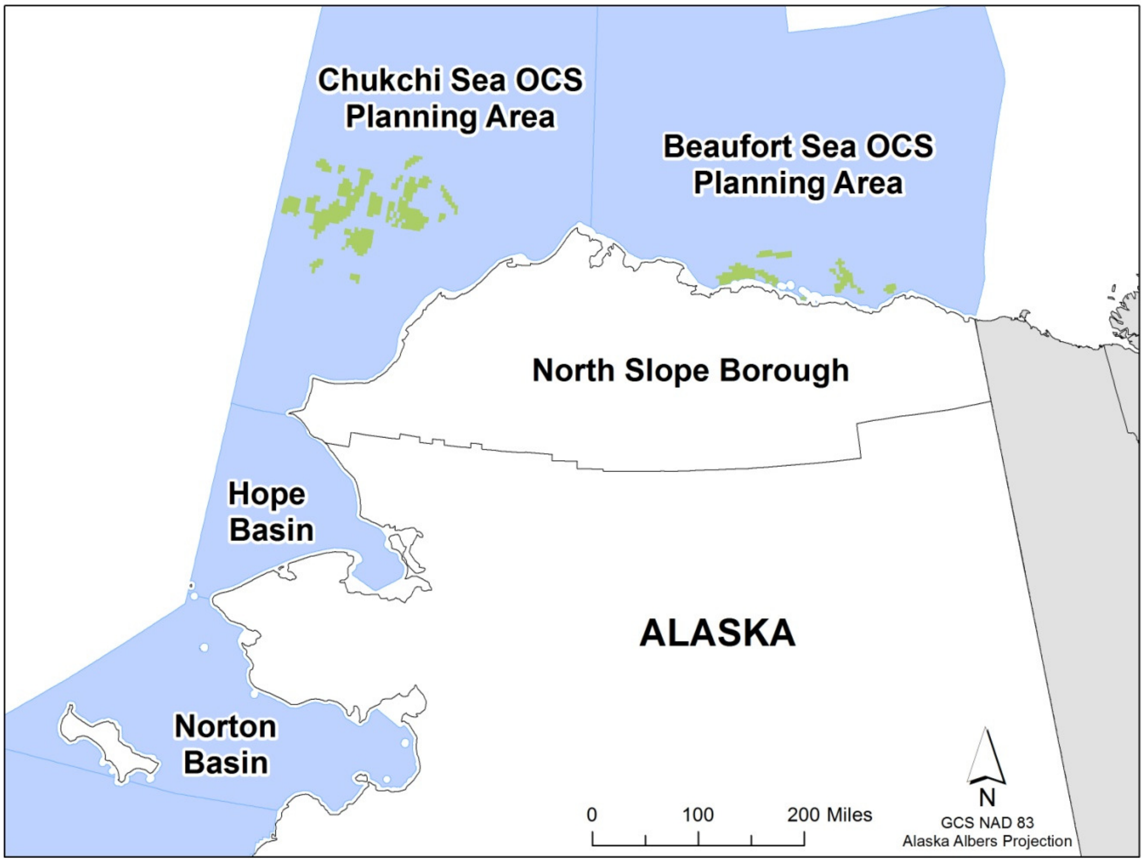
OCS Study
BOEM 2014-1001

Arctic Air Quality Modeling Study: Emissions Inventory – Final Task Report



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Alaska OCS Region

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Emissions Inventory – Final Task Report

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Abbreviations and Acronyms

AADT	annual average daily traffic
ADEC	Alaska Department of Environmental Conservation
AEA	Alaska Energy Authority
ADOT&PF	Alaska Department of Transportation and Public Facilities
AHF	Arctic heating fuel
AIS	automatic identification systems
AOCSRO	Alaska Outer Continental Shelf Regional Office
APSC	Alyeska Pipeline Service Company
AQRP	Air Quality Regulatory Program
APU	auxiliary power unit
ATV	all terrain vehicle
BBL	barrel
BOC	Base Operations Center
BOEM	Bureau of Ocean Energy Management
BPXA	BP Exploration Alaska
BTS	Bureau of Transportation Statistics
BUECI	Barrow Utilities and Electric Co-op, Inc.
CAA	Clean Air Act, as amended
CAAA	Clean Air Act Amendments of 1990
CAP	criteria air pollutant(s)
CCP	Central Compressor Plant
CGF	Central Gas Facility
CH_4	methane
CMV	commercial marine vessel
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COTU	Crude Oil Topping Unit
CPS	Central Power Station
DOI	U.S. Department of the Interior
DQOs	data quality objectives
EA	environmental assessment
ECS	extended continental shelf
EDMS	Emissions and Dispersion Modeling System
EIIP	Emissions Inventory Improvement Program
EPA	U.S. Environmental Protection Agency
FAA	Federal Aviation Administration
ft	feet
G&G	geological and geophysical
gal	gallon
GBS	gravity-based structure
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GIS	geographic information system

GOM	Gulf of Mexico
GOR	gas-to-oil ratio
GSE	ground support equipment
GWP	global warming potential
HAP	hazardous air pollutant(s)
HFC	hydrofluorocarbon
H_2S	hydrogen sulfide
hp	horsepower
km	kilometer
kW	kilowatt
kW-hr	kilowatt-hour
lbs	pounds
LPG	liquid petroleum gas
LRRS	Long-range radar site
LTO	landing and takeoff
m	meter
MCF	1,000 cubic feet
MMscf	million standard cubic feet
mph	miles per hour
MSW	municipal solid waste
m/s	meters per second
m^2	square meter
NARL	Naval Arctic Research Laboratory
NCDC	National Climatic Data Center
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NGL	natural gas liquid
NH_3	ammonia
NMIM	National Mobile Inventory Model
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxide
NO_2	nitrogen dioxide
NSB	North Slope Borough
NSBSD	North Slope Borough School District
N_2O	nitrous oxide
OAR	OCS Air Regulations
OCS	Outer Continental Shelf
OCSLA	OCS Lands Act
OSP	oil spill response
PAH	polycyclic aromatic hydrocarbon
Pb	lead
PBOC/MCC	Prudhoe Bay Operations Center/Main Construction Camp
PBU	Prudhoe Bay unit
PCB	polychlorinated biphenyls
PCE	power cost utilization
PFC	perfluorocarbon

PIs	Principal Investigators
ppm	parts per million
ppmv	parts per million by volume
PM_{10}	particulate matter with an aerodynamic diameter of less than or equal to 10 micrometers
$PM_{2.5}$	particulate matter with an aerodynamic diameter of less than or equal to 2.5 micrometers
PTE	potential to emit
QA	quality assurance
QC	quality control
RVP	Reid vapor pressure
RY	reporting year
SCC	source classification code
scf	standard cubic foot
SF_6	sulfur hexafluoride
SIPE	Seawater Injection Plant East
SMOKE	Sparse Matrix Operator Kernel Emissions model
SOPs	standard operating procedures
SO_2	sulfur dioxide
SRG	Science Review Group
STP	Seawater Treatment Plant
TAF	Terminal Area Forecast
TAPS	TransAlaska Pipeline System
TOS	Thermal Oxidation System
tons/yr	tons per year
UIC	Ukpeagvik Iñupiat Corporation
ULSD	ultra-low sulfur diesel
USCG	United States Coast Guard
USGS	United States Geological Survey
µm	micrometer
VMT	vehicle miles traveled
VOC	volatile organic compound
VSP	vehicle specific power
WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting model

I. INTRODUCTION

The Clean Air Act Amendments of 1990 (CAA) authorize the United States Environmental Protection Agency (EPA) to regulate emission sources proposed for oil and gas activities within certain areas of the United States Outer Continental Shelf (OCS). The jurisdiction of EPA's authority includes, in part, all of the Alaska OCS planning areas (CAA Section 328). Therefore, the EPA promulgated the OCS Air Regulations (OAR) under 40 CFR Part 55 requiring certain operators to apply for EPA permits to construct, as well as air quality permits, to ensure attainment and maintenance of federal and state ambient air quality standards and to comply with the CAA.

In December 2011, jurisdictional air quality control responsibilities for the Arctic OCS were transferred from the EPA to the Department of the Interior (DOI) when Congress revised CAA Section 328 and approved the Consolidated Appropriations Act, 2012. Proposed OCS operators are required to comply with the DOI/Bureau of Ocean Energy Management (BOEM) Air Quality Regulatory Program (AQRP), established under 30 CFR Part 550, Subpart C, and BOEM has the obligation to implement the authority provided in OCS Lands Act (OCSLA) Section 5(a)(8) (see 45 Fed. Reg. 15128, 3/7/1980).

The BOEM Alaska Outer Continental Shelf Regional Office (AOCSR) is responsible for assessing the potential environmental impacts from oil and gas exploration, development, and production activities on the Alaska OCS. In addition, AOCSR is responsible for regulating emission sources from oil and gas activities within the Chukchi Sea and Beaufort Sea OCS Planning Areas adjacent to the North Slope Borough (NSB) of Alaska. Figure I-1 shows the Alaska OCS area and NSB of Alaska.

To enable BOEM to assess potential air quality impacts from oil and gas exploration, development and production on the Alaska OCS as well as those in near-shore state waters (within 3 nautical miles of the coast), and related onshore activities, BOEM is sponsoring this Arctic Air Quality Impact Assessment Modeling Study (Arctic AQ Modeling Study). The study will inform two important objectives and provide several secondary benefits:

- **National Environmental Policy Act (NEPA) Environmental Impact Air Quality Assessments.** To date, much of the emissions and meteorological data developed for the Arctic region are project specific. The Arctic AQ Modeling Study will provide a comprehensive baseline air quality analysis with a comprehensive emissions inventory, consistent meteorological dataset, and air dispersion analysis to support environmental impact assessments under NEPA.
- **BOEM AQRP.** The Arctic AQ Modeling Study will assess current methods for estimating thresholds used to assess the potential adverse effects that planned offshore oil and gas activities might have on onshore air quality, as required by the BOEM AQRP, and recommend improvements, if necessary.
- **Secondary Benefits.** The Arctic AQ Modeling Study will provide improved and consolidated information about the emission sources in the study area, disseminate that information to the public, and inform several environmental justice initiatives.

A. Arctic AQ Modeling Study Purpose

The NEPA air quality assessment and the BOEM AQRP analysis are separate and distinct evaluations required before BOEM can approve plans for oil and gas activities proposed for the Arctic OCS. When these two evaluations are used together, they provide a holistic assessment of Arctic air pollution transport and show how new emission sources, both onshore and offshore, might impact air quality on the North Slope and over near shore areas. In addition, the combined evaluation determines the extent of cumulative effects when considering other emission sources affecting the North Slope (e.g., onshore and in near shore state waters). Results of this study may be used by various entities in support of environmental justice initiatives and permit applications, and the study would serve the public seeking a direct and reliable accounting of air pollution effects on the people and natural environment of the NSB.

BOEM uses air quality dispersion modeling to assess the potential onshore impacts of emissions from proposed Arctic OCS oil and gas activities. The accuracy of the modeling predictions depends on several factors, including the rate of emissions and a representative meteorological dataset. Thus, the air quality impact analysis is only as comprehensive as the emissions inventory on which the analysis is based, and only as accurate as the meteorological dataset applied to simulate dispersion and transport of the pollutants. While the EPA, the Alaska Department of Environmental Conservation (ADEC), and various potential OCS operators have prepared emissions inventories of sources located on the North Slope for purposes of air permitting and other regulatory needs, research is needed to bring together data from these resources that will contribute to a comprehensive accounting of annual emissions.

B. Emissions Inventory Objectives and Protocol

One of the first steps in performing the Arctic AQ Modeling Study, and in support of subsequent air quality modeling analyses, was to develop a comprehensive air emissions inventory that accurately estimates emissions within the study area that encompasses the North Slope region and adjacent waters of the Beaufort Sea and Chukchi Sea Planning Areas (Figure I-1). The primary objective of the inventory was to estimate emissions from equipment and activities that occurred under the baseline and future year scenarios. Development of the scenario on which the inventory projections were based was provided by BOEM, and is described in detail in this report.

The first milestone of the inventory was developing the Arctic AQ Modeling Study Emissions Inventory Protocol. The protocol defines the inventory scope and describes the methodologies to be used for each source type, in order to estimate accurate emissions in a format suitable for use in air quality modeling. The protocol also provides an approach for quality assurance and quality control (QA/QC). A draft emissions inventory protocol was prepared and reviewed by BOEM and the SRG; their comments were incorporated into the final methodology that was used for the inventory.

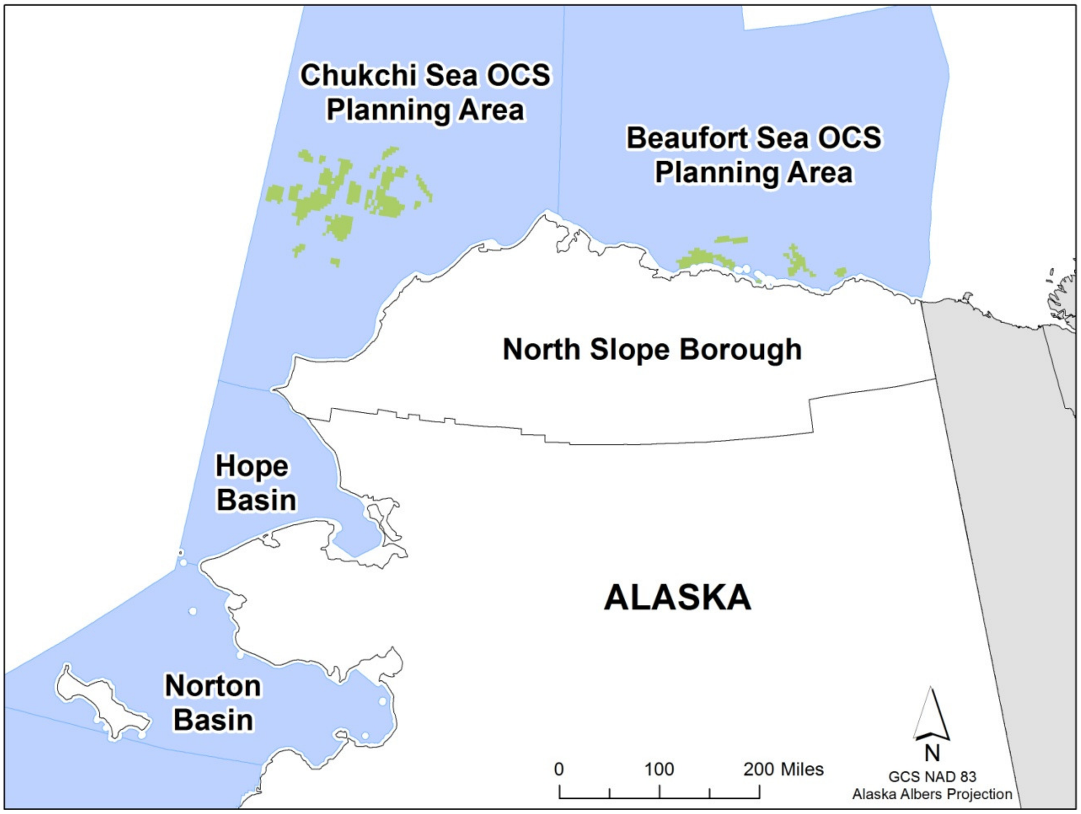

Figure I-1. Regional Map Depicting OCS Planning Areas, including location of Arctic Air Quality Impact Assessment Modeling Study (Currently leased areas are indicated in green.)
Data Source: BOEM, 2014b

C. Emissions Inventory Scope

The scope of the air emissions inventory for the Arctic AQ Modeling Study includes these elements, which are described in detail below:

- Baseline – the year selected for the inventory for which the most recent credible reliable information was available.
- Future scenarios – future year sources and activities that are reasonably foreseeable and expected to continue for an extended period of time.
- Pollutants – the specific air pollutants in the inventory.
- Sources – range of source types/categories for which air emissions are estimated (e.g., onshore oil and gas production, near shore activities, emissions from pipelines, etc.).
- Geographical domain and spatial resolution – area within which emissions are estimated, and the level of detail or specificity at which emissions are estimated (e.g., geographic location, centroid (center) of a community or village[1]).
- Temporal resolution (e.g., annual, monthly, daily, hourly).

[1] The term “village” is used interchangeably with “community” in this report.

1. *Baseline and Future Scenarios*

In an effort to determine a “base year” for the Arctic AQ Modeling Study emissions inventory, several factors were considered including the most suitable year to use for baseline quality modeling (i.e., the primary use of the inventory), and the availability of data needed to estimate emissions.

ERG targeted a base year of 2012 for the Arctic AQ Model Study emissions inventory, although some data from other years (including 2011 and 2013) were substituted as needed to form a complete dataset of emissions for the baseline. It is important to note that year 2012 is representative of “typical” Arctic meteorological conditions (needed for air quality modeling), and provided the best opportunity for collecting the wide range of activity data needed for estimating emissions from most of the air pollution sources operating on the North Slope. The combination of year 2012, 2011, and 2013 data formed the “baseline” for the Arctic AQ Modeling Study emissions inventory.

Also, projected (future year) emissions were estimated for use in evaluating impacts anticipated from potential future oil and gas exploration, development, and production activities on the Arctic OCS. ERG projected future emissions based on information and guidance provided by BOEM for a “full build-out” scenario (BOEM, 2014b). The sources for which emissions were estimated, and the methods used for projecting emissions under the full build-out scenario are discussed in Section IV of this report.

2. *Pollutants*

Emissions were estimated for the CAA pollutants for which air quality “criteria” have been established, hazardous air pollutants, precursors to the criteria air pollutants, and greenhouse gases reported under the EPA’s Greenhouse Gas Reporting Program (U.S. EPA, 2009a). The specific pollutants are listed below:

- Criteria air pollutants (CAPs) as defined by CAA Part A, Section 108:
  - Carbon monoxide (CO).
  - Nitrogen dioxide (NO_2) estimated as nitrogen oxides (NO_x).
  - Sulfur dioxide (SO_2).
  - Particulate matter (PM) with an aerodynamic diameter of less than or equal to 10 micrometers (µm), or PM_{10}.
  - PM with an aerodynamic diameter of less than or equal to 2.5 µm, or $PM_{2.5}$.
  - Ozone (i.e., precursor volatile organic compounds [VOC]).
  - Lead (Pb).
- Coarse fraction of PM (i.e., between 10 and 2.5 µm), or $PM_{10-2.5.}$
- Hydrogen sulfide (H_2S), a potential component of natural gas.
- Greenhouse gases (GHGs) in terms of carbon dioxide equivalents (CO_2e):
  - Carbon dioxide (CO_2).
  - Methane (CH_4).
  - Nitrous oxide (N_2O).
  - Sulfur hexafluoride (SF_6).

- Hydrofluorocarbons (HFCs).
- Perfluorocarbons (PFCs).

Global warming potentials (GWPs) required under EPA's GHG Reporting Program were used to estimate CO_2e (IPCC, 2007) with a GWP of 25 for CH_4 and a GWP of 298 for N_2O. (Although SF_6, HFCs, and PFCs are included in this list, none of these GHGs were emitted by the inventoried sources.)

- Hazardous air pollutants (HAP) as defined by CAA Title III. Note that for a few sources, carbon tetrachloride (CCl_4) and methyl chloroform (CH_3CCl_3) emissions were estimated. Although these are also considered GHGs, they were classified under HAP, only.

3. *Inventory Sources*

Emissions from anthropogenic (i.e., human-caused) sources were estimated for the Arctic AQ Modeling Study emissions inventory, including stationary sources located in North Slope communities and oil fields, onroad motor vehicles, nonroad equipment, marine vessels and other offshore (oil- and gas-related) sources (i.e., both OCS and near shore in state waters), and airports. Also, emissions from other sources were estimated based on their potential influence on air quality concentrations, including dust emissions from paved and unpaved portions of the Dalton Highway and other roads located in communities and the oil fields. Table I-1 lists the source groups and categories included in the Arctic AQ Modeling Study emissions inventory and the associated air pollutants. Although some of the source categories shown in Table I-1 were not active during 2012, these sources are reasonably expected to occur under the future year scenario (e.g., offshore oil and gas platform construction, platform operation, and pipelaying activities).

Also note that emissions from nonanthropogenic biogenic sources (e.g., NO_x emissions from soils and VOC from vegetation; geogenic sources such as oil seeps and wildfires) are closely related to the Sparse Matrix Operator Kernel Emissions (SMOKE) emissions processing performed during a future stage in this study.

4. *Geographic Domain and Spatial Resolution*

The domain of the Arctic AQ Modeling Study emissions inventory is the area encompassing the Arctic OCS, including the Chukchi and Beaufort Seas, near shore state waters (within 3 nautical miles of the coast), and the NSB.

The spatial resolution of the inventory depends on the source. For example, some sources such as power plants were pinpointed based on their geographic coordinates (i.e., latitude and longitude), while other sources such as nonroad vehicles (e.g., snowmobiles and all terrain vehicles (ATVs)) and residential fuel combustion were "placed" at the centroid of the community in which they were used. The latitude/longitude coordinates identify the location of "point sources" and the centroid of a geographic area (e.g., community, oil field) identifies the location of all other source categories (i.e., area, mobile, and nonroad).

The resolution of the geographical area covered by the emissions inventory is based on the grid cell size needed for photochemical and dispersion modeling, which will be designated under other project tasks.

Table I-1. Sources Included in the BOEM Arctic AQ Modeling Study Emissions Inventory

Group and Category		Pollutants for which Emissions were Estimated										
		CO	NO_x	SO_2	VOC	Pb	$PM_{2.5}$	PM_{10}	GHG	HAP	H_2S	NH_3
Offshore Oil & Gas Activities	Seismic survey and supply vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Seismic support helicopters	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	On-ice seismic survey equipment	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Exploratory drilling – drill ships, jackups	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Exploratory drilling – fleet support vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Platform construction and support vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Island construction and support vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Production platform operation	✓	✓	✓	✓		✓	✓	✓	✓		✓
	Platform support – supply and support vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Platform support – helicopters	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Pipelaying and support vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Off-shore - Other	Commercial marine vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Research vessels	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Onshore Oil & Gas Fields	Seismic survey equipment	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Drilling/exploration	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
	Well pads				✓					✓	✓	
	Processing plants, gathering centers, etc.	✓	✓	✓	✓		✓	✓	✓	✓	✓	
	Support (injection, seawater treatment)	✓	✓	✓	✓		✓	✓	✓	✓	✓	
Air-ports	Aircraft and helicopters	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Ground support equipment	✓	✓	✓	✓		✓	✓	✓	✓		✓
TransAlaska Pipeline System	Pump stations (1-4)	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	On-road patrol vehicles	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Aerial surveillance aircraft	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	TAPS fugitives				✓				✓	✓	✓	
	Natural gas supply line fugitives				✓				✓	✓	✓	
	Pigging operations				✓				✓	✓	✓	
	Pipeline replacement, repair	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓

Table I-1. Sources Included in the BOEM Arctic AQ Modeling Study Emissions Inventory (Continued)

Group and Category		Pollutants										
		CO	NO_x	SO_2	VOC	Pb	$PM_{2.5}$	PM_{10}	GHG	HAP	H_2S	NH_3
Onshore Non-Oil & Gas Activities	Power plants	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Industrial/commercial/institutional/residential fuel combustion	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	On-road motor vehicles	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Nonroad mobile sources	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Road dust						✓	✓				
	Waste burning	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
	Wastewater treatment				✓							
	Fuel dispensing				✓					✓		
Spills	OCS pipeline spills				✓					✓		
	Platform spills				✓					✓		

5. *Temporal Resolution*

Emissions for the majority of sources were estimated on an annual basis (i.e., emissions generated during 2012). In a few instances, monthly emissions were estimated first (based on the activity data available), then annual emissions were calculated. For purposes of this emissions inventory report, the emissions inventory results are provided in tons per year (tons/yr).

Emissions on an hourly, daily, and seasonal basis are also needed for near- and far-field dispersion and photochemical modeling. ERG will use temporal allocation factors in the SMOKE emissions model for some sources; other temporal allocations will be source-specific (e.g., residential heating most intensive in the winter months, heavy equipment most active in winter months when tundra is frozen).

After the modeling protocols are finalized and the modeling scenarios are defined, ERG will develop any additional temporal profiles that depict the emissions conditions needed for modeling. These will most likely address the sources projected to operate offshore, as well as sources located in the onshore communities that have seasonal and diurnal variations.

D. Arctic AQ Modeling Study Emissions Inventory Development Team

The development of the Arctic AQ Modeling Study emissions inventory was a collaborative team effort3. In addition to managing the overall project, ERG led development of emissions inventory. A Science Review Group (SRG) of technical experts provides independent technical review for the entire project. Other ERG team members assisting with the modeling work include ENVIRON International Corporation (meteorological and photochemical modeling lead) and University of Alaska Fairbanks (assisting with the photochemical modeling).

E. Report Organization

The remainder of this report comprises the following sections:

- Section II: Development of Offshore Emissions Inventory. This section describes the methods and data used to estimate emissions and allocate emissions temporally and spatially for offshore oil and gas activities (i.e., seismic surveys, drilling, platforms, and pipelaying and support activities) and offshore non-oil and gas activities (i.e., commercial marine and research vessels).
- Section III: Development of Onshore Emissions Inventory. This section describes the methods and data used to estimate emissions and allocate emissions temporally and spatially for onshore oil and gas activities (i.e., seismic surveys, drilling, and production), airports, TAPS, stationary sources (e.g., fuel combustion), paved and unpaved road dust, mobile sources, nonroad motor vehicles, waste burning, and wastewater treatment.
- Section IV: Development of Emissions Projections. This section describes the scenario defined for the basis of the emissions projections (i.e., sources affected, activity levels projected), as well as the methods, data, and assumptions used to estimate emissions.
- Section V: QA/QC. This section describes the elements of the QA Program developed for this project, as well as the specific QC checks performed to ensure the highest quality emissions inventory possible.

- Section VI: Results. This section provides tables of results that show estimated emissions for tons/yr by pollutant and source groups for the baseline inventory and the future year projections. Also, this section discusses the limitations of the estimates caused by uncertainty and presents recommendations for future improvements.
- Section VII: References. This section contains a comprehensive list of all references, source documents, websites, etc., used to develop inventory methods and make estimates.
- Appendix A: This contains a Technical Report with supporting data used to develop the Arctic AQ Modeling emissions inventory.

II. DEVELOPMENT OF OFFSHORE EMISSIONS INVENTORY

This section describes the methods and data used to estimate baseline emissions from all offshore sources and activities occurring within the Chukchi Sea and Beaufort Sea OCS Planning Areas adjacent to the NSB, as well as those in near shore state waters (within 3 nautical miles of the coast).

The method used to estimate vessel emissions was to apply activity data to appropriate GREET marine vessel emission factors (ANL, 2013) and speciation profiles. For estimating helicopter and aircraft landing and takeoff (LTO) emissions, ERG used the Federal Aviation Administration's (FAA's) Emissions and Dispersion Modeling Systems (EDMS) (FAA, 2013). The specific pollutants that were estimated for each source are listed in Table I-1.

A. Oil/Gas Related Sources

Offshore oil and gas activities in 2012 were limited to seismic survey and exploratory drilling operations. The seismic survey occurred during a 76-day period and focused on specified areas in the Beaufort Sea and a small part of the Chukchi Sea. Exploratory drilling in 2012 was implemented in both seas using two teams equipped with drilling rigs, support vessels, ice breakers, oil spill response vessels, and helicopter support for a period of 53 days in the Chukchi Sea and 29 days in the Beaufort Sea. In 2012, there were no offshore production platforms, no platform or pipeline construction activities, and no geohazard or geotechnical surveys.

1. *Seismic Survey Operations*

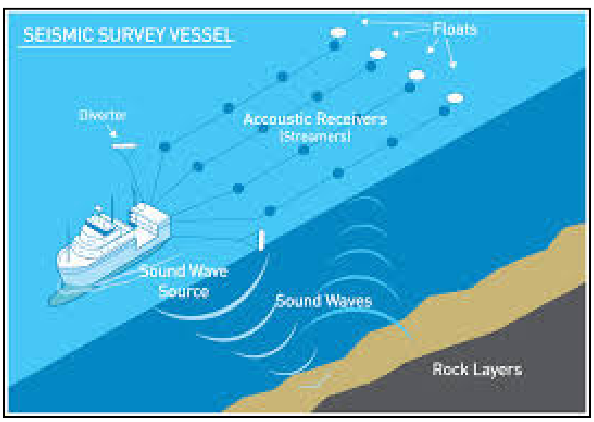

Figure II-1. Typical Seismic Survey
Online image from PG&E: How the 3D High-Energy Survey Works. © Used by Permission.

Seismic surveys are used in the Arctic to evaluate the possible locations of oil-bearing strata (seismic survey), assess geologic risk to constructed structures (geohazard surveys), and provide seabed data for platform design and construction (geotechnical surveys). Only seismic survey vessels are included in the 2012 inventory, while all three types are included in the projected inventory (see Section IV). There are several different types of survey vessels, but most are equipped with an air gun that generates a sound wave that bounces off the seabed and is picked up by an array of acoustic receivers (hydrophones) that are pulled behind the vessel (Figure II-1) (PennWell, 2012). Results from the seismic soundings are mapped to identify density anomalies in the geologic strata that could suggest the existence of oil and possible sites for exploratory drilling.

The survey vessel emissions inventory includes estimates for associated support vessels. Support vessels are ice breakers and scout vessels. Ice breakers travel ahead of the seismic survey vessel to break up ice along the route. Scout vessels are smaller vessels, and travel ahead of the seismic survey vessel to warn of ice coverage or location of sea life, mainly whales. Emissions were estimated by applying emission factors and HAP speciation profiles to activity data and load factors for 2012.

Survey vessel activity was defined in terms of kilowatt hours (kW-hrs) derived from vessel power ratings, hours of operation, and appropriate load factors. Internet searches were implemented to identify seismic surveys conducted in the Arctic in 2012. Through these searches, one seismic survey project implemented in both the Chukchi and Beaufort Seas was identified, the ION Geophysical Seismic Survey (BOEM, 2012b).

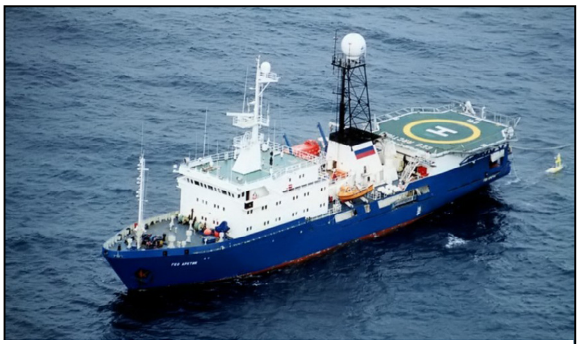

Figure II-2. ***M/V Geo Arctic***
Image from Ion Geophysical

Based on BOEM's Environmental Assessment (EA) for the ION survey, ERG compiled vessel identification information, including engine characteristics (kW power rating) and estimated hours of operation for 2012. The two vessels used in the ION survey were the *M/V Geo Arctic* and the ice breaker *Polar Prince*.

The *M/V Geo Arctic* is a Russian-flagged 2D seismic survey vessel (Figure II-2). This vessel is 81.85 meters (m) long with a breadth of 14.8 m and a draft of 5.23 m. It has a maximum speed of 14 knots and a cruising speed of 12.5 knots. While conducting a seismic survey, the *M/V Geo Arctic* travels at a rate of 3 to 4 knots. This vessel has a power rating of 7,576 kW (BOEM, 2012b).

Figure II-3. ***Polar Prince***
Image from Ion Geophysical

For the 2012 survey, the *M/V Geo Arctic* followed behind the *Polar Prince* at a distance of 0.5 to 1 km. The *Polar Prince* is a medium class 100A icebreaker with a power rating of 3,820 kW (Figure II-3). It is 67.1m long with a breadth of 15 m and a draft of 6 m. It has a maximum speed of 14.5 knots and a cruising speed of 11 knots. The *Polar Prince* provided support duties as necessary, including at-sea refueling for the *M/V Geo Arctic* (BOEM, 2012b).

The EA provided kW ratings for the *M/V Geo Arctic* and the *Polar Prince*, including an estimate of the number of days at sea, estimated start and end dates, and operating hours. BOEM provided the date at which operations were actually completed (BOEM, 2012c). The estimated operating hours were adjusted to reflect the actual number of days the vessels were at sea, based on a ratio of actual days to estimated days. The adjusted number of operating hours for each vessel is listed in Table II-1.

Table II-1. Estimated Operating Hours for the 2012 ION Geophysical Seismic Survey

Vessel Name	Estimated		Actual Number of Days	Adjusted Number of Operating Hours
	Number of Days	Operating Hours		
M/V Geo Arctic	76	1,824	35	840
Polar Prince	76	2,280	35	1,050

Sources: BOEM, 2012b; BOEM, 2012c

Survey vessel activity was defined as kW-hrs derived from the adjusted hours of operation, the vessel power ratings, and an appropriate load factor. The survey vessel engines were assumed to be medium-speed diesel engines, and the load factor was assumed to be 90 percent to account for increased load associated with towing the array of acoustic receptors (Wilson et al., 2014*)*. The load factor for support vessels was assumed to be 62 percent (Marintek, 2010). The survey vessel activity was calculated as follows:

$$\text{kW-hrs} = \text{kW} \times \text{LF} \times \text{hrs}$$

where:

kW = Vessel power rating (kilowatts)
LF = Load factor (%)
hrs = Adjusted number of operating hours for each vessel

Example Calculation:

Total hours of operation in 2012 for the *M/V Geo Arctic* were 840. The power rating is 7,576 kW and the load factor is 0.90.

$$\text{kW-hrs} = 840 \times 7{,}576 \times 0.90$$
$$\text{kW-hrs} = 5{,}727{,}456$$

The survey vessel activity is summarized as follows:

- M/V Geo Arctic: 5,727,456 kW-hrs
- Polar Prince: 2,476,793 kW-hrs

The emission factors for the survey vessels are based on combustion of ultra-low sulfur fuels (15 parts per million (ppm)). Table II-2 lists the emission factors applied to the vessel activity data.

Table II-2. Seismic Survey Vessel Emission Factors (grams/kW-hr)

Pollutant	Emission Factor
NO_x	9.8
VOC	0.5
CO	1.1

Table II-2. Seismic Survey Vessel Emission Factors (grams/kW-hr) (Continued)

Pollutant	Emission Factor
SO_2	0.005953158
PM_{10}	0.151180248
PM_{25}	0.111180248
Pb	0.00002
NH_3	0.003
CO_2	646.08
CH_4	0.004
N_2O	0.031

Source: ANL, 2013

Survey vessel emissions were calculated as follows:

$$E = \text{kW-hrs} \times EF \times CF$$

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)
EF = Emission factor (g/kW-hrs)
CF = Conversion factor (g = 1.10231 10^{-6} ton)

Example Calculation:

Total kilowatt hours for the *M/V Geo Arctic* were 5,727,456 kW-hrs. The emission factor for NO_x is 9.8 g/kW-hr.

$$E = 5{,}727{,}456 \times 9.8 \times 0.00000110231$$
$$E = 61.9 \text{ tons}$$

Support helicopters visit survey vessels to deliver supplies and transfer personnel. Emissions for the helicopter LTOs at airports are included in the onshore emissions inventory (Section III of this report). To estimate the cruise portion between the airport and the survey vessel, the helicopters were assumed to fly from the airport to the survey vessels three times per week at a cruise speed was 100 mph. Therefore, the total flight hours per season was calculated to be 174.86 hours. ERG assumed the helicopter was a Sikorsky SH-60 Sea Hawk. Engine load factors specific for cruising operations of a Sea Hawk were not identified; therefore, the takeoff mode emission factors (100 percent load) were adjusted to 80 percent load to represent cruising engine load conditions, providing a conservative value similar to an equivalent turboprop engine (SDMC, 2014).

Activity and emissions from survey vessel operations were spatially assigned to the anticipated route that the survey vessel and support boats would follow (Figure II-4), as provided in the EA. Support helicopter activity and emissions were also assigned based on the survey operations map included in the EA.

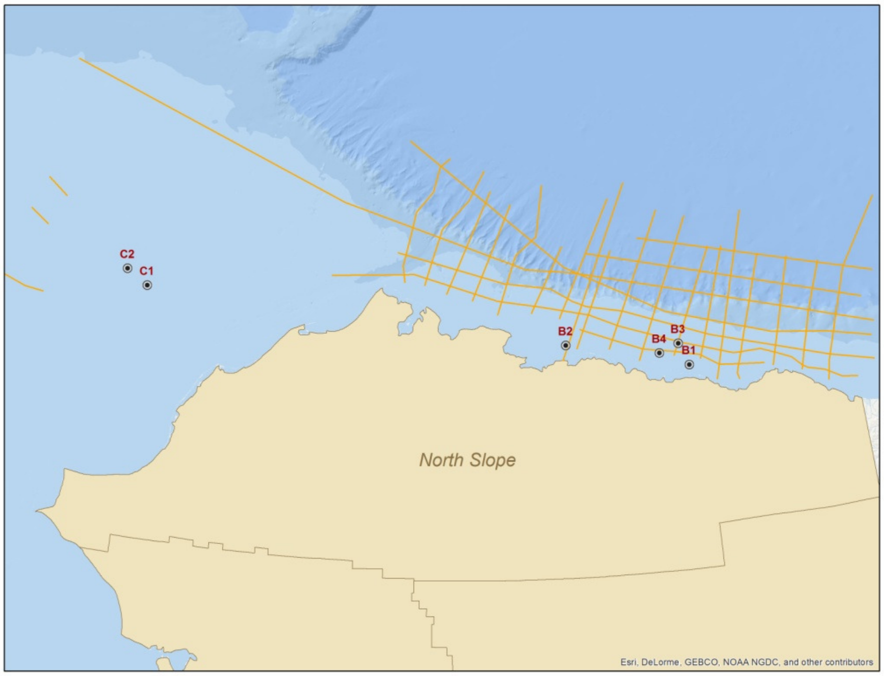

Figure II-4. 2012 Survey Vessel Activities
Data Source: BOEM, 2012b

The accuracy of the survey vessel estimates is dependent upon the engine load conditions that can vary from less than 10 percent for at-sea idling to 90 percent while towing the array of receptors (Wilson et al., 2014). Because detail engine log data were not available, a high-end load factor of 90 percent was assumed.

2. *Exploratory Drilling*

Figure II-5. Typical Jackup Rig
Online image from Yellow & Finch Publishers. http://www.ynfpublishers.com/2014/06/jack-vessel-bold-tern-now-assisting-rotor-star-installation. (Accessed December 2, 2014.)

Exploratory drilling rigs are placed in locations identified by seismic surveys that have a high potential of yielding oil or gas. Geologists implement exploratory drilling to obtain core samples from geologic formations under the seabed that are analyzed for hydrocarbon content. For this emissions inventory, exploratory drilling is expected to occur in relatively shallow water. As such, there is a wide range of drilling rigs that can be used. For example, drillships such as the *Noble Discoverer* have drilling equipment built in. These vessels are self-propelled, faster, and more maneuverable than other drilling vessels. Another type is a "jackup," a rig that is built on hulls that can be moved from location to location (Figure II-5). Jackups can either be self-propelled or towed by other vessels. Once at the drilling site, they have movable self-elevating legs that secure the platform to the seabed and lift the top deck to a safe and appropriate height. Jackups are mobile drilling units that are considered to be very stable and can easily be modified or updated for future applications (Rigzone, 2012).

Drilling rigs generally include multiple emissions sources such as mud pumps, generators, draw works, compressors, and propulsion engines. This emissions inventory includes estimates for all emissions sources that typically operate on a drilling rig off the coast of the North Slope, based on data provided by BOEM and the exploratory drilling plans submitted to BOEM by Shell Gulf of Mexico Inc. (BOEM, 2011; Shell, 2001).

In addition to drilling rigs, other vessels support drilling activities in the Arctic, including:

- Anchor handling vessels.
- Crew boats.
- Icebreakers.
- Oil spill response (OSR) vessels.
- Supply vessels.
- Support helicopters.
- Tugs/towboats.
- Wildlife monitoring aircraft.

Emissions were estimated for all vessels and aircraft involved in the 2012 drilling program off the North Slope coast.

CAP and GHG pollutant emissions were estimated by applying emission factors to activity data. Drilling activity was developed in the same units and derived from the vessel's maximum power ratings, hours of operation, and appropriate load factors. HAP speciation profiles were applied to PM emissions for metallic HAP and VOC emissions for organic HAP.

Based on the Exploration Plan submitted to BOEM by Shell (Shell, 2011) and a report submitted to DOI by Shell (DOI, 2013), ERG compiled vessel and support fleet information, including engine characteristics (kW power rating) and estimated hours of operation for operations in the Beaufort and Chukchi Seas. More information was provided for the Chukchi drilling operations than the Beaufort drilling operations; therefore, when data were missing for Beaufort, information from the Chukchi permit was used to gap fill.

The permits not only included kW ratings for the vessel and associated support fleet, they also included estimated number of days at sea and estimated hours of operation per day. Though the permits indicated a drilling period of 120 days, DOI summarized 2012 drilling activities on the North Slope including actual start and end dates at which operations were completed for each rig. The actual operating days were multiplied by the estimated hours of operation per day to obtain total hours of operation.

Marine vessel engine loads varied depending upon the type of operation; the load factors used are listed in Tables A-1 and A-2 of Appendix A (Wilson et al., 2014). Drilling activity was calculated as follows:

$$\text{kW-hrs} = \text{kW} \times \text{LF} \times \text{hrs}$$

where:

kW = Vessel power rating (kilowatts)
LF = Load factor (%)
hrs = Hours of operation

Example Calculation:

Total hours of operation for the *Discoverer* for 2012 were 1,272 for propulsion. The vessel power rating is 13,288 kW and the load factor is 60 percent.

kW-hrs = 13,288 × 0.60 × 1,272
kW-hrs = 10,141,397

Emissions were estimated by applying emission factors to activity data for 2012 using the equation shown below. Tables A-3 and A-4 of Appendix A lists the emission factors for the Chukchi and Beaufort drilling sites, respectively and Table A-5 lists the HAP speciation profiles.

EM = kW-hrs × EF × CF

where:

EM = Emissions (tons/yr)
kW-hrs = Activity data (kilowatt-hours)
EF = Emissions factor (g/kW-hr)
CF = Grams to tons conversion factor

Example Calculation:

Total kW-hrs for the *Discoverer* for 2012 were 10,141,397 kW-hrs for propulsion. The emission factor for NO_x is 9.8 g/kW-hr and the conversion factor is 0.00000110231 g/tons.

EM = 10,141,397 × 9.8 × 0.00000110231
EM = 109.55 tons of NO_x

In addition to marine vessels, drilling operations also include helicopters and airplanes. The helicopters are used for personnel and equipment transfers and the aircraft are used for wildlife monitoring. Emissions were associated with the LTOs at the airport (which are included in the onshore emission estimates in Section III of this report), the LTOs at the drilling vessels (for helicopters only – airplanes used in wildlife monitoring did not land on the drilling vessels), and the cruise portion between the airports and drilling vessels. For exploratory drilling, the aircraft and helicopter types used were a Saab 340B and a Sikorsky SH-60 Sea Hawk, respectively. For the Beaufort site, the helicopters flew from Deadhorse Airport. For the Chukchi site, the airplanes and helicopters flew from Barrow Airport and Wainwright Airport.

In the Chukchi Sea, the helicopters flew 12 round trips a week from Barrow Airport to the drilling sites at an assumed duration of three hours per trip. Aircraft flew four times a week between Wainwright Airport and Barrow Airport (Shell, 2011). The Saab 340B flies at a speed of 290 miles per hour (mph). The distance between the two airports is 86.66 miles based on the Geographic Information System (GIS) data. At Deadhorse Airport, helicopters flew 12 round trips per week at three hours per trip based on permit data; aircraft flew 7 times a week at 6 hours a trip for wildlife monitoring for the duration of the drilling season. In 2012, the drilling seasons were 53 days for the Chukchi Sea and 29 days for the Beaufort Sea (DOI, 2013).

Table II-3 summarizes the calculated activity data associated with aircraft and helicopter support using assumptions listed in the Shell Exploration Plan for Chukchi Sea and the BOEM Environmental Assessment for the Beaufort Sea Planning Area (Shell, 2011; BOEM, 2011).

Table II-3. Calculated Offshore Drilling-Related Aviation Activity

Site	Source	Activity	Activity Unit	Location
Beaufort Sea	Drilling-wildlife monitor aircraft	174	hours	Deadhorse to Development Site B3
		29	LTO	Deadhorse Airport
	Drilling-helicopter	149	hours	Deadhorse to Development Site B3
		50	LTO	Beaufort-Drilling
Chukchi Sea	Drilling-wildlife monitor aircraft	18	hours	Wainwright to Barrow
	Drilling-helicopter	273	hours	Barrow to Development Site C1
		91	LTO	Chukchi-Drilling

Sources: Shell, 2011; BOEM, 2011

The accuracy of the estimates is dependent upon the operating hours and load factors of the individual pieces of equipment used in the drilling operation. Estimated operating hours were provided in the permit; more precise estimates could be developed if actual hours and load data were available.

Emissions for drilling rigs, ice-breakers, anchor handling tugs, and oil spill response vessels were spatially assigned to the lease block where the activity occurred. Supply vessel emissions were assigned to the shipping route segment between the drilling rig and the nearest port. Helicopter and aircraft emissions were assigned to the flight path segment between the drilling rig and local supply airport.

B. Non-Oil/Gas Related Sources

1. *Commercial Marine Vessels*

Cargo and supplies that are too heavy to be shipped to the North Slope communities on aircraft are transported via commercial marine vessels (CMV). This cargo includes equipment and supplies for the oil and gas industry as well as commercial products for North Slope communities. These shipments occur during the open water period when navigation is possible (generally, July through October). Because ports in the North Slope are relatively shallow, the CMV fleet comprises shallow draft vessels or tugs and barges.

The CMV activity data were defined in terms of kW-hrs and derived from the vessel power rating, hours of operation, and appropriate load factors. Automatic Identification System (AIS) data for July through October 2012 were obtained from the Marine Exchange of Alaska (MEA) for 7 North Slope ports:

- Barrow
- Cape Lisburne
- Kaktovik
- Point Hope
- Point Lay
- Prudhoe Bay
- Wainwright

The dataset was designed to include a single record for each vessel and each trip in or out of the selected ports. The resulting dataset included 753 individual records associated with 29 unique vessels as shown in Table II-4.

Table II-4. Compilation of 2012 Commercial Marine Vessels Operating in the North Slope

MMSI Code	IMO Identification Code	Vessel Name	Radio Call Sign	Ship Type
227161740		POLARIS 1	FAA8347	Dredging
227161780		POLARIS IV	FAA8349	SAR
227161790		POLARIS 2	FAA8350	Dredging
227162950		RESOLUTION	FAA8467	Pleasure
227664640		CORIOLIS 14	FGE6728	Pleasure
338117719		N2 TENDER		Reserved
366197000		NUNANIQ	WRC2049	Other
366622140		MAIA H	WYX2079	Towing long/wide
366888820		KAVIK RIVER	WBN5039	Tug
366888910	9107837	SIKU	WCQ6174	Towing long/wide
366888930	8867882	PT. THOMPSON	WBM5092	Towing
366889350		SAG RIVER	WBN2075	Tug
366898440				N/A
366898440		ARCTIC HAWK	WDB4443	Pilot
366981750		ARCTIC SEAL	WCP4174	Cargo
367014080		FISH HAWK	WDF2995	Towing
367108560	8030647	BRISTOLEXPLORER	WCZ9010	N/A
367176270	7908122	NORSEMANII	WDD6688	Undefined
367182670		HOOK POINT	WDD7159	Fishing
367305830		ARCTIC SKIMMER 1	WDD9011	Pilot
367309280	7826908	NOKEA	WDD9274	Tug
367309330	7114288	PACIFIC RAVEN	WDD9278	Towing long/wide
367309390	7047708	PACIFIC FREEDOM	WDD9283	Tug
367399110	9502491	SESOK	WDE7899	Tug
367399170	9502489	NACHIK	WDE7904	Towing
367438220		GRETA	WDF3298	Other
367494000	7127704	AQUILA	WCS6941	Reserved
369960001	671092001	FA2805	FA2805	Other

Table II-4. Compilation of 2012 Commercial Marine Vessels Operating in the North Slope (Continued)

MMSI Code	IMO Identification Code	Vessel Name	Radio Call Sign	Ship Type
369960004	671092004	FA2808	FA2808	N/A
503536900		TELEPORT		Pleasure

MMSI = Maritime Mobile Service Identification
IMO = International Maritime Organization
Source: MEA, 2014

The dataset was modified to remove vessels not included in this effort (i.e., pleasure craft) and to remove records that had too many missing data elements to be useful in this study. In port and at sea hours of operation both were calculated based on the date/time stamps within the AIS data.

Vessel power ratings were obtained for most vessels from IHS (IHS, 2013). When the vessel was not available in the IHS database, average vessel characteristics data from other similar vessels was used for gap filling the vessel power ratings. Two of the vessels that that did not have vessel characteristics listed in the IHS database were obtained from the manufacturers. The Nunaniq and the Polaris 1 and 2 had power ratings of 1,200 HP (Nichols, 2014) and 5,112 kW (SBI, 2012), respectively.

For this inventory effort, it was assumed that the load factor was 83 percent at sea and 10 percent in port (ANL, 2013). The CMV activity was calculated as follows:

$$kW\text{-}hrs = kW \times LF \times hrs$$

where:

kW = Vessel power rating (kilowatt)
LF = Load factor (%)
hrs = Adjusted number of operating hours for each vessel

Table II-5 summarizes the calculate CMV activity data.

Table II-5. Summary of Commercial Marine Vessel Activity

Mode	MMSI	Vessel Name	Hours of Operation	Engine Power Rating (kW)	kW-hrs
At Sea	366898440	ARCTIC HAWK	83	1,152	79,335
At Sea	366981750	ARCTIC SEAL	721	536	320,758
At Sea	369960004	FA2808	2	1,152	1,912
At Sea	367438220	GRETA	580	1,125	541,575
At Sea	367182670	HOOK POINT	1,175	1,152	1,123,113
At Sea	366888820	KAVIK RIVER	363	804	242,237
At Sea	366622140	MAIA H	159	1,133	149,522
At Sea	367399170	NACHIK	541	1,002	449,928

Table II-5. Summary of Commercial Marine Vessel Activity (Continued)

Mode	MMSI	Vessel Name	Hours of Operation	Engine Power Rating (kW)	kW-hrs
At Sea	366197000	NUNANIQ	773	895	574,120
At Sea	367309390	PACIFIC FREEDOM	2	2,206	3,662
At Sea	367309330	PACIFIC RAVEN	6	2,206	10,986
At Sea	227161740	POLARIS 1	1,163	5,112	4,934,562
At Sea	227161790	POLARIS 2	1,149	5,112	4,875,161
At Sea	366889350	SAG RIVER	876	804	584,572
At Sea	367399110	SESOK	734	1,002	610,438
At Sea	366888910	SIKU	383	932	296,273
In Port	366898440	ARCTIC HAWK	2,008	1,152	231,244
In Port	366981750	ARCTIC SEAL	266	536	14,258
In Port	367305830	ARCTIC SKIMMER 1	22	1,152	2,534
In Port	367108560	BRISTOL EXPLORER	7	1,654	1,158
In Port	369960001	FA2805	3	1,152	345
In Port	369960004	FA2808	74	1,152	8,522
In Port	367014080	FISH HAWK	77	942	7,253
In Port	367438220	GRETA	539	1,125	60,638
In Port	367182670	HOOK POINT	134	1,152	15,432
In Port	366888820	KAVIK RIVER	2,354	804	189,262
In Port	366622140	MAIA H	502	1,133	56,877
In Port	367399170	NACHIK	1,059	1,002	106,112
In Port	367176270	NORSEMANII	1	625	63
In Port	366197000	NUNANIQ	431	895	38,568
In Port	367309330	PACIFIC RAVEN	5	2,206	1,103
In Port	227161740	POLARIS 1	60	5,112	30,672
In Port	227161790	POLARIS 2	91	5,112	46,519
In Port	366889350	SAG RIVER	887	804	71,315
In Port	367399110	SESOK	1,192	1,002	119,438
In Port	366888910	SIKU	326	932	30,383

Sources: MEA, 2014; IHS, 2013

Example Calculation:

Total hours of operation for the vessel NACHIK in 2012 at Port Barrow was 963. The vessel power rating was 1,002 kW, and the load factor was 10 percent.

kW-hrs = 1,002 × 0.1 × 963
kW-hrs = 96,492.6

These activity data were applied to the GREET marine vessel emission factors listed below. The emission factors were based off the Category 2 Tier III factors from the GREET model (ANL, 2013). The base emission factors, which were used for CMVs not associated with the oil and gas industry directly, were the least stringent and based on a marine distillate fuel with a sulfur concentration of 5,000 ppm. Table II-6 lists the criteria and GHG emission factors applied to the CMV activity data. HAP emissions were estimated by applying the speciation profiles provided in Appendix A Table A-5 to the PM and VOC emission estimates.

Table II-6. CMV Criteria Pollutant Emission Factors (g/kW-hr)

Pollutant	Emission Factor (g/kW-hr)
NO_x	9.8
VOC	0.5
CO	1.1
SO_2	1.9843859
PM_{10}	0.31035065
PM_{25}	0.27035065
CO_2	646.08
CH_4	0.004
N_2O	0.031
NH_3	0.006
Pb	0.00005

Source: ANL, 2013

Marine vessel emissions were calculated using the following equation:

$$E = \text{kW-hrs} \times EF \times CF$$

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)
EF = Emission factor (g/kW-hr)
CF = Conversion factor (g = 1.10231×10^{-6} ton)

Example Calculation:

Total kW-hrs for NACHIK at Port Barrow for 2012 were 96,492.6 kW-hrs. The emission factor for NO_x is 9.8 g/kW-hr.

$$E = 1{,}424{,}683 \times 9.8 \times 0.00000110231$$
$$E = 1.04 \text{ tons}$$

CMV emissions were spatially allocated to the closest shipping lanes noted in Figure II-6, associated with the AIS location data.

Note that the accuracy of the emissions estimates for CMV is dependent upon the completeness of the AIS vessel activity data that ERG obtained from the Marine Exchange of Alaska.

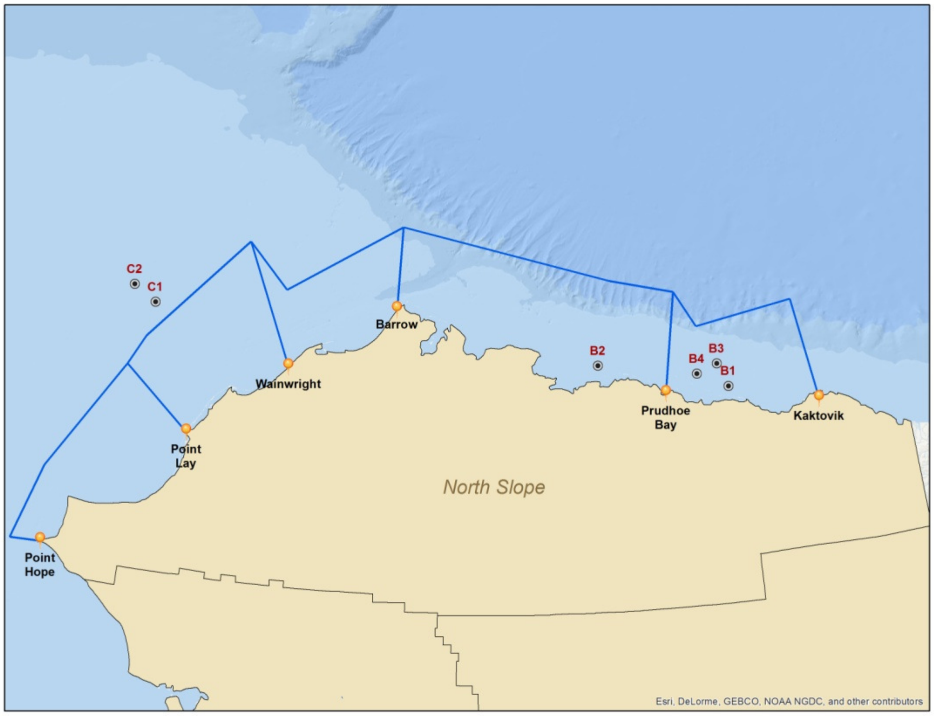

Figure II-6. U.S. Army Corps of Engineers Shipping Lanes and Development Sites (C1, C2, B1, B2, B3, and B4) off the North Slope
Data Source: USACE, 2014

2. *Research Vessels*

Several organizations, such as the Arctic Council, U.S. Geological Survey (USGS), and the National Oceanic and Atmospheric Administration (NOAA), operate research vessels off the North Slope coast to implement oceanographic research and monitor changes in fish and mammal populations. Research vessels that operate in the Arctic are very heavy vessels specifically designed for Arctic operations or refurbished fishing vessels capable of withstanding extreme conditions chartered from private companies. These vessels are equipped with Category 2 or 3 propulsion engines and Category 1 auxiliary engines.

Emissions were estimated by applying diesel marine emission factors and HAP speciation profiles to activity data for 2012.

The research vessel activity data were defined in terms of kW-hrs derived from the vessel power rating, hours of operation, and appropriate load factors (U.S. EPA, 2009c). Internet searches were conducted to identify research projects active in 2012. The United States Coast Guard (USCG) provided the most comprehensive list of projects that occurred in the Beaufort and Chukchi Seas in 2012 (USCG, 2012). The USCG data included vessel names, start and end dates, and location of each project (Table II-7).

Table II-7. Summary of 2012 Research Projects

Vessel	Start Date	End Date	Location
R/V Louis S St. Laurent	8/3/2012	9/8/2012	Beaufort Sea and Canada basin
R/V Mirai	9/16/2012	10/16/2012	Chukchi Sea sampling
R/V Sir Wilfrid Laurier	7/4/2012	7/22/2012	Victoria-Barrow
R/V Sir Wilfrid Laurier	9/25/2012	10/4/2012	Beaufort Sea
USCGC Healy	8/9/2012	8/11/2012	Transit north to Chukchi Sea
USCGC Healy	8/12/2012	8/24/2012	BOEM COMIDA Hanna Shoal
USCGC Healy	8/25/2012	8/25/2012	Offshore Barrow
USCGC Healy	8/26/2012	9/23/2012	Extended Continental Shelf (ECS)
USCGC Healy	10/5/2012	10/8/2012	Transit to North Slope Mooring Mission
USCGC Healy	10/9/2012	10/21/2012	North Slope Moorings

Source: USCG, 2012

The four vessels identified for the 2012 research projects in the Arctic were the *R/V Louis S St. Laurent*, *R/V Mirai, R/V Sir Wilfrid Laurier*, and *USCGC Healy*.

The *R/V Louis S St. Laurent* is a Canadian-flagged Arctic Class 4 heavy ice breaker (CCG, 2014a). This vessel has a cruising speed of 16 knots and a maximum speed of 20 knots. It is equipped with five Krupp Makk 16M453C engines, with a total power rating of 23,170 kW (IHS, 2013).

The *R/V Mirai* is a Japanese-flagged ship capable of long-term observational studies, ocean-based research, and geophysical surveys. It has a cruising speed of approximately 16 knots. The *R/V Mirai* is equipped with five diesel engines, with a power rating of 1,839 kW per engine (IHS, 2013), providing a total power of 7,356 kW.

The *CCGS Sir Wilfrid Laurier* is a Canadian-flagged, Arctic Class 2 high-endurance multitasked vessel (CCG, 2014b). It has a cruising speed of 11 knots and a maximum speed of 15.5 knots. The *CCGS Sir Wilfrid Laurier* is equipped with three Alco 251F engines, with a total power rating of 7,833 kW (IHS, 2013).

The *USCGC Healy* is an ice breaker specializing in research support in polar regions (USCG, 2013; USCG, 2014). It has a cruising speed of 12.5 knots and a maximum speed of 17 knots. The *USCGC Healy* is equipped with four Sultzer 12Z AU40S engines, with a power rating of 7,812 kW per engine, providing a total power of 31,248 kW (IHS, 2013).

To estimate emissions, it was assumed that each research vessel operated 24 hours per day during the duration of each project. Assuming most of each vessel's time was spent maneuvering at sea, a load factor of 60 percent was used. Research vessel activity was calculated as follows:

$$\text{kW-hrs} = \text{kW} \times \text{LF} \times \text{hrs}$$

where:

kW = Vessel power rating (kilowatts)
LF = Load factor (%)
hrs = Adjusted number of operating hours for each vessel

Example Calculation:

Total hours of operation for the *USCGC Healy* in 2012 were 1,512. The vessel power rating is 31,248 kW and the load factor is 60 percent.

kW-hrs = 31,248 × 0.60 × 1,512
kW-hrs = 28,348,186

Table II-7 summarizes the research vessel activity data.

Table II-8. 2012 Research Vessel Activity Data

Vessel Name	kW-hours
R/V Louis S St. Laurent	12,011,328
R/V Mirai	3,177,792
R/V Sir Wilfrid Laurier	3,045,470
USCGC Healy	28,348,186
Total	**46,582,776**

Source: USCG, 2012

These activity data were applied to the GREET vessel emission factors (see Table II-2, above) and HAP speciation profiles listed in Appendix A, Table A-5. The emissions factors used for Arctic research assumed that these vessels use ultra-low sulfur fuels (ULSD, 15 ppm), similar to that used by offshore oil and gas vessels.

Marine vessel emissions were calculated using the following equation:

E = kW-hrs × EF × CF

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)
EF = Emission factor (g/kW-hrs)
CF = Conversion factor (g = 1.10231×10^{-6} ton)

Example Calculation:

Total kW-hrs for *USCGC Healy* in 2012 were 28,348,186 kW-hrs. The emission factor for NO_x is 9.8 g/kW-hr.

E = 28,348,186 × 9.8 × 0.00000110231
E = 306 tons

Because research vessels do not necessarily operate along existing shipping lanes, their emissions were spatially allocated to zones that extend 300 miles from the coast of the North Slope.

III. DEVELOPMENT OF ONSHORE EMISSIONS INVENTORY

This section describes the methods and data used to estimate baseline emissions from all onshore sources and activities located within the North Slope oil and gas fields, as well as those located in the eight villages and elsewhere on the North Slope (e.g., airports, TAPS, non-oil and gas related stationary and mobile sources). The specific pollutants that were estimated for each source are listed in Table I-1.

A. Oil/Gas Related Sources

This section describes the methods and data used to estimate emissions for sources located in the onshore oil and gas fields on the North Slope. Emission sources include devices and activities associated with both oil and gas exploration and production.

1. *Seismic Survey Equipment*

Prior to conducting exploratory drilling, oil and gas companies will typically conduct geological and geophysical (G&G) explorations. These companies will use seismic survey equipment if these exploratory activities occur on sea ice or on land.

Since 1998, BOEM has issued 12 on-ice G&G permits; however, of these 12 permits, 8 were cancelled before the G&G work was performed. According to the BOEM on-ice G&G permits, no on-ice G&G work was conducted in 2012.

Information regarding land-based G&G permits could not be obtained from the Alaska Department of Oil & Gas, so it is not clear whether any land-based G&G work was conducted in 2012. Given this uncertainty, ERG assumed that one G&G project occurred in 2012 that was similar in scope and size to the most recent active G&G permit, which included both ice- and land-based activities (BOEM, 2014a). The permit assumed operation of 12 vibroseis vehicles (i.e., “thumper trucks”), in addition to various other support equipment (e.g., long-haul fuel tractors, remote fuelers, water makers, incinerators, resupply and survival sleighs, tractors, loaders). A total of 477,000 gallons of ultra-low sulfur diesel (ULSD) fuel (4,500 gallons for 106 days) was assumed to be used. As in the BOEM G&G permit, emissions were estimated by combining the ULSD quantity of 477,000 gallons with EPA WebFIRE emission factors (U.S. EPA, 2013a).

2. *Exploratory Drilling*

Emissions from onshore oil and gas exploratory drilling are generated when fuel used in the drilling rig engines, heaters, and boilers used on the drill rig is combusted and from fluid flowback during well completion. Emissions for each of these processes were estimated separately as described below.

a. Drilling Rig Combustion Emissions

Emissions from fuel combustion from onshore oil and gas exploratory drilling rigs are generated as diesel fuel is burned in drilling rig engines, heaters, and boilers. ADEC covers drilling rigs in their permitting programs, and air emissions data for the North Slope drilling rig fleet are available through air permit applications and permits. There are two primary permits that cover the North Slope drilling fleet: ConocoPhillips' Kuparuk Transportable Drilling Rigs permit (ADEC Permit # AQ0909TVP01) and BPXA's Transportable Drilling Rigs permit (ADEC Permit # AQ0455TVP01). These permits list specific rigs and drilling companies permitted to operate on the North Slope, and in many cases, the same rigs are listed in both permits.

In addition to data available in air permits and permit applications, GHG emissions from drilling rigs are reported under subpart W of EPA's Greenhouse Gas Reporting Program (GHGRP).

Four GHGRP facilities (as defined under 40 CFR Part 98, subpart W) produce nearly 99 percent of crude oil from the North Slope: Badami Development Facility; BP Alaska, 890 – Arctic Slope Basin; ConocoPhillips Alaska, Inc. – KRU-ALP Fields; and Nikaitchuq Development (see Appendix A, Table A-9)[2]. Therefore, the GHG emissions from drilling rig engines, heaters, and boilers from these four facilities are considered complete estimates of emissions of GHG pollutants. To estimate emissions of CAP and HAP, ConocoPhillips' Title V renewal application for the Kuparuk Transportable Drilling Rigs permit was reviewed. This permit application contains potential emissions estimates for CO_2, CH_4, N_2O, CAP, and HAP, allowing for a direct comparison to the reported GHGRP actual emissions data for the three GHG pollutants. This comparison showed that reported emissions of all three GHG pollutants for the entire North Slope were approximately one-half (in the case of CO_2, 51.18 percent) of the potential emissions listed in the Kuparuk application. Therefore, total actual emissions across the North Slope for the other pollutants listed in the application (combustion generated CAP and 16 individual HAP) were estimated to be 51.18 percent of the potential emissions of the Kuparuk permit application.

Drilling rig emissions were estimated as follows:

Emission of NO_x from drilling are calculated based on the potential NO_x emissions listed in the Kuparuk application multiplied by the ratio of actual to potential emissions of CO_2 as found in the GHGRP subpart W data and the Kuparuk permit application data as follows:

$$NO_x\text{-actual} = NO_x\text{-potential} \times 0.5118$$

where:

NO_x-actual = estimated NO_x emissions (tons/yr)
NO_x-potential = potential NO_x emissions from the Kuparuk application = 2,711 (tons/yr)
0.5118 = the ratio of actual emissions of CO_2 reported under subpart W for the North Slope to the potential emissions of CO_2 from the Kuparuk permit application

Example Calculation:

$$NO_x\text{-actual} = 2{,}711 \text{ (ton/yr)} \times 0.5118 = 1{,}388 \text{ (ton/yr)}$$

[2] Source: Alaska Oil and Gas Conservation Commission: http://doa.alaska.gov/ogc/production/ProdArchives/parchiveindex.html.

b. Well Completions

ERG developed well completion emission estimates using information contained in the Kuparuk Transportable Drilling Rigs permit application. This permit application contains emission estimates for 30 well completions for VOC, CO_2, CH_4, and six HAP (2,2,4-trimethlypentane, benzene, ethylbenzene, n-hexane, toluene, and xylene). The estimates are based on the total amount of oil assumed to flowback during one well completion, the gas-to-oil ratio (GOR) of the oil, the flowback lift gas volume, and typical flash gas composition data.

Available data indicate that in 2011, 86 wells were completed on the North Slope (U.S. EPA, 2013c). Therefore, total emissions of VOC, CO_2, CH_4, and HAP from North Slope well completions were estimated by multiplying the estimates contained in the Kuparuk permit application by the ratio of total North Slope well completions to the Kuparuk well completions (86/30 = 2.87). H_2S estimates are based on an assumed H_2S concentration of 30 parts per million by volume (ppmv) in the flash gas, based on a recently proposed permit for the North Slope liquefied natural gas facility (ADEC Permit #AQ1379MSS01).

Example Calculation:

Emissions of benzene from well completions are based on the potential benzene emissions listed in the Kuparuk application multiplied by the ratio of the total number of North Slope well completions (86) to the number of well completions assessed in the Kuparuk permit (30):

benzene-actual = benzene-potential × (86/30)

where:

benzene-actual = estimated benzene emissions (tons/yr)
benzene-potential = potential benzene emissions from the Kuparuk application = 1.3 (tons/yr)
(86/30) = the ratio of the total number of North Slope well completions to the number of well completions assessed in the Kuparuk permit

Therefore:

benzene-actual = 1.3 (ton/yr) × (86/30)
benzene-actual = 3.73 (ton/yr)

Table A-10 (in Appendix A) provides the emissions estimated for well completions using this methodology.

The accuracy of the drilling rig emissions are affected by the fact that, historically, the large drilling rig engines have been treated as nonroad engines and have not been subject to annual (or triennial) emission reporting requirements. Therefore, drilling rig emissions are not included in the U.S. NEI. However, as described above, GHG emissions from drilling are well characterized under GHGRP subpart W and formed the basis of the CAP and HAP estimates as described above in Section III.A.2.a. ADEC is in the process of renewing the Title V transportable drilling rig permits for BP and ConocoPhillips. It is expected that the Title V renewal permits will be issued in the near future and these may require emissions submittals in March 2015. These data may be useful for updating future versions of this emissions inventory.

3. *Oil and Gas Production*

Onshore oil and gas production on the North Slope occurs along a 100-mile-by-40-mile span of coastline near Prudhoe Bay. In 2012, this area produced nearly 200,000,000 barrels of crude oil. Natural gas produced from North Slope wells is primarily reinjected back into the reservoir to maintain pressure to facilitate oil production, with some used to fuel various oil and gas exploration and production equipment such as compressor engines. Additionally, there are two small topping plants (refineries) that refine a portion of the crude oil to produce Jet-A, diesel fuels, and Arctic heating fuel (AHF) for use in the North Slope oil fields.

There are approximately 120 well pads located on the North Slope, which are serviced by 14 onshore and three offshore production facilities (located on man-made islands). These production facilities and their 2012 crude oil production are shown in Table III-1.

Table III-1. North Slope Production Facilities

Owner	Facility Name	ADEC Permit Number	2012 Crude Oil Production (BBL)[a]
ConocoPhillips	Alpine Central Processing Facility	AQ0489TVP01	25,852,795
Savant Alaska LLC	Badami Development Facility	AQ0417TVP02	477,560
BPXA	Endicott Production Facility	AQ0181TVP02	3,156,400
BPXA	Flow Station #1 (FS 1)	AQ0167TVP02	93,482,423
BPXA	Flow Station #2 (FS 2)	AQ0268TVP01	
BPXA	Flow Station #3 (FS 3)	AQ0269TVP01	
BPXA	Gathering Center #1 (GC 1)	AQ0182TVP01	
BPXA	Gathering Center #2 (GC 2)	AQ0183TVP01	
BPXA	Gathering Center #3 (GC 3)	AQ0184TVP01	
ConocoPhillips	Kuparuk Central Production Facility #1 (CPF1)	AQ0267TVP01	41,263,040
ConocoPhillips	Kuparuk Central Production Facility #2 (CPF2)	AQ0273TVP01	
ConocoPhillips	Kuparuk Central Production Facility #3 (CPF3)	AQ0171TVP01	
BPXA	Lisburne Production Center	AQ0272TVP02	9,163,358
BPXA	Milne Point Production Facility	AQ0200TVP02	6,401,648
Eni	Nikaitchuq Development	AQ0923TVP01	3,041,408
BPXA	Northstar Production Facility	AQ0503TVP01	3,030,452
Caelus Energy LLC	Oooguruk Development Project	AQ0911TVP01	2,508,258

[a] Source: Alaska Oil and Gas Conservation Commission: http://doa.alaska.gov/ogc/production/ProdArchives/parchiveindex.html. (Accessed August 26, 2014.)

Figure III-1 shows the location of the 17 North Slope production facilities and the approximate production area covered by each facility.

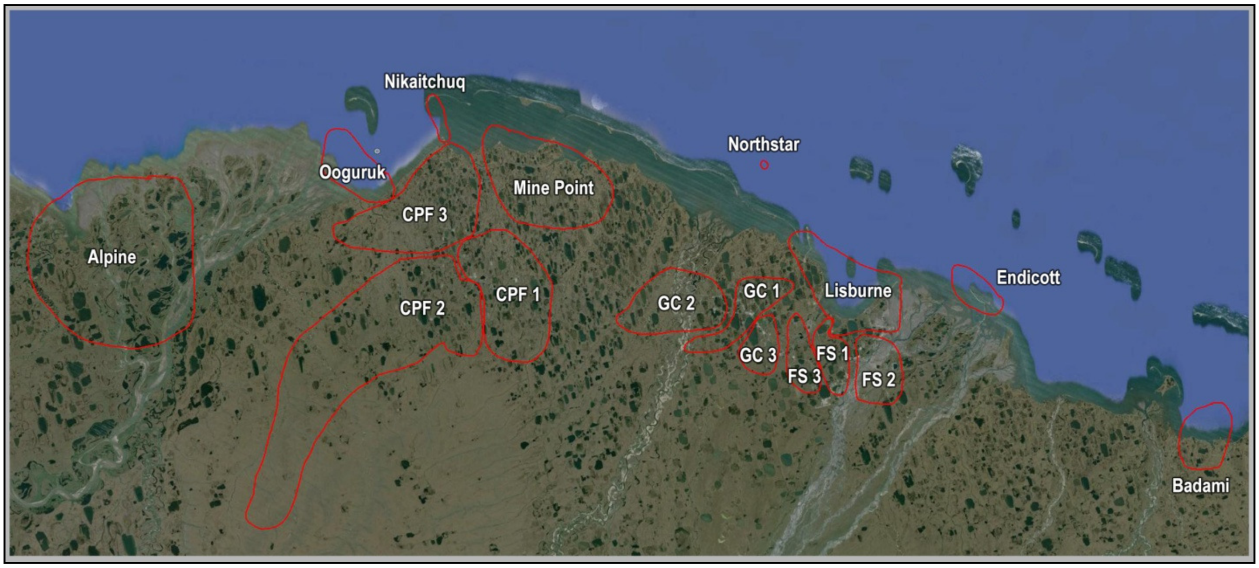

Figure III-1. North Slope Production Facilities
Online image from Google Maps. https://www.google.com/maps/ (Accessed September 22, 2014.)

Each production facility receives three-phase (oil, gas, and water) production fluids from the surrounding well pads, separates the fluid into crude oil, gas, and water, and delivers the crude oil downstream to the TAPS Pump Station #1. As described above, a portion of the gas and oil is used to fuel equipment operated in the North Slope oil fields. As with the majority of the gas produced from these wells, the separated water is also reinjected into the reservoir. Figure III-2 shows ConocoPhillips' CPF2 facility and seven of the well pads it services.

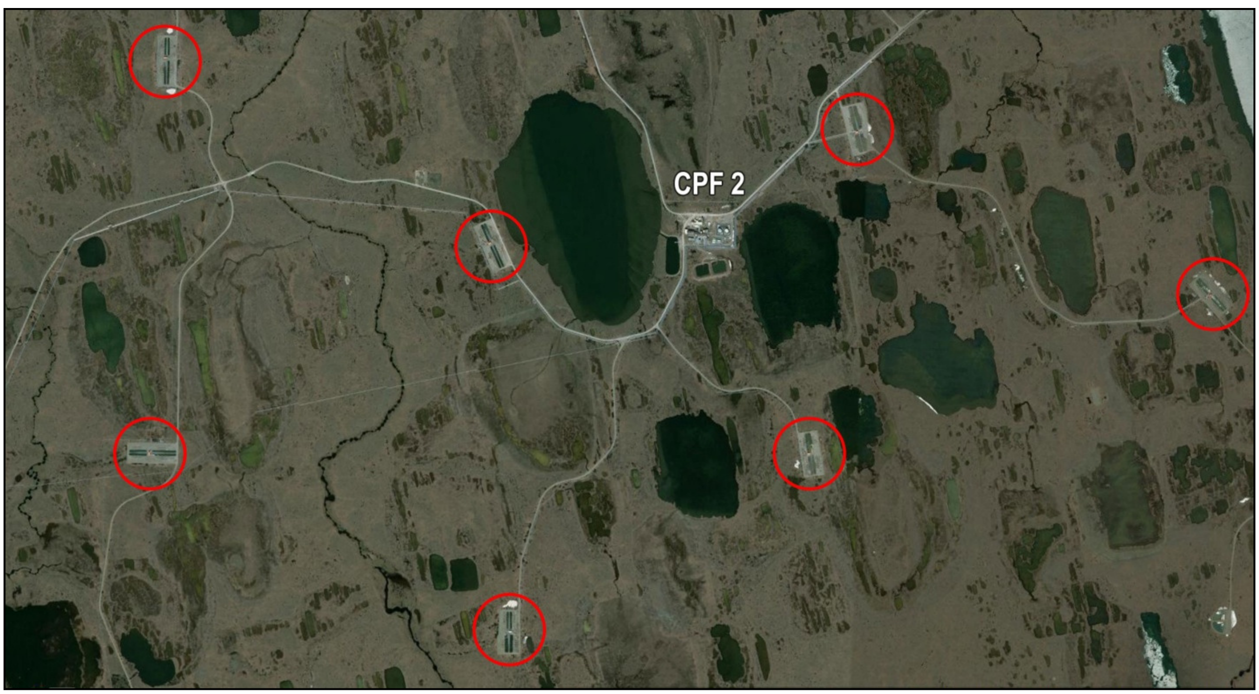

Figure III-2. Conoco's CPF2 and Associated Well Pads
Online image from Google Maps. https://www.google.com/maps/ (Accessed September 22, 2014.)

Under the "wagon wheel" permitting model used by the ADEC to permit North Slope oil and gas sources, a "facility" for permitting purposes is broadly defined as a single production plant (hub) and the surrounding well pads (spokes) that deliver raw materials which consist of wellhead fluids consisting of crude oil, water, and gas to the production plant for processing. This approach results in nearly complete permitting coverage of all emission sources between, and including, the well pads and the production facilities. In the case of ConocoPhillips' CPF2, there are 16 well pads covered under the Title V permit. As described below, this permitting model proved especially useful in developing the onshore oil and gas emissions inventory. Figure III-3 shows BPXA's Gathering Center #2 (GC2) production facility.

Figure III-3. BP Gathering Center #2

Image from ConocoPhillips. *Arctic Energy for Today and Tomorrow.* April, 2006.
http://alaska.conocophillips.com/Documents/ArcticEnergy.pdf

Figure III-4 shows a typical North Slope well pad, in this case consisting of 16 individual wells, half of which may be production wells and the remainder either gas or water reinjection wells. Each wellhead is enclosed within a small shelter for protection from the elements. Production fluids from each well are commingled in the manifold building (orange rectangular building) before being sent via feeder pipelines to the production facility. There is no processing or separation activity on the well pad, with the exception of heaters, which are used on some well pads to heat the three-phase fluid to facilitate flow downstream to the production facility.

In addition to the main production facilities and surrounding well pads, there are numerous other oil and gas production support facilities and operations located on the North Slope. A brief description of the primary production support facilities is provided below.

Base Operations Center (BOC) – The BP Exploration Alaska (BPXA) BOC is a complex of aboveground structures that contains living quarters, offices, shops, recreation areas, and other types of support facilities for the personnel who work at BPXA's many facilities on the North Slope. Power is supplied to the BOC from the Central Power Station (CPS), and three standby generators provide electrical power should primary electrical service be lost. Liquid fuel for the generators and two emergency fire pump engines is provided by the Crude Oil Topping Unit (COTU), described below.

Figure III-4. Typical North Slope Well Pad
Online image from Google Maps. https://www.google.com/maps/ (Accessed September 22, 2014)

Central Compressor Plant (CCP) – The BPXA CCP (see Figure III-5) receives part of the raw gas separated from crude oil in the production hubs. This raw gas flows through the two CCP inlet separators and then to the Central Gas Facility (CGF), where it is processed. The CCP then receives processed low-molecular-weight gas from the CGF, pressurizes it, and distributes it to nearby injection wells for ultimate disposal/storage underground.

Figure III-5. BP Central Compression Plant
Image from ConocoPhillips: *Alaska Fact Sheet - November 2013*. http://www.conocophillips.com/investor-relations/fact-sheet-financial-data/Documents/PDF/SMID_392_FactSheet-Alaska.pdf

Central Gas Facility (CGF) – The BPXA CGF receives low-pressure high-molecular-weight gas from the production hubs, removes miscible injectant/natural gas liquids, pressurizes the low-molecular-weight gas, and delivers it to the Central Compressor Plant for redistribution to production support facilities and nearby injection wells.

Central Power Station (CPS) – The CPS is jointly owned by BPXA, ConocoPhillips Alaska, Inc., Chevron USA Inc., and ExxonMobil Corporation, and is operated by BPXA. The CPS produces all of the electric power for the Prudhoe Bay crude-oil-producing facilities. The source consists of seven fuel gas-fired turbine generators, four insignificant diesel-fired black start engines, two diesel-fired emergency generators, and five heaters used to heat fuel gas prior to combustion in the turbines. The CPS receives its fuel gas supply from the CGF.

Crude Oil Topping Unit (COTU) – The BPXA COTU is a small petroleum refinery that produces Jet-A, diesel fuels, and AHF for the North Slope equipment and drilling operations. Diesel fuels, AHF and Jet-A are the only products the COTU produces for distribution. All of the fuel produced by the COTU is used by equipment onsite at the Prudhoe Bay oil field. The COTU currently receives crude oil for processing from the Flow Station #2 oil transit line.

Grind and Inject Facility (BPXA) – The BPXA Grind and Inject Facility processes reserve pit materials and other production wastes for injection and disposal in a cretaceous well. A conveyor feed system moves frozen drilling waste to a grinding system that thaws, grinds, and then slurries the waste material. The waste material is then pumped to a disposal well and injected down-hole. Electricity for conveying and grinding operations is provided by the CPS.

Kuparuk Seawater Treatment Plant (STP) – The ConocoPhillips Kuparuk STP produces water for water flooding of the oil reservoirs throughout the Kuparuk oil fields. Sea water is pumped from the Beaufort Sea, filtered, heated, degassed, and then pumped to the production pads for injection to increase reservoir pressure and stimulate oil production.

Kuparuk Unit Topping Plant – The ConocoPhillips Kuparuk Unit Topping Plant is designed to process pipeline-quality crude oil feedstock from Central Processing Facility #1 (CPF1) into liquid fuels for use in equipment in the drilling and production operations. This feedstock is sent through a distillation process to extract AHF, which is further processed to control the flashpoint of the fuel before being transferred to a storage facility where users can take delivery. The plant processes approximately 14,500 barrels per day of crude oil feedstock, which yields 1,700 to 2,400 barrels per day of AHF, depending on specific end-product requirements.

Nanuq Inc. Arctic Wolf Camp – The Nanuq Arctic Wolf Camp provides living quarters for the personnel who work on construction of the ExxonMobil Point Thompson production site. (Future missions from the Point Thompson production site construction and operation are addressed in Section IV of this report.)

Northstar Caribou Crossing Compressor Facility – The BPXA Northstar Caribou Crossing Compressor Facility is used to compress gas from both the Western Operating Area and Eastern Operating Area, collectively known as the Prudhoe Bay Unit (PBU), and to provide high-pressure gas to the offshore Northstar Production Facility.

Prudhoe Bay Operations Center / Main Construction Camp (PBOC/MCC) – The PBOC/MCC is jointly owned by BPXA, ConocoPhillips Alaska, Inc., Chevron USA Inc., and ExxonMobil Corporation, and is operated by BPXA. PBOC provides billeting, dining, laundry, and recreational facilities for up to 450 camp residents. The PBOC complex also includes administrative offices, the communication center, water and wastewater treatment plants, an emergency power generation facility, the fire station, a vehicle repair shop, vehicle garages, and the camp maintenance shop. MCC provides billeting, dining, laundry, and recreational facilities for up to 675 camp residents. The complex also includes an infirmary, administrative offices for engineering and engineering support services, a radio shop, the Halon shop, the tool room, and the electrical power plant.

Seawater Injection Plant East (SIPE) – The BPXA Seawater Injection Plant East (SIPE) receives low-pressure treated seawater from the Prudhoe Bay STP, heats and increases the pressure of the seawater, and then distributes the water to the various drill sites for injection into the various reservoirs.

Prudhoe Bay STP – The Prudhoe Bay STP is jointly owned by BPXA, ConocoPhillips Alaska, Inc., Chevron USA Inc., and ExxonMobil Corporation, and is operated by BPXA. The STP produces water for water flooding of the oil reservoirs at Prudhoe Bay oil fields. Seawater is pumped from the Beaufort Sea, strained and filtered, chlorinated, de-aerated to remove oxygen, and then pumped to the SIPE. The fuel gas used in all gas-fired equipment at the Prudhoe Bay STP is supplied by the CGF.

a. Onshore Oil and Gas Production Emissions Inventory Development

2011 Point Source National Emissions Inventory (NEI)

The starting point for onshore oil and gas production emissions estimates was the point source emissions data submitted by ADEC to the EPA for the triennial 2011 U.S. NEI (U.S. EPA, 2013b). The 2011 NEI includes the most complete data currently available for point source emissions from facilities operating on the North Slope, and includes estimates for 26 oil and gas facilities and 43 CAP and HAP. ADEC receives annual emissions inventory submittals directly from the operators of Title V facilities as required under their permits.

Although ADEC has received 2012 emissions data from the operators of these point sources, the reporting threshold for 2012 (and 2013) is much higher than for the 2011 reporting year, making the 2012 ADEC inventory less complete. To illustrate, for 2012, the threshold for reporting of NO_x was 2,500 tons/yr, whereas the reporting threshold for 2011 was 100 tons/yr. Therefore, the 2011 NEI data are the most complete starting point for the Arctic AQ Modeling Study emissions inventory of onshore oil and gas exploration and production sources.

ERG considered how representative the NEI 2011 data were compared to data from operations in 2012. Given that North Slope crude oil production declined by approximately 7 percent between 2011 and 2012 (EIA, 2013), using 2011 data would provide a conservatively high estimate of emissions for 2012. In addition, a review of ADEC permit data identified all sources currently in operation, and identified nine facilities that are not included in the 2011 NEI data. Emission estimates for these nine facilities were derived as described in more detail below.

Table III-2 identifies the North Slope onshore oil and gas facilities reported as point sources in the 2011 NEI (U.S. EPA, 2013b); the CAP emission estimates for these facilities are located in Appendix A (Table A-11).

Table III-2. Oil and Gas Point Source Facilities in the 2011 NEI

Facility Name	Facility Name
Alpine Central Processing Facility	Kuparuk Central Production Facility #1 (CPF1)
Badami Development Facility (formerly BPXA)	Kuparuk Central Production Facility #2 (CPF2)
Base Operations Center	Kuparuk Central Production Facility #3 (CPF3)
Central Compressor Plant	Kuparuk Seawater Treatment Plant
Central Gas Facility	Lisburne Production Center
Crude Oil Topping Unit	Milne Point Production Facility
Endicott Production Facility	Nikaitchuq Development
Flow Station #1 (FS 1)	Northstar Production Facility
Flow Station #2 (FS 2)	Ooguruk Development Project
Flow Station #3 (FS 3)	PBU Central Power Station
Gathering Center #1 (GC 1)	Prudhoe Bay Operations Center / Main Construction Camp
Gathering Center #2 (GC 2)	Seawater Injection Plant East
Gathering Center #3 (GC 3)	Seawater Treatment Plant, Prudhoe Bay Unit (STP)

Source: U.S. EPA, 2013b

ADEC Permits and Permit Applications

Although the 2011 NEI data are the most complete point source emissions data available, the 2011 NEI does not include all facilities or smaller emission units located at covered facilities. For example, the NEI does not include data for non-Title V facilities. The NEI includes emissions data for Title V facilities, but only for the larger emission units such as the large combustion turbines found at the production facilities and not for "insignificant emissions units" (which would include smaller heaters, small emergency engines, and small VOC sources such as storage tanks) or "nonroad engines" such as portable generator or light tower engines.

To address these two categories of missing units, ERG conducted an analysis using the 2011 reported NEI data and the list of emission units found in the ADEC air quality permits and permit applications for a selected subset of the North Slope sources (ADEC, 2013a). ERG obtained permit documents (i.e., permits and background/supporting documents) for all 35 sources identified (i.e., the 26 NEI facilities, and nine non-NEI facilities) and permit applications from ADEC for 16 of the permitted Title V facilities. A detailed, pollutant-specific analysis of the permits and permit application documents was conducted to determine the percentage of total facility assessable emissions subject to reporting to the NEI. Emissions of VOC, NO_x, CO, SO_2, and PM_{10} were evaluated independently. (Estimation of other pollutant emissions, including $PM_{2.5}$, is discussed below.)

In an ADEC permit, assessable emissions are calculated based on the source equipment's potential to emit (PTE), operating 8,760 hours per year, or as limited by the permit.[3] Facility permits typically provide only total facility assessable emissions, while permit applications provide disaggregated potential emission estimates for significant emission units, insignificant emission units, and nonroad engines. This information is needed to determine permit level and to assess permitting fees. In this analysis, total facility assessable emissions are assumed to be the sum of potential emissions from significant emission units, insignificant units, and nonroad engines. Actual emissions are based on actual operating time of the equipment and are typically less than the total assessable emissions of a source. However, as described above, actual emissions from insignificant emission units and nonroad engines are not reported to the NEI.

ERG estimated emissions for equipment at facilities that did not report to the NEI (non-NEI facilities) and for insignificant units and nonroad engines located at facilities that reported to the NEI by analyzing emissions and equipment data for the significant emission units located at those facilities. This analysis compared actual emissions from significant emission units with assessable emissions for significant emission units, and was used to develop estimates for insignificant emission units and nonroad engines using detailed information in permits and permit applications.

This analysis showed that on average, of total facility assessable emissions, significant emission units account for between 70 and 86 percent, insignificant emission units account for between 1 and 6 percent, and nonroad engines account for between 8 and 28 percent. However, there are a few sources on the North Slope with numerous nonroad engines, and for these sources, the potential emissions from nonroad engines can account for well over half of the total potential emissions at any single facility, particularly for VOC. For example, at the three Kuparuk production facilities, there are over 250 nonroad engines that account for approximately 60 percent of the total facility potential VOC emissions. Table III-3 summarizes the results of this analysis.

Table III-3. Significant, Insignificant, and Nonroad Engine Emissions Analysis

Assessable Emissions Component	Average Percentage of Total Assessable Emissions				
	VOC	NO_x	CO	SO_2	PM_{10}
Significant Units	70	76	86	86	76
Insignificant Units	2	1	0.5	6	1
Nonroad Engines	28	23	14	8	23

Source: ERG

To develop actual emission estimates for the insignificant emission units and nonroad engines, the ratio of actual-to-potential emissions for the insignificant emission units and nonroad engines was assumed to be identical to the same ratio for the significant emission units at the facility. The ratio of actual-to-potential emissions for the significant emission units at the facility was developed by comparing the 2011 NEI reported emissions (actual emissions) to the potential emissions as reported in the permits or permit applications. This analysis showed that, for

[3] In this context, the terms "assessable emissions" and "potential emissions" are identical. The term "assessable emissions" comes from ADEC permit applications, and the term "potential emissions" comes from the CAA.

significant emission units subject to NEI reporting, the average actual emissions were 38, 55, 41, 19, and 52 percent of potential VOC, NO_x, CO, SO_2, and PM_{10} emissions, respectively.

ERG conducted this analysis at the facility level for the 16 facilities for which detailed permit application data were available. Actual emission estimates for insignificant units and nonroad engines were calculated by multiplying the estimates for potential emissions from insignificant emission units and nonroad engines, as recorded in the permit applications, by the ratio of actual-to-potential emissions for the reported significant units. For the remainder of the facilities, the percentages in Table III-3 were used to develop actual CAP emission estimates for insignificant units and nonroad engines.

ERG developed actual emission estimates of HAP and $PM_{2.5}$ from insignificant emission units and nonroad engines using HAP and $PM_{2.5}$ data from significant emission units, as reported in the NEI. VOC and PM_{10} (estimated as described above) were used as surrogates to scale emissions of volatile organic and metal HAP/$PM_{2.5}$, respectively. Scaling factors for VOC and PM_{10} were derived by comparing assessable emissions to reported actual emissions in the NEI. These scaling factors were then applied to estimates of VOC and PM_{10} emissions from insignificant emission units and nonroad engines to develop estimates for HAP emissions from these same sources. Table III-4 identifies the pollutant (VOC or PM_{10}) used to scale emissions for each HAP or particulate species.

Table III-4. HAP and Particulate Surrogate Assignments

Pollutant	Surrogate Pollutant	Pollutant	Surrogate Pollutant
Arsenic	PM_{10}	2-Methylnaphthalene	
Beryllium	PM_{10}	Acenaphthene	
Cadmium	PM_{10}	Acenaphthylene	
Chromium (VI)	PM_{10}	Acetaldehyde	
Chromium III	PM_{10}	Acrolein	VOC
Cobalt	PM_{10}	Anthracene	VOC
Lead	PM_{10}	Benz[a]Anthracene	VOC
Manganese	PM_{10}	Benzene	VOC
Mercury	PM_{10}	Benzo[b]Fluoranthene	VOC
Nickel	PM_{10}	Chrysene	VOC
PM Condensable	PM_{10}	Ethyl Benzene	VOC
PM_{10} Filterable	PM_{10}	Fluoranthene	VOC
$PM_{2.5}$ Filterable	PM_{10}	Fluorene	VOC
$PM_{2.5}$ Primary (Filterable + Condensable)	PM_{10}	Formaldehyde	VOC
Selenium	PM_{10}	Hexane	VOC
2-Methylnaphthalene	VOC	Naphthalene	VOC
Acenaphthene	VOC	PAH, total	VOC
Acenaphthylene	VOC	Phenanthrene	VOC
Acetaldehyde	VOC	Phenol	VOC
Acrolein	VOC	Pyrene	VOC
Anthracene	VOC	Toluene	VOC
Benz[a]Anthracene	VOC	Xylenes (Mixed Isomers)	VOC

Source: ERG

As discussed above, nine permitted facilities were identified that were not covered in the 2011 NEI. For these facilities, emissions estimates are based on assessable emissions estimates available in permit documentation using the methodology described above for the NEI-covered facilities. For example, assessable nonroad engine VOC emissions were assumed to equal 28 percent of total facility assessable VOC emissions, and 38 percent of those assessable nonroad engine VOC emissions were assumed to actually be emitted. Table III-5 shows these nine facilities.

In Appendix A, Table A-12 shows the calculated actual emission estimates for VOC, NO_x, CO, SO_2, and PM_{10} for each facility, while Table A-13 provides the insignificant unit and nonroad engine CAP emission estimates for the 26 facilities included in the NEI point source inventory.

Table III-5. Non-NEI Onshore Production Facilities

Facility Name
Badami RTU 3 Flare Project
BPXA Greater Prudhoe Bay Skid 50 Pad Transfer Station – Generator
BPXA Milne Point S Pad (CHOPS)
ConocoPhilips Drill Site #S Palm Development Project
ConocoPhilips Meltwater Development Project
ConocoPhilips Tarn Development Project
Grind and Inject Facility (BPXA)
Nanuq Inc Arctic Wolf Camp
Northstar Caribou Crossing Compressor Facility

Source: ADEC, 2013

<u>EPA's GHGRP</u>

Under the GHGRP, oil and natural gas exploration and production sources may be subject to reporting GHGs under subpart C (General Stationary Fuel Combustion Sources) and subpart W (Petroleum and Natural Gas Systems). Data reported under these subparts were used to supplement the 2011 NEI and ADEC permit data, not only for GHG emission estimates, but also to estimate CAP and HAP emissions for additional sources not included in the NEI (U.S. EPA, 2013c). The data obtained for these types of facilities from the reporting year (RY) 2012 GHGRP include:

- Subpart W Facility ID
- Facility Name
- Reporting Segment
- Source Type
- 2012 GHG Emissions for CO_2 and CH_4 (tons/yr)

Because subpart W is oriented toward reporting CH_4 emissions, some of the larger VOC sources (e.g., compressor seals and fugitive equipment leaks) are more fully covered under the GHGRP than in the NEI or ADEC permit data. The NEI and ADEC permit review described above provided no emissions data for compressor seals or fugitive equipment leaks. In addition, the

NEI does not contain any emissions estimates for CH_4 or CO_2. Table III-6 identifies the North Slope oil and gas facilities that reported emissions under subparts W and C, and the reporting segments under which they reported.

Table III-6. GHGRP Data for Onshore North Slope Oil and Gas Facilities

Subpart W Facility ID	Facility Name	Reporting Segment(s)
522282	Badami Development Facility	Subpart W (Onshore Production)
538439	BP Alaska, 890 - Arctic Slope Basin	Subpart W (Onshore Production)
522334	BPXA Central Compressor Plant	Subpart W (Onshore Natural Gas Processing); Subpart C
522335	BPXA Central Gas Facility	Subpart W (Onshore Natural Gas Processing); Subpart C
522336	BPXA Crude Oil Topping Unit, Prudhoe Bay Operations Center, Tarmac Camp	Subpart C
522284	BPXA Endicott Production Facility	Subpart W (Onshore Natural Gas Processing); Subpart C
522428	BPXA Flow Station #1	Subpart C
522429	BPXA Flow Station #2	Subpart C
522430	BPXA Flow Station #3	Subpart C
522431	BPXA Gathering Center #1	Subpart C
522432	BPXA Gathering Center #2	Subpart C
522433	BPXA Gathering Center #3	Subpart C
522223	BPXA Lisburne Production Center	Subpart W (Onshore Natural Gas Processing); Subpart C
524099	BPXA Northstar Production Facility	Subpart W (Onshore Natural Gas Processing); Subpart C
522434	BPXA Seawater Injection Plant	Subpart C
522435	BPXA Seawater Treatment Plant	Subpart C
527088	ConocoPhillips Alaska Inc - KRU CPF1	Subpart C
527093	ConocoPhillips Alaska Inc - KRU CPF2	Subpart C
527111	ConocoPhillips Alaska Inc - KRU CPF3	Subpart C
527114	ConocoPhillips Alaska Inc - KRU STP	Subpart C
537317	ConocoPhillips Alaska Inc - KRU-ALP Fields	Subpart W (Onshore Production)
538493	Nikaitchuq Development	Subpart W (Onshore Production)
522787	Pioneer Natural Resources Alaska - Oooguruk Tie-in Pad	Subpart C

Source: U.S. EPA, 2014a

Subpart W - Onshore Production

Under the onshore production segment of subpart W, a facility is broadly defined as all operations under common ownership or control that are located in a single hydrocarbon basin. The entire North Slope is considered to be in the Arctic Coastal Plains Province, and with BPXA and ConocoPhillips operating the vast majority of well pads and production facilities, it is estimated that 98.67 percent of North Slope production is covered by the four onshore production facilities (i.e., Badami Development Facility; BP Alaska, 890 - Arctic Slope Basin; ConocoPhillips Alaska Inc - KRU-ALP Fields; and Nikaitchuq Development). Table III-7 shows the reported emissions for these four facilities by source type.

Table III-7. Subpart W Onshore Production Emissions (tons/yr)

Source Type	CO_2	CH_4
Combustion	1,193,646	1,735
Tanks	778.67	31.86
Dehydrators	166.45	71.65
Flares	34,472.21	174.54
Centrifugal Compressors	61.51	507.94
Reciprocating Compressors	0.33	2.01
Equipment Leaks	46.41	223.71

Source: U.S. EPA, 2014b

The information in Table III-7 was used to estimate total emissions for each source type and pollutant combination across the North Slope by extrapolating the reported emissions to include the uncovered 1.33 percent of production. The spatial allocation of these emissions was assumed to cover the production area extending from the Alpine field in the west to the Badami field in the east, bound on the north by the northernmost production facility (Nikaitchuq) and on the south by the southernmost production facility (Badami). GIS mapping software was used to outline the area of coverage.

As mentioned above, compressor seals and fugitive equipment leaks are not covered under the NEI or ADEC permitting inventories. Therefore, the CH_4 emissions reported under subpart W for these two source types were used to develop estimates of VOC, HAP, and H_2S emissions. To do this, ERG obtained natural gas composition profile data from North Slope producers (BP, 2014) and scaled VOC and HAP estimates based on CH_4. Table III-8 shows the natural gas composition data used in this analysis.

Table III-8. North Slope Natural Gas Composition Data

Component	Weight %
Carbon dioxide	23.24%
Ethane	8.38%
Hexanes	0.43%
i-Butane	0.69%
i-Pentane	0.28%
Methane	58.36%
n-Butane	1.21%
Nitrogen	0.86%
n-Pentane	0.31%
Oxygen	0.09%
Propane	6.15%
Benzene	0.08%
Toluene	0.07%
Ethylbenzene	0.01%

Table III-8. North Slope Natural Gas Composition Data (Continued)

Component	Weight %
Xylenes	0.02%
VOC	9.25%
H_2S^a	0.01%

Sources: U.S. EPA, 2011 (benzene, toluene, ethylbenzene and xylene); BP, 2014 (all other components).
[a] H_2S concentration based on an assumed H_2S content of 30 ppmv; all others from BP, 2014.

Subpart W – Onshore Natural Gas Processing

The onshore natural gas processing segment broadly covers facilities that separate natural gas liquids (NGLs) or non-methane gases from produced natural gas, including compression equipment and processing plants that fractionate gas liquids. As shown in Table III-6, there are five North Slope facilities reporting under this segment. As with the onshore production segment, facilities reporting under the onshore natural gas processing segment are also required to submit emission estimates for compressor seals and fugitive equipment leaks. Therefore, the CH_4 emissions reported under subpart W for these two source types were used to develop estimates of VOC, HAP, and H_2S emissions as was done for the onshore production segment.

Appendix A, Table A-14 shows the actual emissions estimates developed for onshore natural gas processing sources using the methodology described in this section.

Subpart C

Under subpart C of the GHGRP, facilities are required to submit GHG emissions estimates if they meet emissions applicability thresholds and have stationary fuel combustion sources. Stationary fuel combustion sources are broadly defined as sources that combust solid, liquid, or gaseous fuel to produce electricity, generate steam, or provide heat or energy for industrial, commercial, or institutional use. Typical sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters. Nineteen North Slope oil and gas facilities reported data in 2012 under this subpart.

Appendix A, Table A-15 shows the estimated GHG emissions for the 19 North Slope oil and gas facilities reporting under subpart C of the GHGRP.

EPA Nonpoint Oil and Gas Emission Estimation Tool

EPA's Nonpoint Oil and Gas Emissions Estimation Tool (Tool) (U.S. EPA, 2013d) contains default emission estimates for oil and gas "area" sources for the North Slope. These data were analyzed to supplement the NEI, ADEC permit, and GHGRP subpart W data to fill in any data gaps in source coverage or in source category coverage.

Table III-9 lists the source categories covered by the Tool and indicates the type of activity that is used as a surrogate to estimate nonpoint emissions from each category and which well type each category is typically associated (oil, gas, or both well types).

Table III-9. EPA Nonpoint Oil and Gas Emission Estimation Tool Categories

Category	Activity Parameter	Oil	Gas
Artificial Lifts	Oil Well Count	✓	
Associated Gas	Oil Production	✓	
Condensate Tanks	Condensate Production		✓
Crude Oil Tanks	Oil Production	✓	
Dehydrators	Gas Production and Well Count		✓
Drill Rigs	Estimated Feet Drilled	✓	✓
Fugitive Leaks	Oil and Gas Well Count	✓	✓
Gas-Actuated Pumps	Oil and Gas Well Count	✓	✓
Heaters	Oil and Gas Well Count	✓	✓
Hydraulic Fracturing Pumps	Horizontal Spud Count	✓	✓
Compressor Engines	Gas Well Count		✓
Liquids Unloading	Gas Well Count		✓
Loading	Oil and Condensate Production	✓	✓
Mud Degassing	Spud Count	✓	✓
Pneumatic Devices	Oil and Gas Well Count	✓	✓
Produced Water Tanks	Produced Water Production	✓	✓
Well Completions	Completion Count	✓	✓
Wellhead Compressors	Gas Well Count		✓

Source: U.S. EPA, 2013d

For each of the categories listed in Table III-9, the Tool contains county-level emission estimates of CAPs, HAPs, and GHGs. Therefore, as with the GHGRP onshore production data, emissions data from the Tool is spatially allocated as an area source.

Table III-10 contains North Slope oil and gas activity data found in the current version of the Tool (U.S. EPA, 2013d). These data primarily came from the DI Desktop® database (formerly HPDI®) (Drillinginfo, 2012) and through the commercial *RigData* database (RigData, 2013).

Table III-10. North Slope Oil and Gas Activity Data

Activity Parameter	Activity Value	Activity Units
Casinghead gas produced	2,997,857,000	MCF
Condensate produced	1,331,087	BBL
Count of conventional gas well completions	2	count
Count of conventional oil well completions	84	count
Count of gas wells	28	count
Count of gas well spuds, vertical drilling	3	count
Count of oil wells	1,542	count
Count of oil well spuds, vertical drilling	142	count
Estimate of feet drilled at gas wells, spuds, vertical drilling	6,731	ft
Estimate of feet drilled at oil wells, spuds, vertical drilling	786,058	ft
Gas well gas produced	67,054,130	MCF

Table III-10. North Slope Oil and Gas Activity Data (Continued)

Activity Parameter	Activity Value	Activity Units
Oil produced	198,804,300	BBL
Produced water from gas wells	597,933	BBL
Produced water from oil wells	706,814,600	BBL

MCF = thousand cubic feet; BBL = barrel; ft = feet.
Source: U.S. EPA, 2013d

ERG evaluated each of the sources and processes covered by the Tool to determine if emissions from that source type are covered under the NEI, ADEC permit data, or GHGRP data. If not, estimates from the Tool were used to gap fill the inventory for uncovered source types. Below is a brief discussion of this analysis for each source type.

Artificial Lift Engines – These are not used on the North Slope.

Associated Gas Venting – All associated gas is collected and reinjected into the reservoir to maintain pressure to facilitate oil production or used in North Slope fuel burning equipment. There is no venting of associated gas on the North Slope.

Condensate Tanks – These are not used on the North Slope.

Crude Oil Tanks – There are no crude oil tanks used on the North Slope. The process stream for crude oil is closed (not exposed to atmospheric pressure) from the wellheads to the manifold buildings to the production plants and then to the TAPS #1 pump station. Emissions from various tanks used to store petroleum liquids such as AHF are characterized using the NEI and ADEC permit emissions estimates.

Dehydrators – Emissions from dehydrators used on the North Slope are included in the NEI, the ADEC permit, and subpart W emissions estimates.

Drilling Rigs – These units are covered by the NEI and ADEC permit data.

Fugitive Leaks – Emissions from fugitive equipment leaks have been characterized using GHGRP subpart W data as described above.

Gas-Actuated Pneumatic Pumps – These not used on the North Slope.

Heaters – Emissions from various heaters used in North Slope oil and gas production are characterized in the NEI and ADEC permit emissions estimates.

Hydraulic Fracturing Pumps – These are not used on the North Slope.

Hydrocarbon Liquids Loading – This category refers to the unloading of crude oil and/or condensate from well pad storage tanks into tanker trucks brought to the pad for production collection. Well pad storage tanks are not used on the North Slope.

Lateral Compressor Engines – Lateral compressor engines are found at the 17 production facilities. These units are covered by the NEI and ADEC permit data.

Liquids Unloading – No liquids are unloaded from gas wells on the North Slope.

Mud Degassing – No emissions data are available for mud degassing in the NEI, the ADEC permit data, or the GHGRP data. Emissions for mud degassing have been taken from the tool and include 415 (tons/yr) of VOC.
Pneumatic Devices – There are no gas-powered pneumatic devices used on the North Slope.
Produced Water Tanks – Emissions from produced water tanks used on the North Slope are included in the NEI and ADEC permit emissions estimates.

Well Completion Venting – Emissions from well completion venting are addressed in Section 3.a.i (Onshore Oil and Gas Exploratory Drilling).

Wellhead Compressor Engines – These are not used on the North Slope.

The accuracy of the emissions estimates from the oil and gas production sources is influenced by the availability of reported emissions data for these sources. Data available to estimate emissions from onshore oil and gas exploration and production sources came from a variety of sources, including actual emissions as reported by each facility to ADEC (as found in the 2011 NEI), actual emissions of GHG as reported to EPA as part of the GHGRP, and potential emissions as documented in ADEC air permits and permit applications. The available data for actual emissions has been used as the basis for scaling emissions of unreported sources or unreported pollutants to develop a comprehensive inventory. For the largest facilities (i.e., Title V permitted production plants), CAP and HAP pollutant data were available to develop emissions estimates for unreported sources (smaller units and nonroad engines). For the smaller facilities, only CAP emissions data were available; HAP estimates have not been developed. However, these HAP emissions are relatively minor in relation to the entire onshore oil and gas inventory (i.e., VOC from these sources accounts for 13 percent of the total).

B. Airports, Aircraft, and Support Equipment

Alaska’s aviation sector is one of the largest and most active of any state. This is particularly true for the North Slope where commercial and general aviation are used to move people, supplies, and mail, provide medical airlift, monitor pipeline for spills, and track wildlife.

Airport emissions include aircraft main engines, auxiliary power units (APUs) and ground support equipment (GSEs). Airport emissions include only the LTO cycle, not the cruise portion of the flight. In Figure III-6, activities below the horizontal dotted line (mixing height) are part of a typical LTO. The cruise portion appears above the mixing height.

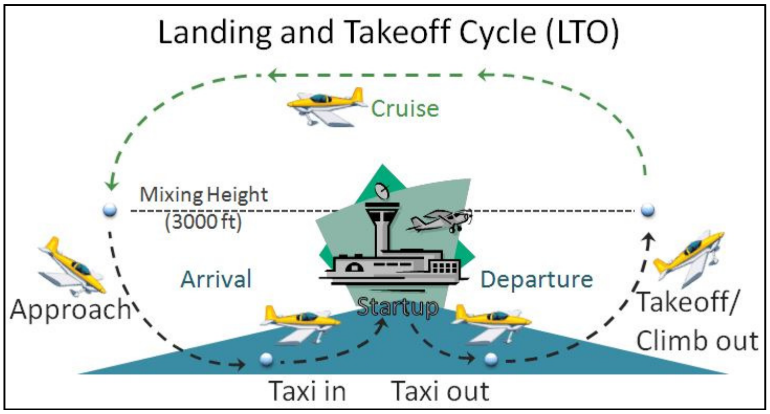

Figure III-6. Diagram of a Landing and Takeoff Cycle
Image from ERG

BOEM selected 16 airports located on the North Slope to include in the emissions inventory based on level of activity and geographic location (See Figure III-7). The 16 airports are also listed in Table III-11. Representatives from each airport were contacted to obtain activity and operational data, including information about possible operating conditions for airports on the North Slope that could affect emission estimates due to longer idling times or shorter taxi times, for example.

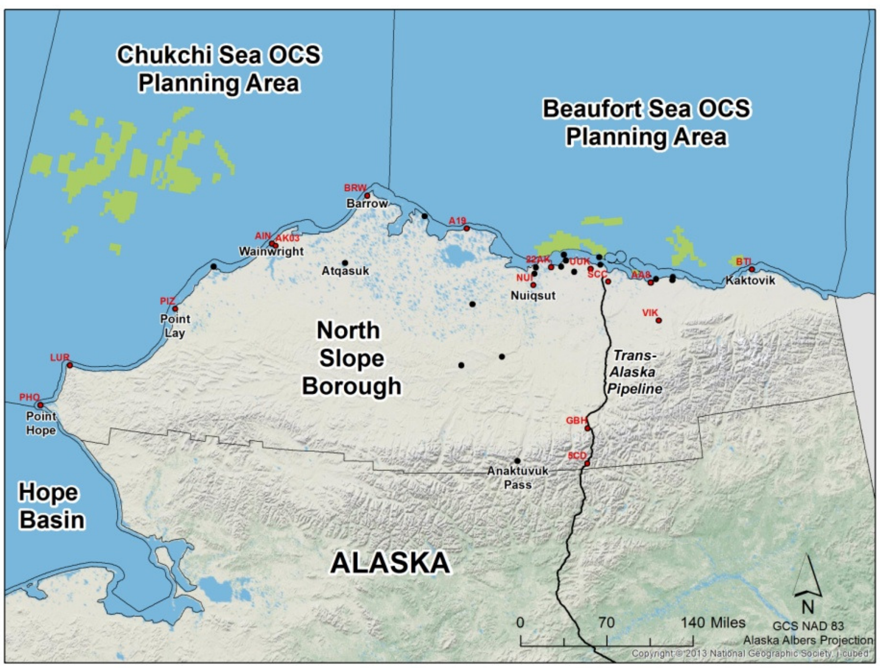

Figure III-7. North Slope Airport Locations and FAA Codes
Image from U.S. EPA, 2013e

Table III-11. Sixteen Airports Located on the North Slope

FAA Site ID	2011 NEI Site ID	Airport Name
AA8	16091011	Badami
BTI	10568311	Barter Island LRRS
LUR	10567811	Cape Lisburne LRRS
5CD	10572111	Chandalar Shelf
SCC	10567411	Deadhorse
GBH	10568111	Galbraith Lake
22AK	11056311	Helmericks
VIK	10567111	Kavik River
A19	11609311	Lonely Air Station
UUK	10567211	North Kuparuk / Ugnu-Kuparuk
NUI	10571811	Nuiqsut
PHO	10567611	Point Hope
PIZ	10567511	Point Lay LRRS
AIN	10571611	Wainwright
AK03	11623911	Wainwright As
BRW	10568411	Wiley Post-Will Rogers

Sources: FAA, 2012; U.S. EPA, 2013b; BTS, 2014.

Of the 16 airports, two airports have been closed (Lonely Air Station and Wainwright Air Station); and three airports did not have data (Chandalar Shelf, Cape Lisburne Long Range Radar Station [LRRS], and Point Hope).

ERG reviewed, formatted, and linked the local airport data collected to specific aircraft where possible. In some cases, the data provided by the airport included detailed aircraft information. In other cases, the data contained only information on the carriers that used the airport. Using the air carrier companies' websites and FAA data available on the Bureau of Transportation Statistics (BTS) website (all cited below), ERG identified various aircraft owned and used by the carriers. A major assumption in linking the airport commercial activity data to the aircraft fleets was that the aircraft that operate out of North Slope airports were similar to the commercial aircraft that were flown throughout the rest of the state. Appendix A, Table A-6 summarizes the air carriers and their fleet makeup. ERG attempted to discuss this issue with North Slope airport operators to identify aircraft that were too large for the local facility. Where these larger aircraft were identified, they were removed from the airport dataset. For Deadhorse Airport, ERG estimated the activity data because no information was available to link the aircraft. Appendix A, Table A-7 summarizes the compiled activity data for the 11 reporting airports.

Some of the data from the local airports were actually passenger enplanements and not LTOs or operations. The enplanement data were very similar to the FAA's Terminal Area Forecast (TAF) data, which include both enplanement and operations data. Therefore, ERG decided that the TAF activity data would be used in place of the local enplanement data (FAA, 2012).

Ten of the 11 airports provided aircraft-specific or air-carrier-specific data, which were applied to the FAA's Emission and Dispersion Modeling System (EDMS) to estimate aircraft, APU, and GSE emissions (FAA, 2013). The remaining airport, Deadhorse, provided approximate LTO data. Because the data were approximations, the detailed TAF data for Deadhorse were used. The Deadhorse aircraft were assumed to all be general aviation aircraft equipped with piston engines, based on information provided by the airport operator. The TAF LTOs were applied to emission factors from the 2011 NEI (U.S. EPA, 2013e) to estimate emissions for Deadhorse.

Most of the aircraft used on the North Slope are smaller aircraft that do not have APUs or do not require GSE; therefore, APU and GSE emissions were included only for airports serviced by commercial aircraft that are associated with APU and GSE in the FAA's EDMS model.

Airport representatives were also asked about taxi in and taxi out times. Only two airports provided taxi in and out times (Badami Airport and North Kuparuk Airport), given as total time on the ground. These times were split into taxi in and out using 27 percent in and 73 percent out, which is based on the EDMS default of 7 minutes in and 19 minutes out but adjusted to account for their local data. For all other airports, the EDMS defaults of 7 minutes taxi in and 19 minutes taxi out were used. Appendix A, Table A-8 summarizes the taxi in and out times.

In addition to normal passenger and cargo activities at the airports, there were also helicopter operations associated with supporting offshore oil and gas exploratory drilling and seismic survey vessel operations, as well as wildlife monitoring. Table III-12 summarizes the airport LTOs for helicopter operations. The cruising hours and platform LTOs are provided in the offshore emissions inventory (Section II of this report).

Table III-12. Oil- and Gas-Related Helicopter Activity at Airports

Location	Category	LTOs
Deadhorse Airport	Drilling-Aircraft	29
	Drilling-Helicopters	50
Wainwright Airport	Drilling-Aircraft	15
Wiley Post-Will Rogers / Barrow Airport	Drilling-Aircraft	15
	Drilling-Helicopters	91
	Survey-Helicopter	51

Sources: Shell, 2013; FAA, 2013

Airport emissions were spatially allocated to the latitude and longitude coordinates of each airport as shown in Table III-12.

The accuracy of the airport estimates is dependent upon the accuracy of the LTO data used, time in mode assumptions, and appropriate matching of aircraft to engines. Using local LTO and time in mode data ensures that the best available data were used to develop these estimates.

C. TransAlaska Pipeline System

The TAPS pipeline has a total length of 800 miles from the North Slope oil fields to the Valdez Marine Terminal with 11 pump stations; the portion of the TAPS pipeline within the North Slope is approximately 177 miles long with four pump stations (Pump Stations 1 through 4) (Alyeska, 2013). The pipeline is operated by the Alyeska Pipeline Service Company (APSC). Emissions were estimated for both the actual pipeline sources as well as APSC activities associated with pipeline operation and maintenance.

1. *TAPS Pump Stations*

Pump Stations 1 through 4 along the TAPS are the only four pump stations located within the North Slope, as shown in Figure III-8.[4] Emissions from these pump stations are generated by fuel burning equipment such as gas turbines, compressors, generators, heaters, boilers, booster pumps, and fire pumps. Emissions from Pump Stations 1, 3, and 4 were obtained from the 2011 NEI (U.S. EPA, 2013b); Pump Station 2 was ramped down on July 1, 1997, due to declining production (Alyeska, 2013) and does not have any active emission sources. Although 2012 TAPS crude oil throughput decreased by 6 percent relative to 2011 (i.e., 547,866 bbls/day compared to 582,895 bbls/day) (Alyeska, 2013), ERG assumed that 2011 emissions were representative of 2012 operating levels. Pump Stations 1, 3, and 4 emissions were reported in the 2011 NEI for NO_x, SO_2, VOC, CO, PM_{10}, $PM_{2.5}$, Pb, and HAP. GHG emissions were estimated by multiplying relevant 2011 throughput data with EPA WebFIRE emission factors (U.S. EPA, 2013a).

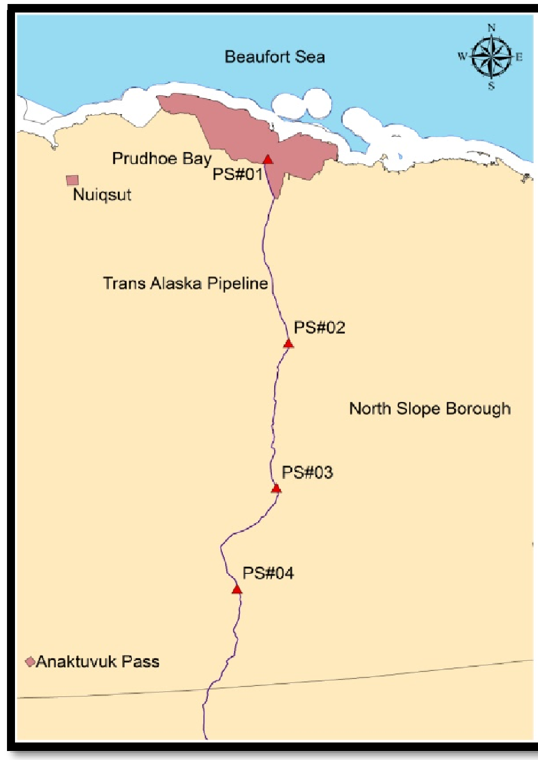

Figure III-8. TAPS Pump Stations Located within the North Slope
Data Sources (See footnote)

2. *TAPS Fugitive Emissions*

Emissions were estimated using national production-based (i.e., Tier 1) emission factors from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006). These factors were then applied to the TAPS crude oil throughput to obtain VOC, CO_2, and CH_4 emissions. Finally, the calculated emissions were scaled by the ratio of the TAPS pipeline mileage within the North Slope (177 miles) to national crude oil pipeline mileage (51,349 miles) (BTS, 2014).

3. *Natural Gas Supply Line Fugitive Emissions*

Fugitive emissions are emitted from the natural gas supply line that fuels the TAPS pumping stations north of the Brooks Range (i.e., Pump Stations 1 through 4).

Fugitive emissions from the natural gas supply were estimated using national production-based (i.e., Tier 1) emission factors obtained from the *2006 IPCC Guidelines for National Greenhouse*

[4] Data Sources (All Accessed June 25, 2013): ADEC (TAPS pump station locations: http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory/); Alaska Department of Natural Resources (TAPS shapefile: http://dnr.alaska.gov/mdfiles/trans_alaska_pipeline.html; Borough Boundaries shapefile: http://dnr.alaska.gov/mdfiles/borough.html; Physical Features/Alaska Coast shapefile: http://dnr.alaska.gov/mdfiles/alaska_63360_xsi.html); BOEM (Alaska OCS Planning Areas shapefile: http://www.boem.gov/Oil-and-Gas-Energy-Program/Mapping-and-Data/Alaska.aspx)

Gas Inventories (IPCC, 2006). These factors were then applied to the natural gas consumed at Pump Stations 1, 3, and 4 (3,983.9 million standard cubic feet [MMscf]) in 2011 as reported in the 2011 NEI to obtain VOC, CO_2, and CH_4 emissions (U.S. EPA, 2013b). Finally, the calculated emissions were scaled by the ratio of the supply line mileage (177 miles) to national natural gas transmission pipeline mileage (303,303 miles) (BTS, 2014).

4. *Pigging Operations*

Pigging operations conducted on the TAPS pipeline involve pushing a mechanical device through the pipeline to perform various operations on the pipeline without stopping the flow of oil. In general, APSC runs a cleaning or scraper pig through the pipeline every nine days, which removes wax, water, or solids buildup. In addition, APSC also has instrumented “smart” pigs that measure pipeline corrosion, deformity, or movement. These smart pigs are run every three years or as required by operational needs. Pigs are launched from Pump Station 1 and are received at Pump Station 4 or are launched from Pump Station 4 and are received at the Valdez Marine Terminal (Alyeska, 2013).

The EPA’s Emissions Inventory Improvement Program (EIIP) guidance recommends estimating emissions from pigging operations based upon measurements (EIIP, 1999). Detailed emissions information regarding TAPS pigging operations were not available; therefore, pigging operations were assumed to be conducted once a week. Pigs were also assumed to be launched from Pump Station 1 and received at Pump Station 4 and that emissions are released directly to the atmosphere at these two locations.

Methane emissions from pigging operations on the TAPS were estimated using guidance from the EPA’s Methane to Markets program (U.S. EPA, 2007). Although this guidance is for pigging of gathering lines, it was considered to be a reasonable approximation in the absence of any data from APSC. Based on the equation provided in the guidance, a launcher and receiver volume of 170.7 cubic feet was assumed (based on a line diameter of 48 inches); other default values (i.e., line pressure of 315 psia and 78.8 percent methane content) were also assumed. Calculated emissions were estimated on an annual basis and were split evenly between Pump Station 1 and Pump Station 4.

5. *TAPS Patrol Vehicles*

On-road motor vehicles patrolling the TAPS also generate exhaust and evaporative emissions, as well as re-entrained road dust emissions from driving on unpaved roads.

Information regarding the type and extent of patrol vehicles was not available; therefore, two trucks were assumed to patrol the length of the TAPS pipeline within the North Slope every day (i.e., 354 total daily vehicle miles traveled [VMT]). Motor vehicle exhaust and evaporative emissions and unpaved road dust emissions associated with these vehicles were estimated as described in Section III.D of this report.

ERG estimated emissions from the on-road patrol vehicles on an annual basis and then spatially allocated the emissions along the length of the TAPS pipeline. The location of the TAPS pipeline is a reasonable approximation of the TAPS access road.

6. *TAPS Pipeline Replacement and Repair*

Nonroad construction equipment involved in pipeline replace and repair projects along the TAPS generate exhaust and evaporative emissions. Since the TAPS pipeline was completed in 1977, replacement and repair construction projects are periodically conducted to maintain the integrity of the system.

Information regarding the type and extent of replacement and repair projections was not available; therefore, it was assumed that two work crews operating a dump truck, backhoe, and a bulldozer worked a 10-hour shift somewhere along the TAPS pipeline on the North Slope during the winter (October through April). It was assumed that 10 work crews operating similar equipment worked a 10-hour shift during the summer (May through September). Emissions were estimated as described in Section III.D of this report.

All TAPS pipeline replacement and repair emissions were estimated on an annual basis and will be spatially allocated along the length of the TAPS pipeline.

7. *TAPS Aerial Surveillance*

Emissions from helicopters occur during aerial surveillance of the TAPS and feeder lines, which are the smaller pipelines that connect the onshore wells to pumping stations and to the TAPS (See Figure III-9) (ADNR, 2014). The helicopters used for TAPS surveillance were based at the Fairbanks International Airport, which is outside of the North Slope area.

Figure III-9. TAPS and Feeder Pipelines
Data Source: ADNR, 2014

The total miles of TAPS (177 miles) (BLM, 2014; AP, 2013) and feeder lines (349 miles) (BLM, 2014; AP, 2013) were summed and then doubled to account for round trips (1,056.8 miles). The total distance was divided by 100 miles per hour to yield 634.065 daily minutes of flight. As surveillance flights are implemented daily, this equated to 3,857.23 annual hours of operation. This was multiplied by 80 percent of the takeoff mode portion of the emission factor for the Bell 407 from EDMS (FAA, 2013) to approximate cruising operating load and emissions. The Bell 407 is the model used for surveillance by the Bristow Group, which was in charge of TAPS surveillance during 2012.

It was assumed that a similar helicopter was used to monitor the feeder pipelines (Figure III-9) connected to the TAPS. Activity and emissions from pipeline surveillance operations were spatially assigned to onshore pipeline segments.

With the exception of the pump station emissions that were reported to the 2011 NEI by APSC, all of the other emission estimates associated with TAPS operations should be considered to be fairly uncertain due to the inability to obtain any specific information from APSC. Although engineering judgment and reasonable assumptions were used to estimate these emissions, detailed information would provide more certain estimates.

D. Non-Oil/Gas Stationary Point, Area, and Mobile Sources

This section describes the methods and data used to estimate emissions from non-oil/gas stationary point, area, and mobile sources located in the eight North Slope villages, as well as the related support activities (that not directly related to oil production) within the onshore oil and gas fields (Figure III-10). Barrow is the largest village on the North Slope with an estimated population of 4,445 people in 2012 (ADL&WD, 2013). The remaining seven villages are considerably smaller with populations ranging from 196 people (Point Lay) to 668 people (Point Hope) (ADL&WD, 2013). Four villages are located on the coast (Point Hope, Wainwright, Kaktovik, and Point Lay), while the other three villages are located inland (Nuiqsut, Atqasuk, and Anaktuvuk Pass). The onshore oil and gas fields in Prudhoe Bay do not have a permanent population, but have thousands of workers that rotate in and out on a transient basis.

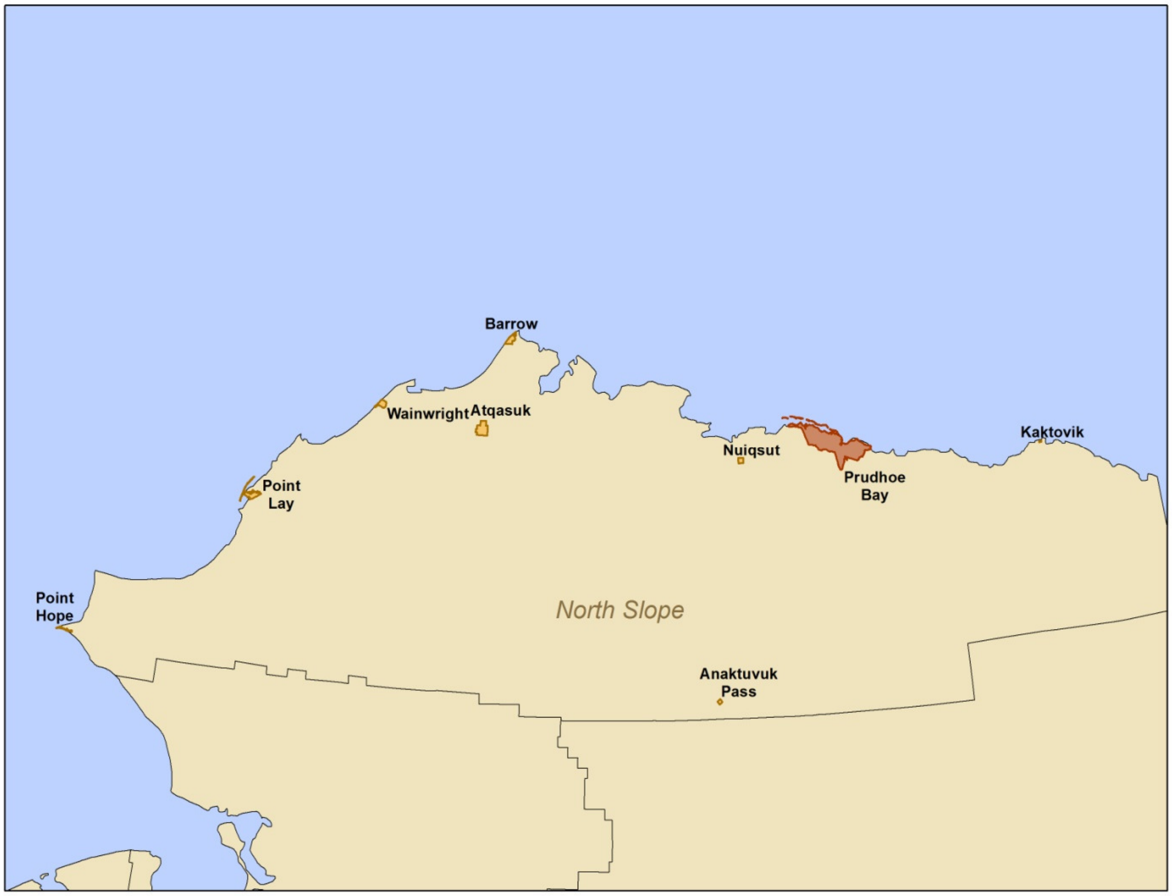

Figure III-10. Locations of North Slope Villages

Data Source: ArcGIS Online, so the official source may still be ESRI: http://www.arcgis.com/home/item.html?id=4e75a4f7daaa4dfa8b9399ea74641895 (Accessed September 26, 2014.)

The emission sources located in the onshore villages are broadly classified as follows:

- Fuel combustion – Power plants, commercial/institutional, and residential.
- Mobile sources – On-road motor vehicles and nonroad mobile sources.
- Road dust – Paved and unpaved roads.
- Miscellaneous – Waste burning, wastewater treatment, and other stationary sources.

1. *Power Plants*

Power plants are located in each of the eight North Slope villages; two additional plants are located in the oil and gas fields (Deadhorse Facility and North Slope Generating Power Plant). The Barrow Power Plant is operated by the Barrow Utilities and Electric Co-op, Inc. (BUECI); the remaining village power plants are run by the North Slope Borough (NSB) Department of Public Works. The Deadhorse Facility, North Slope Generating Power Plant, Barrow Power Plant, and Nuiqsut Power Plant use natural gas as a primary fuel, while the other power plants use fuel oil as a primary fuel.

Emissions from the Deadhorse Facility, North Slope Generating Power Plant, and the three largest village power plants (Barrow, Point Hope, and Wainwright) were obtained from the 2011 NEI (U.S. EPA, 2013b). It was assumed that 2011 emissions were representative of 2012 operating levels (i.e., there are no NEI emissions available for 2012).

Emissions for the five smaller village power plants (Anaktuvuk Pass, Atqasuk, Kaktovik, Nuiqsut, and Point Lay) were estimated by multiplying fuel consumption data with EPA WebFIRE emission factors (U.S. EPA, 2013a). Metal HAP species emissions were estimated by applying speciation fractions from the SPECIATE database to $PM_{2.5}$ emissions (U.S. EPA, 2014c). Fuel consumption data for these smaller village power plants were obtained from the Alaska Energy Authority's (AEA's) Power Cost Equalization (PCE) rural energy subsidy program (Williams, 2014) (included in Table A-16 of Appendix A). Although ULSD fuel is currently used in the North Slope power plants, according to fuel invoice records, it was not used as fuel oil in 2012 (Slatton, 2014a). The fuel oil sulfur content was assumed to be 2,500 ppm based upon fuel specifications for Fairbanks fuel oil (Leelasakultum et al., 2012).

2. *Industrial and Commercial/Institutional Fuel Combustion*

The two primary fuels used within the North Slope (natural gas and distillate fuel oil) are combusted within industrial (not related to oil and gas production) and commercial/institutional (e.g., schools, community facilities, village corporations) settings. Commercial/institutional fuel combustion does not include the village power plants. In general, emissions were estimated by multiplying fuel consumption data with EPA WebFIRE emission factors (U.S. EPA, 2013a). Metal HAP species emissions were estimated by applying speciation fractions from the SPECIATE database to $PM_{2.5}$ emissions (U.S. EPA, 2014c).

One specific industrial facility that burned natural gas and distillate fuel oil provides logistical support to the oil and gas fields – Peak Oilfield Services, Peak Base Shop, Peak Wellex, and Nabors Base Camp Facilities (Permit # AQ1282ORL04P) (ADEC, 2013); however, it could not be definitively confirmed that this facility was the sole provider of logistical support to the oil and gas fields. Emissions were based upon the estimated emissions provided in the permit's limits.

Another industrial source that combusts distillate fuel oil is the Service Area 10 Incinerator Plant, which is operated by the NSB (Permit # AQ0187PL202P) (ADEC, 2013). Emissions were estimated by combining the permitted distillate fuel quantity of 250,000 gallons/year with EPA WebFIRE emission factors (U.S. EPA, 2013a) and speciation fractions from the SPECIATE database (U.S. EPA, 2014c). Because geographic coordinate locations could not be identified for the Service Area 10 Incinerator Plant, it was assumed to be located near the Oxbow Landfill.

Distillate heating oil is also consumed at each of the K-12 North Slope Borough School District (NSBSD) schools in the villages with the exception of Barrow; specific monthly consumption quantities for 2012 were provided by the NSB's Department of Public Works' Fuel Division (Slatton, 2014a) (included in Table A-17 of Appendix A). Emissions were estimated with reported distillate fuel oil quantities combined with EPA WebFIRE emission factors (U.S. EPA, 2013a) and speciation fractions from the SPECIATE database (U.S. EPA, 2014c).

Distillate heating oil is also consumed at four North Slope Long-Range Radar Sites (LRRS) operated by the U.S. Air Force (Barter Island LRRS, Cape Lisburne LRRS, Oliktok LRRS, and Point Barrow LRRS). Barter Island LRRS is located near Kaktovik and Point Barrow LRRS is located near Barrow; Cape Lisburne LRRS and Oliktok LRRS are located at remote locations away from the North Slope villages. Specific 2012 fuel consumption quantities could not be identified, so permitted fuel quantities from the LRRS permits were used instead – 200,000 gallons/year at Cape Lisburne LRRS and Oliktok LRRS and 50,000 gallons/year at Barter Island LRRS and Point Barrow LRRS (ADEC, 2013). Emissions were estimated using EPA WebFIRE emission factors (U.S. EPA, 2013a) and speciation fractions from the SPECIATE database (U.S. EPA, 2014c). Specific location coordinates were identified for each LRRS facility.

Unlike other North Slope villages (which almost exclusively use distillate heating oil), Barrow meets much of its energy needs from fuel supplied by three nearby natural gas fields (South Barrow, East Barrow, and Walakpa). Specific 2012 natural gas consumption quantities were obtained from invoices for two commercial/institutional consumers in Barrow: the Ukpeaġvik Iñupiat Corporation (UIC)/Naval Arctic Research Laboratory (NARL) Complex Water Plant and the Aeronautical Radio, Inc. radio towers (Nesteby, 2014) (included in Table A-18 of Appendix A). Emissions were estimated using EPA WebFIRE emission factors (U.S. EPA, 2013a).

In addition to the specific industrial and commercial/institutional fuel combustion sources described above, there is additional unspecified commercial/institutional fuel combustion in the North Slope. BUECI staff provided natural gas consumption quantities in Barrow (Nesteby, 2014), while NSB staff provided fuel oil consumption quantities (Slatton, 2014a). Although ULSD is currently used on the North Slope for industrial and commercial/institutional fuel combustion, according to fuel invoice records, it was not used as fuel oil in 2012 (Slatton, 2014a). The fuel oil sulfur content was assumed to be 2,500 ppm based upon fuel specifications for Fairbanks fuel oil (Leelasakultum et al., 2012). Emissions were estimated using EPA WebFIRE emission factors (U.S. EPA, 2013a).

3. *Residential Fuel Combustion*

Private residences within the North Slope use two primary fuels (natural gas and distillate fuel oil) for space heating, water heating, backup electricity generation, cooking, etc. As shown in Figure III-11, most village residences (outside of Barrow and Nuiqsut) are heated using distillate fuel oil. (Note fuel oil tank on left side of house in Figure III-11).

Figure III-11. House in Wainwright
Photo courtesy of M. Wolf (ERG), September 10, 2014

Distillate fuel oil residential combustion devices include forced air furnaces (as shown in Figure III-12), Toyo stoves, and residential boiler systems. Unlike other regions within Alaska, wood is not used in the North Slope for residential heating and cooking because there are no natural wood sources in close proximity. Minor quantities of liquefied petroleum gas (LPG) are also used on the North Slope, but mainly for hunting and camping activities, not as a primary residential fuel.

Figure III-12. Fuel Oil Forced Air Furnace in Wainwright (approximately 30 years old)
Photo courtesy of M. Wolf (ERG), September 10, 2014

In general, residential fuel combustion emissions were estimated by multiplying fuel consumption data with EPA WebFIRE emission factors (U.S. EPA, 2013a). Metal HAP species emissions were estimated by applying speciation fractions from the SPECIATE database to $PM_{2.5}$ emissions (U.S. EPA, 2014c).

Residential fuel combusted in Barrow is strictly limited to natural gas, while residential fuel combusted in Nuiqsut is a mix of natural gas and distillate fuel oil. Residential fuel combusted in the remaining six villages is distillate fuel oil. BUECI provided Barrow residential natural gas consumption statistics (Nesteby, 2014), while NSB's Department of Public Works' Fuel Division provided all residential fuel consumption statistics in the other villages (Slatton, 2014a) (included in Table A-18 and Table A-19 of Appendix A). Although ULSD is currently used in the North Slope for residential fuel combustion, according to fuel invoice records it was not used as fuel oil in 2012 (Slatton, 2014a). The fuel oil sulfur content was assumed to be 2,500 ppm based upon fuel specifications for Fairbanks fuel oil (Leelasakultum et al., 2012).

Because LPG is not a primary residential fuel, usage statistics were not specifically tracked by the NSB. Eskimos, Inc. (i.e., the Barrow fuel supplier) provided an estimate of LPG usage in Barrow (Snow, 2014). The NSB's Department of Public Works' Fuel Division also had an estimate of LPG purchases in the village of Atqasuk (Slatton, 2014a). The Atqasuk LPG purchase data were extrapolated to the other six villages without LPG information based upon village population (ADL&WD, 2013). Compared to residential fuel oil and natural gas consumption, residential LPG consumption is more uncertain due to a lack of data.

4. *On-Road Motor Vehicles*

On-road motor vehicle emissions in the North Slope were developed using emission factors from EPA's MOVES2014 model (MOVES) (U.S. EPA, 2014d) with local meteorological and vehicle activity data for VMT and fuel consumption. All on-road motor vehicle emissions were estimated on a monthly basis and then summed up to an annual total.

The on-road emissions inventory includes six vehicle categories:

- On-road emissions by village for the eight villages in the North Slope.
- Wintertime idling (in addition to typical on-road emission processes) for the eight villages.
- Vehicles traveling on the Dalton Highway.
- TAPS patrols.
- Vehicles traveling within the Prudhoe Bay oil fields.
- Gasoline refueling emissions in the North Slope.

ERG ran MOVES and processed the results to produce the emission factors, and in conjunction with fleet activity data, estimated on-road emissions for each category listed above. The following approach describes key inputs to MOVES and then details the emissions inventory methods separately for the six categories.

Most of the MOVES input data specific to the North Slope were prepared by ADEC for the 2011 NEI (ADEC, 2012). The specific MOVES inputs that ERG used included fuel supply and formulation, fleet age, fleet diesel fractions, and VMT patterns as well as local meteorological data recorded at Deadhorse Airport (for Dalton Highway) and Barrow Airport (all other categories) (NCDC, 2014). The other fleet activity used outside of MOVES framework to calculate on-road emissions (i.e., VMT, speeds, and fuel consumption) is described in the following sections.

a. On-Road Emissions – Villages

On-road emissions were calculated for each North Slope village. Because Barrow is the most populous village and had the only available VMT, ERG ran MOVES specifically for Barrow and then scaled the emission results to the smaller villages based on population (ADL&WD, 2013).

Vehicle traffic information for the North Slope is extremely limited. The Alaska Department of Transportation and Public Facilities (ADOT&PF) collected annual average daily traffic (AADT) statistics in 2012 for Barrow (ADOT&PF, 2014); see Figure III-13. Although these AADT statistics do not represent all vehicle activity in Barrow, they do represent traffic on the most heavily travelled roads, and were used to represent Barrow vehicle activity. Limited field observations indicate that the roads for which AADT data were collected are the primary roads traveled in Barrow. Because no other traffic statistics exist for the other North Slope villages, Barrow AADT data statistics were extrapolated to the other villages based on population.

On-road driving at the village level was modeled in MOVES as rural non highway road (Rural Unrestricted Access) with a distribution of speeds – 25 mph (40 percent of VMT), 35 mph (35 percent), and 45 mph (25 percent). The annual average daily VMT for Barrow is estimated at 16,163 based on the AADT and length of 13 major roads in the village (included in Table A-20 of Appendix A). This VMT estimate is likely low because the smaller roads do not have traffic counts to estimate AADT. However, the gasoline and diesel consumed by each village is fully accounted for because fuel not consumed by on-road vehicles was assumed to be used by nonroad vehicles such as NSB nonroad equipment and personal snowmobiles and ATVs.

Figure III-13. 2012 Average Daily Traffic Count Statistics for Barrow
Source: ADOT&PF, 2014

The total VMT was disaggregated by vehicle and fuel type using modified fleet mix information submitted by ADEC (ADEC, 2012). The North Slope total fleet mix was modified to remove long-haul trucks and combination-unit short-haul trucks because these are unable to access villages through any roadway network and they already are accounted for under the separate analysis of Dalton Highway. The average day VMT in Barrow was also converted to an annual total and then disaggregated to months using the North Slope month VMT fractions. ERG ran the model using seasonal meteorology data from Barrow Airport for each month and calculated monthly emission factors for each vehicle type. The emission factors include all emission processes associated with on-road (i.e., start exhaust, running exhaust, evaporative emissions, brake and tire) in a single gram/mile factor per pollutant by month and vehicle/fuel type. These emission factors were then multiplied with corresponding VMT to estimate Barrow emissions.

The fuel consumed in Barrow from on-road activity (e.g., VMT and engine starts) was calculated based on total CO_2 emissions from each vehicle type divided by the carbon content of fuel (i.e., 8.91 kg CO_2/gallon of non-ethanol gasoline and 10.15 kg CO_2/gallon of diesel). As with the village-level emissions, village-level fuel consumption was estimated by scaling Barrow gasoline and diesel consumption by population (ADL&WD, 2013).

b. Wintertime Idling – Villages

MOVES does not estimate wintertime idling activity by default as part of any on-road inventory. MOVES accounts for a small amount of idling as part of typical driving cycles that reflect trip patterns where vehicles stop for short periods while waiting at a traffic light or stop sign. However, in the Arctic, vehicles are frequently left idling while parked during the wintertime, particularly during the coldest months of the year. Staff of NSB Public Works Department indicated that some of the NSB vehicles may idle more than 3,000 hours per year (Lewis, 2014); however, this level of idling is probably too high for the overall vehicle population. Therefore, wintertime idling was assumed to be 640 hours per vehicle per year, based on eight hours per day, five days per week (Monday-Friday), and four months per year (December – March).

ERG ran MOVES to estimate idle emission factors in grams/hour using average meteorological conditions for daytime in the four winter months. MOVES is a "modal" emissions model, meaning that it contains base emission rates for operating modes, which are defined by vehicle-specific power (VSP) and speed. In general, the operating mode bins represent different operation of vehicles on a typical trip, including idle, deceleration, coast, and acceleration. To estimate the idle emission factors, ERG ran MOVES using the "Project Scale" mode and a unique operating mode distribution with 100 percent idle operation. The results of this modeling were grams/hour for each vehicle type. The grams/hour idle emission factors were multiplied by 640 hours and the population of vehicles in Barrow.

Although the exact number of vehicles was not known, it was estimated by dividing the annual VMT by a fleet average annual mileage accumulation rate of approximately 10,400 miles per vehicle per year. The estimated number of total vehicles (e.g., cars, passenger trucks, buses) in Barrow was 569 vehicles. ERG estimated the vehicle population by vehicle type using the population fleet mix provided by ADEC for the North Slope for the NEI with heavy-duty trucks removed (ADEC, 2012). Fuel consumed by wintertime idling was also calculated using the CO_2

g/gallon factors described previously for the general on-road calculations by village. As with the general on-road emissions, wintertime idling emissions and the associated fuel consumption for the other villages were estimated by scaling by population (ADL&WD, 2013).

c. Dalton Highway

The Dalton Highway was modeled in MOVES as a rural highway (Rural Restricted Access) with an average speed of 50 mph (i.e., posted speed limit). VMT on the highway averaged 20,855 miles per day in 2012, dominated by heavy-duty diesel truck traffic (82 percent) with the remaining 18 percent from light-duty gasoline trucks (ADOT&PF, 2013). The VMT was reallocated from annual average day VMT into seasonal patterns using the VMT patterns for rural highway in the North Slope (ADEC, 2012). MOVES monthly emission factors in grams/mile were multiplied with monthly VMT to estimate season-specific emissions generated by trucking on the Dalton Highway.

d. TAPS Patrols

As described in Section III.C, trucks were assumed to patrol the length of the TAPS pipeline within the North Slope every day (i.e., 354 total daily VMT). The running emission factors for light commercial trucks operating on rural nonhighway roads developed for the Barrow on-road analysis were used to represent patrol vehicles driving along the TAPS. The emission factors in grams/mile were multiplied with VMT estimates to produce the patrol truck emissions. Wintertime idling emissions were not estimated for this category.

e. Prudhoe Bay

A considerable amount of on-road motor vehicle fuel (i.e., gasoline and ULSD) is transported across the Dalton Highway from Fairbanks up to Prudhoe Bay. Staff from NSB provided an estimate of the amount of motor vehicle fuel transported in 2012 (2,775,000 gallons of gasoline) (Monnin, 2014). These staff indicated that the ULSD should be covered by the relevant Title V permits; therefore, emissions were estimated only for gasoline-fueled vehicles. Neither Prudhoe Bay VMT nor vehicle population was available. Due to the absence of better data, the corresponding VMT and population of trucks was estimated based on the total gasoline using the corresponding activity proportions from the Barrow analysis, but accounting for higher rates of wintertime idling. The assumed rate of wintertime idling in Prudhoe Bay was 1,140 hours of idling per vehicle per year (60 hours per week, six months per year).

Emissions factors developed for Barrow for gasoline-fueled light commercial trucks from the "general on-road" and "wintertime idle" analysis were multiplied by the activity in Prudhoe Bay.

5. *Nonroad Mobile Sources*

Nonroad mobile source emissions in the North Slope were estimated using EPA's NONROAD2008a model (U.S. EPA, 2009b) to derive emission factors based on fuel consumption. Custom inputs to NONROAD specific to the North Slope were used where available; otherwise, NONROAD default data were used. The custom inputs to NONROAD are discussed below:

- Meteorological Data: Village-specific meteorological data were used to run the NONROAD2008a model. Monthly temperature data were obtained from the National Climatic Data Center (NCDC) (NCDC, 2014).
- Fuel Characteristics: The nonroad mobile source fuel inputs were synchronized with the MOVES inputs provided by ADEC. The gasoline sulfur content was 30 ppm and the ULSD sulfur content was 15 ppm. Based on ADEC's input, gasoline Reid vapor pressure (RVP) was assumed to be 12.4 from May to September and 14.69 from October to April (ADEC, 2012).
- Daily and Monthly Data: Based on discussions with NSB personnel (Slatton, 2014b), the monthly and daily activity distribution for some key nonroad equipment was updated from the NONROAD defaults in the SEASON.DAT file. The following monthly activity data adjustments were made:
    - 2-stroke gasoline snowmobiles – October through April.
    - 4-stroke ATVs – May through September.
    - 4-stroke recreational marine motors – June through September.

  The weekday/weekend allocations were set equal for these nonroad equipment types.

Emissions Estimation Methodology

After the NONROAD inputs were updated with local data specific to the North Slope, the NONROAD model was run to estimate annual emissions for each area and month for the year 2012. The model produced both emissions estimates and fuel consumption estimates for each source classification code (SCC). Based on discussions with NSB personnel concerning conditions in the North Slope (Slatton, 2014b), only the following types of nonroad equipment were included in the emission estimates:

- 2-stroke gasoline snowmobiles (see Figure III-14).
- 4-stroke ATVs.
- 4-stroke recreational marine (inboard/sterndrive).
- Diesel rollers.
- Diesel graders (see Figure III-15).
- Diesel off-highway trucks.
- Diesel tractors/loaders/backhoes.
- Diesel dumpers/tenders.

The NONROAD model estimates emissions for CAPs, only. Emissions for HAP were estimated using a modified version of the NONROAD reporting utility, which applies speciation factors obtained from the EPA's NMIM model. Using these NONROAD outputs, ton/gallon emission factors were developed for each SCC and pollutant combination. The NONROAD outputs were also used to calculate the fraction of total fuel consumption for each SCC.

Figure III-14. Snowmobiles in Front of a Barrow Residence

Figure III-15. Grader Leveling Barrow Unpaved Road

Photo courtesy of M. Wolf (ERG), September 8-9, 2014

The amount of annual gasoline and diesel fuel consumption for nonroad equipment was then allocated to each SCC based on the fuel use fraction calculated from the NONROAD outputs. The amount of nonroad gasoline and diesel fuel consumption was determined by subtracting the amount of on-road gasoline and diesel from the total gasoline and diesel quantities. Once the amount of fuel used by each piece of equipment was calculated, the tons per gallon emission factor derived from the NONROAD outputs were applied, resulting in a total emissions estimate for each SCC and pollutant combination.

6. *Road Dust*

Dust emissions are generated from vehicle and equipment travelling over unpaved roads located in villages and other areas within the North Slope. Figure III-16 shows one of the major roads in Barrow (Eben Hopson Street) and its unpaved road surface. Although paved road dust is also typically included in regional emissions inventories, no sufficiently important paved areas were identified in the North Slope.

Figure III-16. Eben Hopson Street, Barrow, and the Unpaved Road Surface

Photo courtesy of M. Wolf (ERG), September 7, 2014

Emissions were estimated by multiplying unpaved road VMT by emission factors derived from empirical equations found in AP-42, Section 13.2.2 (U.S. EPA, 1995). The annual average daily VMT for Barrow was estimated at 16,163 VMT based on the AADT, which was then extrapolated to the other villages based upon population.

Detailed vehicle traffic information was available for the Dalton Highway. Based upon ADOT&PF data, there are 20,588 daily VMT from the Atigun River to Deadhorse – approximately 82 percent of this VMT was determined to be from trucks (ADOT&PF, 2013). As described in Section III.C, two daily surveillance patrols were assumed to traverse the entire length of the TAPS pipeline. These patrols correspond to daily VMT of 354 miles and annual VMT of 129,564 miles.

As described in Section III.D.4, a total of 2,775,000 gallons of gasoline are consumed annually in the Prudhoe Bay oil and gas field; this quantity of gas corresponds to 23,339,562 VMT.

Unpaved road dust emissions for the North Slope villages were calculated using the following two equations (U.S. EPA, 1995):

$$E_{ur} = VMT_{ur} \times EF_{ur} \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$

$$EF_{ur} = \left[\frac{k \times \left(\frac{s}{12}\right)^{a} \times \left(\frac{S}{30}\right)^{d}}{\left(\frac{M}{0.5}\right)^{c}} - C\right] \times \left(1 - \left[\frac{P}{N}\right]\right)$$

where:

E_{ur}	=	Emissions from unpaved road dust (tons)
VMT_{ur}	=	Unpaved road VMT (miles)
EF_{ur}	=	Unpaved road dust emission factor (lbs/VMT)
s	=	Surface material silt content (%)
S	=	Mean vehicle speed (mph)
M	=	Surface material moisture content (%)
C	=	Emission factor for exhaust, brake wear, and tire wear (0.00047 lb/VMT for PM_{10}; 0.00036 lb/VMT for $PM_{2.5}$)
k	=	Empirical particle size multiplier (1.8 lb/VMT for PM_{10}; 0.18 lb/VMT for $PM_{2.5}$)
a	=	Empirical constant (1.0 for PM_{10} and $PM_{2.5}$)
c	=	Empirical constant (0.2 for PM_{10} and $PM_{2.5}$)
d	=	Empirical constant (0.5 for PM_{10} and $PM_{2.5}$)
P	=	Number of "wet" days during averaging period with ≥ 0.01 inches precipitation
N	=	Number of days in the averaging period (i.e., 365 for annual).

The following alternative emission factor equation for unpaved surfaces at industrial sites was used for the Dalton Highway, the Prudhoe Bay oil and gas fields, and the TAPS patrols:

$$EF_{ur} = k \times \left(\frac{s}{12}\right)^a \times \left(\frac{W}{3}\right)^b \times \left(1 - \left[\frac{P}{N}\right]\right)$$

where:

EF_{ur}	=	Unpaved road dust emission factor (lbs/VMT)
s	=	Surface material silt content (%)
W	=	Mean vehicle weight (tons)
k	=	Empirical particle size multiplier (1.8 lb/VMT for PM_{10}; 0.18 lb/VMT for $PM_{2.5}$)
a	=	Empirical constant (1.0 for PM_{10} and $PM_{2.5}$)
b	=	Empirical constant (0.45 for PM_{10} and $PM_{2.5}$)
P	=	Number of "wet" days during averaging period with ≥ 0.01 inches precipitation
N	=	Number of days in the averaging period (i.e., 365 for annual)

Although silt content samples were not collected on the North Slope in this study, ERG identified a silt content value of 25 percent that was previously collected on the Dalton Highway (Walker and Everett, 1987). This value was used for all unpaved dust calculations. An average speed of 35 mph was assumed for vehicle travel in the villages. Because moisture content samples were not collected, a default value of 0.5 percent (i.e., the unadjusted correction parameter when local moisture content was not measured) was used for the village unpaved road dust emission calculations (U.S. EPA, 1995).

Both emission factor equations presented above include a correction factor that accounts for the number of days with ≥0.01 inches of precipitation. These precipitation days suppress the production of entrained road dust emissions. Although there are some days during the winter when there is no measureable precipitation, residual snow and ice cover due to extremely low temperatures also prevents the unpaved road dust emissions. Discussions with NSB Public Works Department staff revealed that entrained road dust emissions primarily occur during the summer, between May and October (Lowery, 2014). This temporal adjustment was applied to the annual emissions by multiplying annual emissions by a factor of 0.418 (i.e., 153 days from May to October divided by 366 days [in 2012]).

7. *Waste Burning*

Municipal solid waste (MSW) (i.e., paper, plastics, wood, glass, rubber, leather, textiles, and food wastes) is widely burned in the North Slope landfills to reduce the overall waste volume and to discourage scavenging by wild animals (see Figure III-17). Emissions were estimated by multiplying

Figure III-17. Open waste burning at Wainwright Landfill

Photo courtesy of M. Wolf (ERG), September 10, 2014 landfilled waste quantities by EPA WebFIRE emission factors (U.S. EPA, 2013a) and 2011 U.S. NEI emission factors (U.S. EPA, 2013b).

Waste in Barrow is burned at the Barrow Thermal Oxidation System (TOS) Facility; incinerated MSW quantities were provided by NSB Department of Public Works staff (Heath, 2014). As described in Section III.D.2, the NSB also operated the Service Area 10 Incinerator plant in 2012. However, the quantity of waste burned at the second facility could not be identified, so emissions from this facility were limited to fuel combustion only.

In the remaining seven villages, waste is burned at the community landfills either in a burn box, burn cage, or a trench (as shown in Figure III-17). As far as can be determined, waste is not burned in burn piles or burn barrels located at individual residences in the North Slope villages. For each village landfill, NSB Department of Public Works staff provided the quantity of waste hauled and the quantity of waste landfilled (Heath, 2014); the difference of these two quantities was assumed to be the quantity of waste burned (included in Table A-21 of Appendix A). The provided village waste quantities were for the 2013 fiscal year (i.e., July 2012 through June 2013). It was assumed that these quantities were representative of the 2012 calendar year.

All waste burning emissions were estimated on an annual basis. Specific location coordinates were identified for the Barrow TOS Facility and the village landfills.

8. *Wastewater Treatment*

Wastewater treatment is conducted in each of the eight North Slope villages. The Barrow wastewater treatment plant is a bioreactor membrane filtration system with ultraviolet purification, while the other village wastewater treatment plants are simpler package plants based on an extended activated sludge process. Treated wastewater effluent quantities were provided by NSB Department of Public Works staff (Winalski, 2014a). The NSB also operates a wastewater treatment plant in Service Area 10; however, treated wastewater effluent quantities could not be identified.

Emissions were estimated for VOC, NH_3, and HAP. VOC and NH_3 emissions were estimated by multiplying treated effluent quantities by EPA WebFIRE emission factors (U.S. EPA, 2013a); HAP emission were estimated using speciation fractions from the SPECIATE database (U.S. EPA, 2014c).

9. *Fuel Dispensing*

In addition to the non-oil/gas stationary point, area, and mobile sources listed above, some additional sources were identified. The methods used to estimate emissions from these sources are described below.

Both on-road motor vehicles and nonroad mobile sources are refueled in each of the eight North Slope villages, as well as in the oil and gas fields. Because of the relative higher volatility of gasoline compared to ULSD, only gasoline refueling emissions were estimated.

Barrow is the only village with a "gasoline station" (i.e., ASRC SKW Eskimos); other villages have simple free-standing gasoline and ULSD pumps (see Figure III-18). In Anaktuvuk Pass, Atqasuk, Nuiqsut, Point Lay, and Wainwright, these pumps are located at the village tank farm, while in Kaktovik and Point Hope, they are located at a different location separate from the tank farm (Winalski, 2014b). In the oil and gas fields, vehicles are primarily refueled from refueling trucks.

Refueling emission factors were estimated using the MOVES model without Stage II controls (i.e., no gasoline dispensing pump vapor control devices). The refueling emissions estimates include both displacement vapor and spillage losses. ERG calculated emission factors in units of grams/gallon of gasoline by month. These emission factors were multiplied by the volume throughput at each village gasoline dispensing facility. Emissions were estimated for VOC and HAP.

Figure III-18. (Left) ASRC SKW Eskimos Gasoline Station in Barrow; (Right) Village Fuel Pump in Wainwright

Photo courtesy of M. Wolf (ERG), September 7 and 10, 2014

IV. DEVELOPMENT OF EMISSIONS INVENTORY PROJECTIONS

ERG estimated future year emissions for the sources and activities that are reasonably foreseeable and expected to continue for an extended period of time. The projections reflect a future full-buildout scenario as defined by BOEM (BOEM, 2014b). The projections also include anticipated increases in future emissions from certain onshore sources including: operation of new production facilities; increased TAPS throughput; increased airport activities necessary to support offshore production; and construction and operation of new onshore pipelines to transport the anticipated offshore oil produced. Finally, the projections reflect decreased emissions for a few stationary and area sources that are anticipated to convert to exclusive use of ULSD in the future.

Note that the projected emissions for the future scenario that are described in this section do not represent the total future year projected onshore and offshore emissions. The projections include only the sources and activities that are expected to change (i.e., increase or decrease) in the future. Furthermore, the future year projected emissions should not simply be added to the baseline emissions of the sources that are not expected to change to calculate total future year emissions because onshore oil and gas emissions from existing facilities, and emissions from construction and operation emissions from new facilities will likely not all occur during the same year. Future work by ERG and ENVIRON during the modeling phase of the BOEM Arctic AQ study will define which specific sources should be modeled to determine future air quality impacts; at that time, the total future year inventory will be calculated.

A. Offshore Oil/Gas Related Sources

The offshore projection emissions inventory represents a single future year when offshore operations are “fully built out” and includes operations such as:

- Seismic, geotechnical, geohazard, and on-ice surveys.
- Exploratory drilling.
- Platform construction.
- Gravel island construction.
- Pipelaying.
- Active production platforms.
- Potential spill events.

BOEM developed the offshore projection scenario by BOEM (BOEM, 2014b) for two sites in the Chukchi Sea, and four sites in the Beaufort Sea as noted in Figure IV-1. (The figure also shows the anticipated location of the Liberty (gravel) Island, discussed below in Section IV.B). Table IV-1 summarizes the details concerning the offshore component of the projection scenario.

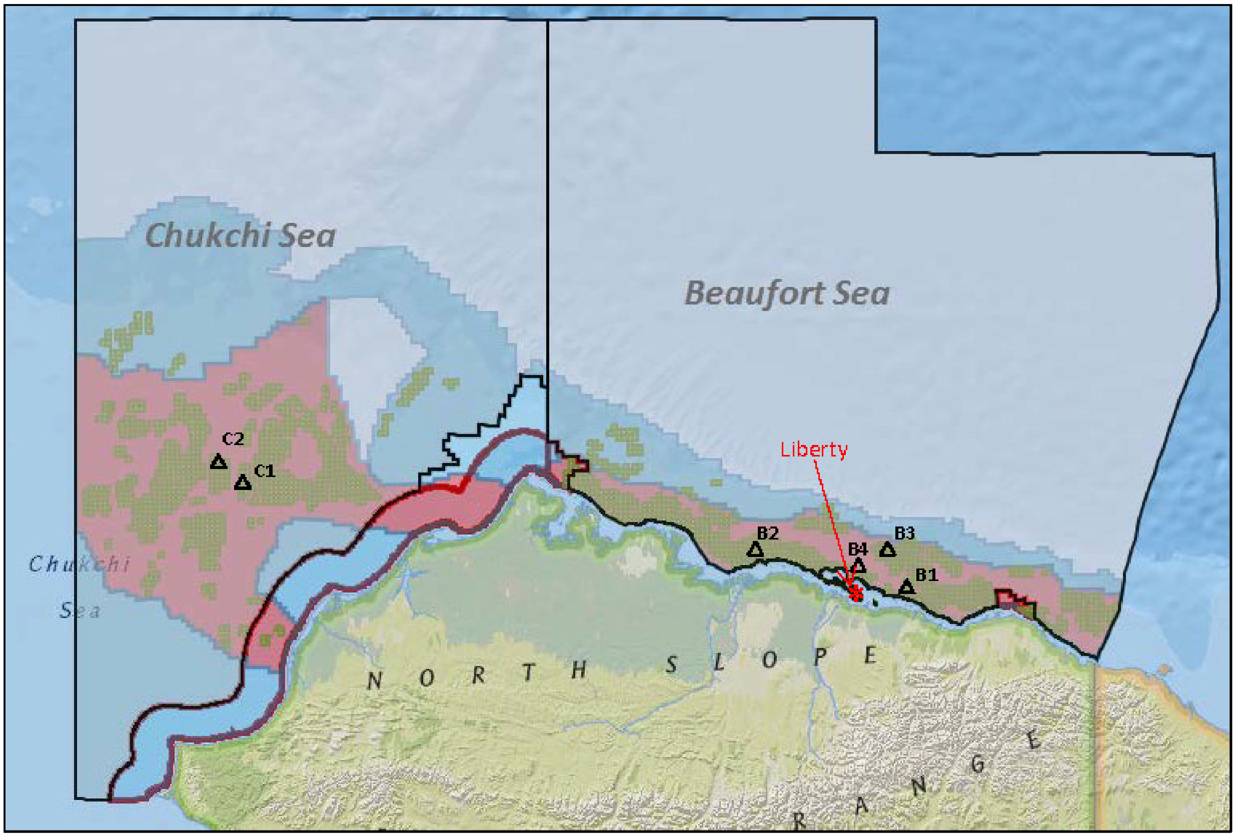

Figure IV-1. Offshore Projected Development Areas
Data Source: BOEM, 2014b

Because the projection scenario does not identify specific vessels and aircraft to be used, actual periods of activities, or actual vessel traffic patterns, a number of assumptions were made. As a result, there is considerable uncertainty associated with the offshore oil and gas projected emission estimates. Actual emissions may be larger than the estimates reported here if, for example, larger vessels or aircraft are used, or the frequency or duration of the activity is greater than predicted. Conversely, actual emissions may be lower than the estimates reported here if smaller vessels or aircraft are used in a more efficient, coordinated logistics operation (e.g., trip sharing), vessels and aircraft are equipped with newer more fuel-efficient engines, or alternative biofuels or LNG are used.

Activities not addressed in this future year scenario include non-oil and gas offshore activities such as CMVs and research vessel operations, as any prediction of future activities for these sources would be highly speculative at this time.

1. *Survey Operations*

As noted in Section II of this report, seismic survey vessels are used in the Arctic to evaluate the possible locations of oil-bearing strata (seismic surveys), assess geologic risk to constructed structures (geohazard surveys), and provide seabed data for platform design and construction (geotechnical surveys).

Table IV-1. Full Build-Out Projections Scenario for Offshore Oil and Gas Activities

		Beaufort Sea	Chukchi Sea
Projected Production			
Production: Gas	BCF/yr	167	115
Production: Oil, Condensate	MMbbl/yr	132	204
Total Platform wells		215	260
Total Subsea Wells		34	90
Projected Activities and Duration (B1, B2, B3, and B4 = Development Areas in the Beaufort Sea; C1 and C2 = Development Areas in the Chukchi Sea)			
Offshore Pipeline Construction	July – October	• 44 miles of new construction • Includes pipelaying vessel, dredge ships, support vessels, helicopters	• 40 miles of new construction • Includes pipelaying vessel, dredge ships, support vessels, helicopters
Seismic Surveys	July – October	8-week run includes survey vessel, support and scout vessels	4-week run includes survey vessel, support and scout vessels
	December – May	1 on-ice operation lasting 4 weeks	None
Geohazard Surveys	July – October	8-week run includes survey and support vessels	8-week run includes survey and support vessels
Geotechnical Surveys		8-week run includes survey and support vessels	8-week run includes survey and support vessels
Exploratory Drilling	July – October	• 1 jackup at B3 and 1 jackup at B4 • Includes support vessels, icebreaker, spill response team, helicopter support	• 2 drill ships at C1 • Includes support vessels, icebreaker, spill response team, helicopter support
Platform Construction	July – October (Gravel island construction December – May)	• 1 gravity-base system constructed at B1 • 1 gravity-base system constructed at B2 • 1 gravel island at Liberty location • Includes support vessels, icebreaker, helicopter support, gravel trucks	• 1 gravity- based system constructed at C1 • Includes support vessels, icebreaker, helicopter support
		• Subsea well construction • 2 jackups at B2 and 1 jackup at B3 • Includes support vessels, helicopter support	• Subsea well construction • 1 jackup and 2 drill ships at C1 • Includes support vessels, helicopter support
Production Platform Operation	Throughout the Year	• 1 platform at B1; 27 on platform wells • 2 platforms at B2; 81 on platform wells, 23 subsea wells • 1 platform at B3; 54 on platform wells, 11 subsea wells • 1 platform at B4; 54 on platform wells, providing a total of 215 on platform wells and 34 subsea wells • Includes platform equipment, support vessels, helicopter support	• 2 platforms at C1; 260 on platform wells and 90 subsea wells • Includes platform equipment, support vessels, helicopter support
		• Production at Liberty Island; 32 wells • Includes platform equipment, support vessels	None

BCF/yr = billion cubic feet per year; MMbbl/yr = million barrels per year. Source: BOEM, 2014b

For the projection scenario, it was assumed that each seismic survey vessel will require a support vessel and an ice-breaker/scout vessel. Similar to the approach for the 2012 seismic survey vessel activity estimates, the seismic survey and support vessels are assumed to have the same characteristics as the *M/V Geo Arctic* and the *Polar Prince*. The scout vessels was assumed to have a power rating of 1,268 kW (BOEM, 2013). For the geohazard and geotechnical surveys, it was assumed that two survey vessels with an average power rating of 1,519 kW each and six support vessels with an average power rating of 824 kW each will be used, based on Arctic survey fleet data compiled by BOEM (BOEM, 2014c).

Table IV-2 summarizes BOEM's projected survey activities including the location and type of survey to be implemented, duration of each survey trip, and composition of each survey fleet.

Table IV-2. Projection Scenario for Seismic Survey Operations

Survey Type	Duration	Fleet Vessel Composition
	Beaufort Sea	
Seismic Surveys	8 weeks	1 survey vessel, 1 support vessel, 1 scout
Geohazard Survey	8 weeks	2 survey vessels, 6 support vessels
Geotechnical Survey	8 weeks	2 survey vessels, 6 support vessels
	Chukchi Sea	
Seismic Surveys	4 weeks	1 survey vessel, 1 support vessel, 1 scout
Geohazard Survey	8 weeks	2 survey vessels, 6 support vessels
Geotechnical Survey	8 weeks	2 Survey vessels, 6 support vessels

Source: BOEM, 2014b

Based on the vessel power rating assumptions listed above and BOEM's projection scenario, the survey vessel activity (kW-hrs) was estimated by multiplying the vessel power rating by hours of operation and the load factor for each vessel, using the same methodology that was used for the 2012 seismic survey vessel activity estimates (see Section II of this report). Table IV-3 summarizes the survey vessel activity for the projection scenario.

Table IV-3. Projection Scenario Seismic Survey Vessel Activity Data

Survey Type	Vessel Type	Vessel Power Rating (kW)	Operation (Hours)	Load Factor	Number of Vessels	kW-hrs
			Beaufort Sea			
Seismic Surveys	Survey vessel	7,576	1,344	90%	1	9,163,930
	Support vessel	3,820	1,344	62%	1	3,170,294
	Scout	1,268	1,344	62%	1	1,052,073
Geohazard Surveys	Survey vessel	1,519	1,344	90%	2	3,675,732
	Support vessel	824	1,344	62%	6	4,101,216
Geotechnical Surveys	Survey vessel	1,519	1,344	90%	2	3,675,732
	Support vessel	824	1,344	62%	6	4,101,216
			Chukchi Sea			
Seismic Surveys	Survey vessel	7,576	672	90%	1	4,581,965
	Support vessel	3,820	1,344	62%	1	1,585,147
	Scout	1,268	1,344	62%	1	526,036

Table IV-3. Projection Scenario Seismic Survey Vessel Activity Data (Continued)

Survey Type	Vessel Type	Vessel Power Rating (kW)	Operation (Hours)	Load Factor	Number of Vessels	kW-hrs
Geohazard Surveys	Survey vessel	1,519	1,344	90%	2	3,675,732
	Support vessel	824	1,344	62%	6	4,101,216
Geotechnical Surveys	Survey vessel	1,519	1,344	90%	2	3,675,732
	Support vessel	824	1,344	62%	6	4,101,216

Sources: BOEM, 2014b; BOEM, 2012b; BOEM, 2012c; BOEM, 2013; Wilson et al., 2014.

The CAP and GHG emissions factors for these survey vessels are for combusting ULSD fuels (15 ppm) and are the same as those shown in Section II, Table II-2. HAP speciation profiles were applied to the PM emissions for metallic HAP and VOC emissions for organic HAP.

CAP and GHG emissions were estimated by multiplying kW-hrs and the emission factor for each vessel, which is the same method used to estimate the 2012 seismic survey vessel emissions (see Section II of this report). CAP and GHG emissions were calculated as follows:

$$E = \text{kW-hrs} \times EF \times CF$$

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)
EF = Emission factor (g/kW-hr)
CF = Conversion factor (g = 1.10231 10^{-6} ton)

Example Calculation:

Total kW-hrs for seismic survey vessel in the Beaufort Sea for the projection year were 9,163,930 kW-hrs. The emission factor for NO_x is 9.8 g/kW-hr.

$$E = 9{,}163{,}930 \times 9.8 \times 0.00000110231$$
$$E = 99 \text{ tons}$$

In addition to survey and support vessels, support helicopters visit the survey vessels to deliver supplies and transfer personnel. This section addresses emissions from the cruise portion of flight between the airport and the survey vessel as well as the LTOs at the survey vessels. (Increased airport LTOs associated with these flights are covered in the onshore projections.) It was assumed that, during the 120-day open water season when the sea ice has melted (July through October), helicopters will fly from the airport to the area where the survey vessels operate three times a week, at a cruising speed of 100 mph. Therefore the total hours per season was calculated to be 174.86 hours. The emissions from the LTOs were calculated using the FAA's EDMS for a Sikorsky SH-60 Sea Hawk (FAA, 2013). Engine load factors specific for cruising operations of a Sea Hawk were not identified there for, the takeoff mode emission factors (100 percent load) were adjusted to 80 percent load to represent cruising engine load conditions, providing a conservative value similar to an equivalent turboprop engine (SDMC, 2014)

Projected activity and emissions were allocated to large shapefiles of the Beaufort and Chukchi Seas. (Specific locations within specific lease blocks to be assigned based on BOEM guidance.)

2. *Exploratory Drilling*

For the projection scenario, exploratory drilling and subsea well construction are expected to continue; both activities will require use of drilling rigs, specifically drillships and jackups. The anticipated drilling activity locations (B1, B2, B3, B4, C1 and C2) are noted in red on Figure IV-2.

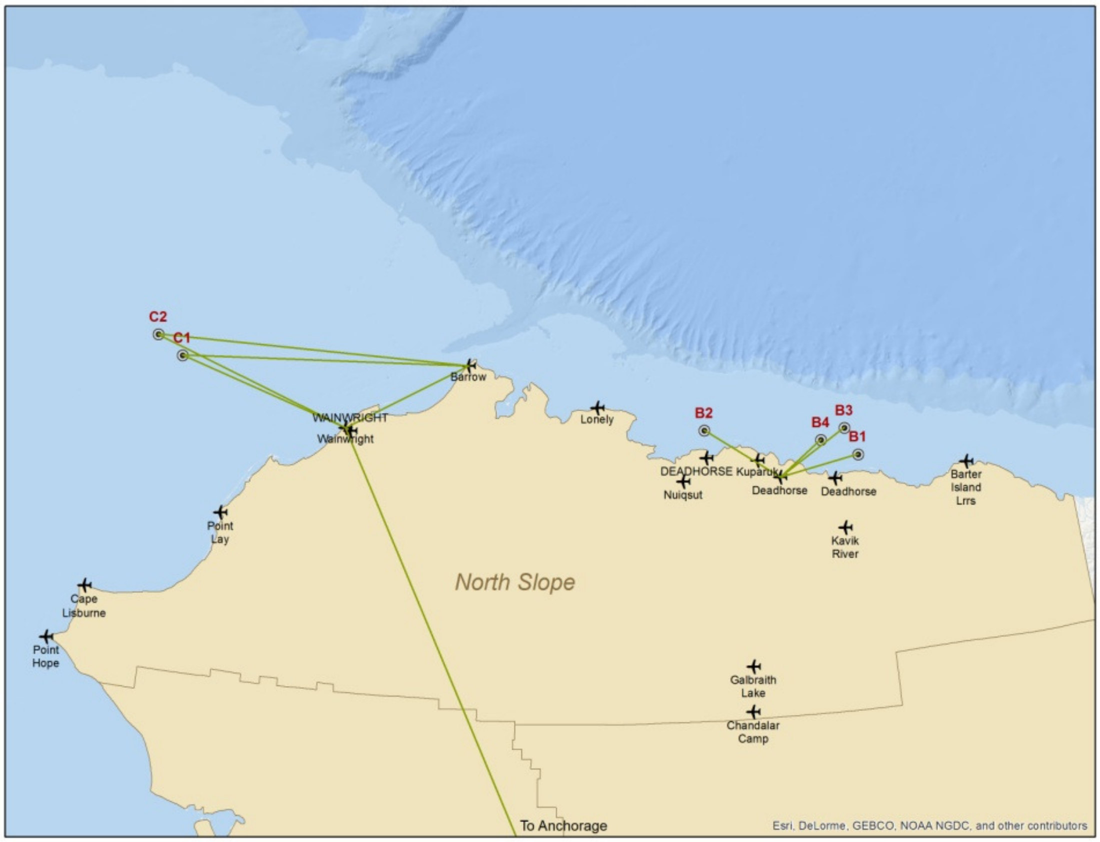

Figure IV-2. Location of Projected Drilling Operations
Data Source: BOEM, 2014b

Using the drilling data (Shell, 2011) and fleet information provided by BOEM (see Section III of this report) daily emission factors were developed for drillships, jackups, and a support fleet. There were no jackup data in the North Slope exploration plans, so average jackup kW ratings from the Gulf of Mexico were used.

BOEM provided projected daily activity (BOEM, 2014b), which is summarized in Table IV-4.

Table IV-4. Projected Drilling Activity

Activity Type	Development Areas	Vessel Type	Number of Vessels	Wells per Vessel	Days per Well	Total Days
Exploratory	B3	Jackup	1	2	38	76
		Support Fleet	1	2	38	76
	B4	Jackup	1	1	38	38
		Support Fleet	1	1	38	38
	C1	Drillship	2	2	38	152
		Support Fleet	1	2	38	76
Subsea Well	B2	Jackup	2	3	38	228
		Support Fleet	1	3	38	114
	B3	Jackup	1	3	38	114
		Support Fleet	1	3	38	114
	C1	Drillship	2	3	38	228
		Jackup	1	3	38	114
		Support Fleet	1	3	38	114

Source: BOEM, 2014b

The total number of drilling days was calculated using the following equation:

$$TDays = V \times W \times D$$

where:

TDays = Total number of drilling days
V = Number of vessels
W = Number of wells per vessel
D = Number of construction days per well

Example Calculation:

For site B3 jackups, the number of vessels is 1, the number of wells per vessel is 2, and the number of construction days per well is 38.

$$TDays = 1 \times 2 \times 38$$
$$TDays = 76 \text{ days}$$

Drilling rig emissions were estimated as follows:

$$EM = EF \times TDays$$

where:

EM = Emissions (tons)
EF = Emission factor (tons/day)
TDays = Total number of days of activity

Example Calculation:

For site B3 exploratory jackups, the total number of drilling days is projected to be 76, and the emissions factor for NO_x is 4.899 tons per day.

$$EM = 4.899 \times 76$$
$$EM = 372.324 \text{ tons of } NO_x$$

Projected drilling operations will also include helicopters and airplanes. Projected emissions from these sources are described in Section IV.C, below.

At the Chukchi sites, the helicopters were assumed to fly 12 round trips a week from Barrow Airport to the drilling sites at three hours per trip. Airplanes were assumed to fly four times a week between Wainwright Airport and Barrow Airport to bring supplies to the helicopters at Barrow Airport (Shell, 2011). The Saab 340-B cruising speed is 290 mph and the distance between the airports is 86.66 miles. At the Deadhorse Airport, helicopters were assumed to fly 12 round trips a week at three hours per trip based on offshore permit data. Wildlife monitoring aircraft were assumed to fly seven times a week at six hours a trip. It was also assumed that when the helicopters fly to the drilling sites, they will land at more than one drilling rig; therefore, each trip will have multiple LTOs at the drilling sites but only one LTO at the airport. Helicopters and airplanes were assumed to fly for the entire 120-day open water season when the sea ice has melted (July through October).

Airplane and helicopter LTO emissions were estimated using the FAA's EDMS (FAA, 2013). For the cruise portion of both, the takeoff mode emission factors (at 100 percent load) were adjusted to 80 percent load, to represent cruising engine load conditions and provide a value similar to an equivalent turboprop engine (SDMC, 2014).

Drilling emissions were allocated to the latitude and longitude coordinates of the development area sites, as shown in Figure IV-2, above. Support vessel emissions were assigned to shapefiles between the development area sites and the nearest port, and helicopter and aircraft emissions were assigned to shapefiles between the development area sites and the nearest airport.

3. *Pipelaying and Associated Support Vessels*

Pipelines link offshore platforms to onshore refineries and storage facilities and connect to other pipelines. Pipelines are constructed using special pipelaying vessels. There are two types of pipelaying vessels: vessels installing flexible pipe that is unwound from giant reels (S lay), and vessels installing ridged pipe that is welded together while at sea (Figure IV-3). Pipelaying vessels also install underwater valves and pumps, which requires using large heavy-lift cranes.

Figure IV-3. S Lay Pipelaying Vessel Allseas' *Soltaire*

Image from Allseas' Equipment Gallery. © Used by Permission.

Pipelaying vessels can be self-propelled ships equipped with Category 2 or 3 propulsion engines and Category 2 auxiliary engines or they can be non-self propelled barges that require tugs to tow them to the site. These barges are specifically designed to lay pipe and equipped with large auxiliary engines.

Pipelaying vessel emissions include estimates for vessels providing pipeline construction services, as well as associated support vessels and dredges. The pollutants estimated for these vessels are NO_x, SO_2, VOC, CO, PM_{10}, $PM_{2.5}$, Pb, GHGs, HAP, and NH_3. CAP and GHG emissions were estimated by applying emission factors to activity data for the projection scenario provided by BOEM. HAP emissions were estimated by applying HAP speciation profiles to PM emissions for metallic HAP and VOC emissions for organic HAP.

The projected pipelaying activity data were derived from the vessel power rating, load factor, and hours of operation in terms of kW-hrs. The vessel power rating is assumed to be 67,200 kW based on a representative ice class pipelaying vessel (Saipem, 2014), and 3,820 kW for associated support vessels (BOEM, 2012b). The hours of operation were based on total pipeline length in miles constructed in both the Beaufort and Chukchi Seas (BOEM, 2014b). Table IV-5 lists the projected pipeline length for the projection year.

Table IV-5. Projected Offshore Pipeline Lengths (miles)

Location	Pipeline Length (miles)
Beaufort Sea	44
Chukchi Sea	40

Source: BOEM, 2014b

Each pipelaying vessel was assumed to require four support vessels (BOEM, 2014b). The pipelaying vessels and their associated support vessels were also assumed to operate 24 hours per day laying pipe at a rate of 1 mile per day (Athmer and Gijzel, 2006). The total vessel hours were estimated based on the following equation:

$$T_{pi} = L_i \times 1 \text{ mile/day} \times 24 \text{ hrs/day}$$

where:

T_{pi} = Total vessel time involved in pipelaying for Sea i (hours)
L_i = Length of new pipeline within the boundaries of Sea i (miles)

Example Calculation:

The total length of pipeline in the projection scenario for Beaufort Sea is 44 miles.

$$T_{pi} = 44 \times 1 \times 24$$
$$T_{pi} = 1{,}056 \text{ vessel-hours}$$

The projected vessel-hours associated with new pipeline construction total 1,056 vessel-hours for the Beaufort Sea and 960 vessel-hours for Chukchi Sea.

Figure IV-4. *DCI Dredge Aquarious*
Online image from Dredgepoint.org.
https://www.dredgepoint.org/dredging-database/owners/zanen-verstoep
(Accessed November 24, 2014.)

It was assumed that two dredging vessels are also required for pipelaying activities: one cutter suction dredger, such as the *DCI Dredge Aquarious* (shown Figure IV-4) and one trailing hopper dredger, such as the *Kaishuu* (shown in Figure IV-5). The cutter suction dredger is used to dredge down into the sea bed prior to pipelaying. Once pipelaying is complete, the trailing hopper dredge covers the pipeline to protect it from ice flow in shallow waters. Each dredge type was assumed to operate 24 hours a day for 30 days, which assumes a dredging rate of 100 cubic meters per hour for a trench three meters deep by three meters wide extending from shore approximately 4.5 miles (CEDA, 2014).

Figure IV-5. *Kaishuu*
Online image from Dredgepoint.org.
https://www.dredgepoint.org/dredging-database/owners/zanen-verstoep
(Accessed November 24, 2014.)

Based on an inventory of representative cutter suction dredges (Athmer and Gizel, 2006), the average vessel power rating for cutter suction dredges was assumed to be 16,575 kW with an average cruising speed of 11.3 knots. Similarly, the average vessel power rating for trailing hopper dredges was assume to be 16,981 kW with an average vessel cruising speed of 14.3 knots.

The following load factors for these vessels were assumed: 80 percent for pipelaying vessels, 62 percent for support vessels (Marintek, 2010), and 63 percent for dredge vessels (U.S. EPA, 2009c). Pipelaying vessel activity was estimated as follows:

$$\text{kW-hrs} = \text{kW} \times \text{LF} \times \text{hrs} \times N_v$$

where:

kW = Vessel power rating (kilowatt)
LF = Load factor (%)
hrs = Adjusted number of operating hours for each vessel
N_v = Number of vessels

Example Calculation:

Total hours of operation for the pipelaying vessels in the Beaufort Sea were 1,056. The power rating was 67,200 kW, and the load factor was 0.80.

kW-hrs = 67,200 × 0.80 × 1,056 × 1
kW-hrs = 56,770,560

Table IV-6 summarizes the pipelaying activity.

Table IV-6. Projected Pipelaying Activity Data

Location	Vessel Type	kW-Hrs
Beaufort Sea	Pipelaying	56,770,560
	Support	9,963,782
	Dredge - Cutter	7,518,193
	Dredge - Trailing Hopper	7,702,582
Chukchi Sea	Pipelaying	51,609,600
	Support	9,057,984
	Dredge - Cutter	7,518,193
	Dredge - Trailing Hopper	7,702,582
	Total	**157,843,476**

Sources: BOEM, 2014b; Athmer and Gijzel, 2006; CEDA, 2014; Marintek, 2010; U.S. EPA, 2009c

These activity data were applied to the GREET's CAP and GHG emission factors and HAP speciation profiles. The emissions factors associated with the pipelaying, support, and dredging vessels were based on use of ULSD fuels (15 ppm) as noted in the Shell Exploration Plan (Shell, 2011). The CAP emission factors applied to the pipelaying vessel activity data are shown above in Section II, Table II-2.

CAP and GHG emissions were estimated by multiplying kW-hrs by the emission factor for each vessel type. HAP speciation profiles were applied to PM emissions for metallic HAP and VOC emissions for organic HAP. CAP and GHG emissions for pipelaying vessels and associated support and dredging vessels were calculated as follows:

E = kW-hrs × EF × CF

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)
EF = Emission factor (g/kW-hrs)
CF = Conversion factor (g = 1.10231 x 10^{-6} ton)

Example Calculation:

Total kW-hrs for the pipelaying vessel in the Beaufort Sea for the projection year were 6,770,560 kW-hrs. The emission factor for NO_x is 9.8 g/kW-hr.

$$E = 56{,}770{,}560 \times 9.8 \times 0.00000110231$$
$$E = 613 \text{ tons}$$

Pipelaying emissions were allocated to shapefiles between the development area sites and the nearest port.

4. *Platform Construction*

Various types of offshore platforms such as fixed platforms, floating spars, and tension leg platforms are used for offshore extraction such as fixed platforms, floating spars, and tension leg platforms. In BOEM's scenario it is anticipated that the platforms to be constructed offshore of the North Slope will be gravity-based structures (GBS) built to withstand winter ice flows (see Figure IV-6; Malyutin and Kalinsky, 2007). Globally there are about 35 GBS operating.

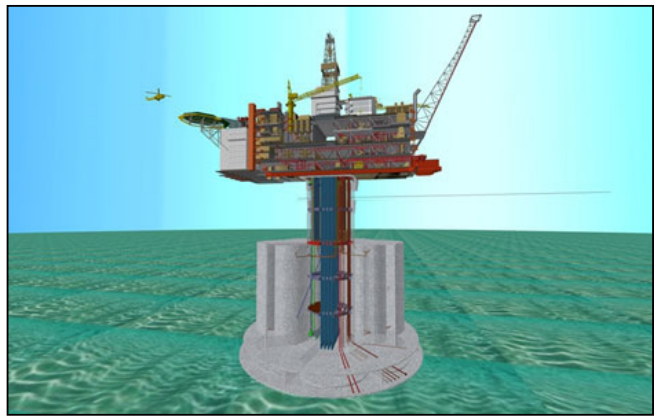

Figure IV-6. Gravity Base System
Image from Sonistics.com. © Used by Permission.

GBS platforms are typically constructed offsite at a dry dock or adjacent to a protected harbor. The base and topside are constructed separately. The base is typically towed to a deep water location where water is pumped into the structure allowing it to sink below the surface. Next, the topside structure is positioned above the base, and compressed air is added allowing the base to rise, connecting it to the topside structure. The combined base and topside structure are then towed to the site where the GBS will operate. Once the GBS is at the site, the platform is carefully positioned and ballast water is added to the base allowing it to slowly sink to the sea bed. Then the ballast water is displaced with denser material such as stone, sand, or concrete to provide the necessary mass needed to secure the base to floor of the sea (PetroWiki, 2013; Vos, 1995).

The projected year emissions inventory includes vessels involved in towing the GBS to the site, positioning the platform, ballasting the base, as well as support vessel and helicopter activities necessary to complete the platform construction.

In developing emission estimates for the projected offshore platform construction, ERG identified other applications similar to those expected in the Arctic (EMCP, 2010), and determined the Hibernian Platform off the coast of Newfoundland, Canada, to be an appropriate model on which to base Arctic GBS activities (Offshore-Technology, 2011; SubseaIQ, 2011; Kverner, 2011). The Hibernian is larger than what would be needed because it was designed for

75-foot waves and icebergs, while in the Arctic the maximum wave height is 16 feet, and there are no icebergs, although all Arctic platforms must be able to withstand extended periods of ice flow. Therefore, the Hibernian construction vessel fleet was adjusted (e.g., the number of tugs used to tow the GBS to the site was reduced from six puller tugs and three steering tugs to four puller tugs and two steerer tugs, and two icebreakers were added).

As with other GBSs, it is assumed that the platforms in the Arctic will be constructed offsite (not on the North Slope as special dry docks or deep water locations are needed), probably elsewhere in Alaska or the western coast of Canada and transported to offshore locations in the Beaufort and Chukchi Seas. During towing, a platform will travel at 2 mph. BOEM has developed maps of the most direct routes to the projected platform construction sites using GIS mapping tools. This mapping activity provides an estimate of the travel distances with which to calculate the period of time each GBS would be towed to site. Table IV-7 summarizes the various distances from the western edge of the Chukchi Sea to the oil platform sites (BOEM, 2014b).

Table IV-7. Distances from Construction Sites to Projected Platform Sites

Site	Number of Platforms	Miles
Beaufort Sea: B1	1	712.7
Beaufort Sea: B2	1	647.3
Chukchi Sea: C2	1	208.7

Source: BOEM, 2014b

It was assumed that it will take 40 hours (compared to the 70 hours for the Hibernian) for the tugs to set the platform in place. After the platform is set, two support tugs will be needed for transporting ballast material (i.e., rock, sand, or cement) to the platforms for one month (compared to the two-month period for the Hibernian). Lastly, it is assumed that two support vessels will continue activities during the remaining open water season (2.5 months), to transfer supplies and crew changes to complete platform construction.

Table IV-8 summarizes the specific units, operational characteristics, and activity data anticipated for the various vessels used for GBS platform construction (AT, 2014; BOEM, 2014b; Bruijn, 1998; Shell, 2011).

Table IV-8. Units, Operational Characteristics, and Activity Predicted for GSS Platform Construction Vessels in the Arctic

Site	Vessel	Unit Types	Hours	Engine Power (kW)	Load	Activity (kW-hrs)
B1	Ice-breakers	Propulsion and Generation	793	37,816	0.6	17,986,797
	Ice-breakers	Heaters and Boilers	793	895	0.8	567,502
	Towing Tugs	Propulsion and Generation	2,378	4,325	0.6	6,171,472
	Ballasting Tugs	Propulsion and Generation	1,440	2,983	0.6	2,577,136
	Resupply Ship/Support	Propulsion and Generation	3,527	2,983	0.6	6,312,789

Table IV-8. Units, Operational Characteristics, and Activity Predicted for GSS Platform Construction Vessels in the Arctic (Continued)

Site	Vessel	Unit Types	Hours	Engine Power (kW)	Load	Activity (kW-hrs)
B2	Ice Breakers	Propulsion and Generation	727	37,816	0.6	16,503,106
	Ice Breakers	Heaters and Boilers	727	895	0.8	520,690
	Towing Tugs	Propulsion and Generation	2,182	4,325	0.6	5,662,401
	Ballasting Tugs	Propulsion and Generation	1,440	2,983	0.6	2,577,136
	Resupply Ship/Support	Propulsion and Generation	3,593	2,983	0.6	6,429,819
C1	Ice Breakers	Propulsion and Generation	289	37,816	0.6	6,549,800
	Ice Breakers	Heaters and Boilers	289	895	0.8	206,653
	Towing Tugs	Propulsion and Generation	866	4,325	0.6	2,247,310
	Ballasting Tugs	Propulsion and Generation	1,440	2,983	0.6	2,577,136
	Resupply Ship/Support	Propulsion and Generation	4,031	2,983	0.6	7,214,912

Derived from BOEM, 2014b (activity data); Wilson et al., 2014 (load factors).

GSB platform construction vessel activity was calculated as follows:

$$\text{kW-hrs} = \text{kW} \times \text{LF} \times \text{hrs} \times N_v$$

where:

kW = Vessel power rating (kW)
LF = Load factor (%)
hrs = Adjusted number of operating hours for each vessel
N_v = Number of vessels

Example Calculation:

The ice-breaker vessels at site B1 have a power rating of 37,816.2 kW. The number of operating hours was 396.36 hours per vessel, the number of vessels was 2, and the load factor was 60 percent.

kW-hrs = 37,816.2 × 0.6 × 396.36 × 2
kW-hrs = 17,986,797 kW-hrs

These activity data are applied to the GREET marine vessel CAP and GHG emission factors (ANL, 2013; Shell, 2011) and speciation profiles for engines using ULSD fuels, which were also used for the drilling vessels. Emissions from platform construction include NO_x, SO_2, VOC, CO, PM_{10}, $PM_{2.5}$, Pb, GHGs, HAP, and NH_3.

The platform construction vessel emissions were calculated as follows:

$$E = \text{kW-hrs} \times \text{EF} \times \text{CF}$$

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)
EF = Emission factor (g/kW-hrs)
CF = Conversion factor (g = 1.10231×10^{-6} ton)

Example Calculation:

The ice-breaker vessels at site B1 are projected to have a total of 17,986,797 kW-hrs. The emission factor for NO_x is 1.6 g/kW-hr.

$$E = 17{,}986{,}797 \times 1.6 \times 0.00000110231$$
$$E = 31.7 \text{ tons of } NO_x \text{ from ice breakers' propulsion and generation}$$

This projected platform construction scenario also assumes three helicopter trips weekly for personnel transfers using a Sikorsky S-61N. This helicopter model is not included in the FAA's EDMS; therefore, a similar helicopter, the Sikorsky SH-60 Sea Hawk, was used as a surrogate.

The helicopter LTO emissions were estimated using the FAA's EDMS (FAA, 2013). Engine load factors specific for cruising operations of a Sea Hawk were not identified, therefore, the takeoff mode emission factors (100 percent load) were adjusted to 80 percent load to represent cruising engine load conditions, providing a conservative value similar to an equivalent turboprop engine (SDMC, 2014).

Construction emissions were allocated to shapefiles of the shipping lane used to tow the platforms from the western border of the Chukchi Sea to the development area sites (e.g., in the Beaufort Sea, B1 and B2 and the Chukchi Sea, C2). Support vessel emissions were assigned to shapefiles between the development area sites and the nearest port, while helicopter emissions were assigned to shapefiles between the development area sites and the nearest airports.

5. *Platform Operation and Associated Support Vessels*

Constructed platforms are put into operation to drill production wells, extract crude and gas from the sea bed, re-inject gas to maintain site production rates, and pump product to shore. The process of extracting and pumping oil and gas to shore creates combustion and evaporative emissions from the following emission units (Wilson, et al., 2014):

- Boilers/heaters/burners
- Diesel engines
- Drill rig system
- Combustion flares
- Fugitive sources
- Glycol dehydrators
- Loading operations
- Mud degassing
- Natural gas engines
- Natural gas turbines
- Pneumatic pumps
- Pressure/level controllers
- Storage tanks
- Cold vents

Amine units, used to remove sulfur from the crude, are sometimes used on offshore platforms. However, it is assumed that these will not be used on production wells offshore in the Arctic because amine units are not used in similar offshore oil and gas production platforms in the Cook Inlet, Alaska.

Because there are currently no production platforms in the Chukchi or Beaufort Seas, details concerning the actual unit process configurations for Arctic platforms are unknown. Emission profiles for projected offshore production platforms were derived from available data from some of the larger offshore platforms operating in Cook Inlet. The representative Cook Inlet platforms are the following: Dolly Varden, Grayling, King Salmon, and Steelhead.

Emissions data for these platforms were compiled from the EPA's 2011 NEI and the GHGRP, and the GHGRP subpart C (combustion sources) and subpart W (petroleum and natural gas systems) data submittals for RY2012. The number of wells for each platform was obtained from the *Cook Inlet Facility Assessment: Report, Final Draft* (CH2MHILL, 2013).

An emissions profile was developed for each pollutant at each production platform (Tables IV-11 and IV-12), using the equation below, then averaged to obtain an estimate of average emissions per well.

$$EP_i = EM / n$$

where:

EP_i = Emissions per well by pollutant, i
EM = Compiled emissions (tons/yr)
n = Total number of wells per production platform

This approach assumes the ratio of production versus injector wells for the Arctic offshore platforms will be similar to the Cook Inlet platforms. In addition, the NEI includes only the most important sources on the platform (i.e., minor or sources that occur occasionally are not included in the NEI data); therefore, actual emissions from production platforms may be slightly larger than the values calculated for this study.

Example Calculation:

In 2011, NO_x emissions from the Dolly Varden Platform for natural gas turbine engines totaled 180.08 tons, and the number of wells for this platform was 37.

$$EP_i = 180.08 / 37$$
$$EP_i = 4.87 \text{ tons of } NO_x \text{ per well}$$

The CAP and GHG emissions per well for Cook Inlet platforms are listed in Tables IV-9 and IV-10, respectively. As stated above, these average emissions per well for the Cook Inlet platforms were applied to the projected number of production wells for each development area (e.g., B1, B2, B3, B4, and C1) included in BOEM's projection scenario to obtain emissions for the Arctic platforms.

Table IV-9. Average Criteria Pollutant Emissions per Well for Cook Inlet

Description	Dolly Varden Platform	Grayling Platform	King Salmon Platform	Steelhead Platform
CO (tons)				
Natural Gas Boiler, < 10 MMBtu/hr	0.06	0.06	0.06	-
Reciprocating Diesel Engine	0.03	0.04	0.05	0.15
Natural Gas Turbine Engine	2.74	2.05	1.30	1.31
Large Bore Diesel Engine	0.03	-	0.0004	-
Natural Gas Production Flares	0.43	0.74	0.58	0.51
NO_x (tons)				
Natural Gas Boiler, < 10 MMBtu/hr	0.07	0.07	0.08	-
Reciprocating Diesel Engine	0.15	0.17	0.25	0.68
Natural Gas Turbine Engine	4.87	9.32	4.73	5.73
Large Bore Diesel Engine	0.12	-	0.001	-
Natural Gas Production Flares	0.08	0.14	0.11	0.09
PM_{10} (tons)				
Natural Gas Boiler, < 10 MMBtu/hr	0.01	0.01	0.01	-
Reciprocating Diesel Engine	0.01	0.01	0.02	0.04
Natural Gas Turbine Engine	0.14	0.20	0.13	0.21
Large Bore Diesel Engine	0.004	-	-	-
Natural Gas Production Flares	0.03	0.05	0.04	0.04
$PM_{2.5}$ (tons)				
Natural Gas Boiler, < 10 MMBtu/hr	0.01	0.01	0.01	-
Reciprocating Diesel Engine	0.01	0.01	0.02	0.04
Natural Gas Turbine Engine	0.14	0.20	0.13	0.21
Large Bore Diesel Engine	0.004	-	-	-
Natural Gas Production Flares	0.03	0.05	0.04	0.04
SO_2 (tons)				
Natural Gas Boiler, < 10 MMBtu/hr	0.12	0.02	0.13	-
Reciprocating Diesel Engine	0.001	0.0003	0.01	0.01
Natural Gas Turbine Engine	3.37	0.98	3.27	0.003
Large Bore Diesel Engine	0.005	-	-	-
Natural Gas Production Flares	0.19	0.07	0.25	-
VOC (tons)				
Natural Gas Boiler, < 10 MMBtu/hr	0.004	0.004	0.004	-
Reciprocating Diesel Engine	0.01	0.01	0.02	0.04
Natural Gas Turbine Engine	0.04	0.06	0.04	0.07
Large Bore Diesel Engine	0.003	-	-	-
Natural Gas Production Flares	0.07	0.13	0.10	0.09
Natural Gas Boiler, >10 MMBtu/hr	-	-	-	0.04

MMBtu/hr = million British Thermal Units per hour. Source: ADEC, 2013

Table IV-10. Average GHG Emissions per Well for Cook Inlet

Description	Dolly Varden Platform	Grayling Platform	King Salmon Platform	Steelhead Platform
CH_4 (tons)				
Combustion Flares	3.38	2.83	3.08	1.28
Mud Degassing	-	-	-	22.3
Fugitive Emissions	120	197	127	297
Combustion Sources	0.08	0.11	0.07	0.12
CO_2 (tons)				
Combustion Flares	148	125	137	60
Mud Degassing	-	-	-	0.004
Combustion Sources	4,435	5,933	3,954	6,054
N_2O (tons)				
Combustion Flares	0.81	0.68	0.74	0.32
Combustion Sources	0.01	0.01	0.01	0.01

"-" indicates pollutant not reported for the platform. Sources: ADEC, 2013; CH2MHill, 2013

The average Cook Inlet platform emissions per well were applied to the projected number of production wells for each development area (e.g., B1, B2, B3, B4, and C1) in BOEM's projection scenario as noted in Table IV-11, using the following equation:

$$EM_p = EP_i \times N$$

where:

EM_p = Projected emissions per developmental area (tons/yr)
EP_i = Average emissions per well by pollutant, i
N = Projected number of wells per developmental area

Table IV-11. Projected Number of On-platform and Subsea Production Wells

Location	Well Type	Development Areas	Number of Wells
Beaufort Sea	On-platform	B1	27
Beaufort Sea	On-platform	B2	81
Beaufort Sea	On-platform	B3	54
Beaufort Sea	On-platform	B4	54
Beaufort Sea	Subsea	B2	23
Beaufort Sea	Subsea	B3	11
Chukchi Sea	On-platform	C1	260
Chukchi Sea	Subsea	C1	9
Liberty Island[a]	-	-	32

[a] Liberty Island data are provided as a production unit with 32 wells and in Section IV.B.3 where construction and drilling are addressed.
Source: BOEM, 2014b

Example Calculation:

The projected number of on-platform wells in the developmental area B1 was 27, and the average emissions per well for NO_x was 6.16 tons per year for natural gas turbine engines.

$EM_p = 6.16 \times 27$
$EM_p = 166$ tons of NO_x

In addition to emission sources located on each production platform, support helicopters also visit the production platforms to drop off supplies and transfer personnel. Three helicopter trips per week were assumed to occur for personnel transfers using a Sikorsky SH-60 Sea Hawk (i.e., used as a surrogate).

For the cruise portion of the helicopter emissions, the takeoff mode emission factors (100 percent load) was adjusted to 80 percent load to represent cruising engine load conditions providing a conservative value similar to an equivalent turboprop engine (SDMC, 2014). These emissions were allocated at the most direct flight path between the airport and the site. Support vessels regularly visit the platforms to deliver supplies, equipment, and personnel. Table IV-12 summarizes the assumed activity per site based on two support vessels per platform at each site operating 24 hours a day for the 120-day season.

Table IV-12. Projected Support Vessel Activity (kW-hr) Associated with Platform Production

Site	Total Hours	Power Rating (kW)	Load Factor	Total kW-Hrs
C1	11,520	2,983	80%	27,489,933
B1	5,760	2,983	80%	13,744,966
B2	11,520	2,983	80%	27,489,933
B3	5,760	2,983	80%	13,744,966
B4	5,760	2,983	80%	13,744,966

Derived from Wilson et al., 2014

To estimate emissions, these support vessel activity data (kW-hrs) were applied to the CAP, GHG, and NH_3 emission factors. HAP speciation profiles were applied to PM and VOC estimates to quantify the HAP emissions. The emissions factors used for support vessels were based on using ULWD fuels (15 ppm). The CAP emission factors applied to the support vessel activity data are shown in Section II, Table II-2.

CAP and GHG emissions for support vessels and associated dredging and support vessels were calculated as follows:

$$E = \text{kW-hrs} \times EF \times CF$$

where:

E = Emissions (tons)
kW-hrs = Annual activity data (kilowatt-hours)

EF = Emission factor (g/kW-hrs)
CF = Conversion factor (g = 1.10231×10^{-6} ton)

Example Calculation:

The total kW-hrs at site C1is projected to be 27,489,933 kW-hrs. The emission factor for NO_x is 9.8 g/kW-hr.

$$E = 27{,}489{,}933 \times 9.8 \times 0.00000110231$$
$$E = 297 \text{ tons of } NO_x$$

Production emissions were allocated to the appropriate development area sites. Support vessel emissions were assigned to shapefiles between the development area sites and the nearest port, while helicopter emissions were assigned to shapefiles between the development area sites and the nearest airports.

6. *Spills*

BOEM anticipates that there may be emissions associated with spills from oil and gas exploration and production activities in the Chukchi and Beaufort Seas. This includes evaporation from the spill and emissions associated with operating the spill response vessels.

Oil spills can occur at any time, but recovery efforts will be particularly challenging during periods of extreme cold, which may include the presence of sea ice, high winds, strong water currents, and limited visibility due to short daylight hours during the winter months.

To estimate air emissions from offshore oil spills, BOEM provided the following volumes of crude and diesel that would be spilled was provided by BOEM (BOEM, 2014b):

- 1,700 barrels of crude leaked from underwater pipeline.
- 5,100 barrels of crude spilled from offshore platform.
- 48 barrels of diesel spilled from offshore platform.

It was assumed that wind speeds in the Chukchi and Beaufort Seas will average from 5 to 9 mph, be directed primarily to the southwest and south (Woodgate et al., 2004; Hopcroft et al., 2008), and increase during the summer and fall when sea ice is at its annual minimum. Surface water currents in the central Chukchi Sea flow northward, while currents along the North Slope coastline flow northward along the coast to Point Barrow and then either northward or eastward along the North Slope shore. Given these typical wind and water currents, it is expected that when there is no sea ice, spills in the Chukchi Sea will be driven by wind away from the coast or along the coast, while spills in the Beaufort Sea will be driven toward the shore. When the surface is covered in sea ice, spills may be trapped in sea ice.

It was assumed that the composition of the crude oil used in modeling emissions from spills in the Chukchi and Beaufort Seas will be equivalent to that produced on the North Slope (Wang, et al., 2003). North Slope crude oil is heavy crude with a VOC content of 33 percent and a HAP content of 3.26 percent (API, 2011). The composition of diesel used in modeling emissions from spills will be a commercial diesel with a VOC content of 55 percent and a HAP content of 2 percent (API, 2011; Environment Canada, 2001). Evaporative emissions from the volume of oil and diesel spilled were developed using evaporative emission curves that quantified the range of emissions from an offshore spill for different water temperatures. Film thickness of the spill is not considered in evaporation calculations, as both crude and diesel spread quickly on water.

The percentage of evaporation versus amount of time occurring after crude oil and diesel spills associated with winter water temperatures (-2°C) and summer water temperatures (5°C) are shown in Figure IV-7 (Wang, et al., 2003; Fingas, 2002) and Figure IV-8 (Environment Canada, 2001; Fingas, 2002). These curves indicate that, even in the coldest months, the majority of the volatile content of spilled crude oil and diesel will evaporate within one to two days. Since most toxic substances in oil tend to be those of lightest molecular weight, the air emissions of the first few days will include the majority of the HAP (U.S. EPA, 1999). Given the quick evaporation of the volatile components of crude oil and diesel, the response time of spill recovery teams will have a direct impact on the total amount of evaporative emissions from any spill. Spills can disperse over a wide area quickly in rough seas (ITOPF, 2014). The experience of cleanup crews in Cook Inlet suggests that diesel spills will fully disperse within two days (Whitney, 2002).

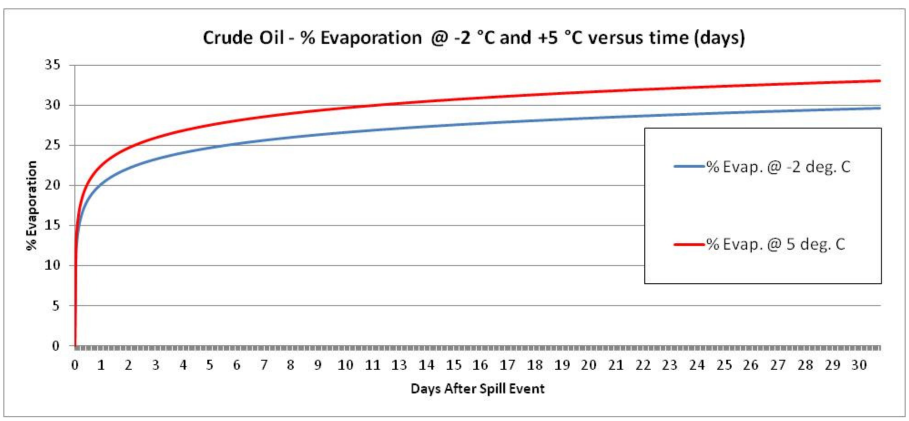

Figure IV-7. Evaporative Emission Curves – Crude Oil
Data Sources: Wang, et al., 2003; Fingas, 2002

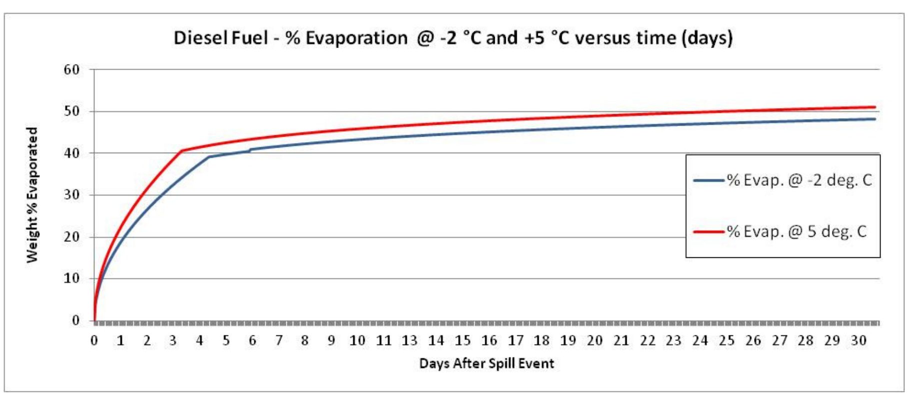

Figure IV-8. Evaporative Curves - Diesel Fuel
Data Sources: Environment Canada, 2001; Fingas, 2002

a. <u>Emissions from Oil Spill Responses</u>

In addition to evaporative emissions from the spill, combustion emissions from the spill response vessels will occur. These vessels include a variety of ships that provide different services, including the following types of vessels:

- Oil spill response vessel.
- Tug and oil spill containment system barge (operated offshore).
- Skimmer boats.
- Work boats.

Oil spill response vessels vary in size and capacity. Vessels operating in Arctic waters are larger and with greater spill cleanup capacity and have greater holding capacity for recovered petroleum products than similar vessels operating in less extreme environments.

Figure IV-9. ***M/V Nanuq***
Image from Royal Dutch Shell Plc. © Used by Permission.

The North Slope oil spill response fleet includes the *M/V Nanuq*, a U.S.-flagged 300-foot ice-class oil spill response vessel, built for Shell by Edison Chouest (Figure IV-9). It is large enough to carry three 34-foot work boats, several skimming boats, and a containment boom. It is equipped with two propulsion engines rated at 3,748 kW. (No data for auxiliary engines on the *M/V Nanuq* were available.)

In addition to the *M/V Nanuq*, the *M/V Aiviq* is a 360-foot U.S.-flagged ice management vessel used for towing and laying anchors for drilling rigs and is also equipped for oil spill response, having a 3,200-barrel holding capacity (Figure IV-10). The vessel is intended to operate in conjunction with the *M/V Nanuq* in response to oil spills.

Figure IV-10. ***M/VAiviq***
Online image from Wikipedia.
http://en.wikipedia.org/wiki/Aiviq. (August 6, 2014.)

The M/V*Aiviq* was built in 2012 and is equipped with four Caterpillar C280-12 4-stroke medium speed engines that provide total propulsion power of 16,240 kW. There are also two 2,000-kW shaft generators and four 1,700-kW Caterpillar 3512C auxiliary diesel generators that provide power for onboard consumers, including the firefighting system (Meredith, 2012).

Figure IV-11. *Point Barrow* Tug
Online image from Tugboatinformation.com. http://www.tugboatinformation.com/tug.cfm?id=1115. (Accessed November 24, 2014.)

The U.S.-flagged *Arctic Endeavor* is also part of the North Slope spill response fleet. This vessel is a 205-foot ice-strengthened oil spill response barge operating in the Beaufort Sea with a holding capacity of 16,800 barrels. The barge also has a suite of skimmers, work boats, containment booms, and other equipment for use in oil spill cleanup. The barge is towed by available tugs such as the *Point Barrow* (Figure IV-11), which is a U.S.-flagged 85-foot tug equipped with two Caterpillar 3512 V-12 propulsion engines rated at 1,500 kW each and two Caterpillar 3304 auxiliary engines with a maximum power rating of 75 kWs each.

Figure IV-12. Skimmer Boat
Online image from Munson Boats. http://www.munsonboats.com (Accessed: August 15, 2014.)

Skimmer boats are small, 75-foot boats with built-in oil skimmers, and are designed to be fast and maneuverable in and around ice. The Uniaq Corporation has developed a lightweight skimmer equipped with two Volvo D6 330 engines providing a total power of 500 kW (Figure IV-12).

Six work boats were included in the oil spill emissions estimates. These smaller vessels help set booms that confine and consolidate product floating on the surface.
Spill recovery fleets often include tankers to store and transport the crude oil, emulsion, and free water that may be recovered from an oil spill. Given the relatively small volumes of product spilled in these oil spill scenarios, the available storage capacity associated with the *Nanuq, Aiviq,* and *Arctic Endeavor* is assumed to be more than sufficient to store the oil recovered. Given the volume of the spills and typical wave action, this assessment did not include the option of in situ burning of spilled material as it was not considered appropriate. In addition, there is evidence that dispersants are not suitable for cold water spill responses and are not approved for use in Alaska; therefore, vessels associated with applying dispersants were not included in this analysis.

To assess emissions from the spill response activities, power ratings of vessels currently in the fleet were compiled for propulsion and auxiliary engines. Typical operating loads were also included along with an assumption that these vessels will be at sea for three days for a 1,700-barrel pipeline leak; five days for a 5,100-barrel offshore platform crude spill; and two days for a 48-barrel diesel spill. The larger vessels were assumed to operate 24 hours per day, while the tug and other boats were assumed to operate 12 hours per day. Table IV-13 summarizes operational characteristics for the oil response fleet.

Table IV-13. Summary of Oil Spill Response Fleet and Operations

Vessel	Power rating (kW)		Operating Load Factor (%)		Hours of Operation	Total kW-Hrs	
	Propulsion	Auxiliary	Propulsion	Auxiliary		Propulsion	Auxiliary
Nanuq	7,496		70	50	144	1,079,424	
Aiviq	16,240	1,080	70	50	144	2,338,560	155,520
Point Barrow[a] (towing *Arctic Endeavor)*	3,000	150	60	50	72	216,000	10,800
Skimmer boat	500	-	70	-	72	36,000	
Work Boats (6)	100	-	80	-	432	43,200	

[a] Propulsion power is associated with the *Point Barrow* tug and auxiliary power is associated with the *Arctic Endeavor* barge.

Sources: Shell 2013; BOEM, 2014b

These activity data (kW-hrs) were applied to the CAP, GHGs, and NH_3 emission factors. HAP speciation profiles were applied to the PM components and VOC emissions to quantify the HAP components. The emissions factors used for vessels associated with the oil and gas industry were assumed to be based on ULSD fuels (15 ppm). The CAP emission factors applied to the vessel activity data are shown in Section II, Table II-1.

Spill response vessels emissions were calculated using the following equation:

$$E = \text{kW-hrs} \times EF \times CF$$

where:

E = Emissions (tons)

kW-hrs = Annual activity data (kilowatt-hours)

EF = Emission factor (g/kW-hrs)

CF = Conversion factor (g = 1.10231×10^{-6} ton)

Example Calculation:

Total kW-hrs for *Aiviq*'s propulsion engine are 2,338,560. The emission factor for NO_X is 9.8 g/kW-hr.

$$E = 2{,}338{,}560 \times 9.8 \times 0.00000110231$$

$$E = 25.3 \text{ tons}$$

Activity and emissions were allocated to the centroid of the closest active lease block to shore.

Factors that will affect uncertainty in the spill emissions estimates include the following:

- Daylight and day length.
- Presence or absence of sea ice.
- Spill detection time and recovery team response time.
- Wind speed and direction.
- Water temperature, current, and direction.
- Type and amount of oil/fuel spilled.

Some of these factors vary seasonally. Because a spill can occur at any time of the year, changes in monthly temperature and wind speed can impact the emission rate and ability of the spill response fleet to address the spill. Strong wave action is a function of wind speed, and rough seas will impede or prevent recovery. Wave action mixes spilled materials into the water column, which will affect both emissions and recovery. The emission estimates developed here are derived from the volume of material spilled and the VOC content of the spilled material; therefore, the evaporative estimates should be reasonable, although the period of the release may be shorter when temperatures are warmer, wind speeds are higher and waves are larger, compared to colder calmer periods with ice coverage.

B. Onshore Oil/Gas and Non-Oil/Gas Related Sources

The onshore projected emissions represent anticipated future year emissions for sources that can reasonably be expected to be constructed and/or operated in during a future year that is consistent with the offshore projection scenario. These sources, which are also listed in Table IV-14 along with general assumptions used to estimate emissions, include the following:

- Onshore oil/gas related sources:
  - Future new production facilities.
  - New pipelines to transport future new offshore production from locations in the Beaufort and Chukchi Seas, across the North Slope to the TAPS and other existing pipelines.
  - Liberty Island.
- Airports, aircraft, and a supply boat terminal to support increased offshore activities.
- TAPS fugitive emission increases due to increased throughput.
- Non-oil/gas stationary point and area sources.

Sources and activities not addressed in this future year scenario include existing onshore oil and gas production facility activities and several non-oil/gas related stationary point and mobile sources, as any prediction of future activities for these sources would be highly speculative at this time. Also, note that no future (post-2012) regulations are anticipated to reduce future emissions from the existing onshore oil and gas production facilities and the existing non-oil/gas related stationary point and mobile sources, with one exception: Tier 4 diesel manufacturer emission standards coming into effect in 2014. Although these standards will serve to reduce emissions from affected engines after 2012 as older engines are replaced, the rate of turnover is difficult to predict. Therefore, ERG did not estimate these reductions, which will provide a conservatively high estimate of these emissions for modeling.

Table IV-14. Projections Scenario for Onshore Sources

Group and Category		Growth Factor Basis	(Post-2012) Control Factor Basis		Comments
			Federal Reg.	State Reg.	
Onshore Oil/Gas Related Sources	Greater Moose's Tooth Unit 1	First production expected in 2017	Potential revisions to the NSPS OOOO regulations will be reflected in permit	As shown in EIS (BLM, 2014b)	Future new source, projected emissions based on EIS. No ADEC permit yet, but EIS indicates operational emissions to be less than 100 tons/yr for each criteria pollutant.
	Point Thomson Production Facility	First production expected in 2016		As permitted	Future new source. Projected emissions based on permit limits (current permit issued June 12, 2013 with an amendment in August, 2014; ADEC, 2014). Permit limits emissions to less than 165 tons/yr for each criteria pollutant.
	CD-5 Satellite at Alpine	First production expected in 2015/2016		As permitted	Future new source. Projected emissions based on permit limits (current permit issued April 4, 2006 with an amendment September 17, 2009; ADEC, 2013). Permit limits emissions to less than 100 tons/yr for each criteria pollutant.
	New processing production base facility on Chukchi coast	New processing plant to be built and operated (BOEM, 2014b)	Potential revisions to the NSPS OOOO regulations will be reflected in permit	Facility likely to be major for PSD and subject to case-by-case BACT limits	• Construction emissions based on Greater Moose's Tooth Unit 1 facility. • Operation emissions based on actual emissions of Alpine Central Processing Facility currently operating on the North Slope (25 MMbbl/yr production, scaled up to 200 MMbbl/yr).
	New pipelines constructed and operated to transport new offshore production	20 miles of new pipeline from Beaufort coast to existing pipelines	New Tier 4 diesel manufacturer emission standards effective beginning in 2014 (>56 kW)	None	• Construction emissions based on Greater Moose's Tooth Unit 1 facility. • Fugitive emissions scaled to new activity using same method as was used for onshore and TAPS pipelines.
		75 miles of new pipeline from Chukchi coast across North Slope to existing pipelines		None	• Construction emissions based on Greater Moose's Tooth Unit 1 facility. • Fugitive emissions scaled to new activity using same method as was used for onshore and TAPS pipelines.
	Liberty Island	Construction	New Tier 4 diesel manufacturer emission standards effective beginning in 2014 (>56 kW)	None	Construction emissions based on Greater Moose's Tooth Unit 1 facility.
		Drilling		None	Emissions based on permitted onshore drilling operations.

Table IV-14. Projections Scenario for Onshore Sources (Continued)

Group and Category		Growth Factor Basis	(Post-2012) Control Factor Basis		Comments
			Federal Reg.	State Reg.	
	Liberty Island (continued)	Production	Potential revisions to the NSPS OOOO regulations will be reflected in permit	Facility likely to be major for PSD and subject to case-by-case BACT limits	Operation emissions based on platform production estimates as noted in the offshore table. Actual emissions may be less than estimated emissions as they are dependent on future permit conditions.
Airports, Aircraft, and Supply Boat Terminal	Airports	Increased operations to support increased offshore exploration and production	EDMS emission factors include compliance with federal and international engine exhaust standards	No applicable state standards for aircraft emissions operating in state air space	Growth factors based on national aviation projections (FAA, 2014)
	Chukchi Exploration, Air Support, Search & Rescue Bases	New facility	New Tier 4 diesel manufacturer emission standards effective beginning in 2014 (>56 kW)	None	Construction emissions based on Greater Moose's Tooth Unit 1 facility
	Chukchi Supply Boat Terminal	New facility		None	Construction emissions based on Greater Moose's Tooth Unit 1 facility. (Actual vessel emissions covered above in Section IV.A for offshore sources.)
TransAlaska Pipeline System	• Pump stations • Fugitives (TAPS and natural gas supply line)	Growth based on increased throughput (BOEM, 2014b)	None	None	Projection based on increased projection (2012 compared to BOEM full-buildout scenario). Increased throughput remains under TAPS peak throughput (from 1988) and any existing permitted limits.
Non-Oil/Gas Stationary Area Sources	• Residential, Commercial/ institutional fuel combustion • 7 NSBSD schools • 4 LRRS facilities • 5 power plants • Service Area 10 Incinerator Plant	No growth	Full ULSD implementation	None	These sources have switched over (as of 2014) from a high sulfur content (2,500 ppm) heating oil to ultra-low sulfur diesel (15 ppm).

Source: BOEM, 2014b

ADEC = Alaska Department of Conservation
BACT = best available control technology
EIS = Environmental Impact Statement
kW = kilowatt
LRRS = long-range radar site
MMbbl/yr = million barrels per year
NSBSD = North Slope Borough School District
NSPS = New Source Performance Standard
ppm = parts per million
PSD = Prevention of Significant Deterioration
ULSD = ultra-low sulfur diesel
TAPS = TransAlaska Pipeline Systems

1. *New Production Facilities*

Projected emissions from future onshore oil and gas exploration and production facilities were estimated using a combination of available information on the planned facilities and emissions data for existing facilities. The four future production facilities of interest are:

- Greater Moose's Tooth Unit 1.
- Point Thomson Production Facility.
- CD-5 Satellite at Alpine.
- Planned Chukchi coast processing production base facility.

The methodology used to estimate projected emissions from each of these facilities is based on ADEC construction permits, BLM EIS, and actual emissions estimates for similar facilities already in operation on the North Slope. Each of these facilities is discussed separately below.

a. Greater Moose's Tooth Unit 1

The Greater Moose's Tooth Unit 1 project is being undertaken by ConocoPhillips. Unit 1 will be located in the Alpine satellite field located in the National Petroleum Reserve-Alaska (NPR-A), to the west of the current Alpine Central Processing Facility. Emissions data for the proposed project is available through the BLM (BLM, 2014b). Emission sources at this location will include a permanent line heater, fugitive equipment leaks, and emissions from well intervention and maintenance activities.

b. Point Thomson Production Facility

The Point Thomson project is being undertaken by ExxonMobil approximately 20 miles east of the current Badami Production Facility. Unlike the current North Slope fields, Point Thomson is primarily a natural gas play with an estimated 8 trillion cubic feet (TCF) of gas and 200 million barrels of condensate. Construction on this facility commenced in 2008 and initial condensate production into the TAPS is expected to begin in late 2015 or early 2016.

ADEC issued a revised construction permit for this facility on August 7, 2014 (AQ1201CPT03) (ADEC, 2014). Emission estimates for the Point Thomson Production Facility are based on the PTE for the greater emitting units listed in the permit (as documented in the Technical Analysis Report), and the emission characterization profiles developed for existing sources as described in Section III.A.3 of this report. As no operating permit for this facility will be issued until after it begins production, emission estimates for nonroad engines associated with the facility are not available (not required for construction permits). Therefore, estimates for potential emissions from nonroad engines are based on the emissions analysis data for existing facilities presented in Table III-3. Actual emissions are estimated to be 38, 55, 41, 19, and 52 percent of potential VOC, NO_x, CO, SO_2, and PM_{10} emissions, respectively, as described in Section III.A.3.a. $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions, and VOC and PM_{10} were used as surrogates to scale emissions of volatile organic and metal HAP/$PM_{2.5}$, respectively, using the Alpine Production facility HAP emissions profile and as described in Section II.A.3.a.

c. CD-5 Satellite at Alpine

The CD-5 Satellite project is being undertaken by ConocoPhillips and will consist of a new production drill site and well pad located approximately 6 miles west of the existing Alpine field in the NPR-A. Fluids from this well pad will be processed at the existing Alpine Central Processing Facility. First production is expected in late 2015.

ADEC issued a revised construction permit for this facility on September 17, 2009 (AQO945MSSO1 Revision 2) (ADEQ, 2014). Emission estimates for the Alpine Satellite CD-5 facility are based on the PTE listed in the permit (as documented in the Technical Analysis Report), and the emission characterization profiles developed for existing sources as described in Section III.A.3 of this report. However, unlike the Point Thomson Production Facility, the Technical Analysis Report for this facility does include potential emission estimates for nonroad engines. Estimates of actual emissions are estimated to be 38, 55, 41, 19, and 52 percent of potential VOC, NO_x, CO, SO_2, and PM_{10} emissions, respectively, based on the analysis conducted on existing permits as described in Section III.A.3.a. $PM_{2.5}$, volatile organic and HAP/$PM_{2.5}$ emissions were estimated in the same manner as for the Point Thomson Production Facility.

d. New Processing Production Base Facility – Chukchi Coast

This new facility will be located on the western coast of the North Slope and will process fluids from offshore platforms operating in the Chukchi Sea. No permit or existing data is available for this potential facility, which will have an estimated maximum peak production of 200 million barrels per year. Current oil production on the North Slope is slightly less than 200 million barrels per year.

Construction emissions for the new processing facility were estimated based upon construction emissions associated with Greater Moose's Tooth Unit 1 (AECOM, 2013). Based upon aerial images of the largest existing North Slope processing facility (i.e., the Alpine Central Production Facility), the identified facility footprint was visually estimated to be 0.1 square miles (i.e., 0.5 miles by 0.2 miles). Although the throughput for the proposed processing facility has been estimated to be eight times larger than the Alpine Central Production Facility, it is unlikely that the footprint of the proposed processing facility will be eight times larger. ERG assumed that facility footprint of the proposed processing facility will be 0.25 square miles (or 160 acres); construction emissions for Greater Moose's Tooth Unit 1 were scaled up based on the ratio of the proposed facility footprint divided by the Greater Moose's Tooth Unit 1 pad footprint (i.e., 11.8 acres). Only emissions from the ice roads, gravel roads and pads, and facilities installation construction activities (both on-road motor vehicle and nonroad equipment) were used for this estimate. All of these construction activities at Greater Moose's Tooth Unit 1 occurred over a 2-year period; it was assumed that this would also occur with the construction of the new processing facility. Therefore, all estimated construction emissions were multiplied by a factor of 0.50.

Emission estimates from operation of this facility are based on the emissions data generated for the Alpine Central Production Facility as described in Section III.A.3.a, scaled up to reflect the larger capacity of the planned Chukchi coast processing facility.

2. *New Pipeline Construction and Operation*

Construction emissions for the two new pipelines to be constructed and operated to transport new offshore production to TAPS and the existing feeder pipelines were estimated based on construction emissions associated with Greater Moose's Tooth Unit 1 (AECOM, 2013). A total of 20 miles of pipeline will be built for the Beaufort Sea and 75 miles will be built for the Chukchi Sea. Construction emissions for Greater Moose's Tooth Unit 1 were scaled up based on the ratio of the proposed pipeline length divided by the pipeline length associated with Greater Moose's Tooth Unit 1 (i.e., 8.4 miles). Only emissions from the pipelines, power lines, fiber optics, ice roads, and gravel roads and pads, and facilities installation construction activities (both on-road motor vehicle and nonroad equipment) were used for this estimate. The pipelines, power lines, and fiber optics construction activities occurred over a one-year period and the ice roads and gravel roads and pads construction activities occurred over a two-year period. It was assumed that this would also occur with the construction of the new processing facility. The estimated construction emissions for the ice roads and gravel roads and pads construction activities were multiplied by a factor of 0.50; the estimated construction emissions for the pipeline, power lines, and fiber optics construction activities were unadjusted.

Operation emissions from the two new pipelines were estimated by scaling the TAPS operation emissions by the ratio of pipeline. The only TAPS operation emissions that were scaled were pipeline fugitives, pigging operation emissions, and on-road patrol vehicle emissions; emissions from other TAPS operations (i.e., aerial surveillance aircraft, natural gas supply lines (fugitives), and pipeline replacement and repair) were not estimated as these are not expected to increase with increased throughput.

3. *Liberty Island Construction and Drilling*

Liberty Island will be a self-contained offshore drilling/production facility located on a conventional gravel island with pipelines to shore. The island will be built in Foggy Island Bay in the Beaufort Sea in approximately 21 feet of water.

The future emissions expected to be emitted by Liberty Island will be due to its construction, followed by drilling and production operations. These are described separately below.

Construction emissions for Liberty Island were estimated based upon construction emissions associated with Greater Moose's Tooth Unit 1 (AECOM, 2013). Construction emissions for Greater Moose's Tooth Unit 1 were scaled up based on the ratio of the amount of gravel to be used for Liberty Island (i.e., 790,000 cubic yards) (BP, 2000) divided by the amount of gravel to be used for Greater Moose's Tooth Unit 1 pad footprint (i.e., 130,000 cubic yards). Only emissions from the ice roads, gravel roads and pads, and facilities installation construction activities (both on-road motor vehicle and nonroad equipment) were used for this estimate. All of these construction activities at Greater Moose's Tooth Unit 1 occurred over a two-year period; it was assumed that the construction of Liberty Island would follow the same timeline. Therefore, all estimated construction emissions were multiplied by a factor of 0.50.

The emissions estimates for the Liberty Island drilling operation were derived from the Kuparuk River Transportable Drilling Rigs Renewal Application (ADEC, 2012b), and the peak number of production wells to be drilled as provided in the BOEM scenario (BOEM, 2014b).

The PTE data from the Kuparuk Application is for 30 wells; therefore, the per-well calculation for each pollutant is based off the following equation:

$$EP_i = EM / n$$

where:

EP_i = Production drilling emissions factor for pollutant, i (tons per well)
EM = Emissions (tons/yr)
n = Total number of wells (30)

Example Calculation:

The projected number of wells for Kuparuk is 30 and the potential emissions for NO_x are 2,664 tons per year for nonroad engines.

$$EP_i = 2{,}664/30$$
$$EP_i = 88.8 \text{ tons/yr per well}$$

The BOEM AQ Scenario (BOEM, 2014b) provided an estimate of peak production well drilling at Liberty Island (eight wells). The projected peak drilling emissions were calculated using the following equation:

$$EL_i = EP_i \times n_{LI}$$

where:

EL_i = Drilling emissions at Liberty Island for pollutant, I (tons/yr)
EP_i = Production drilling emissions factor for pollutant, i (tons per well)
n_{LI} = Peak number of wells at Liberty Island (wells per year: eight)

Example Calculation:

The projected number of wells for the Liberty Island project is eight wells per year, and the per-well emissions for NO_x from the Kuparuk data are 88.8 tons/yr.

$$EL_i = 88.8 \times 8$$
$$EL_i = 710.4 \text{ tons per year for all wells at Liberty Island}$$

C. Airports, Aircraft, and Supply Boat Terminal

As offshore activities increase on the North Slope, aviation is anticipated to increase proportionally for transporting supplies and personnel. Additional local helicopter and small aircraft activities are also anticipated to increase to provide necessary support to the offshore platforms, as well as wildlife and pipeline surveillance. This section of the projection scenario includes aviation-related emissions that occur in the vicinity of the airports, while the emissions for the aircraft and helicopters that occur at/near the drilling rigs, survey vessels, and construction platforms are described in Section IV.B.

The airport emissions were projected into the future using the FAA's Air Traffic Activity (FAA, 2014) from the FAA's Aerospace Forecast Fiscal Years 2012-2032. Note these activities are provided in terms of one LTO cycle comprising two separate operations, landings and takeoffs. For this study, operations were used only to develop the growth factors; to estimate aviation emissions, LTO data were used for airports and platforms. The FAA projection activity data account for changes in activity by aircraft type (commercial air carriers, air taxis, and general aviation). The projected aircraft-type growth factors were calculated by dividing year 2020 national activity data (assumed to provide a conservatively high level of growth, and commensurate to a year that could be expected for the BOEM full-buildout scenario) by the year 2012 national data for each aircraft type. The projected growth factors were then applied to the 2012 emissions data for each airport based on the aircraft categories.

The airport emissions growth factors were estimated as follows:

$$GF = PA / BA$$

where:

GF = Growth factor
PA = Projected year activity (operations)
BA = 2012 activity (operations)

Example Calculation:

Commercial aircraft has 15,432.3 operations for the projected year and 12,887.3 operations for 2012.

$$GF = 15{,}432.3/12{,}887.3$$
$$GF = 1.1975$$

The LTOs associated with offshore support helicopters were added to the FAA's projected airport commercial and general aviation activities, listed in Table IV-15. This table includes activity for aircraft as well as APUs, which are small jet engines built into the aircraft to provide power and assist with engine start-up and GSE, which are nonroad engines involved in moving the aircraft, transferring bags and luggage, fueling activities, resupplying water and food, and removing waste.

Table IV-15. Projected Airport Activities

Airport	Type	LTOs
Badami	Aircraft	270
	APU	270
	GSE	270
Barter Island LRRS	Aircraft	1,919
	APU	1,919
	GSE	1,919
Deadhorse	Aircraft	17,037
Galbraith Lake	Aircraft	92
	APU	92
	GSE	92
Helmericks	Aircraft	11
	APU	11
	GSE	11
Kavik River	Aircraft	186
	APU	186
	GSE	186
North Kuparuk	Aircraft	1,129
	APU	1,129
	GSE	1,129
Nuiqsut	Aircraft	1,035
	APU	1,035
	GSE	1,035
Point Lay LRRS	Aircraft	1,177
	APU	1,177
	GSE	1,177
Wainwright	Aircraft	634
	APU	634
	GSE	634
Wiley Post-Will Rogers	Aircraft	7,123
	APU	7,123
	GSE	7,123

Sources: FAA, 2013; BTS, 2014; U.S. EPA, 2013b

The projected LTOs were compared to the 2012 LTOs; these growth factors were applied to the 2012 emissions to project emissions. These emissions were assigned to the location for the appropriate airport.

In support of increased aircraft activities, a number of additional facilities will need to be built, including the following: an Exploration Base, an Air Support Base, and a Search and Rescue Base. Also, a new Supply Boat Terminal will be built to support increased offshore production in the Chukchi Sea. ERG assumed that the Exploration Base, the Air Support Base, and the Search and Rescue Base will all be built as an expansion to an existing airport. It was also assumed that the Supply Boat Terminal was collocated with the production base processing facility, even though it is a separate and distinct facility.

The exact size of these four facilities is not known. Because these facilities will be adjacent to other existing or proposed facilities, the facilities are not expected to be extremely large. The following facility sizes were assumed:

- Exploration Base – 20 acres.
- Air Support Base – 20 acres.
- Search and Rescue Base – 15 acres.
- Supply Boat Terminal – 10 acres.

Construction emissions from these four facilities were based on construction emissions for Greater Moose's Tooth Unit 1, scaled based on the ratio of the proposed facility footprint divided by the Greater Moose's Tooth Unit 1 pad footprint (i.e., 11.8 acres). Only emissions from the ice roads, gravel roads and pads, and facilities installation construction activities (both on-road motor vehicle and nonroad equipment) were used for this estimate. All of these construction activities at Greater Moose's Tooth Unit 1 occurred over a two-year period; it was assumed that this would also occur with the construction of these four new facilities. Therefore, all estimated construction emissions were multiplied by a factor of 0.50.

D. TransAlaska Pipeline System

The future year increased production (i.e., 200 million barrels per year) will affect some of the existing emissions associated with the TAPS. According to APSC statistics, the 2012 TAPS throughput was 200,518,907 barrels (Alyeska, 2013), so the future year increased production will effectively double the TAPS throughput.

ERG assumed that the following emissions sources associated with the TAPS will increase with increased production throughput: pump stations, pipeline fugitives, and natural gas supply line fugitives. A review of five pump station inventories (i.e., 2002, 2005, 2008, 2011, and 2013) from ADEC's on-line Point Source Emissions Inventory (ADEC, 2014) indicated a general trend of decreased pump station emissions with decreasing throughput. Conversely, increased throughput should result in increased emissions. Future year emissions for pump stations, pipeline fugitives, and natural gas supply line fugitives were estimated by doubling the 2012 emissions. It was assumed that future year emissions did not increase for on-road patrols, aerial surveillance, pigging operations, and pipeline replacement and repair.

E. Non-Oil/Gas Stationary Point and Area Sources

With regard to the non-oil and gas sources (i.e., sources in the North Slope villages), use of ULSD in all equipment and vehicles is expected by 2017. Year 2012 emissions modeling of on-road motor vehicles and nonroad mobile sources was conducted using ULSD; however, a number of point sources (i.e., seven schools, four Air Force LRRS facilities, five power plants, and the Service Area 10 incinerator) and two area source categories (i.e., commercial/institutional fuel combustion and residential fuel combustion) used heating oil with a higher sulfur content (i.e., 0.25 percent or 2500 ppm). To account for the use of ULSD in these sources, their future year SO_2 emissions will be reduced by 99.4 percent (i.e., corresponding to a shift from 2500 ppm sulfur content of heating oil to 15 ppm sulfur content of ULSD).

V. QUALITY ASSURANCE/QUALITY CONTROL ACTIVITIES

In preparing the Arctic AQ Modeling Study emissions inventory, ERG closely followed the procedures outlined in the *Quality Assurance Plan for Arctic Air Quality Impact Assessment Modeling Study: Emission Inventory*.

As outlined in the Quality Assurance Plan, ERG's QA Coordinator conducted the following QA coordination and data management activities:

- Ensured that archival procedures, backups, and alternate storage facilities were in place for each specific dataset developed during the study.
- Ensured that datasets are formatted properly for use in near- and far-field modeling, and for use in evaluating the emissions exemption thresholds.
- Ensured secure transfer of data files for all data from BOEM and within the ERG inventory.
- Reviewed the QC procedures conducted by the ERG inventory team.
- Ensured the data utilized were of known and high quality such that the project objectives and data quality objectives (DQOs) were met.
- Audited the project files to ensure that the ERG inventory team used appropriate methodologies to document the data quality and the deliverable review process.

A. Data Collection

Development of the emissions inventory consisted of identifying onshore and offshore emissions source categories to be included in the inventory, and collecting, compiling, and reviewing secondary data such as activity data (e.g., hours of operation, fuel usage, production data) for each emission source category and emission factor data for each emission source. This project did not include collecting any primary data (e.g., source testing, surveys). The ERG inventory team collected and reviewed activity data and emission factor data to determine usefulness in developing inventory estimates for each source category. Priority was given to quantitative data that were reasonable, complete, and defensible.

Data collection efforts were coordinated so that all ERG inventory team members understood the project goals and DQOs. Following the kickoff discussions with BOEM staff and submittal of the Protocol, ERG had an internal team meeting to discuss and verify data collection efforts for each emission source category. The ERG inventory team discussed the key data needs and quality requirements relating to developing the emission inventory for the BOEM Arctic Modeling Study and defined the procedures that would be used to identify these data. The ERG Project Manager confirmed that each team member had a clear understanding of the project objectives and deliverables and the data (and their quality) needed to support those deliverables.

All original information gathered during the course of this project has been retained in the project file and includes reports, spreadsheets, databases, and other data gathered for emission inventory development, and all other pertinent data and information relating to this project.

B. QA/QC Activities Implemented

After collecting and compiling the secondary data for each emission source category, the ERG inventory team members reviewed the data to identify missing data and outliers. In addition, the team attempted to verify the activity data and emission factors by replicating them from a second reference source. In addition, a staff member who was not involved in the initial identification and collection of the data independently checked each data point to verify the correct value and units.

All information used to develop the emission estimates was checked and verified for reasonableness to the extent possible, primarily by replicating the values through independent sources. All calculations were checked by a second staff member who attempted to replicate the values by independently applying the input values and assumptions to see if the same results could be produced. Data that were found to be questionable were examined in greater detail to determine what errors might be present and what adjustments were needed. If data were revised or rejected, the procedures and assumptions used were thoroughly documented. The Project Manager and Principal Investigators (PIs) reviewed and approved all data adjustments.

In cases where quantitative data were created, the ERG inventory team checked them to ensure their accuracy and reasonableness (i.e., avoiding extremely low or high values that are indicative of errors). Data that were found to be questionable were examined in greater detail to determine what errors might be present and what adjustments were needed. If data were revised, the procedures and assumptions used were thoroughly documented. The Project Manager and PIs reviewed and approved all data adjustments. All QC findings were documented in the project file and in this final report.

Table V-1 summarizes the emission source categories included in the inventory, the data used to develop emission estimates, and the QA/QC activities implemented.

Table V-1. Data Gathering, Emission Estimation, and QA/QC Activities Implemented for the Arctic AQ Modeling Study Emissions Inventory

Source Category	Emission Source	Activity Data	Activity Data Sources	QA/QC Activities
Onshore Oil and Gas Fields	• Drilling/exploration • Well pads • Processing plants, gathering centers, flow stations • Support facilities (injection, seawater treatment)	• Well production data • Well completion and drilling data	• 2011 ADEC point source inventory • Permits and permit applications • 2011 NEI • EPA Oil and Gas Tool	• Independent calculations • 10% data check

Table V-1. Data Gathering, Emission Estimation, and QA/QC Activities Implemented for the Arctic AQ Modeling Study Emissions Inventory (Continued)

Source Category	Emission Source	Activity Data	Activity Data Sources	QA/QC Activities
Offshore Oil and Gas Activities	• Seismic survey vessels • Drilling rigs • Spill response vessels • Supply vessels • Tugs/barges • Crew boats • Shuttle tankers • Pipelaying vessels • Production platforms	• Offshore vessel fleet • Active lease blocks • Survey vessel routes • Harbor vessel/activity data • Projected activity data	• Offshore drilling permits • Seismic Survey Environmental Assessment • BOEM information (full-buildout scenario) • Community data • Arctic Council research plans	• Independent review of calculations/ database queries • Comparison with comparable arctic data
TAPS	• Pumping stations • On-road patrol vehicles • Aerial surveillance aircraft • TAPS fugitives • Natural gas supply line fugitives • Pigging operations • Pipeline replacement	• Survey flight activity data • Road patrol activity data • Operational information • Pigging measurements • Construction equipment activity	• ADEC • APSC • Alyeska aviation surveillance data	• Independent review of calculations/ database queries
Onshore Non-Oil and Gas Sources and Activities	• Commercial/institutional fuel combustion • Residential fuel combustion • On-road motor vehicles • Nonroad mobile sources • Paved road dust • Unpaved road dust • Waste burning • Power plants • Other stationary sources • Supply vessels • Research vessels	• Fuel statistics • VMT • Vehicle/ equipment populations • Fuel sales and characteristics • Speed distribution • Meteorological data • Silt loading/ content • Waste quantities	• Tribe/village corporation • ADOT&PF • Alaska DMV • NSB • AEA	• Independent calculations
Airports	• Commercial aviation aircraft • General aviation aircraft • Ground support equipment • Deicing • Heating • Aircraft maintenance • Aviation fuel storage & distribution	• Aircraft/ helicopter activity data • Aircraft fleet data • Deicing operations • Fuel oil consumed • Aviation fuel through put	• Airport operators' local data • FAA TAF data • EPA airport data • Helicopter service company data	• Independent review of calculations/ database queries • Comparison of operator data with FAA and EPA data

Table V-1. Data Gathering, Emission Estimation, and QA/QC Activities Implemented for the Arctic AQ Modeling Study Emissions Inventory (Continued)

Source Category	Emission Source	Activity Data	Activity Data Sources	QA/QC Activities
Oil spills	• OCS pipeline spill • Platform spill	• Pipeline/Platform throughput • BOEM modeled spill rate	• BOEM spill model data • BOEM projected production rate	• Independent review of calculations/ database queries • Comparison with comparable arctic data

Source: ERG

1. *Spreadsheets and Databases*

Electronic spreadsheets and databases developed in the project conformed to ERG's internal Standard Operating Procedures (SOPs). Each spreadsheet and database contains documentation of the project name, contract number, ERG internal tracking number, who prepared the sheet, and on what date. All spreadsheet data fields are fully and properly labeled. All assumptions, constants, conversion factors, equations, etc. used in the spreadsheet or database and calculations are clearly defined. All data are fully explained and completely transparent and reproducible. At least 10 percent of calculations were independently replicated to ensure accuracy. References for all input data parameters are provided in the spreadsheets and databases.

2. *Documentation*

The entire process used to develop the Arctic AQ Modeling Study emission inventory has been fully documented from start to finish. All procedures and data sources used to determine emission estimates are clearly and transparently presented such that BOEM can replicate any part of the process. Providing interim products and incorporating BOEM review comments enhanced the completeness and quality of the documentation in the final report.

The results of all project QA/QC activities are conveyed in this project report in each emission source category section, including the QA/QC activities that were performed, the results of the investigations, and data corrections that were implemented to address any identified deficiencies.

3. *Peer Review*

The SRG reviewed the Emission Inventory Protocol, and their comments were addressed and incorporated. The SRG is concurrently reviewing the results of the draft emission inventory and documentation with BOEM. Responses to comments received from both the SRG and BOEM will be addressed within the final Arctic AQ Modeling Study emissions inventory.

In addition to the SRG, ERG used a senior technical peer reviewer to review all methods and results of the work. ERG's senior peer reviewer was involved in the initial planning stages of this project to ensure the planned approaches were technically sound and reviewed and checked the quality of all final products prior to submittal to BOEM to ensure the project procedures were properly implemented. Editorial staff reviewed the project report to ensure its clarity and editorial quality. The Project Manager and PIs also reviewed and signed off on all deliverables.

C. Blending/Merging of Sector Emissions Inventories

Prior to developing emission estimates, ERG developed emission inventory templates for each sector (point, nonpoint, onroad, and nonroad). The templates presented the required and necessary data fields, types of data fields (e.g., text, numeric), size of the data field, assigned primary keys, and description. The final list of data fields also satisfies the requirements needed for air quality modeling in the future. ERG inventory team members populated the templates for their respective sectors and submitted the files to the Data Manager. Tables A-22 through A-25 in Appendix A present these templates.

All data were housed in a Microsoft Access database, which provided the optimal flexibility in data management, QA, reproducibility, and transparency. The ERG Data Manager reviewed every emission record to ensure that it met the requirements, as prescribed in the EI Protocol. Such checks included:

- Standardizing consistent information, such as address, city, state, facility identifiers, and NAICS codes for the individual facilities.
- Ensuring that each emission process had a unique SCC and not multiple SCCs per process.
- Checking that the emission inventory codes used were correct. These include SCC, pollutant code, emissions type code, emission release type code, and control information codes.
- Checking stack and fugitive parameter parameters for consistency.
- Applying default stack and fugitive parameters for missing data.
- Checking interrelationships of the pollutant emissions, such as ensuring that $PM_{10} \geq PM_{2.5}$ emissions.
- Visually plotting point sources to ensure they reside in the designated areas of interest.
- Comparing reported pollutants and source categories in the emissions inventory files to the ones listed in the EI Protocol.

When errors or data inconsistencies were identified, the ERG Data Manager conferred with the applicable ERG inventory team member for resolution. All submittal files, whether used or not, are retained in the project file.

The ERG Data Manager generated emission summaries and presented them to the ERG inventory team members to validate that the emission estimates translated correctly into the master database. Discrepancies that were identified were resolved. Once the emissions inventory files were finalized, ERG performed two additional post-processing emission estimates:

- For Coarse PM, the $PM_{2.5}$ emissions were subtracted from the PM_{10} emissions.
- For CO_2e, GWP factors were applied to the GHG pollutants as shown in the following equation:

$$CO_2e = \sum GHG_i \times GWP_i$$

where:

CO_2e = Carbon dioxide equivalent, tons/yr
GHG_i = Mass emissions of each greenhouse gas, tons/yr
GWP_i = Global warming potential for each GHG in the inventory (IPCC, 2007)
(CO_2 = 1; CH_4 = 25; N_2O = 298)

VI. EMISSIONS INVENTORY RESULTS

The emissions inventory developed using the methods and data described in this report are summarized in the following tables and figures. Inventory uncertainties and recommendations for future improvements to the emissions inventory also are discussed.

A. Baseline Emissions Inventory

Tables VI-1, VI-2, and VI-3 summarize the baseline emissions inventory for CAP, GHGs, and other pollutants (i.e., HAP, H_2S, and NH_3), respectively. In the baseline emissions inventory, offshore sources include emissions from seismic survey vessels, drilling rigs, and survey/drilling support aircraft and vessels; CMV; and, research vessels. Onshore sources include oil and gas activities (i.e., seismic surveys, exploratory drilling, and oil and gas production); airports, aircraft, and GSE; TAPS; and non-oil and gas related stationary and mobile sources.

These tables show that emissions from onshore sources in the baseline inventory are much larger (i.e., by two orders of magnitude for most pollutants) than emissions from offshore sources. This result is not unexpected given that the offshore sources that operated during this time were limited to a very small number of sources as compared to the onshore sources.

Table VI-1. Summary of Baseline Emissions – Criteria Air Pollutants (tons/yr)

Sector	Pollutant						
	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	Pb
Offshore	1,816.3	38.2	106.0	248.6	35.8	27.2	0.005
Onshore	45,733.9	1,235.2	2,886.1	14,001.9	35,643.9	4,770.8	0.325
Total	**47,550.2**	**1,273.3**	**2,992.0**	**14,250.5**	**35,679.7**	**4,798.0**	**0.330**

Table VI-2. Summary of Baseline Emissions – Greenhouse Gases (tons/yr)

Sector	Pollutant			
	CO_2	CH_4	N_2O	CO_2e[a]
Offshore	139,982.5	0.8	6.5	141,932.6
Onshore	13,567,667.1	8,791.9	29.1	13,796,134.6
Total	**13,707,649.6**	**8,792.7**	**35.6**	**13,938,067.2**

[a] Calculated using GWPs from IPCC (IPCC, 2007).

Table VI-3. Summary of Baseline Emissions – Other Pollutants (tons/yr)

Sector	Pollutant		
	HAP	H_2S	NH_3
Offshore	18.1	0.0	0.7
Onshore	390.2	16.4	4.4
Total	**408.4**	**16.4**	**5.2**

Figures VI-1 through VI-6 provide the relative contributions of various sources to the baseline emissions inventory for selected CAPs, CO_2e, and HAPs, respectively. These figures show that onshore oil and gas sources are the largest contributors to the baseline emissions inventory. In particular, onshore oil and gas sources are the predominant sources of NO_x and CO_2e in the inventory (i.e., two orders of magnitude larger than other sources). Unpaved road dust contributes over 96 percent of the total PM_{10} emissions, and about 70 percent of the total $PM_{2.5}$ emissions. A few other sources are also significant, including other nonroad vehicles/equipment (VOC and HAPs); waste incineration, combustion, and landfills (VOC); and onroad gasoline trucks (HAPs).

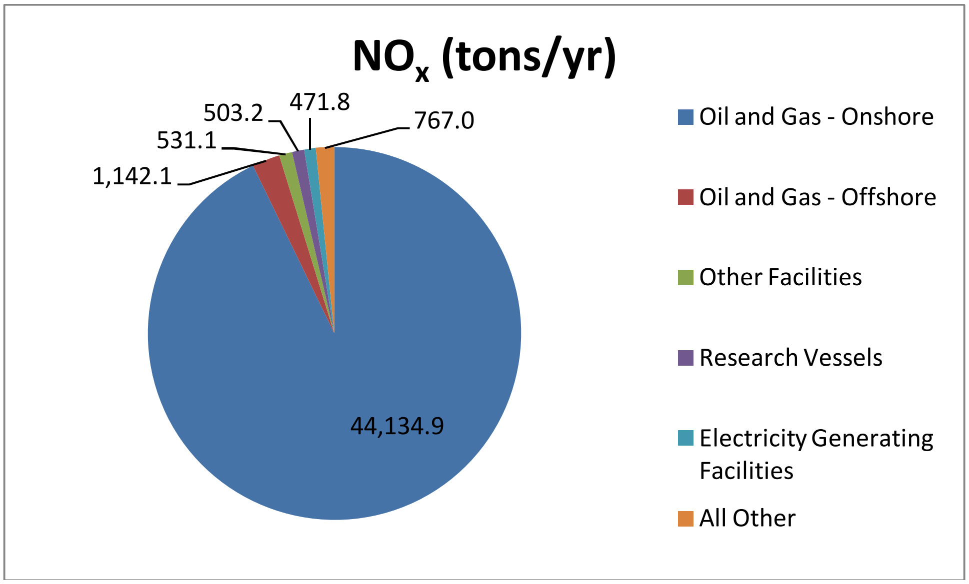

Figure VI-1. Baseline Emissions by Source – NO_x

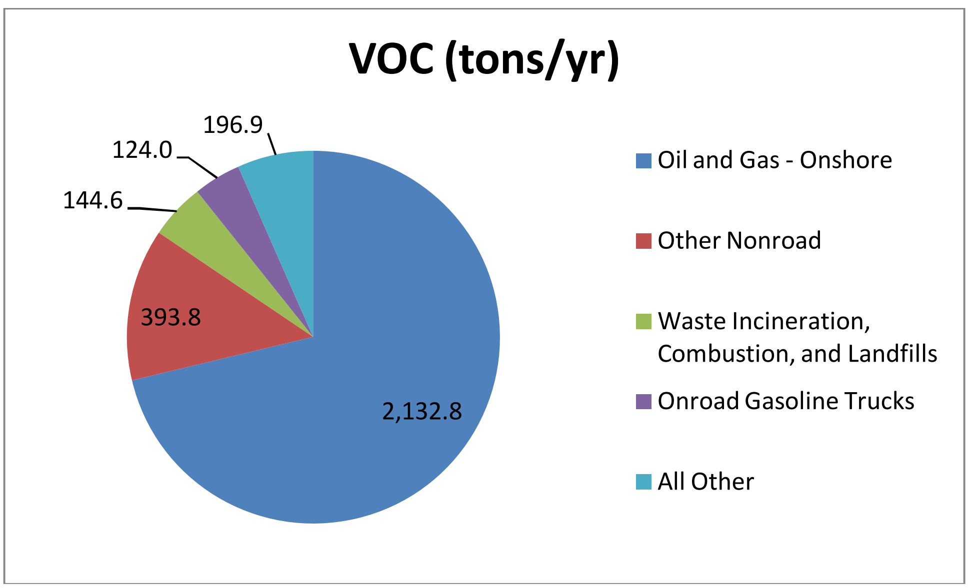

Figure VI-2. Baseline Emissions by Source – VOC

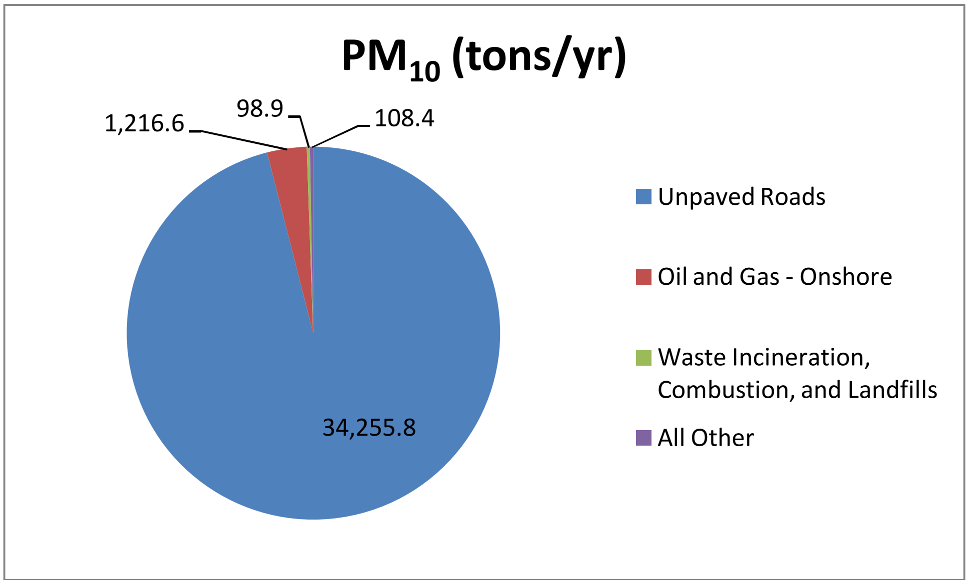

Figure VI-3. Baseline Emissions by Source – PM_{10}

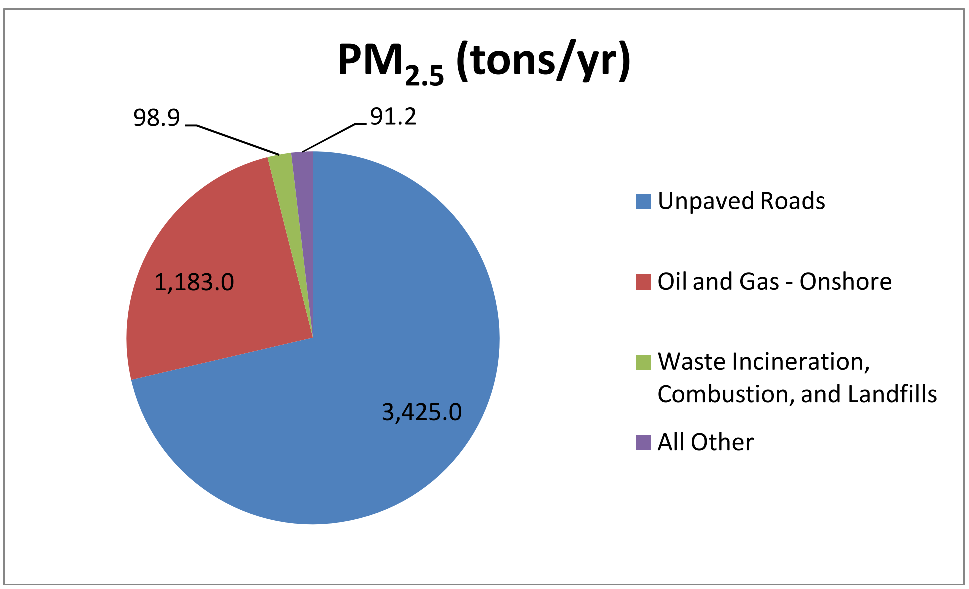

Figure VI-4. Baseline Emissions by Source – $PM_{2.5}$

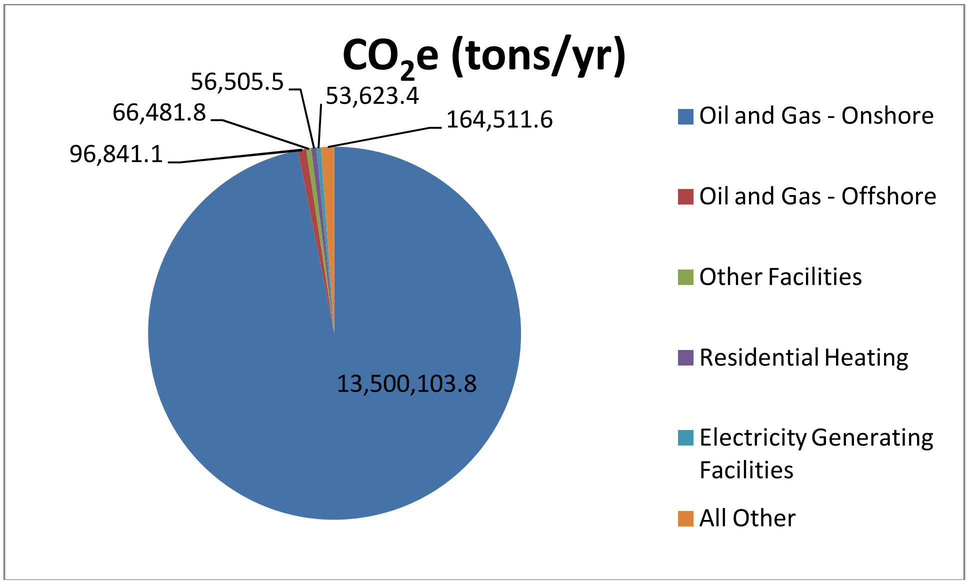

Figure VI-5. Baseline Emissions by Source – CO_2e

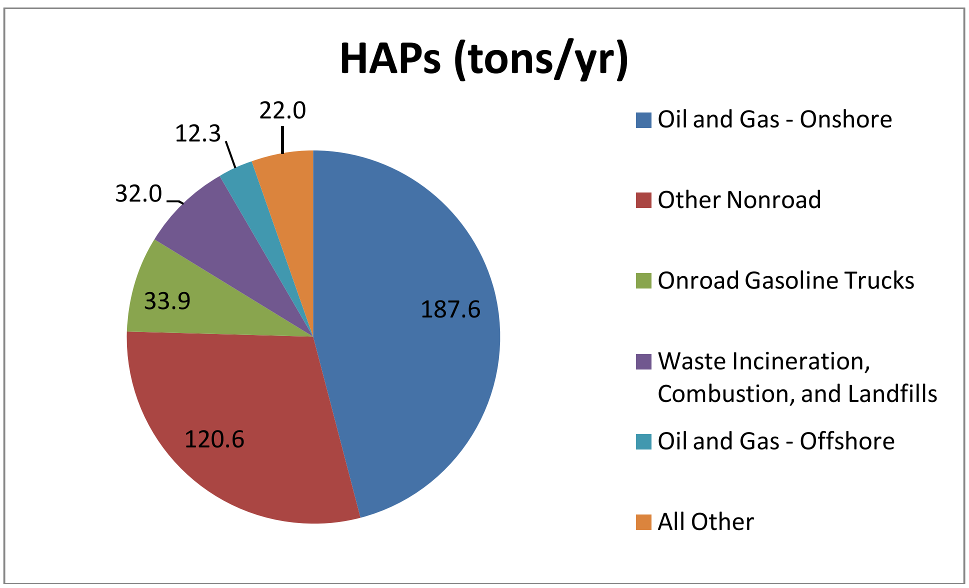

Figure VI-6. Baseline Emissions by Source – HAPs

Table VI-4 shows the baseline emissions inventory for the onshore oil and gas sector, by source category. This table provides the total emission (tons/yr) by pollutant and source category within the onshore oil and gas sector, as well as the percentage of the total pollutant emissions contributed by each source category. As can be seen, production accounts for the majority of emissions generated within the sector.

Table VI-4. Selected Baseline Emissions from Onshore Oil and Gas, by Source Category

Pollutant		Exploratory Drilling	Oil and Gas Production	Seismic Survey Equipment	Total
NO_x	**Tons/yr**	**1,388.2**	**42,260.1**	**144.1**	**43,792.4**
	Percent of Total	3%	97%	<1%	100%
SO_2	**Tons/yr**	**42.1**	**1,049.0**	**9.5**	**1,100.6**
	Percent of Total	4%	95%	1%	100%
VOC	**Tons/yr**	**354.2**	**1,707.2**	**2.7**	**2,064.1**
	Percent of Total	17%	83%	<1%	100%
CO	**Tons/yr**	**318.0**	**8,967.5**	**31.0**	**9,316.5**
	Percent of Total	3%	96%	<1%	100%
PM_{10}	**Tons/yr**	**19.0**	**1,168.6**	**10.1**	**1,197.7**
	Percent of Total	2%	98%	<1%	100%
CO_2e	**Tons/yr**	**108,823.1**	**13,185,512.4**	**5,390.1**	**13,299,725.6**
	Percent of Total	<1%	99%	<1%	100%
HAP	**Tons/yr**	**16.4**	**168.6**	**0.1**	**185.1**
	Percent of Total	9%	91%	<1%	100%

B. Emissions Inventory Projections

Tables VI-5, VI-6, and VI-7 summarize the emissions inventory projections for the CAPs, GHGs, and other pollutants (i.e., HAPs, H_2S, and NH_3), respectively. These tables show projection emissions for the offshore sources based on BOEM "fully built out" scenario (BOEM, 2014b), and for the onshore sources reasonably expected to occur and that are affected by increased offshore production and exclusive use of ULSD fuel in selected onshore point and area sources. The BOEM scenario, along with the methods, data and assumptions used to estimate the projections are described in detail in Section IV of this report.

Note that the projected emissions described in this section do not represent the <u>total</u> future year projected emissions. The projected emissions include only those sources and activities that are <u>expected to change</u> (i.e., increase or decrease) in the future. Furthermore, the future year projected emissions should not simply be added to the 2012 emissions of the sources that are not expected to change to calculate total future year emissions because onshore oil and gas emissions from existing facilities, and emissions from construction and operation emissions from new facilities will likely not all occur during the same year. Future work by ERG and ENVIRON to be conducted during the modeling phase of the BOEM Arctic AQ study will define which specific sources should be modeled to determine future air quality impacts; at that time, the total future year inventory will be calculated.

These tables show that the emissions projected for the offshore sources are distributed nearly equally across sources anticipated to operate in the Beaufort and Chukchi Seas in the future.

Table VI-5. Summary of Emissions Projections – Criteria Air Pollutants (tons/yr)

Sector	Pollutant						
	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	Pb
Offshore – Beaufort Sea	7,474.2	561.3	417.8	1,484.6	174.5	144.5	0.017
Offshore – Chukchi Sea	6,961.9	768.5	353.1	1,528.5	173.2	149.7	0.013
Onshore[a]	17,067.9	341.5	894.1	7,407.7	952.7	879.2	0.105
Total	**31,504.0**	**1,671.3**	**1,665.0**	**10,420.8**	**1,300.4**	**1,173.4**	**0.135**

[a] Includes only emissions from new sources and from sources expected to change under the projection scenario (i.e., future new oil and gas production facilities; new pipelines; Liberty (gravel) Island; airports, aircraft and supply boat terminal; TAPS; and certain non-oil and gas stationary point and area sources).

Table VI-6. Summary of Emissions Projections – Greenhouse Gases (tons/yr)

Sector	Pollutant			
	CO_2	CH_4	N_2O	CO_2e[a]
Offshore – Beaufort Sea	1,293,500.1	52,375.3	181.9	2,657,097.2
Offshore – Chukchi Sea	1,532,252.9	73,618.2	242.4	3,444,957.2
Onshore[b]	18,359,826.6	26,601.4	76.8	19,047,753.7
Total	**21,185,579.6**	**152,594.8**	**501.2**	**25,149,808.2**

[a] Calculated using GWPs from IPCC (IPCC, 2007).
[b] Includes only emissions from new sources and from sources expected to change under the projection scenario (i.e., future new oil and gas production facilities; new pipelines; Liberty (gravel) Island; airports, aircraft and supply boat terminal; TAPS; and certain non-oil and gas stationary point and area sources).

Table VI-7. Summary of Emissions Projections – Other Pollutants (tons/yr)

Sector	Pollutant		
	HAP	H_2S	NH_3
Offshore – Beaufort Sea	68.3	0	2.3
Offshore – Chukchi Sea	55.9	0	1.8
Onshore[a]	71.9	0	0.002
Total	**196.1**	**0**	**4.1**

[a] Includes only emissions from new sources and from sources expected to change under the projection scenario (i.e., future new oil and gas production facilities; new pipelines; Liberty (gravel) Island; airports, aircraft and supply boat terminal; TAPS; and certain non-oil and gas stationary point and area sources).

Tables VI-8, VI-9, and VI-10 show the projected offshore emissions by source for the CAPs, GHGs, and other pollutants (i.e., HAPs, H_2S, and NH_3), respectively. The largest contributors to the projected offshore emissions are platform operation, resupply of drilling vessels, pipelaying activities, production support, and drilling vessels.

Table VI-8. Offshore Emissions Projections by Source – Criteria Air Pollutants (tons/yr)

Source	Pollutant						
	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	Pb
Survey Operations	553.8	0.5	28.3	62.9	8.6	6.3	0.001
Exploratory Drilling	6,550.8	12.3	442.1	1,043.2	138.3	102.2	0.021
Pipelaying and Support Vessels	1,705.1	1.0	87.0	191.4	26.3	19.3	0.004
Platform Construction	537.9	0.6	30.5	62.5	14.0	10.3	0.002
Platform Operations and Support Vessels	5,061.7	1,306.0	181.7	1,650.1	159.0	154.8	0.002
Spills	26.8	9.4	1.2	3.1	1.5	1.3	0.0002
Total	**14,436.1**	**1,329.9**	**770.9**	**3,013.1**	**347.7**	**294.3**	**0.031**

Table IV-9. Offshore Emissions Projections by Source – Greenhouse Gases (tons/yr)

Source	Pollutant			
	CO_2	CH_4	N_2O	CO_2e[a]
Survey Operations	36,805.3	0.2	1.7	37,332.2
Exploratory Drilling	572,142.2	3.5	27.0	580,393.1
Pipelaying and Support Vessels	112,413.0	0.7	5.4	114,037.8
Platform Construction	60,024.7	0.4	2.9	60,890.4
Platform Operations and Support Vessels	2,042,439.1	125,988.7	387.3	5,307,451.6
Spills	1,928.6	0.0	0.1	1,949.3
Total	**2,825,753.0**	**125,993.5**	**424.4**	**6,102,054.4**

[a] Calculated using GWPs from IPCC (IPCC, 2007).

Table VI-10. Offshore Emissions Projections by Source – Other Pollutants (tons/yr)

Source	Pollutant		
	HAP	H_2S	NH_3
Survey Operations	4.8	0	0.2
Exploratory Drilling	75.5	0	2.7
Pipelaying and Support Vessels	14.8	0	0.5
Platform Construction	5.2	0	0.3
Platform Operations and Support Vessels	23.6	0	0.3
Spills	0.2	0	0.03
Total	**124.2**	**0**	**4.1**

Tables VI-11, VI-12, and VI-13 show the projected onshore emissions by source for the CAPs, GHGs, and other pollutants (i.e., HAPs, H_2S, and NH_3), respectively. The largest contributors to the projected onshore emissions are the new oil and gas production facilities (i.e., CD-5 Satellite at Alpine, Greater Moose's Tooth Unit 1, Point Thomson Production Facility, and the new Chukchi Sea Processing Facility).

Table VI-11. Onshore Emissions Projections by Source – Criteria Air Pollutants (tons/yr)

Source	Pollutant						
	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	Pb
New oil and gas production facilities	13,425.3	207.3	541.9	3,431.9	729.1	703.1	
New pipelines	713.1	1.4	55.7	398.4	98.1	53.4	
Liberty (gravel) Island	1,271.9	92.2	83.0	442.1	41.8	41.1	0.001
Airports, aircraft, supply boat terminal	391.1	10.3	44.5	510.0	26.6	25.3	0.103
TAPs fugitives	685.1	24.3	137.3	2,435.3	37.9	37.6	0.0004
Selected non-oil/gas stationary point and area sources	581.4	5.8	31.7	189.9	19.2	18.8	0.0003
Total	**17,067.9**	**341.5**	**894.1**	**7,407.7**	**952.7**	**879.2**	**0.105**

Table VI-12. Onshore Emissions Projections by Source – Greenhouse Gases (tons/yr)

Source	Pollutant			
	CO_2	CH_4	N_2O	CO_2e[a]
New oil and gas production facilities	17,344,350.1	19,654.2	37.4	17,846,864.2
New pipelines	164,394.5	2.5	3.5	165,487.9
Liberty (gravel) Island	230,215.6	6,792.6	22.6	406,763.7
Airports, aircraft, supply boat terminal	94,151.0	1.1	1.4	94,599.1
TAPs fugitives	396,815.3	34.2	10.1	400,677.5
Selected non-oil/gas stationary point and area sources	129,900.1	116.8	1.8	133,361.3
Total	**18,359,826.6**	**26,601.4**	**76.8**	**19,047,753.7**

[a] Calculated using GWPs from IPCC (IPCC, 2007).

Table VI-13. Onshore Emissions Projections by Source – Other Pollutants (tons/yr)

Source	Pollutant		
	HAP	H_2S	NH_3
New oil and gas production facilities	49.7	0	
New pipelines	4.4	0	0.002
Liberty (gravel) Island	4.1	0	
Airports, aircraft, supply boat terminal	7.6	0	
TAPs fugitives	5.0	0	
Selected non-oil/gas stationary point and area sources	1.2	0	
Total	**71.9**	**0**	**0.002**

C. Emissions Inventory Uncertainty

There are uncertainties associated with the emission estimation methods for the sources addressed in the baseline emissions inventory, as well as in the emissions inventory projections. Overall, the use of emission factors combined with activity data (e.g., amount of fuel combusted, vessel activity kW-hrs, aircraft travel distances, etc.) results in an approximate estimate of emissions, and does not reflect actual emissions with the same accuracy that direct source tests would yield. In the absence of direct source test data, other limitations are due to the availability of source-specific data, such that surrogate data from similar sources is needed to ensure completeness of the inventory in terms of sources covered and pollutants included. If the surrogate data selected are not fully representative of the intended sources, uncertainty is introduced. In using surrogate data, uncertainty also arises based on the assumptions that must be made in order for the inventory to be complete.

1. *Baseline Emissions Inventory Uncertainty and Recommendations*

The following discussion highlights some key uncertainties in the data and emission estimation methods used to estimate the baseline emissions inventory for the Arctic AQ Modeling Study. In terms of priority, the sources that contribute the greatest emissions to the total baseline inventory (by pollutant) are the onshore sources, as follows:

- Oil and gas production (greatest NO_x, VOC, SO_2, CO, CO_2e, and HAP emissions).
- Unpaved road dust reentrainment (greatest PM_{10} and $PM_{2.5}$ emissions).

The remainder of this discussion focuses on the uncertainties associated with estimating emissions from these most important sources, and makes several recommendations to help address these uncertainties in the future. ERG also provides a listing of uncertainties associated with the smaller sources.

a. <u>Onshore Oil and Gas Production</u>

The NEI is the best source of data to estimate emissions from onshore oil and gas production sources, although the NEI does not include smaller units at covered sources (i.e., Title V permitted facilities). Permit data were available for these smaller units; however, for all pollutants except HAPs and $PM_{2.5,}$ estimates for these pollutants were developed using HAP and $PM_{2.5}$ data for larger emission units reported under the NEI. The NEI also does not include non-Title V facilities operating on the North Slope. Emissions for these sources were estimated by analyzing emissions and equipment data for the larger facilities in the NEI, combined with detailed information available in permits and permit applications for the non-Title V facilities. Neither the NEI nor the ADEC permits or permit applications include emissions from compressor seals and fugitive equipment leaks. However, emissions from these sources are reported under the GHGRP, and so the GHGRP CH_4 estimates were used to estimate VOC and HAP emissions. Finally, no North Slope oil fields data were available to estimate emissions from mud degassing; therefore, emission estimates were taken from EPA's Nonpoint Oil and Gas Emission Estimation Tool.

Recommendations for alleviating these uncertainties in future versions of the emissions inventory for onshore oil and gas production include the following:

- Evaluate emissions data submitted to ADEC for 2014 to determine if source type coverage has been expanded (particularly for drilling sources given pending renewal of several Title V drilling permits).
- Conduct additional research on mud degassing emissions to obtain North Slope-specific data.
- Contact North Slope operators to assess current GHGRP emissions data and coverage of sources/facilities as GHGRP reporting requirements change.

b. Unpaved Road Dust Reentrainment

An important source of uncertainty associated with unpaved road dust is the lack of robust local silt and moisture content samples for the North Slope villages. A single measured silt content value of 25 percent measured on the Dalton Highway and a default moisture content value of 0.5 percent was used to estimate unpaved road dust emissions. Examination of the empirical unpaved road dust emission estimation equations indicates a linear relationship between silt content and the estimated emission factor. A 20 percent increase in silt content (i.e., from 25 percent to 30 percent) increases the unpaved road dust emission factor by 20 percent; likewise, a 20 percent decrease in silt content (i.e., from 25 percent to 20 percent) decreases the unpaved road dust emission factor by 20 percent. The relationship between moisture content and the estimated emission factors is inversely related and smaller than for silt content. A 20 percent increase in moisture content (i.e., from 0.5 percent to 0.6 percent) decreases the unpaved road dust emission factor by almost 4 percent, while a 20 percent decrease in moisture content (i.e., from 0.5 percent to 0.4 percent) increases the unpaved road dust emission factor by slightly more than 4 percent.

To address these uncertainties, ERG recommends that silt and moisture content sampling be conducted in the North Slope villages following the sampling procedures detailed in Appendix C.1 and C.2 of U.S. EPA's AP-42 (U.S. EPA, 1995). Sampling should be conducted during time periods without measurable precipitation and residual snow/ice cover (i.e., primarily during the summer). Additional care should be taken to ensure that representative sampling is conducted with consideration of local traffic patterns, periodic road grading, and community dust control efforts.

c. Other Emissions Inventory Uncertainties

Uncertainties associated with the development of the offshore emission estimates for oil/gas related sources stem from the assumptions made for seismic surveys regarding the operating load factors. In addition, information on exploratory drilling operations in the Beaufort Sea was incomplete; Chukchi Sea drilling permit data were used to gap fill for the missing Beaufort Sea information. Also, additional vessels not covered under the drilling permit were not included in this inventory because details concerning these vessels were not available. These additional vessels were brought in to assist with problems the drilling teams encountered during 2012. Assumptions were also made for seismic survey and exploratory drilling activities related to helicopters and wildlife surveillance aircraft used, frequency of trips, and flying times. Uncertainties in offshore non-oil/gas related source emission estimates are due to the incompleteness of data. The AIS data obtained from the Marine Exchange of Alaska were specific to the ports vessels visited – it did not include activities outside the port area. More specific data are needed to estimate CMV monthly vessel movement to reduce the uncertainty associated with the estimated time at sea. Increased time spent at sea due to storms or delays associated with rough sea or ice encounters are not reflected in the emission estimates. For research vessels, limited data were found to support assumptions made for time spent and operating loads during maneuvering, cruising, and at-sea operations.

Ways to improve the data used to estimate emissions from these offshore sources include the following:

- Request information from Shell to better identify vessel characteristics for the additional vessels used in the baseline inventory.
- Obtain detailed satellite monitoring automatic identification system data for Chukchi and Beaufort Seas for support vessels. (This also would improve the estimates for CMV and research vessels.)
- (In the future) use information provided by operators in their "operational plans" required to be submitted to BOEM prior to initiating any seismic survey and exploratory drilling operations, pipelaying activities, platform construction, and oil and natural gas production. This includes consideration of potential increases in time at sea due to incremental weather, and mitigation of unforeseen problems encountered. These data can be used to update the activity data in the inventory.

With regard to the North Slope onshore oil and gas seismic survey equipment, this analysis considered one project that was similar in scope and size to the most recent active permit for on-ice survey work (permitted and conducted in 2014) (BOEM, 2014a). For onshore exploratory drilling, large drilling rig engines are treated as nonroad engines for purposes of reporting to the NEI, and therefore are not subject to the NEI emissions reporting requirements. Drilling rig combustion estimates were scaled up based on a comparison of GHGRP emissions data (for drilling rig engines) and detailed permit application data for one facility. Uncertainty in the well completion estimates is also due to the lack of information. Emission estimates for well completions were developed by multiplying the estimates for well completions in one facility permit application by the ratio of total North Slope well completions.

Uncertainty in the emissions estimates for the airports may occur due to inaccuracies in the available LTO data, time in mode assumptions, and appropriate matching of aircraft to engines. Use of local LTO and time in mode data ensures that the best available data were used to develop these estimates. Additionally, none of the airport operators provided data on secondary emissions sources such as aircraft fuel distribution and refueling and aircraft maintenance. Ground support equipment emissions were based on equipment profiles built into FAA's EDMS, which may over- or under-estimate actual equipment populations used at these airports. Very small facilities extracted from the 2011 NEI, were based on regression analysis of anticipated air traffic; actual activity levels may be different than what the analysis indicates. Ways to improve the data used to estimate emissions from these sources include the following:

- Visit airports and landing strips to obtain detailed information about refueling, maintenance operations, and building heating.
- Obtain actual flight plans for aircraft and helicopter operations associated with offshore oil and gas support.

With regard to the TAPS emissions, detailed fugitive equipment counts (e.g., valves, pump seals, connectors, flanges, open-ended lines, pressure relief valves, compressors, meters, etc.) were not available; therefore, national production-based emission factors were obtained from IPCC (IPCC, 2006). These factors were applied to the 2012 TAPS crude oil throughput to estimate VOC, CO_2, and CH_4 emissions, and the calculated emissions were scaled by the ratio of the TAPS pipeline miles within the North Slope to national crude oil pipeline miles. Similarly, assumptions and surrogate data were needed to develop estimates for pigging operations and TAPS patrol vehicles. With the exception of the pump station emissions, which are included in the NEI, all of the emission estimates associated with TAPS operations should be considered to be fairly uncertain due to the inability to obtain detailed information to accurately estimate emissions. Although engineering judgment and reasonable assumptions were used to estimate these emissions, detailed information would provide more certain estimates.

For non-oil and gas stationary sources, uncertainties in the village industrial and commercial/ institution fuel combustion emission estimates stem from lack of information on the reported fuel use between stationary sources and mobile sources. While some fuel is used in community buildings, other fuel is used for on-road motor vehicles and nonroad equipment. It was assumed that all NSB fuel quantities were used by on-road motor vehicles and nonroad equipment and none were used in commercial/institution fuel combustion. For the on-road sources, emission estimates for other villages were developed by scaling the estimated Barrow emissions based on population, because the number of vehicles was not available. In addition, the quality of the on-road emission estimates is limited based on the assumption made concerning vehicle idling. Also, nonroad vehicle and equipment emissions estimates are uncertain because the quantity of nonroad fuel use is directly linked with the quantity of on-road motor vehicle fuel use. Ways to improve the data used to estimate emissions from these sources include:

- Further analyze NSB invoice data to attempt to disaggregate fuel use between community buildings, on-road motor vehicles, and nonroad equipment.
- Continue research regarding amount of on-road motor vehicle idling.

2. *Projection Emissions Inventory Uncertainty and Recommendations*

Future year emissions were estimated for the sources and activities that are reasonably foreseeable and expected to continue for an extended period of time and reflect BOEM's future full build-out scenario (BOEM, 2014b). In terms of priority, the sources that contribute the greatest emissions to the projected emissions inventory (by pollutant) are the following:

- New oil and gas production facilities (high NO_x, VOC, CO, PM_{10}, $PM_{2.5}$ and CO_2e emissions)
- Offshore exploratory drilling, and platform operations and support vessels (high NO_x, SO_2 and VOC emissions)

The remainder of this discussion focuses on the uncertainties associated with estimating emissions from these most important sources.

It is important to note that there is an "inherent" uncertainty in emissions projections due to the fact that future conditions that will affect emissions cannot be known with certainty. The best approach to projecting emissions involves accounting for as many variables that will affect future emissions as possible, and documenting those variables well so that adjustments can be made if necessary. This report should be used during the modeling phase of the Arctic AQ Modeling study to help interpret the modeling results made using the projected inventory.

a. New Onshore Oil and Gas Production Facilities

Uncertainty related to the projected emission estimates associated with the proposed onshore oil and gas facilities described in Section IV primarily involves the planned Chukchi coast processing production base facility. The other three projected facilities (Greater Moose's Tooth Unit 1, Point Thomson Production Facility, and CD-5 Satellite at Alpine) have all entered into the permitting process, and potential (and permitted) emissions data for these facilities are available in the public record. While these facilities are not yet operational, it is unlikely there will be major changes in the capacity or design of these facilities moving forward.

In contrast, there are no data or permitting documents available indicating the size, unit types, or controls that may be put in place at the proposed Chukchi coast production facility. Given that the projected throughput of the Chukchi facility is equivalent to the total North Slope oil production in 2012, it is likely that it will be the largest of its kind in operation on the North Slope once it reaches capacity. Until a permit application is submitted or more is known about the design of this facility, a great degree of uncertainty will remain concerning expected emission levels.

The primary sources of uncertainty associated with projected construction activities of new production facilities, new pipelines, Liberty Island, and aircraft and supply boat facilities is unknown facility size and the use of construction activity emissions from Greater Moose's Tooth Unit 1 as a basis for extrapolation. The size of the planned Chukchi coast processing production base facility was estimated based on a reasonable size compared to the largest existing facility in the North Slope (i.e., Alpine Central Production Facility); the size of four other support facilities near the Chukchi Sea (i.e., the Exploration Base, Air Support Base, Search and Rescue Base, and Supply Boat Terminal) was estimated based on the assumption of co-location with the processing production base facility or an existing airport. Estimated construction emissions for relevant construction activities (i.e., pipelines, power lines, fiber optics, ice roads, gravel roads/pads, and facilities installation) from Greater Moose's Tooth Unit 1 were scaled based upon proposed pipeline length, gravel quantity, and pad footprint size; uncertainty in these three parameters will contribute to emissions uncertainty. In addition, it was assumed that the construction activities from Greater Moose's Tooth Unit 1 are comparable to the projected construction activities. To the extent that the construction activities are not comparable, then additional emissions uncertainty will be introduced.

The uncertainties associated with the projected emissions from the onshore production facilities are likely to remain in place until additional data become available. In particular, for the three facilities that have been permitted to construct (or that have permit and permit application data available), once they become operational and receive operating permits, their final emissions "cap" will be known and they will likely be required to submit actual annual emission estimates to the permitting authority. More importantly, no data are currently available regarding the design of the proposed Chukchi coast processing production base facility. An initial construction permit application for this facility will be extremely beneficial to inform the projected emissions inventory.

b. Offshore Exploratory Drilling, and Platform Operations and Support Vessels

The offshore projection emissions inventory represents a single future year under BOEM's "full build-out" scenario. As such, these estimates should be considered conservatively high. Uncertainties exist due to several reasons, including:

- Assumptions of the number of support and scout vessels (for surveys, exploratory drilling, platform construction, production platforms, and pipelaying).
- Surrogates used for vessel characteristics, and the number of helicopter trips (for surveys, exploratory drilling, platform construction, and production platforms).
- Assumptions made for all vessel power rating and load factors, dredging vessel operating hours, and surrogate dredging vessels (for pipelaying).
- Assumed gravity based structures used Hibernian as surrogate and adjusted downward for Arctic conditions (for platform construction).
- Surrogate data used from a platform in Cook Inlet (for platform production).

Three of the largest projected offshore emission sources include drilling, pipelaying, and production platforms. One of the elements used to calculate vessel emissions is the power rating of the vessels used in these activities. To help understand uncertainty associated with drill ships and pipe laying vessels, Table VI-14 shows the variance of vessel power ratings for the global fleet.

Table VI-14. Variances in Vessel Power Ratings

Vessel Type	Values used in the Inventory Projections (kW)	Total Engine kW	
		Minimum	Maximum
Drilling Ship	44,532	254	54,000
Pipe Burying Vessel	16,981	2,795	22,505
Pipe Layer Crane Vessel	67,200	1,074	67,200

Source: IHS, 2013

As Table VI-14 indicates, the surrogate vessels used in this report's projections tend to be some of the larger, if not largest vessels, in the fleet, such that actual future emissions may be less than estimates developed for this study, if vessels with smaller total power are used.
As discussed previously, the production platform projected emissions for the Chukchi and Beaufort Seas were based on other larger platforms in the Cook Inlet. Therefore, to inform the uncertainties in using the Cook Inlet data, ERG compared the variance between the various Cook

Inlet platforms for NO_x, SO_2, and VOC emissions; see Table VI-15. The "Average Values" in the table are the values used for the production platform emissions projections. For some of the processes, there is only one reported value, therefore the minimum, average, and maximum values are the same.

Table VI-15. Comparison of Platform Production Emissions Data

		Emissions per Well (tons/yr)		
	Pollutant	**Minimum**	**Average**	**Maximum**
Large Bore Diesel Engine	NO_x	0.001	0.059	0.116
Natural Gas Boiler, < 10 million Btu/hr	NO_x	0.070	0.073	0.077
Natural Gas Production Flares	NO_x	0.078	0.103	0.136
Natural Gas Turbine Engine	NO_x	4.734	6.161	9.319
Reciprocating Diesel Engine	NO_x	0.150	0.313	0.683
Large Bore Diesel Engine	SO_2	0.005	0.005	0.005
Natural Gas Boiler, < 10 million Btu/hr	SO_2	0.023	0.091	0.128
Natural Gas Production Flares	SO_2	0.066	0.169	0.253
Natural Gas Turbine Engine	SO_2	0.003	1.907	3.366
Reciprocating Diesel Engine	SO_2	0.000	0.007	0.014
Large Bore Diesel Engine	VOC	0.003	0.003	0.003
Natural Gas Boiler, < 10 million Btu/hr	VOC	0.004	0.004	0.004
Natural Gas Production Flares	VOC	0.072	0.096	0.126
Natural Gas Turbine Engine	VOC	0.042	0.054	0.067
Reciprocating Diesel Engine	VOC	0.012	0.023	0.045
Glycol Dehydrator	VOC	0.036	0.036	0.036

Note: emissions have been normalized relative to each platform's well count.
Source: ADEC, 2013

As shown in Table IV-15, natural gas turbines have the largest range of NO_x and SO_2 emissions, which could be due to operating differences in temperature or fuel sulfur content. Reciprocating diesel engines have the largest relative variance for NO_x and VOC, which may be to due to the variety of diesel engines on the platforms that are being used in different applications.

Uncertainty associated with these estimates can be addressed in the future when Beaufort/Chukchi platform operators apply for air quality permits. During the application process, they will be required to document the actual equipment to be used and the hours of operation, which can be used to estimate emissions for those platforms (instead of using Cook Inlet platform data). Studies to validate emissions such as testing and data logging of activity, throughput, and operating load will also be needed to more accurately assess emissions from the future Beaufort/Chukchi platforms.

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APPENDIX A TECHNICAL REPORT: SUPPORTING DATA FOR ARCTIC AIR QUALITY STUDY EMISSIONS INVENTORY

Table A-1. 2012 Activity Data by Source for the Chukchi Drilling Site

Vessel	Units	Days	Hr per Day	Total Hours	Engine	Units	kW-hr	Load	Notes
Discoverer	Propulsion	53.00	24	1272	13,288	kW	10,141,397	0.6	Drilling Permit
	Generation	53.00	24	1272	4,916	kW	5,002,629	0.8	Drilling Permit
	Emergency Generator	53.00	2	106	0	kW	0	0.8	Drilling Permit
	MLC Compressor	8.83	24	212	1,305	kW	221,327	0.8	Drilling Permit
	Cranes	26.50	24	636	1,383	kW	703,821	0.8	Drilling Permit
	Cement/Logging	19.88	24	477	2,163	kW	825,235	0.8	Drilling Permit
	MLC HPUs	53.00	24	1272	21,477	kW	21,854,497	0.8	Drilling Permit
	Seldom Used Units	53.00	24	1272				1	No data on kW, use permit hourly EF
	Heaters and Boilers	0.88	24	21.2	16	mBtu/hr		1	No data on kW, use permit hourly EF
	Incinerator	48.58	5	242.9	276	lb/hr		1	No data on kW, use permit hourly EF
Ice Management Vessel	Propulsion and Generation	19.88	24	477	37,816	kW	10,822,996	0.6	Vessel *Fennica*
	Heaters and Boilers	17.67	24	424	895	Kw	303,535	0.8	No Aux using Spillage Info (Aiviq)
	Seldom Used Units	26.50	24	636				1	No data on kW, use permit hourly EF
	Incinerator	19.88	24	477	308	lb/hr		1	No data on kW, use permit hourly EF
Anchor Handler	Propulsion and Generation	19.88	24	477	22,140	kW	6,336,523	0.6	Vessel *Tor Viking*
	Heaters and Boilers	26.50	24	636				1	No data on kW, use permit hourly EF
	Seldom Used Units	26.50	24	636				1	No data on kW, use permit hourly EF
	Incinerator	19.88	24	477	308	lb/hr		1	Assume same as ice management
Resupply Ship* - transport mode	Propulsion and Generation	10.60	1	10.6	2,983	kW	18,971	0.6	Vessel *Harvey Spirit* split 1/2 time
					0	kW	0	0.6	Vessel *C-Leader* split 1/2 time
Resupply Ship* - Dynamic Positioning mode	Propulsion and Generation	3.53	24	84.8	2,983	kW	151,767	0.6	Vessel *Harvey Spirit* split 1/2 time
					0	kW	0	0.6	Vessel *C-Leader* split 1/2 time

Table A-1. 2012 Activity Data by Source for the Chukchi Drilling Site (Continued)

Vessel	Units	Days	Hr per Day	Total Hours	Engine	Units	kW-hr	Load	Notes
OSR Vessel	Propulsion and Generation	53.00	24	1272	7,600	kW	5,800,548	0.6	Spillage Doc (Nanuq Cat 2)
	Seldom Used Units	53.00	24	1272				0.8	Assume same rate as anchor handling
	Incinerator	53.00	24	1272	308	lb/hr		1	Assume same rate as anchor handling
OSR Work Boats	Propulsion and Generation	53.00	24	1272	44,443	kW	33,919,226	0.6	See Spillage section. (6 vessels * 100 kW)

* Permit Data said two ships were possible. Therefore both ships were used but each but shared the activity equally with half the hours.
Sources: Shell, 2013; IHS, 2014; Wilson et al., 2014.

Table A-2. 2012 Activity Data by Source for the Beaufort Drilling Site

Vessel	Units	Days	Hr per Day	Total Hours	Engine	Units	kW-hr	Load	Notes
Aivig	Propulsion	29.00	24	696	16,240	kW	6,781,824	0.6	See Spillage section.
	Auxiliary	29.00	2	58	1,080	kW	50,112	0.8	See Spillage section.
Kulluk	Electricity Generation	29.00	24	696	7,719	kW	4,298,209	0.8	Exploratory plan
	Emergency Generator	29.00	2	58	781	kW	36,227	0.8	Exploratory plan
	MLC Air Compressor	4.83	24	116	1,119	kW	103,801	0.8	Exploratory plan
	Deck Crane	14.50	24	348	895	kW	249,123	0.8	Exploratory plan
	MLC HPU	29.00	24	696	1,119	kW	622,809	0.8	Exploratory plan
	Seldom Used Sources	29.00	24	696	1,230	kW	685,089	0.8	No data on kW
	Heaters and Boilers	0.48	24	11.6	6	mBtu/hr		1	No data on kW
	Incinerator	26.58	5	132.9	276	lb/hr		1	No data on kW
Ice Management Vessel 1	Propulsion and Generation	10.88	24	261	37,816	kW	5,922,017	0.6	Exploratory plan
	Heaters and Boilers	9.67	24	232	895	Kw	166,085	0.8	No Aux using Spillage Info (Aiviq)
	Seldom Used Units	14.50	24	348				1	No data on kW, use Exploratory plan hourly EF
	Incinerator	10.88	24	261	154	lb/hr		1	No data on kW, use Exploratory plan hourly EF
Ice Management Vessel 2 / Anchor Handler	Propulsion and Generation	10.88	24	261	22,140	kW	3,467,154	0.6	Exploratory plan
	Heaters and Boilers	14.50	24	348	0	kW	0	0.8	No Aux using Spillage Info (Aiviq)
	Seldom Used Units	14.50	24	348				1	No data on kW, use Exploratory plan hourly EF
	Incinerator	10.88	24	261	154	lb/hr		1	No data on kW, use Exploratory plan hourly EF
Resupply Ship - transport mode	Propulsion and Generation	5.80	1	5.8	2,983	kW	10,380	0.6	Exploratory plan
Resupply Ship - Dynamic Positioning mode	Propulsion and Generation	1.93	24	46.4	2,983	kW	83,043	0.6	Exploratory plan
OSR Vessel	Propulsion and Generation	29.00	24	696	7,600	kW	3,173,885	0.6	See Spillage section. (Nanuq Cat 2)
	Seldom Used Units	29.00	24	696				0.8	Assume same rate as anchor handling
	Incinerator	29.00	24	696				1	Assume same rate as anchor handling
OSR Work Boats	Propulsion and Generation	29.00	24	696	44,443	kW	18,559,576	0.6	See Spillage section.

* Permit Data said two ships were possible. Therefore both ships were used but each but shared the activity equally with half the hours.

Sources: Shell, 2013; IHS, 2014; Wilson et al., 2014.

Table A-3. Emission Factors (g/kW-hrs) by source for the Chukchi Drilling Site

Vessel	Units	NO_X	VOC	CO	SO_2	PM_{10}	PM_{25}	Pb	NH_4	CO_2	CH_4	N_2O	EF References
Discoverer	Propulsion	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	Generation	0.5*	0.15*	0.22*	0.00595	0.0777*	0.0577*	0.00002	0.006	646	0.004	0.031	ANL, 2013 and Shell, 2011 denoted with *
	Emergency Generator	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	MLC Compressor	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	Cranes	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	Cement/Logging	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	MLC HPUs	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	Seldom Used Units	0.5	0	0.1	0.0002	0	0	0.00002	0.003				Shell, 2011
	Heaters and Boilers	3.2	0	1.2	0.025	0.4	0.4	0.00002	0.003				Shell, 2011
	Incinerator	0.7	0.4	4.3	0.35	1.1	1	0.00002	0.003				Shell, 2011
Ice Management Vessel	Propulsion and Generation	1.6*	0.15*	0.22*	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013 and Shell, 2011 denoted with *
	Heaters and Boilers	9.8	0.5	1.1	0.00595	0.151	0.111			646	0.004	0.031	ANL, 2013
	Seldom Used Units	0.3	0	0.1	0.0001	0	0						Shell, 2011
	Incinerator	0.4	7.7	23.1	0.19	1	0.7						Shell, 2011
Anchor Handler	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	Heaters and Boilers	0.6	0	0.2	0.0064	0.1	0.1						Shell, 2011
	Seldom Used Units	0.3	0	0.1	0.0001	0	0						Shell, 2011
	Incinerator	0.4	7.7	23.1	0.19	1	0.7						Shell, 2011
Resupply Ship - transport mode	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
		9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
Resupply Ship - Dynamic Positioning mode	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
		9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
OSR Vessel	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013
	Seldom Used Units	0.3	0	0.1	0.0001	0	0						Shell, 2011
	Incinerator	0.4	7.7	23.1	0.19	1	0.7						Shell, 2011
OSR Work Boats	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	ANL, 2013

Source: ANL, 2013

Table A-4. Emission Factors (g/kW-hrs) by source for the Beaufort Sea Drilling Site

Vessel	Units	NO_X	VOC	CO	SO_2	PM_{10}	PM_{25}	Lead	NH_4	CO_2	CH_4	N_2O	Black Carbon	EF References
Aivig	Propulsion	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	Auxiliary	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
Kulluk	Electricity Generation	0.5*	0.15*	0.22*	0.00595	0.0777*	0.0577*	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013 and Shell, 2011 denoted with *
	Emergency Generator	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	MLC Air Compressor	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	Deck Crane	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	MLC HPU	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	Seldom Used Sources	9.8	0.5	1.1	0.00595	0.151	0.111			646	0.004	0.031	0.0030	Shell, 2011
	Heaters and Boilers	3.2	0	1.2	0.025	0.4	0.4							Shell, 2011
	Incinerator	0.7	0.4	4.3	0.35	1.1	1							Shell, 2011
Ice Management Vessel 1	Propulsion and Generation	1.6*	0.15*	0.22*	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013 and Shell, 2011 denoted with *
	Heaters and Boilers	9.8	0.5	1.1	0.00595	0.151	0.111			646	0.004	0.031	0.0030	ANL, 2013
	Seldom Used Units	0.3	0	0.1	0.0001	0	0							Shell, 2011
	Incinerator	0.4	7.7	23.1	0.19	1	0.7							Shell, 2011
Ice Management Vessel 2 / Anchor Handler	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	Heaters and Boilers	9.8	0.5	1.1	0.00595	0.151	0.111			646	0.004	0.031	0.0030	ANL, 2013
	Seldom Used Units	0.3	0	0.1	0.0001	0	0							Shell, 2011
Ice Management Vessel 2 / Anchor Handler (Cont.)	Incinerator	0.4	7.7	23.1	0.19	1	0.7							Shell, 2011
Resupply Ship - transport mode	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
Resupply Ship - Dynamic Positioning mode	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
OSR Vessel	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013
	Seldom Used Units	0.3	0	0.1	0.0001	0	0							Shell, 2011
	Incinerator	0.4	7.7	23.1	0.19	1	0.7							Shell, 2011
OSR Work Boats	Propulsion and Generation	9.8	0.5	1.1	0.00595	0.151	0.111	0.00002	0.003	646	0.004	0.031	0.0030	ANL, 2013

Source: ANL, 2013

Table A-5. Category 1 and 2 Marine Engine HAP Speciation Profiles

Pollutant Code	Pollutant	Associated basis for speciation	Speciation Profile
	Copper	PM_{10}	1.75E-03
	Zinc	PM_{10}	1.00E-03
100414	Ethylbenzene	VOC	1.25E-03
100425	Styrene	VOC	1.31E-03
107028	Acrolein	VOC	2.19E-03
108883	Toluene	VOC	2.00E-03
110543	n-Hexane	VOC	3.44E-03
118741	HCB	PM_{10}	4.00E-08
120127	Anthracene	$PM_{2.5}$	2.31E-05
123386	Propionaldehyde	VOC	3.81E-03
129000	Pyrene	$PM_{2.5}$	2.44E-05
1330207	Xylene	VOC	3.00E-03
1336363	PCB	PM_{10}	5.00E-07
16065831	Chromium III	PM_{10}	3.30E-05
18540299	Chromium VI	PM_{10}	1.70E-05
191242	Benzo[g,h,I,]Perylene	$PM_{2.5}$	5.63E-06
193395	Indeno[1,2,3-c,d]Pyrene	PM_{10}	1.00E-05
205992	Benzo[b]Fluoranthene	PM_{10}	1.00E-05
206440	Fluoranthene	$PM_{2.5}$	1.38E-05
207089	Benzo[k]Fluoranthene	PM_{10}	5.00E-06
208968	Acenaphthylene	$PM_{2.5}$	2.31E-05
218019	Chrysene	$PM_{2.5}$	4.38E-06
50000	Formaldehyde	VOC	9.35E-02
50328	Benzo[a]Pyrene	PM_{10}	5.00E-06
540841	2,2,4-trimethylpentane	VOC	2.50E-04
56553	Benz[a]Anthracene	$PM_{2.5}$	2.50E-05
628	Dioxin	PM_{10}	5.00E-09
71432	Benzene	VOC	1.27E-02
7439965	Manganese	PM_{10}	1.28E-06
7439976	Mercury	PM_{10}	5.00E-08
7440020	Nickel	PM_{10}	1.00E-03
7440382	Arsenic	PM_{10}	3.00E-05
7440439	Cadmium	PM_{10}	5.15E-06
7440473	Chromium	PM_{10}	5.00E-05
75070	Acetaldehyde	VOC	4.64E-02
7782492	Selenium	PM_{10}	5.15E-08
83329	Acenaphthene	$PM_{2.5}$	1.50E-05
85018	Phenanthrene	$PM_{2.5}$	3.50E-05
86737	Fluorene	$PM_{2.5}$	3.06E-05
91203	Naphthalene	$PM_{2.5}$	8.76E-04

Source: U.S. EPA, 2013b

Table A-6. Fleet Makeup and Percent Allocation by Air Carriers

Carrier Name	Percent	Aircraft	Engine
Alaska Airlines, Inc.	6.76%	B737-9	8CM051
Alaska Airlines, Inc.	14.99%	B737-4	1CM007
Alaska Airlines, Inc.	15.26%	B737-7	3CM030
Alaska Airlines, Inc.	63.00%	B737-8	3CM034
Alaska Central Express	100.00%	BEECH1900-C	PT6A6B
Arctic Transportation Services, Inc.	33.33%	CASA212-3	TPE10R
Arctic Transportation Services, Inc.	33.33%	PC12	PT6A67
Arctic Transportation Services, Inc.	33.33%	CNA206	TIO540
Avjet Corporation	3.57%	DC8-7	1PW003
Avjet Corporation	3.57%	GULF200	7PW077
Avjet Corporation	7.14%	B737-7	3CM030
Avjet Corporation	7.14%	GULF3	MK511
Avjet Corporation	7.14%	HS125-8	1AS002
Avjet Corporation	7.14%	IAI1124A	1AS002
Avjet Corporation	21.43%	GULF5	4BR008
Avjet Corporation	42.86%	GULF450	11RR048
Bering Air, Inc.	14.29%	PA31	TIO540
Bering Air, Inc.	14.29%	BEECH1900-D	PT67D
Bering Air, Inc.	14.29%	BEECH200	PT6A42
Bering Air, Inc.	14.29%	CASA212-3	TPE10R
Bering Air, Inc.	14.29%	CNA208	P6114A
Bering Air, Inc.	14.29%	H500D	250B17
Bering Air, Inc.	14.29%	R44	TIO540
ERA Aviation, Inc.	12.50%	BEECH1900-C	PT6A6B
ERA Aviation, Inc.	12.50%	BEECH1900-D	PT67D
ERA Aviation, Inc.	12.50%	CNA206	TIO540
ERA Aviation, Inc.	12.50%	CNA208	P6114A
ERA Aviation, Inc.	12.50%	DHC8-1	PW121
ERA Aviation, Inc.	12.50%	PA31	TIO540
ERA Aviation, Inc.	12.50%	REIMS406	PT6112
ERA Aviation, Inc.	12.50%	SD330	PT6A4R
Frontier Flying Service, Inc.	12.50%	BEECH1900-C	PT6A6B
Frontier Flying Service, Inc.	12.50%	BEECH1900-D	PT67D
Frontier Flying Service, Inc.	12.50%	CNA206	TIO540
Frontier Flying Service, Inc.	12.50%	CNA208	P6114A
Frontier Flying Service, Inc.	12.50%	DHC8-1	PW121
Frontier Flying Service, Inc.	12.50%	PA31	TIO540
Frontier Flying Service, Inc.	12.50%	REIMS406	PT6112
Frontier Flying Service, Inc.	12.50%	SD330	PT6A4R
Hageland Aviation Services, Inc.	12.50%	BEECH1900-C	PT6A6B
Hageland Aviation Services, Inc.	12.50%	BEECH1900-D	PT67D
Hageland Aviation Services, Inc.	12.50%	CNA206	TIO540
Hageland Aviation Services, Inc.	12.50%	CNA208	P6114A
Hageland Aviation Services, Inc.	12.50%	DHC8-1	PW121
Hageland Aviation Services, Inc.	12.50%	PA31	TIO540
Hageland Aviation Services, Inc.	12.50%	REIMS406	PT6112
Hageland Aviation Services, Inc.	12.50%	SD330	PT6A4R
Lynden Air Cargo LLC	100.00%	MIL-C130	T56A15
Miami Air International, Inc.	100.00%	B737-8	3CM034
Northern Air Cargo, Inc.	100.00%	B737-1	1PW012
Tatonduk Outfitters Ltd	2.05%	PC12	PT6A67
Tatonduk Outfitters Ltd	5.34%	DC9-3	1PW007
Tatonduk Outfitters Ltd	10.58%	DC3	R1820
Tatonduk Outfitters Ltd	10.94%	EMB120	PW118
Tatonduk Outfitters Ltd	12.90%	PA32	TIO540

Table A-6. Fleet Makeup and Percent Allocation by Air Carriers (Continued)

Carrier Name	Percent	Aicraft	Engine
Tatonduk Outfitters Ltd	13.36%	CNA208	P6114A
Tatonduk Outfitters Ltd	44.82%	DC6	R1820
Warbelow	100.00%	PA31	TIO540
Wright Air Service, Inc.	5.88%	BEECH36	TIO540
Wright Air Service, Inc.	11.76%	CNA206	TIO540
Wright Air Service, Inc.	17.65%	MIL-U10	TIO540
Wright Air Service, Inc.	17.65%	PA31	TIO540
Wright Air Service, Inc.	47.06%	CNA208	P6114A

Source: FAA, 2011.

Table A-7. Compiled Aircraft Activity Data

Airport	Aircraft	Engine	LTO
Badami	BEECH1900-C	PT6A6B	18
Badami	CNA206	TIO540	142
Badami	CNA208	P6114A	1
Badami	DHC2T	PT6A60	1
Badami	DHC8-1	PW121	20
Badami	MIL-AH1J	T400	17
Badami	MIL-U10	PT6A27	41
Badami	SD330	PT6A4R	1
Barter Island LRRS	PA31	TIO540	127
Barter Island LRRS	BEECH1900-C	PT6A6B	49
Barter Island LRRS	BEECH1900-D	PT67D	49
Barter Island LRRS	CNA206	TIO540	49
Barter Island LRRS	CNA208	P6114A	49
Barter Island LRRS	DHC8-1	PW121	49
Barter Island LRRS	PA31	TIO540	49
Barter Island LRRS	REIMS406	PT6112	49
Barter Island LRRS	SD330	PT6A4R	49
Barter Island LRRS	BEECH1900-D	PT67D	1
Barter Island LRRS	BEECH200	PT6A42	1
Barter Island LRRS	CASA212-3	TPE10R	1
Barter Island LRRS	CNA208	P6114A	1
Barter Island LRRS	H500D	250B17	1
Barter Island LRRS	PA31	TIO540	1
Barter Island LRRS	R44	TIO540	1
Barter Island LRRS	BEECH36	TIO540	2
Barter Island LRRS	CNA206	TIO540	4
Barter Island LRRS	CNA208	P6114A	14
Barter Island LRRS	MIL-U10	TIO540	5
Barter Island LRRS	PA31	TIO540	5
Barter Island LRRS	BEECH1900-C	PT6A6B	141
Barter Island LRRS	BEECH1900-D	PT67D	141
Barter Island LRRS	CNA206	TIO540	141
Barter Island LRRS	CNA208	P6114A	141
Barter Island LRRS	DHC8-1	PW121	141
Barter Island LRRS	PA31	TIO540	141
Barter Island LRRS	REIMS406	PT6112	141
Barter Island LRRS	SD330	PT6A4R	141
Deadhorse	N/A	N/A	24,000
Galbraith Lake	DHC8Q-3	PW123B	80
Helmericks	CNA206	TIO540	10
Kavik River	CNA208	P6114A	10
Kavik River	PA23	TIO540	100
Kavik River	DC3	R1820	6
Kavik River	CNA206	TIO540	30
Kavik River	R44	TIO540	20
Kavik River	MAULE7	TIO540	6
Kavik River	N/A	N/A	6
Kavik River	PC12	PT6A67	1
North Kuparuk	B737-7	3CM030	54
North Kuparuk	DHC6-1	PT6A20	474
North Kuparuk	CASA212-2	TPE10	187
North Kuparuk	CNA441	TPE10	98
North Kuparuk	BEECH1900-C	PT67B	15
North Kuparuk	LEAR35	1AS001	5
North Kuparuk	BEECH200	PT6A42	3
North Kuparuk	B737-2	1PW010	150

Table A-7. Compiled Aircraft Activity Data (Continued)

Airport	Aircraft	Engine	LTO
Nuiqsut	BEECH1900-C	PT6A6B	5
Nuiqsut	BEECH1900-D	PT67D	5
Nuiqsut	CNA206	TIO540	5
Nuiqsut	CNA208	P6114A	5
Nuiqsut	DHC8-1	PW121	5
Nuiqsut	PA31	TIO540	5
Nuiqsut	REIMS406	PT6112	5
Nuiqsut	SD330	PT6A4R	5
Nuiqsut	BEECH1900-C	PT6A6B	107
Nuiqsut	BEECH1900-D	PT67D	107
Nuiqsut	CNA206	TIO540	107
Nuiqsut	CNA208	P6114A	107
Nuiqsut	DHC8-1	PW121	107
Nuiqsut	PA31	TIO540	107
Nuiqsut	REIMS406	PT6112	107
Nuiqsut	SD330	PT6A4R	107
Point Lay	BEECH1900-C	PT6A6B	5
Point Lay	BEECH1900-D	PT67D	5
Point Lay	CNA206	TIO540	5
Point Lay	CNA208	P6114A	5
Point Lay	DHC8-1	PW121	5
Point Lay	PA31	TIO540	5
Point Lay	REIMS406	PT6112	5
Point Lay	SD330	PT6A4R	5
Point Lay	BEECH1900-D	PT67D	1
Point Lay	BEECH200	PT6A42	1
Point Lay	CASA212-3	TPE10R	1
Point Lay	CNA208	P6114A	1
Point Lay	H500D	250B17	1
Point Lay	PA31	TIO540	1
Point Lay	R44	TIO540	1
Point Lay	BEECH36	TIO540	1
Point Lay	CNA206	TIO540	1
Point Lay	CNA208	P6114A	2
Point Lay	MIL-U10	TIO540	1
Point Lay	PA31	TIO540	1
Point Lay	BEECH1900-C	PT6A6B	122
Point Lay	BEECH1900-D	PT67D	122
Point Lay	CNA206	TIO540	122
Point Lay	CNA208	P6114A	122
Point Lay	DHC8-1	PW121	122
Point Lay	PA31	TIO540	122
Point Lay	REIMS406	PT6112	122
Point Lay	SD330	PT6A4R	122
Wainwright	BEECH1900-C	PT6A6B	6
Wainwright	BEECH1900-D	PT67D	6
Wainwright	CNA206	TIO540	6
Wainwright	CNA208	P6114A	6
Wainwright	DHC8-1	PW121	6
Wainwright	PA31	TIO540	6
Wainwright	REIMS406	PT6112	6
Wainwright	SD330	PT6A4R	6
Wainwright	BEECH1900-D	PT67D	1
Wainwright	BEECH200	PT6A42	1
Wainwright	CASA212-3	TPE10R	1
Wainwright	CNA208	P6114A	1

Table A-7. Compiled Aircraft Activity Data (Continued)

Airport	Aircraft	Engine	LTO
Wainwright	H500D	250B17	1
Wainwright	PA31	TIO540	1
Wainwright	R44	TIO540	1
Wainwright	BEECH36	TIO540	1
Wainwright	CNA206	TIO540	1
Wainwright	CNA208	P6114A	1
Wainwright	MIL-U10	TIO540	1
Wainwright	PA31	TIO540	1
Wainwright	BEECH1900-C	PT6A6B	63
Wainwright	BEECH1900-D	PT67D	63
Wainwright	CNA206	TIO540	63
Wainwright	CNA208	P6114A	63
Wainwright	DHC8-1	PW121	63
Wainwright	PA31	TIO540	63
Wainwright	REIMS406	PT6112	63
Wainwright	SD330	PT6A4R	63
Wiley Post	B737-7	3CM030	1
Wiley Post	DC8-7	1PW003	1
Wiley Post	GULF200	7PW077	1
Wiley Post	GULF3	MK511	1
Wiley Post	GULF450	11RR048	1
Wiley Post	GULF5	4BR008	1
Wiley Post	HS125-8	1AS002	1
Wiley Post	IAI1124A	1AS002	1
Wiley Post	PA31	TIO540	30
Wiley Post	BEECH1900-C	PT6A6B	6
Wiley Post	BEECH1900-D	PT67D	6
Wiley Post	CNA206	TIO540	6
Wiley Post	CNA208	P6114A	6
Wiley Post	DHC8-1	PW121	6
Wiley Post	PA31	TIO540	6
Wiley Post	REIMS406	PT6112	6
Wiley Post	SD330	PT6A4R	6
Wiley Post	CASA212-3	TPE10R	1
Wiley Post	CNA206	TIO540	1
Wiley Post	PC12	PT6A67	1
Wiley Post	BEECH1900-D	PT67D	1
Wiley Post	BEECH200	PT6A42	1
Wiley Post	CASA212-3	TPE10R	1
Wiley Post	CNA208	P6114A	1
Wiley Post	H500D	250B17	1
Wiley Post	PA31	TIO540	1
Wiley Post	R44	TIO540	1
Wiley Post	B737-4	1CM007	645
Wiley Post	B737-7	3CM030	657
Wiley Post	B737-8	3CM034	2,713
Wiley Post	B737-9	8CM051	291
Wiley Post	B737-8	3CM034	167
Wiley Post	BEECH1900-C	PT6A6B	181
Wiley Post	BEECH1900-D	PT67D	181
Wiley Post	CNA206	TIO540	181
Wiley Post	CNA208	P6114A	181
Wiley Post	DHC8-1	PW121	181
Wiley Post	PA31	TIO540	181
Wiley Post	REIMS406	PT6112	181
Wiley Post	SD330	PT6A4R	181

Sources: BTS, 2014; FAA, 2013

Table A-8. Taxi and Out Times by Airport and Aircraft

Airport	Aircraft	EDMS Aircraft	EDMS Engine	Average Time on Ground (Min)	Count	Taxi Out (Min)	Taxi In (Min)
Badami	Agusta SPA AB139	MIL-AH1J	T400	13.25	16	9.7	3.6
Badami	AgustaBell AW 139	MIL-AH1J	T400	13.25	16	9.7	3.6
Badami	AgustaWestland AW 139	MIL-AH1J	T400	13.25	16	9.7	3.6
Badami	Beechcraft 1900C	BEECH1900-C	PT6A6B	19.25	16	14.1	5.2
Badami	Cessna Caravan	CNA208	P6114A	14	1	10.2	3.8
Badami	Cessna TU206C	CNA206	TIO540	11.93	60	8.7	3.2
Badami	de Havilland Beaver*	DHC2T	PT6A60	**15.54**	0	11.3	4.2
Badami	de Havilland DHC-8-103	DHC8-1	PW121	29.76	17	21.7	8
Badami	Helio Courier	MIL-U10	PT6A27	13.39	23	9.8	3.6
Badami	Short 330 Sherpa	SD330	PT6A4R	92	1	67.2	24.8
North Kuparuk	N/A	N/A	N/A	5	N/A	3	2

* No times were provided by the airport personnel; estimates were made based on aggregated averages of all aircraft at Badami.

Sources: Henning, 2014; Tupper, 2014

Table A-9. 2012 Subpart W North Slope Onshore Production Emissions (tons/yr)

Facility	CO_2	CH_4	N_2O
Badami Development Facility	420		
BP Alaska, 890 - Arctic Slope Basin	36,630	1.49	0.30
ConocoPhillips Alaska Inc - KRU-ALP Fields	42,404	1.74	0.35
Nikaitchuq Development	12,836	0.52	0.10

Table A-10. Well Completion Emissions

Pollutant	Emissions (tons/yr)
VOC	309.60
CO_2	24.42
CH_4	636.40
2,2,4-Trimethlypentane	2.90
Benzene	3.73
Ethylbenzene	0.83
n-Hexane	6.88
Toluene	1.46
Xylenes	0.46
H_2S	0.053

Table A-11. Oil and Gas Point Source Facility Emissions in the 2011 NEI[a] (tons/yr)

Facility Name	VOC	NO_x	CO	SO_2	PM_{10}
Alpine Central Processing Facility	28.33	1,098.82	266.82	18.75	32.28
Badami Development Facility (formerly BPXA)	2.44	134.26	159.53	1.93	3.47
Base Operations Center	0.11	3.94	0.89	0.04	0.11
Central Compressor Plant	49.10	8,440.35	1,173.55	117.11	156.13
Central Gas Facility	39.20	5,961.07	835.66	82.00	122.20
Crude Oil Topping Unit	0.55	10.09	10.91	0.51	0.84
Endicott Production Facility	26.13	1,500.49	149.71	199.84	35.96
Flow Station #1 (FS 1)	11.79	1,300.01	565.20	18.11	42.12
Flow Station #2 (FS 2)	9.71	1,281.09	422.58	40.12	32.57
Flow Station #3 (FS 3)	11.09	1,853.90	508.87	23.58	37.97
Gathering Center #1 (GC 1)	14.37	1,718.55	566.91	19.15	45.74
Gathering Center #2 (GC 2)	10.35	937.08	272.65	12.94	29.48
Gathering Center #3 (GC 3)	7.00	839.17	258.92	11.23	20.99
Kuparuk Central Production Facility #1 (CPF1)	48.18	1,932.93	252.48	60.22	56.19
Kuparuk Central Production Facility #2 (CPF2)	27.38	1,587.57	163.51	55.40	49.03
Kuparuk Central Production Facility #3 (CPF3)	19.56	1,008.08	556.04	79.75	40.34
Kuparuk Seawater Treatment Plant	3.89	87.54	6.10	7.89	3.71
Lisburne Production Center	21.44	1,410.74	694.26	79.68	59.47
Milne Point Production Facility	13.55	738.61	108.10	5.53	14.22
Nikaitchuq Development	34.80	191.89	84.42	22.70	10.53
Northstar Production Facility	11.22	345.93	129.50	17.65	27.43
Oooguruk Development Project	14.57	175.48	138.89	8.29	22.41
PBU Central Power Station	13.81	2,359.60	300.68	31.38	42.55
Prudhoe Bay Operations Center / Main Construction Camp	0.40	8.60	6.19	0.36	0.57
Seawater Injection Plant East	3.27	707.75	101.54	7.20	9.33
Seawater Treatment Plant, Prudhoe Bay Unit (STP)	6.01	89.45	68.03	5.72	8.30

Source: U.S. EPA, 2013b. These emissions are from Version 1 of the 2011 NEI. ERG will monitor availability of the Version 2, and will advise BOEM of any future changes.that might affect the emissions inventory in the future.

Table A-12. Non-NEI Facility Emissions Estimates (tons/yr)

Facility Name	VOC	NO_x	CO	SO_2	PM_{10}
Badami RTU 3 Flare Project	2.55	3.94	16.19	1.72	1.21
BPXA Greater Prudhoe Bay Skid 50 Pad Transfer Station – Generator	1.23	21.87	3.55	0.90	1.49
BPXA Milne Point S Pad (CHOPS)	1.23	21.87	3.55	0.90	1.49
ConocoPhilips Drill Site #S Palm Development Project	13.91	10.76	1.75	0.44	0.73
ConocoPhilips Meltwater Development Project	37.22	19.46	3.16	0.80	1.33
ConocoPhilips Tarn Development Project	36.75	11.22	1.82	0.46	0.76
Grind and Inject Facility (BPXA)	0.33	8.54	5.36	0.34	0.61
Nanuq Inc Arctic Wolf Camp	1.18	20.95	3.40	0.86	1.43
Northstar Caribou Crossing Compressor Facility	1.37	17.33	67.15	1.07	0.84

Table A-13. Smaller Emitting Unit and Nonroad Engine Emissions Estimates for NEI Facilities (tons/yr)

Facility Name	VOC	NO_x	CO	SO_2	PM_{10}
Alpine Central Processing Facility	20.05	338.98	55.46	3.44	46.50
Badami Development Facility (formerly BPXA)	3.06	322.77	86.71	1.16	0.78
Base Operations Center (BOC)	0.03	0.94	0.13	0.01	0.03
Central Compressor Plant (CCP)	0.07	1.11	0.98	0.02	0.10
Central Gas Facility (CGF)	0.00	0.09	0.03	0.01	0.01
CPF 1, Kuparuk Central Production Facility #1	14.55	463.16	35.72	8.40	13.35
CPF 2, Kuparuk Central Production Facility #2	40.05	376.52	25.68	22.65	26.27
CPF 3, Kuparuk Central Production Facility #3	39.52	284.75	104.93	36.73	24.96
Crude Oil Topping Unit	0.01	0.60	0.07	0.04	0.05
Endicott Production Facility	3.79	112.93	9.00	0.06	7.78
Flow Station #1 (FS 1)	3.56	311.50	79.96	2.53	10.00
Flow Station #2 (FS 2)	14.98	173.63	36.83	5.79	12.40
Flow Station #3 (FS 3)	3.35	444.22	71.99	3.29	9.02
Gathering Center #1 (GC 1)	4.34	411.79	80.20	2.67	10.86
Gathering Center #2 (GC 2)	8.83	236.35	49.58	2.21	16.18
Gathering Center #3 (GC 3)	2.11	201.08	36.63	1.57	4.99
Kuparuk Seawater Treatment Plant (STP)	1.17	20.98	0.86	1.10	0.88
Lisburne Production Center (LPC)	17.13	317.85	100.19	8.91	31.94
Milne Point Production Facility (MPU)	1.19	192.87	11.57	3.72	5.84
Nikaitchuq Development	11.13	1,068.88	165.91	1.69	6.60
Northstar Production Facility (NOR)	1.29	49.21	2.80	0.49	3.49
Oooguruk Development Project	13.57	312.51	37.04	1.72	8.35
PBU Central Power Station (CPS)	4.17	565.40	42.54	4.38	10.11
Prudhoe Bay Operations Center / Main Construction Camp (PBOC/MCC)	0.12	2.06	0.88	0.05	0.14
Seawater Injection Plant East (SIPE)	0.99	169.59	14.37	1.00	2.22
Seawater Treatment Plant, Prudhoe Bay Unit (STP)	1.81	21.43	9.62	0.80	1.97

Table A-14. Subpart W Onshore Natural Gas Processing Emissions (tons/yr)

Pollutant	Centrifugal Compressors	Dehydrators	Equipment Leaks	Flares
Benzene	2.15	NA[a]	1.79	NA[a]
CH_4	1,512	7.70	1,260	1,693
CO_2	1,317	3,163	577	332,196
Ethylbenzene	0.13	NA[a]	0.11	NA[a]
Toluene	1.92	NA[a]	1.60	NA[a]
VOC	240	NA[a]	200	NA[a]
Xylenes	0.54	NA[a]	0.45	NA[a]
H_2S	0.12	0	0.10	0

[a] Note applicable. Benzene, toluene, ethylbenzene, xylene, and VOC emissions from these source types covered under the NEI and ADEC permit data.

Source: U.S. EPA, 2014b

Table A-15. Subpart C North Slope Oil and Gas Facility Emissions

Facility	CO_2	CH_4	N_2O
BPXA Central Compressor Plant	2,858,258	48.35	4.84
BPXA Central Gas Facility	2,059,378	34.81	3.49
BPXA Endicott Production Facility	716,629	11.41	1.15
BPXA Lisburne Production Center	628,393	10.62	1.06
BPXA Northstar Production Facility	302,378	5.83	0.59
BPXA Crude Oil Topping Unit, Prudhoe Bay Operations Center, Tarmac Camp	29,731	0.51	0.06
BPXA Flow Station #1	484,264	8.16	0.83
BPXA Flow Station #2	544,565	9.11	0.92
BPXA Flow Station #3	663,281	11.21	1.12
BPXA Gathering Center #1	457,870	8.63	0.86
BPXA Gathering Center #2	459,011	8.65	0.87
BPXA Gathering Center #3	331,411	6.26	0.63
BPXA Seawater Injection Plant	239,785	4.06	0.41
TBPXA Seawater Treatment Plant	193,145	3.26	0.33
ConocoPhillips Alaska Inc - KRU CPF1	584,457	12.10	1.33
ConocoPhillips Alaska Inc - KRU CPF2	359,426	6.78	0.68
ConocoPhillips Alaska Inc - KRU CPF3	354,914	6.70	0.67
ConocoPhillips Alaska Inc - KRU STP	86,015	1.62	0.16
Pioneer Natural Resources Alaska - Oooguruk Tie-in Pad	45,059	0.85	0.08

[a] CAP and HAP pollutant emission estimates for these combustion sources are covered under the NEI and ADEC permit data.

Source: U.S. EPA, 2014a

Table A-16. 2012 North Slope Village Power Plant Fuel Use – Distillate Heating Oil (gallons)

	Anaktuvuk Pass	Atqasuk	Kaktovik	Nuiqsut	Point Hope	Point Lay	Wainwright
January	29,212	25,156	35,165	24,746	42,736	27,783	46,174
February	26,942	22,761	30,938	12,739	36,570	25,125	43,540
March	29,845	24,683	33,498	3,980	41,636	27,726	48,147
April	25,412	22,469	29,877	0	30,833	24,535	39,749
May	25,160	20,900	28,803	307	32,441	21,445	37,606
June	21,869	18,411	25,991	246	26,569	19,306	35,650
July	22,523	20,001	26,234	15,004	28,163	20,191	37,707
August	22,569	20,262	27,729	16,626	32,587	20,928	36,626
September	23,584	19,376	28,254	819	34,565	21,439	30,474
October	25,696	21,331	30,051	2,191	33,562	23,720	35,464
November	27,567	23,016	30,558	13,437	36,846	24,237	41,613
December	29,334	25,196	32,461	17,523	42,715	26,283	46,211
Total	**309,713**	**263,562**	**359,559**	**107,618**	**419,223**	**282,718**	**478,961**

Sources: Williams, 2014, except for emissions for Point Hope and Wainwright power plants (U.S. EPA, 2013b)

Table A-17. 2012 North Slope Village School Fuel Use – Distillate Heating Oil (gallons)

	Nunamiat School (Anaktuvuk Pass)	Meade River School (Atqasuk)	Harold Kaveolook School (Kaktovik)	Nuiqsut Trapper School (Nuiqsut)[a]	Tikigaq School (Point Hope)	Kari School (Point Lay)	Alak School (Wainwright)
January	1,226	4,634	7,845		9,106	4,915	12,330
February		3,884	5,197		9,384	5,154	6,053
March	2,485	12,656	6,482	794	8,328	6,259	9,742
April	1,714	7,632	3,560		7,332	7,815	8,758
May		2,749	3,449		4,690	3,175	6,980
June		3,898	3,323		723	2,700	6,158
July			2,504		18		23
August			3,457		2,740	850	6,527
September			1,952		2,368		6,932
October	5,577	976	4,132		3,013	4,286	6,364
November	4,345	928	4,603		3,690	6,833	7,186
December	7,146	7,380	7,305		7,693	5,185	6,395
Total	22,493	44,737	53,809	794	59,085	47,172	83,448

[a] Distillate fuel use at Nuiqsut Trapper School is limited because of the availability of natural gas in Nuiqsut.
Source: Slatton, 2014a.

Table A-18. 2012 North Slope Natural Gas Use (mscf)

	Barrow					
	Non-Federal Generation (BUECI Power Plant)[a]	Non-Federal Users (Residential)	Federal Users (Commercial/ Institutional)	UIC/NARL Water Plant	Aeronautical Radio[b]	Nuiqsut[c]
January	76,039	82,774	3,392	10,482		11,000
February	69,576	72,621	3,721	8,891		12,288
March	73,539	86,262	3,357	10,887		12,222
April	65,071	59,731	3,383	7,400		11,139
May	57,509	47,120	2,174	5,282		8,418
June	53,157	34,948	1,504	3,275		6,038
July	52,959	27,452	1,282	2,762		5,811
August	53,732	24,934	1,231	2,808		5,175
September	52,595	36,139	1,394	3,748		6,417
October	58,937	45,636	1,394	5,281		7,843
November	66,340	59,903	2,638	7,653		11,339
December	78,024	74,526	3,108	9,747		12,646
Total	757,478	652,046	28,578	78,216	27,835	110,335

[a] Emissions for the BUECI Power Plant were obtained from the 2011 NEI (U.S. EPA, 2013b) and were not estimated using these data.
[b] Aeronautical Radio, Inc. natural gas usage was not available on a monthly basis, but was derived from five periodic invoices.
[c] Nuiqsut natural gas usage was not available for 2012; 2013 data were assumed to be representative of 2012.
Source: Nesteby, 2014; Slatton, 2014a.

Table A-19. 2012 North Slope Village Residential Fuel Use – Distillate Heating Oil (gallons)

	Anaktuvuk Pass	Atqasuk	Kaktovik	Nuiqsut	Point Hope	Point Lay	Wainwright
January	7,417	7,239	12,017	844	32,524	4,990	19,336
February	6,850	6,911	8,652	966	21,584	6,185	14,351
March	13,258	7,523	9,240	1,069	24,728	7,651	18,923
April	5,263	5,433	5,287	0	16,093	3,903	14,220
May	0	4,458	5,319	0	11,352	2,131	8,347
June	0	2,325	1,268	0	6,836	1,609	4,742
July	0	1,128	1,025	0	5,123	597	3,896
August	0	2,074	2,549	0	7,550	1,779	5,273
September	0	2,670	3,125	0	8,993	1,802	6,108
October	7,618	4,969	6,845	0	12,770	4,839	10,052
November	7,506	5,344	4,247	0	15,181	4,044	13,135
December	13,784	6,977	10,234	0	25,554	5,288	19,552
Total	61,696	57,051	69,808	2,879	188,288	44,818	137,935

Source: Slatton, 2014a

Table A-20. 2012 Barrow AADT Statistics and VMT Calculations

Street Description	AADT	Length (miles)	VMT (Daily)
Stevenson (between Ahkovak and Ilisagvik entrance)	1,795	2.2	3,949
Ahkovak (between Stevenson and D)	3,600	0.8	2,880
Laura Madison (between Ahkovak and Qaiyaan)	2,670	0.7	1,869
Eben Hopson (between Stevenson and Brower)	4,575	0.4	1,830
Okpik (between Kiogak and D)	1,375	0.8	1,100
Stevenson (between Apayauk and Eben Hopson)	2,070	0.5	1,035
Laura Madison (between Ahkovak and Tahak)	4,225	0.2	845
Stevenson/Brower (between Eben Hopson and Ahkovak)	1,500	0.5	750
Momegana (between Ogrook and Agvik)	2,160	0.3	648
Ahkovak (between Okpik and D)	1,625	0.3	488
Karluk (between Tahak and Ahmaogak)	670	0.7	469
Eben Hopson/Laura Madison (between Brower and Tahak)	2,250	0.1	225
Eben Hopson (between Kiogak and Stevenson)	750	0.1	75
Total			16,163

Source: ADOT&PF, 2014

Table A-21. 2013 Fiscal Year North Slope Village Landfill Open Burning Quantities (tons)[a,b]

	Anaktuvuk Pass	Atqasuk	Kaktovik	Nuiqsut	Point Hope	Point Lay	Wainwright
July 2012	0	52	127	225	192	19	222
August 2012	22	83	54	297	420	0	117
September 2012	56	75	46	219	560	37	12
October 2012	0	70	99	272	726	76	58
November 2012	35	48	37	262	551	38	35
December 2012	0	0	85	262	0	40	35
January 2013	0	52	40	149	0	78	35
February 2013	0	70	14	245	179	29	32
March 2013	0	53	61	272	534	65	14
April 2013	0	87	63	311	161	0	58
May 2013	18	52	60	222	27	37	32
June 2013	0	52	26	359	52	201	56
Total FY 2013	**131**	**694**	**712**	**3,095**	**3,402**	**620**	**706**

[a] Landfill burning quantities were calculated as the difference between the amount of waste hauled and the amount of waste landfilled.

[b] Landfill burning quantities were not available for calendar year 2012; fiscal year 2013 data were assumed to be representative of calendar year 2012.

Source: Heath, 2014

Table A-22. Point Sources Data Fields

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
STATE_COUNTY_FIPS	Y	Y	TEXT	5	Populate with "02185"
STATE_FACILITY_IDENTIFIER	Y	Y	TEXT	25	Local facility identifier
EIS_FACILITY_IDENTIFIER	N	N	TEXT	25	Emission Inventory System facility identifier
FACILITY_REGISTRY_IDENTIFIER	N	N	TEXT	25	Facility Registry System facility identifier
TRI_IDENTIFIER	N	N	TEXT	25	Toxic Release Inventory identifier
PERMIT_IDENTIFIER	N	N	TEXT	25	ADEC permit identifier for the facility
FACILITY_NAME	N	Y	TEXT	80	Name of facility
FACILTY_DESCRIPTION	N	N	TEXT	80	Description of the facility (e.g., Electricity Generating Unit)
NAICS_PRIMARY	N	N	TEXT	10	North American Industrial Classification System identifier
LOCATION_ADDRESS	N	Y	TEXT	25	Address of the facility
CITY	N	Y	TEXT	40	City name
STATE_ABBR	N	Y	TEXT	2	2-digit state abbreviation; populate with "AK"
ZIPCODE	N	Y	TEXT	10	5 or 9-digit zip code
EMISSION_UNIT_IDENTIFIER	Y	Y	TEXT	25	Emission unit identifier
EMISSION_UNIT_DESCRIPTION	N	N	TEXT	40	Description of the emission unit
EMISSION_UNIT_PERMIT_IDENTIFIER	N	N	TEXT	25	ADEC permit identifier for the emission unit
PROCESS_IDENTIFIER	Y	Y	TEXT	25	Emission process identifier
PROCESS_DESCRIPTION	N	N	TEXT	40	Description of the emission process
PROCESS_PERMIT_IDENTIFIER	N	N	TEXT	25	ADEC permit identifier for the emission process
SCC	N	Y	TEXT	10	Source Classification Code for the emission process
THROUGHPUT_VALUE	N	N	NUMERIC	Single	Activity data value to estimate emissions
THROUGHPUT_UOM	N	N	TEXT	15	Unit of Measure for the throughput value
THROUGHPUT_MATERIAL	N	N	TEXT	40	Material for the throughput (e.g. "natural gas consumed")
EMISSION_RELEASE_POINT_IDENTIFIER	Y	Y	TEXT	15	Emission release point identifier
EMISSION_RELEASE_POINT_DESCRIPTION	N	N	TEXT	40	Description of the emission release point
EMISSION_RELEASE_POINT_PERMIT_IDENTIFIER	N	N	TEXT	15	ADEC permit identifier for the emission release point
EMISSION_RELEASE_POINT_TYPE	N	Y	TEXT	25	Type of emission release point (e.g., stack, fugitive)
EMISSION_RELEASE_POINT_ANGLE	N	Y	NUMERIC	Single	For stack releases, angle of release (e.g., 0 degrees = horizontal; 90 degrees = vertical)

Table A-22. Point Sources Data Fields (Continued)

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
STACK_HEIGHT	N	Y	NUMERIC	Single	Height of the stack from the ground in feet
EXIT_GAS_TEMPERATURE	N	Y	NUMERIC	Single	Exit gas temperature of the stack in degrees Fahrenheit
STACK_DIAMETER	N	Y	NUMERIC	Single	Diameter of the stack in inches
EXIT_GAS_VELOCITY	N	Y	NUMERIC	Single	Exit gas velocity of the stack in feet per second
EXIT_GAS_FLOW_RATE	N	Y	NUMERIC	Single	Flowrate of the stack gas in cubic feet per second
FUGITIVE_LENGTH_SIGMAX_FT	N	Y	NUMERIC	Single	For fugitive releases, length of the area in feet
FUGITIVE_WIDTH_SIGMAY_FT	N	Y	NUMERIC	Single	For fugitive releases, width of the area in feet
FUGITIVE_ANGLE_DEGREES	N	Y	NUMERIC	Single	For fugitive releases, angle of release (e.g., 0 degrees = horizontal; 90 degrees = vertical)
X_COORDINATE	N	Y	NUMERIC	Double	Longitude in decimal degrees
Y_COORDINATE	N	Y	NUMERIC	Double	Latitude in decimal degrees
YEAR	Y	Y	TEXT	4	Year of emissions estimate
POLLUTANT_CODE	Y	Y	TEXT	20	CAS Number of the pollutant or criteria pollutant abbreviation
POLLUTANT_DESCRIPTION	N	Y	TEXT	80	Pollutant Name
EMISSION_FACTOR_NUMERATOR	N	N	NUMERIC	Double	Emission factor value
EMISSION_FACTOR_NUMERATOR_UOM	N	N	TEXT	15	Unit of Measure for the numerator of the emission factor (e.g., "LB")
EMISSION_FACTOR_DENOMINATOR_UOM	N	N	TEXT	15	Unit of Measure for the denominator of the emission factor (e.g., "TON")
EMISSIONS_TPY	N	Y	NUMERIC	Double	Emissions of the pollutant in tons per year
EMISSIONS_TYPE	Y	Y	TEXT	25	Type of emissions (e.g., actual, permitted, allowable)
MODELED_DATA	N	N	TEXT	25	Name of Emissions Model, if applicable
CONTROL_STATUS	N	N	TEXT	25	Control status of the emission (e.g., Controlled, Uncontrolled)
CONTROL_DEVICE_1_TYPE	N	N	TEXT	50	Primary control device
CONTROL_DEVICE_1_EFFICIENCY	N	N	NUMERIC	Single	Primary control device efficiency in percent
CONTROL_DEVICE_2_TYPE	N	N	TEXT	50	Secondary control device
CONTROL_DEVICE_2_EFFICIENCY	N	N	NUMERIC	Single	Secondary control device efficiency in percent
CONTROL_DEVICE_3_TYPE	N	N	TEXT	50	Third control device
CONTROL_DEVICE_3_EFFICIENCY	N	N	NUMERIC	Single	Third control device efficiency in percent
CONTROL_DEVICE_4_TYPE	N	N	TEXT	50	Fourth control device
CONTROL_DEVICE_4_EFFICIENCY	N	N	NUMERIC	Single	Fourth control device efficiency in percent

Table A-23. Nonpoint Sources Data Fields

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
STATE_COUNTY_FIPS	Y	Y	TEXT	5	Populate with "02185"
SUB_COUNTY_AREA	Y	Y	TEXT	40	City/community name; census tract; or shape identifier
SUB_COUNTY_AREA_TYPE	N	Y	TEXT	40	Describes the type of sub-county area
STATE_ABBR	N	Y	TEXT	2	2-digit state abbreviation; populate with "AK"
SCC	Y	Y	TEXT	10	Source Classification Code for the emission process
THROUGHPUT_VALUE	N	N	NUMERIC	Single	Activity data value to estimate emissions
THROUGHPUT_UOM	N	N	TEXT	15	Unit of Measure for the throughput value
THROUGHPUT_MATERIAL	N	N	TEXT	40	Material for the throughput (e.g. "natural gas consumed")
YEAR	Y	Y	TEXT	4	Year of emissions estimate
POLLUTANT_CODE	Y	Y	TEXT	20	CAS Number of the pollutant or criteria pollutant abbreviation
POLLUTANT_DESCRIPTION	N	Y	TEXT	80	Pollutant Name
EMISSION_FACTOR_NUMERATOR	N	N	NUMERIC	Double	Emission factor value
EMISSION_FACTOR_NUMERATOR_UOM	N	N	TEXT	15	Unit of Measure for the numerator of the emission factor (e.g., "LB")
EMISSION_FACTOR_DENOMINATOR_UOM	N	N	TEXT	15	Unit of Measure for the denominator of the emission factor (e.g., "TON")
EMISSIONS_TPY	N	Y	NUMERIC	Double	Emissions of the pollutant in tons per year
EMISSIONS_TYPE	Y	Y	TEXT	25	Type of emissions (e.g., actual, permitted, allowable)
MODELED_DATA	N	N	TEXT	25	Name of Emissions Model, if applicable
CONTROL_STATUS	N	N	TEXT	25	Control status of the emission (e.g., Controlled, Uncontrolled)
CONTROL_DEVICE_1_TYPE	N	N	TEXT	50	Primary control device
CONTROL_DEVICE_1_EFFICIENCY	N	N	NUMERIC	Single	Primary control device efficiency in percent
CONTROL_DEVICE_2_TYPE	N	N	TEXT	50	Secondary control device
CONTROL_DEVICE_2_EFFICIENCY	N	N	NUMERIC	Single	Secondary control device efficiency in percent
CONTROL_DEVICE_3_TYPE	N	N	TEXT	50	Third control device
CONTROL_DEVICE_3_EFFICIENCY	N	N	NUMERIC	Single	Third control device efficiency in percent
CONTROL_DEVICE_4_TYPE	N	N	TEXT	50	Fourth control device
CONTROL_DEVICE_4_EFFICIENCY	N	N	NUMERIC	Single	Fourth control device efficiency in percent

Table A-24. Onroad Sources Data Fields

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
STATE_COUNTY_FIPS	Y	Y	TEXT	5	Populate with "02185"
SUB_COUNTY_AREA	Y	Y	TEXT	40	City/community name; census tract; or shape identifier
SUB_COUNTY_AREA_TYPE	N	Y	TEXT	40	Describes the type of sub-county area
STATE_ABBR	N	Y	TEXT	2	2-digit state abbreviation; populate with "AK"
SCC	Y	Y	TEXT	10	Source Classification Code for the emission process
THROUGHPUT_VALUE	N	N	NUMERIC	Single	Activity data value to estimate emissions
THROUGHPUT_UOM	N	N	TEXT	15	Unit of Measure for the throughput value
THROUGHPUT_MATERIAL	N	N	TEXT	40	Material for the throughput (e.g. "natural gas consumed")
YEAR	Y	Y	TEXT	4	Year of emissions estimate
POLLUTANT_CODE	Y	Y	TEXT	20	CAS Number of the pollutant or criteria pollutant abbreviation
POLLUTANT_DESCRIPTION	N	Y	TEXT	80	Pollutant Name
EMISSION_FACTOR_NUMERATOR	N	N	NUMERIC	Double	Emission factor value
EMISSION_FACTOR_NUMERATOR_UOM	N	N	TEXT	15	Unit of Measure for the numerator of the emission factor (e.g., "LB")
EMISSION_FACTOR_DENOMINATOR_UOM	N	N	TEXT	15	Unit of Measure for the denominator of the emission factor (e.g., "TON")
EMISSIONS_TPY	N	Y	NUMERIC	Double	Emissions of the pollutant in tons per year
EMISSIONS_TYPE	Y	Y	TEXT	25	Type of emissions (e.g., actual, permitted, allowable)
MODELED_DATA	N	N	TEXT	25	Name of Emissions Model, if applicable
CONTROL_STATUS	N	N	TEXT	25	Control status of the emission (e.g., Controlled, Uncontrolled)
CONTROL_DEVICE_1_TYPE	N	N	TEXT	50	Primary control device

Table A-24. Onroad Sources Data Fields (Continued)

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
CONTROL_DEVICE_1_EFFICIENCY	N	N	NUMERIC	Single	Primary control device efficiency in percent
CONTROL_DEVICE_2_TYPE	N	N	TEXT	50	Secondary control device
CONTROL_DEVICE_2_EFFICIENCY	N	N	NUMERIC	Single	Secondary control device efficiency in percent
CONTROL_DEVICE_3_TYPE	N	N	TEXT	50	Third control device
CONTROL_DEVICE_3_EFFICIENCY	N	N	NUMERIC	Single	Third control device efficiency in percent
CONTROL_DEVICE_4_TYPE	N	N	TEXT	50	Fourth control device
CONTROL_DEVICE_4_EFFICIENCY	N	N	NUMERIC	Single	Fourth control device efficiency in percent

Table A-25. Nonroad Sources Data Fields

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
STATE_COUNTY_FIPS	Y	Y	TEXT	5	Populate with "02185"
SUB_COUNTY_AREA	Y	Y	TEXT	40	City/community name; census tract; or shape identifier
SUB_COUNTY_AREA_TYPE	N	Y	TEXT	40	Describes the type of sub-county area
STATE_ABBR	N	Y	TEXT	2	2-digit state abbreviation; populate with "AK"
SCC	Y	Y	TEXT	10	Source Classification Code for the emission process
THROUGHPUT_VALUE	N	N	NUMERIC	Single	Activity data value to estimate emissions
THROUGHPUT_UOM	N	N	TEXT	15	Unit of Measure for the throughput value
THROUGHPUT_MATERIAL	N	N	TEXT	40	Material for the throughput (e.g. "natural gas consumed")
YEAR	Y	Y	TEXT	4	Year of emissions estimate
POLLUTANT_CODE	Y	Y	TEXT	20	CAS Number of the pollutant or criteria pollutant abbreviation
POLLUTANT_DESCRIPTION	N	Y	TEXT	80	Pollutant Name
EMISSION_FACTOR_NUMERATOR	N	N	NUMERIC	Double	Emission factor value
EMISSION_FACTOR_NUMERATOR_UOM	N	N	TEXT	15	Unit of Measure for the numerator of the emission factor (e.g., "LB")
EMISSION_FACTOR_DENOMINATOR_UOM	N	N	TEXT	15	Unit of Measure for the denominator of the emission factor (e.g., "TON")
EMISSIONS_TPY	N	Y	NUMERIC	Double	Emissions of the pollutant in tons per year
EMISSIONS_TYPE	Y	Y	TEXT	25	Type of emissions (e.g., actual, permitted, allowable)
MODELED_DATA	N	N	TEXT	25	Name of Emissions Model, if applicable

Table A-25. Nonroad Sources Data Fields (Continued)

FIELD_NAME	PRIMARY_KEY	REQUIRED	FIELD_TYPE	FIELD_SIZE	FIELD_DESCRIPTION
CONTROL_STATUS	N	N	TEXT	25	Control status of the emission (e.g., Controlled, Uncontrolled)
CONTROL_DEVICE_1_TYPE	N	N	TEXT	50	Primary control device
CONTROL_DEVICE_1_EFFICIENCY	N	N	NUMERIC	Single	Primary control device efficiency in percent
CONTROL_DEVICE_2_TYPE	N	N	TEXT	50	Secondary control device
CONTROL_DEVICE_2_EFFICIENCY	N	N	NUMERIC	Single	Secondary control device efficiency in percent
CONTROL_DEVICE_3_TYPE	N	N	TEXT	50	Third control device
CONTROL_DEVICE_3_EFFICIENCY	N	N	NUMERIC	Single	Third control device efficiency in percent
CONTROL_DEVICE_4_TYPE	N	N	TEXT	50	Fourth control device
CONTROL_DEVICE_4_EFFICIENCY	N	N	NUMERIC	Single	Fourth control device efficiency in percent